North Sea Transition Authority

Emissions Monitoring Report

2022

Contents

The North Sea Transition Authority (NSTA), formerly the Oil and Gas Authority, is tasked with optimising UK oil and gas production while driving North Sea energy transition, realising the enormous potential of the UK Continental Shelf (UKCS) as a critical energy and carbon abatement resource.

The NSTA regulates and influences the oil and gas and carbon storage industries. This pivotal role is reflected by its revised Strategy, which came into force in February 2021 and obliges industry to help the UK Government reach its 2050 net zero target while continuing to provide secure supplies of domestic energy. An example of the Strategy in action followed one month later with the introduction of Stewardship Expectation 11 – Net Zero, which requires licensees to develop and implement Emissions Reduction Action Plans (ERAPs) for their operations.

The North Sea Transition Deal (NSTD), signed by the UK Government and industry in March 2021, supports the NSTA's approach and sets bold targets to cut upstream emissions – by 10% by 2025, 25% by 2027, and 50% by 2030, against a 2018 baseline. Achieving these goals is the absolute minimum the NSTA expects from industry, which should be ambitious and aim to surpass them.

As part of its commitment to hold industry to account on the NSTD targets, the NSTA published its first Emissions Monitoring Report in October 2021. These yearly reports bring together in one place data on United

Kingdom Continental Shelf (UKCS) emissions reductions, methane emissions, performance benchmarking, and flaring and venting.

Key findings of the 2022 Emissions Monitoring Report:

- The NSTA estimates that total upstream greenhouse gas (GHG) emissions declined by 14.6% in 2021, resulting in an estimated overall reduction relative to 2018 of 21.5%[1].
- 79% of offshore facilities reduced emissions between 2020 and 2021.
- Combustion of hydrocarbons for power generation was the main source of UKCS upstream GHG emissions between 2018 and 2020, making up 71%, followed by flaring, 22%, venting, 4%, and other non-combustion processes, 3%.
- The average carbon intensity of offshore assets increased from 20.7 to 21.2 kgCO_2e between 2020 and 2021 due to a drop in production; this remains below the 21.6 recorded in 2018.
- Total offshore natural gas flared volumes fell by 20.1% between 2020 and 2021. Offshore vented gas dropped by 22.2% relative to 2020.

For the UKCS upstream industry, 2021 was a challenging period as operations continued to be disrupted and subdued amid the COVID-19 pandemic. In addition, platform shutdowns and major maintenance activities resulted in a large number of installations halting production during late spring and early summer. The resulting temporary reduction in activity levels, coupled with proactive efforts to decarbonise, was reflected in Environmental Emissions and Monitoring System (EEMS) and UK Emissions

[1] Updated data from the National Atmospheric Emissions Inventory shows that UK upstream oil and gas industry GHG emissions decreased by 8.1% between 2018 and 2020. Official figures for 2021 will be published early 2023.

Trading Scheme (UK ETS) data, used by the NSTA to estimate that total UK upstream emissions declined for a second consecutive year in 2021.

To monitor progress against the NSTD emissions reduction targets, the NSTA has updated its business as usual (BAU) emissions projections. While these forecasts are sensitive to underlying assumptions and are uncertain by nature, it appears industry is on track to meet the 2025 and 2027 emission reduction targets of 10% and 25% respectively. However, the sector is not on track to meet the 2030 target on the current BAU trajectory – which strips out the potential impact of investments in emissions reduction technology that the NSTA expects to see, meaning further effort is required to meet and surpass the 2030 target.

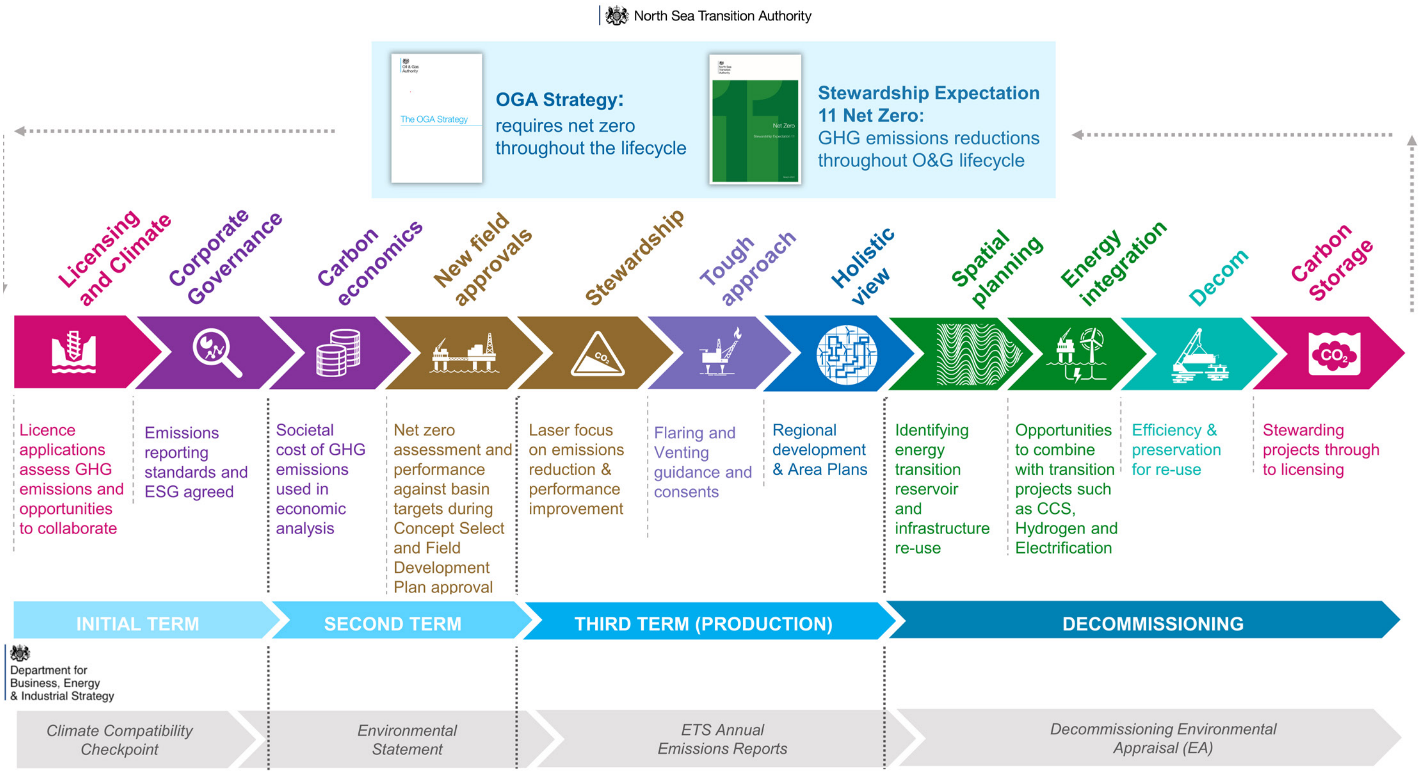
The NSTA will continue to work closely with industry on security of supply, against the backdrop of Russia's invasion of Ukraine, while also adopting a wide range of approaches to ensure its Strategy is implemented and the NSTD emissions targets are met, including:

- Robust emissions performance regulation, proactive stewardship, monitoring and benchmarking, and the publication of new and updated guidance for all North Sea oil and gas projects. For example, the NSTA issued updated guidance last year requiring zero routine flaring and venting by 2030, or sooner. Encouragingly, a number of operators have subsequently installed flare gas recovery systems, each estimated to save up to 22 tonnes of flared gas per day.

- Integrated net zero in every part of the project lifecycle regulation and main activities and processes (Figure 1).
- Opening the UK's first carbon storage licensing round in June 2022, in support of the UK Government's aim to store 20–30 million tonnes per annum of carbon dioxide (CO_2) by 2030.
- Engagement with operators to progress platform electrification projects at pace. Electrification is essential to meeting the NSTD target.

Since its new Strategy came into force, the NSTA interventions have contributed to preventing emission of 1.2 million tonnes of lifetime CO_2 equivalent. This is the same as taking more than 500,000 cars off the road for a year.

Figure 1: NSTA Lifecycle approach to net zero



About the data used in the report

The UK National Atmospheric Emissions Inventory (NAEI) publish annual UK GHG figures for all sectors of the UK economy. GHG emissions from the UK upstream oil and gas industry can be extracted from this dataset using relevant Intergovernmental Panel on Climate Change (IPCC) categories (see Annex A):

Emissions under these IPCC categories cover the following activities:

- All fuel and non-fuel combustion emissions from offshore facilities and onshore receiving terminals.
- Vented and unintentionally released gases (fugitives) to atmosphere from offshore facilities and onshore receiving terminals.
- Gas flared from mobile drilling rigs during the drilling of exploration and appraisal wells.

And the following GHGs:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous Oxide (N_2O)

NAEI has data available up to 2020. Information for 2021 will be published early next year.

1. Asset level GHG emissions are based on statistics from BEIS **Environmental Emissions and Monitoring System (EEMS)**.
2. **UK ETS replaced participation in EU ETS on Jan 2021**
   - Traded CO_2 emissions before 2020 (inclusive) are sourced from the European Union Emissions Trading System (EU ETS). Traded CO_2 emissions from 2021 (inclusive) are sourced from the UK ETS.

3. **Numbers for previous years have been revised** in line with most recently published data sets. Therefore, variations in historic data compared with the past report are due to corrections or refinements of previously reported values.

4. **Non-carbon dioxide GHGs have been converted to carbon dioxide equivalent (CO_2e)** units using global warming potential (GWP) factors presented in the IPCC's Fifth Assessment Report (table 8.7, page 714). The GWP factors used are without inclusion of climate-carbon feedbacks (no cc fb) and are over a 100-year timescale.

Greenhouse Gas	GWP100 (no cc fb)
Carbon Dioxide (CO_2)	1
Methane (CH_4)	28
Nitrous Oxide (N_2O)	265

5. **Emissions Monitoring Report Dashboard and Annex**

The report is accompanied by a dashboard that allows the user to conduct a more detailed analysis by UKCS region, year, type of oil and gas facility, and other relevant variables.

The Annex presents additional details, defines the assumptions for the BAU projections, assumptions for the electrification abatement scenarios, and lists relevant sources to the analysis of this report.

1. UK upstream oil and gas emissions

1.1 Breakdown of industry GHG emissions

GHG emissions from upstream oil and gas activity accounted for 4% of net UK territorial GHG emissions in 2020 according to data from the NAEI.

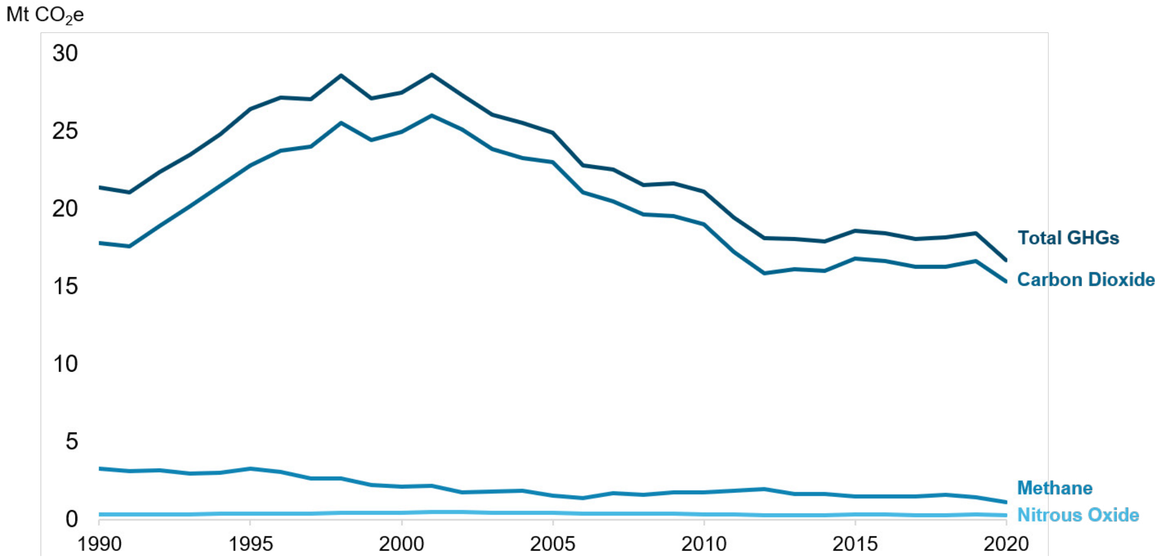
Carbon dioxide (CO_2) emissions drive the overall trend in GHG emissions from upstream oil and gas in the UK. From 1990 to 2020, CO_2 accounted for 89% of total upstream emissions on average; methane (CH_4) for 9%; nitrous oxide (N_2O) for 2%.

Emissions peaked in the early 2000s as new facilities were commissioned and brought online. When production fell and decommissioning of older installations began, emissions fell, albeit at lower rates than production.

Total emissions have remained relatively flat in the last decade but fell during the last two years due to combination of proactive industry efforts to decarbonise, disruption caused by the COVID-19 pandemic and large-scale maintenance programmes that reduced overall activity in the UKCS.

After peaking in 2001, CO_2 emissions have been reduced by 41% to stand at 15.3 $MtCO_2$ in 2020. Methane (CH_4) emissions halved between 1990 and 2006 and have since remained relatively flat at an average of 1.6 $MtCO_2e$ per year. Nitrous oxide (N_2O) has remained stable since 1990 at annual average levels of 0.4 $MtCO_2e$.

Figure 2: UK upstream oil and gas emissions by GHG gas, 1990–2022



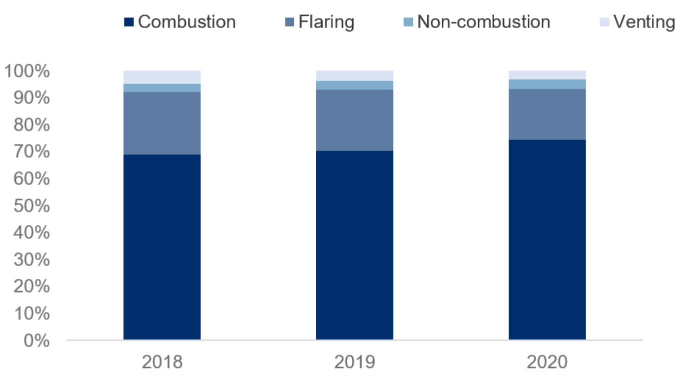
Source: NAEI.

A breakdown of GHG emissions by source between 2018 and 2020 is presented in Figure 3. Combustion for power generation is the main source with an average of 71%. Flaring follows with 22%. Venting and other non-combustion processes have similar levels with 4% and 3% respectively.

Combustion for power generation shows a progressive increase in the share of GHG emissions between 2018 and 2020. This is due to significant decreases in emissions from flaring.

Figure 4 shows an indicative breakdown of emissions by source for 2021. This breakdown uses a different data source which suggests combustion for power generation fell slightly to 70% with flaring at 24% and venting 3%. While these changes are very small they reflect a fall in emissions from power generation rather than a rise in emissions from flaring. This is discussed further in Section 1.4.

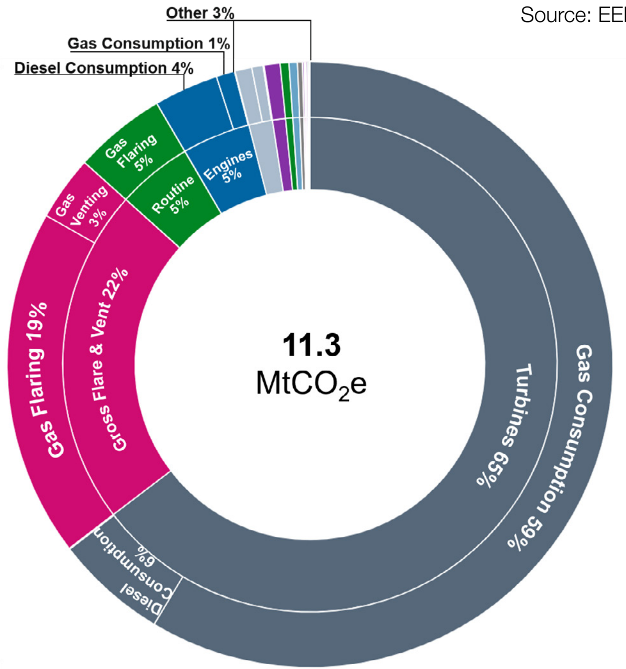
Figure 3: Breakdown of GHG emissions by source, 2018–2020



Source: NAEI. Note: Conversion to CO_2e done with AR5 without feedback GWP.

Figure 4: Facility emissions by source and category, 2021

Source: EEMS.



1.2 Current progress against emissions reduction targets

The NSTD established emission reduction targets for the UK upstream oil and gas industry. The targets commit industry to achieve the following reductions against a 2018 baseline: 10% by 2025, 25% by 2027 and 50% by 2030.

Updated NAEI data shows that UK upstream oil and gas industry emissions decreased by 8.1% between 2018 and 2020.

While NAEI data for 2021 will not be published until next year, it is possible to estimate the change with a certain degree of confidence using other sources such as BEIS EEMS and the UK ETS.

EEMS data shows that upstream offshore GHG emissions fell 14.4% between 2020 and 2021; while UK ETS shows a 13.6% reduction of CO_2 emissions for the same period.

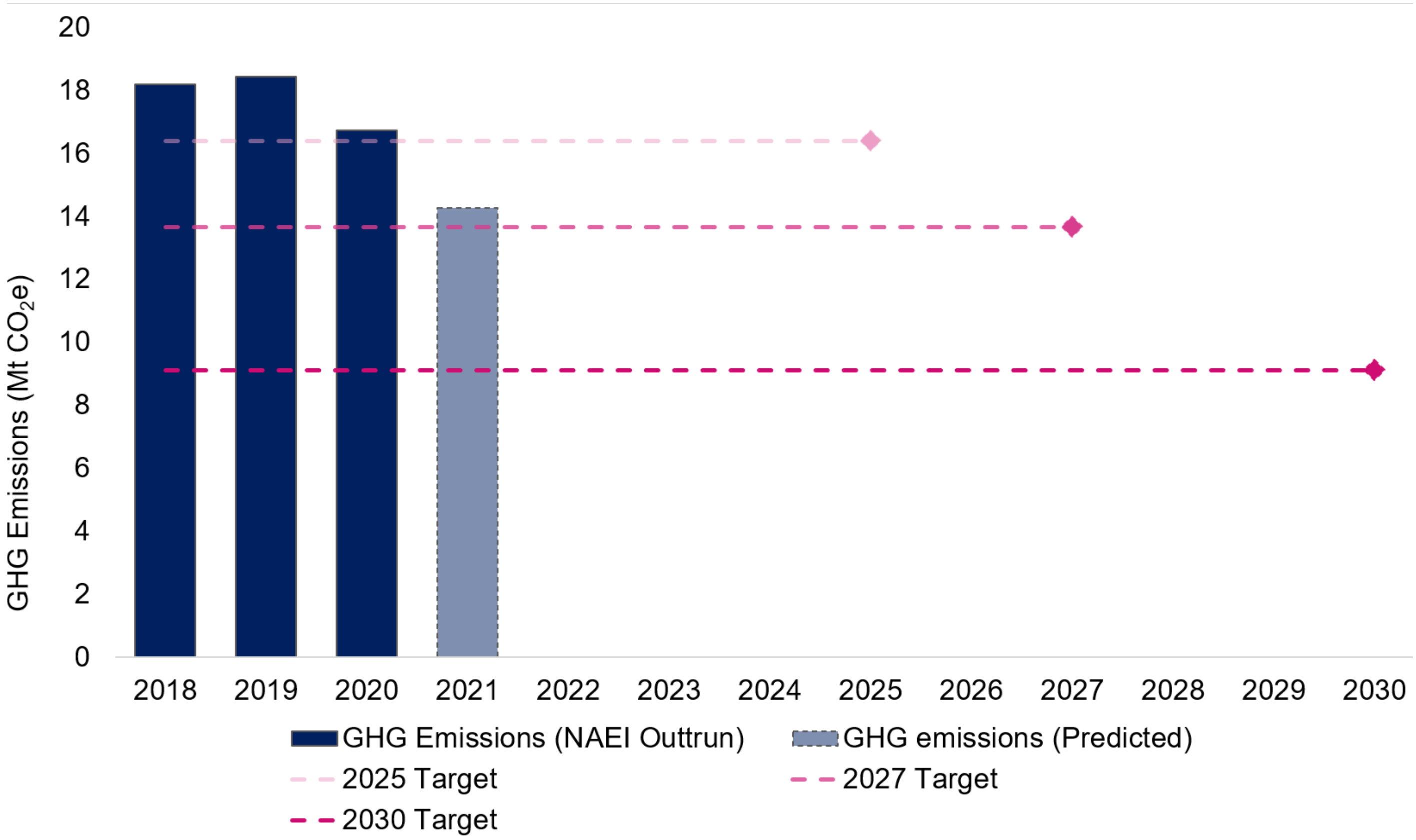
The NSTA therefore estimates that total upstream oil and gas GHG emissions will decrease by 14.6% from 2020 to 2021 resulting in an overall reduction relative to 2018 of 21.5% (see Figure 5).

The large reduction reflects continued efforts by the NSTA and operators to implement emissions saving initiatives and the impact of Emissions Reduction Action Plans introduced as part of Stewardship Expectation 11 in Q2 2021.

While the observed trends are promising, it should be noted that 2020 and 2021 have been unusual years for upstream activity in the UKCS.

As upstream operations return to a more regular and consistent rhythm, the challenge will be to sustain these reductions in future years.

Figure 5: UK upstream oil and gas GHG emissions, progress towards NSTD targets 2025–2030



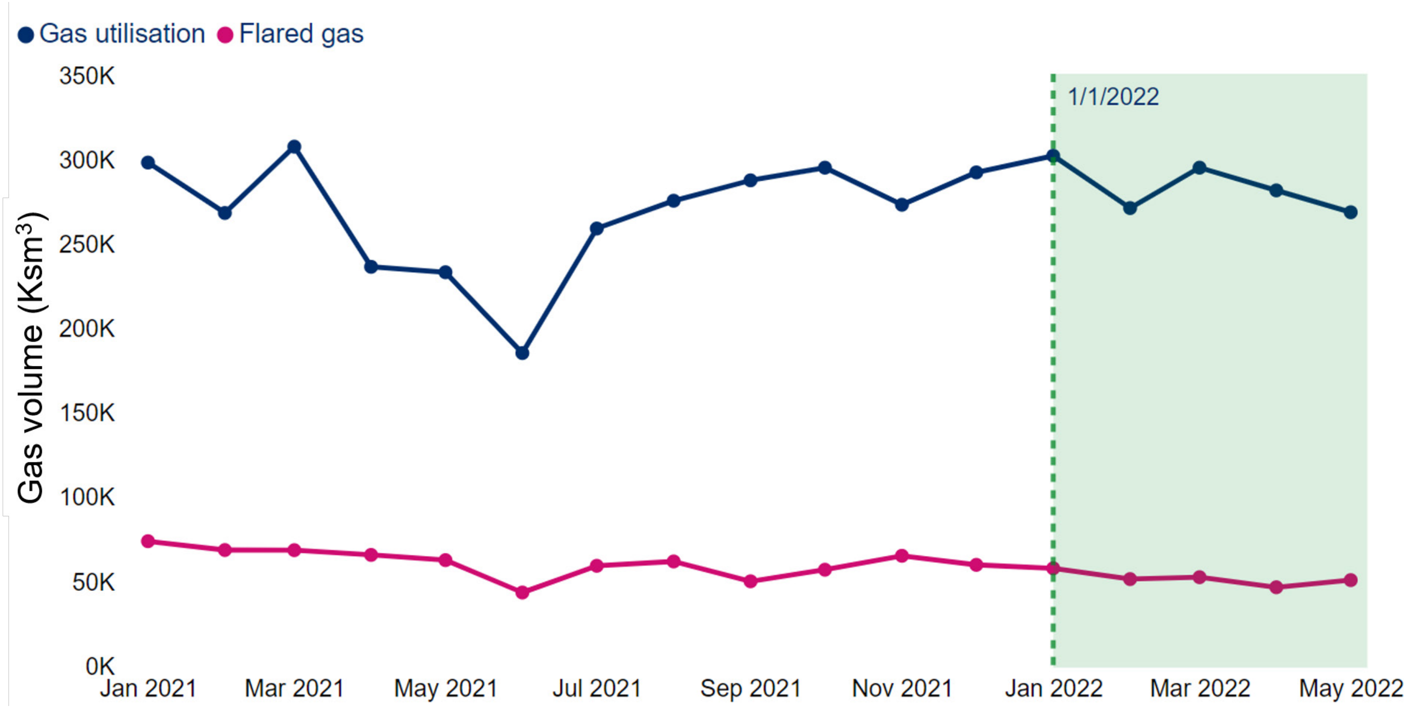
1.3 Year-to-date emissions and expectation for 2022

The use of produced gas by operators has a strong relationship with overall upstream emissions (see Annex D). Consequently, it is possible to monitor in-year progress using outturn data for gas utilisation in 2022 from the NSTA's Petroleum Production Reporting System (PPRS).

Following a stark reduction in gas utilisation during the early summer of 2021 (Figure 6), volumes increased until January 2022 and have since remained at higher levels compared to the first half of 2021.

Gas utilisation levels are likely to decrease slightly over the summer of 2022; an expected seasonal pattern in the UKCS underpinned by routine maintenance. However, the general trend suggests that total emissions in 2022 will increase from their low point last year as existing facilities which were shut down or underwent maintenance during COVID-19 resume normal production.

Figure 6: Gas utilisation and flaring as proxy for emissions trend in 2022

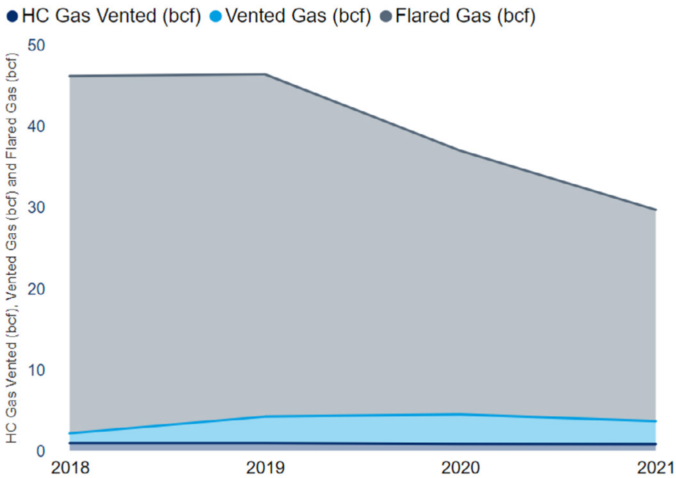


Source: PPRS.

1.4 Flaring and venting activity in 2021 with 2022 update

Total gas flared in 2021 was 25.8 billion cubic feet (bcf) and vented gas 2.8 bcf. representing a 20.1% and 22.2% reduction relative to 2020 respectively. Hydrocarbon venting (primarily methane emissions) declined by 2.3% during the same period.

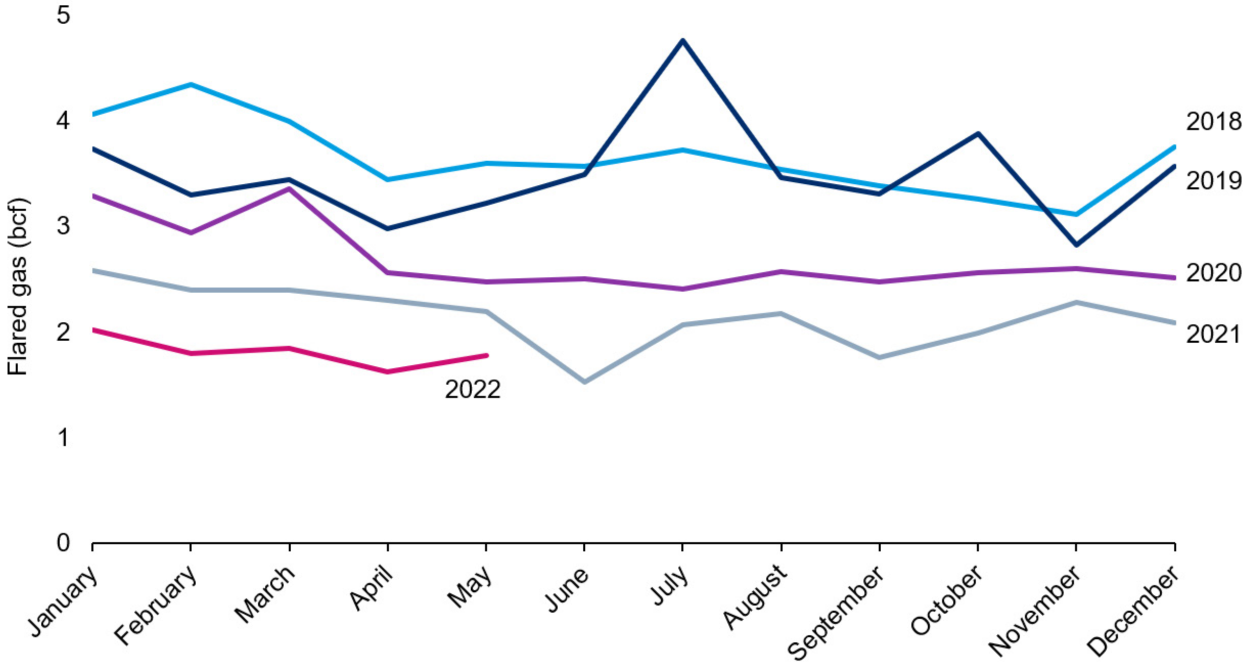
Figure 7: Annual flared and vented gas volumes 2018–2021



Monthly data reported through PPRS shows that gas flared during the first half of 2022 is lower than the same period in any of the last four years (Figure 8), continuing a declining trend. However, looking at the seasonal patterns, it is likely that flaring in summer 2022 will not decrease to the same extent as in 2021, a period marked by an unusually high number of delayed shutdowns and maintenance programmes. Vented hydrocarbons during the first half of 2022 are also lower compared to recent years.

As normal production levels return and stabilise, this continued focus on reducing flaring and venting emissions remains essential. The NSTA issued updated flaring and venting guidance last year which requires facilities to have zero routine flaring and venting by 2030, or sooner. This has already delivered positive outcomes including operators installing flare gas recovery systems and new developments including zero routine flaring and venting. The next Annual Consents Exercise starting on 1 January 2023 provides an opportunity for operators to demonstrate steps being taken to reduce and eliminate routine flaring and venting.

Figure 8. Monthly gas flaring, January 2018 to May 2022



Source: PPRS.

1.5 Methane emissions

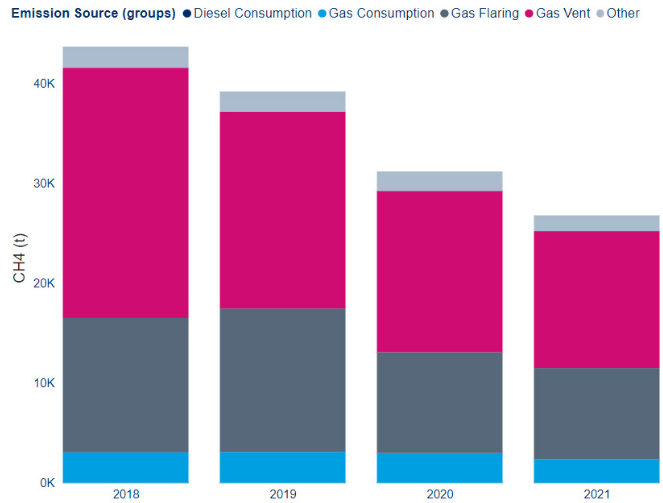
While the industry's emissions footprint is mostly determined by CO_2 output, methane represents 9% of upstream GHG emissions.

Between 2020 and 2021 methane emissions decreased by 14% taking the total estimated reduction when compared with the baseline year of 2018 to 38%.

For a second consecutive year, the primary driver behind this reduction is gas venting which decreased by 15.1%.

The decreasing trend in methane emissions is a result of different factors, a reduction in production levels due to shutdowns and maintenance activities plus industry pursuing proactive initiatives to reduce flaring and venting such as increasing equipment efficiency and leakage detection systems. The NSTA updated flaring and venting guidance strengthens stewardship, performance monitoring and benchmarking.

Figure 9: Offshore methane emissions by source, 2018–2021



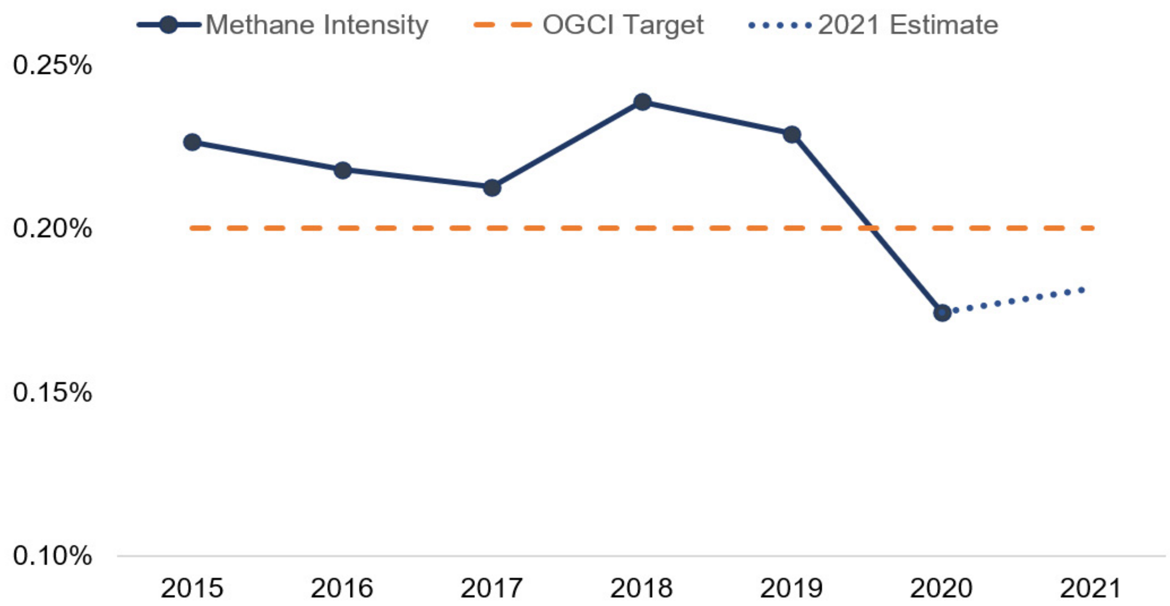
Source: EEMS excludes terminals.

Methane intensity, the amount of methane emitted per unit of natural gas to market, is a key performance metric used to measure the relationship between net gas production and methane emissions. The Oil and Gas Climate

Initiative (OGCI) has set a methane intensity target of less than 0.20% by 2025[2]. After increasing to 0.24% in 2018, methane intensity fell below the OGCI target to 0.17% in 2020.

The NSTA estimates methane intensity to have increased to 0.18% in 2021. This is due to falls in net gas production being higher than the fall in methane emissions.

Figure 10. Recent methane intensity trends, 2015–2021



Source: BEIS and NAEI data including offshore facilities and terminals.

[2] See OGCI Reducing methane emissions | OGCI Action & Engagement

2. Baseline projection of UK upstream oil and gas emissions: 2022 update

The NSTA published its first BAU emissions projections in 2021 to create a baseline from which to measure the basin's progress towards achieving the NSTD targets – and to measure the impact of abatement initiatives. These projections have been updated and enhanced to reflect the most up-to-date assessment of future emissions.

The projections:

- Assume continued production from existing installations without any further proactive abatement activities.
- Do not assume abatement from zero routine flaring by 2030 (see section 3.3 for details).
- Assume that any new installations will be designed to minimise GHG emissions in line with the NSTA effective net zero test.

The NSTA BAU projections suggest upstream emissions will rise briefly in 2022 as production and activity returns to a more regular rhythm before falling again from 2024 onwards. The downward trend will continue until 2043 when emissions reductions plateau. The expected sharp fall in 2021 is supported by recent EEMS and UK ETS data, while the 2022 growth from own gas utilisation data in PPRS.

Relevant updates to 2022 BAU emissions projections

Baseline emissions for 2018 have been revised down owing to updates in NAEI data.

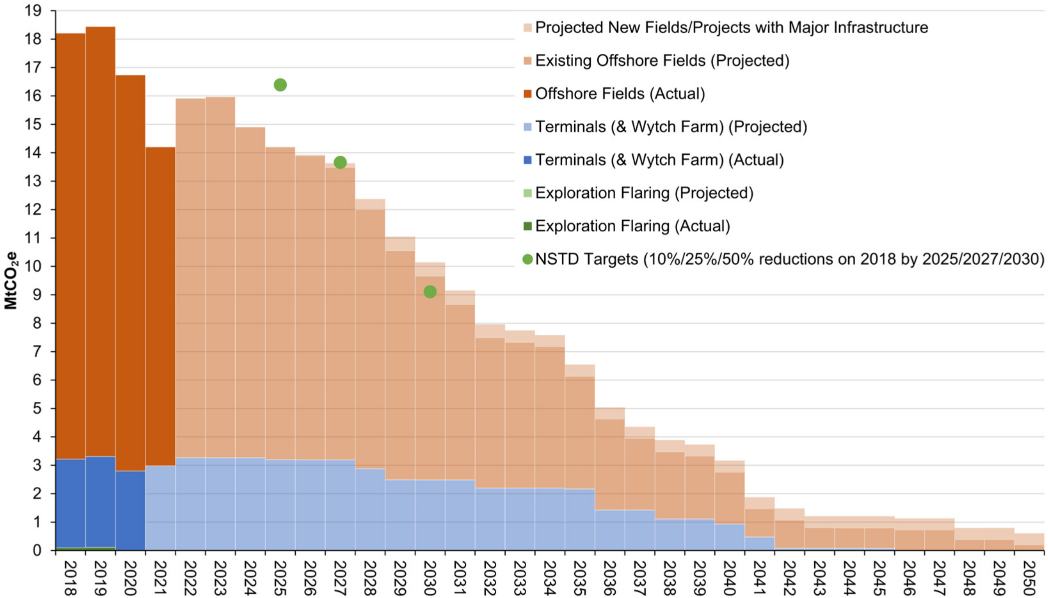
AR5 without inclusion of climate-carbon feedback GWPs are used to calculate emissions in CO_2 equivalent (CO_2e) terms (see About Data section above).

Recently approved projects that were previously categorised as new fields have been recategorised into existing offshore fields. The result is a shift to the right in the projected new fields emissions compared to last year.

Cessation of production dates has been updated to reflect information from the latest UK Stewardship Survey (UKSS).

Projected emissions for a small number of recent and new installations are based on operators' emissions forecasts collected for the first time in the UKSS.

Figure 11. Actual and projected business as usual GHG emissions, 2018–2050



Source: NAEI, EEMS, EU ETS, UK ETS, BEIS, NSTD.

Note: Business as usual projections, that is, excludes abatement and decarbonisation projects.

The projections indicate that industry is on track to the 2025 and 2027 emission reduction targets. However, this is not the case for the 2030 target on the current BAU trajectory and further abatement initiatives are required if the NSTD targets are to be achieved.

Meeting these targets is the absolute minimum the NSTA expects from industry, which must make a sustained effort in the coming years to surpass them.

3. Potential abatement opportunities

3.1 Offshore electrification deployment scenarios

In 2021, approximately 70% of all offshore upstream oil and gas industry emissions were the result of the combustion of either natural gas or diesel for fuel. Industry has been working for some time to develop options for replacing natural gas and diesel with electricity as the main source of energy to power offshore operations.

In its 2021 report, the NSTA produced low, central, and high technical deployment scenarios for electrification abatement on the UKCS. As the challenges and benefits of platform electrification become clearer, these technical scenarios have been updated to take account of:

(1) Better understanding of the scope of offshore and onshore facilities that could be electrified.

(2) Revised emissions for installations based on the baseline emissions projections.

(3) Updated first-power assumptions for abatement savings.

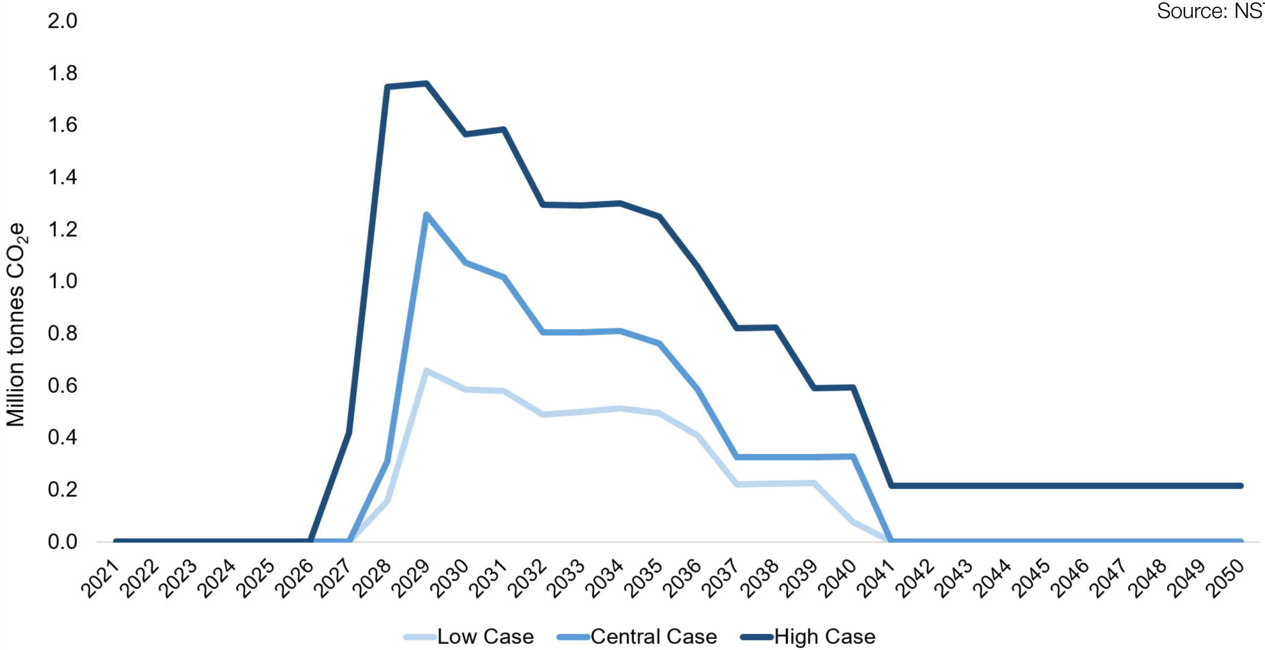
In the revised central case, total cumulative abatement from 2027 to 2050 is estimated at 8.7 $MtCO_2e$. The minimum estimate stands at 5.1 $MtCO_2e$ and a maximum of 18.2 $MtCO_2e$. The high case assumes that all regulatory and economic enablers are realised for electrification projects to start by 2026 and is considered optimistic. Estimates have changed compared to the 2021 Emissions Monitoring Report mainly due to further understanding of facilities considered for electrification projects based on assessments from industry and NSTA.

While the projections carry a high degree of uncertainty, abatement estimates after 2040 are even more uncertain, due to lack of clarity around greenfield electrification projects.

The wide range is driven by factors such as variations in year of first-power, potential electricity sources, degree of electrification and grid intensity assumptions.

Figure 12: Annual estimated GHG emissions abatement from technical deployment scenarios, 2021–2050

Source: NSTA analysis.

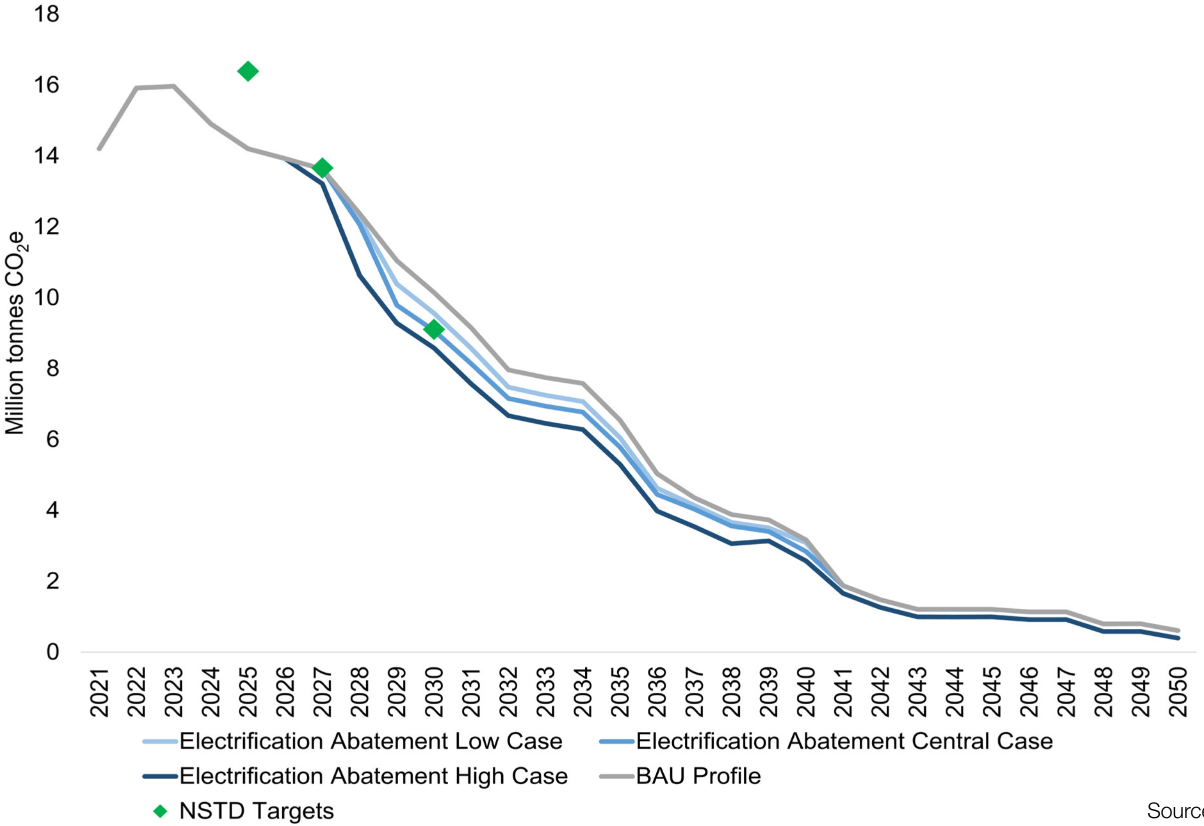


The impact of emissions abatement from electrification on the achievement of the NSTD targets, can be seen by setting the estimated technical GHG emissions abatement scenarios against the baseline emissions projections from the previous section (see Figure 13).

Electrification is fundamental to the attainment of the 2030 target. As minimum, the central case is required.

Like the baseline emissions projections, it is important to note that the abatement potential estimated in the above technical scenarios is not a forecast and should not be used as such. The scenarios are based on the NSTA's best understanding of the scope of projects that could be electrified and makes assumptions that strive to capture abatement from a range of deployment options. In this sense, the technical abatement scenarios are subject to high levels of uncertainty.

Figure 13: Technical projections of UK upstream oil and gas GHG emissions: baseline emissions projections and abatement scenarios, 2021–2050



Source: NSTA analysis.

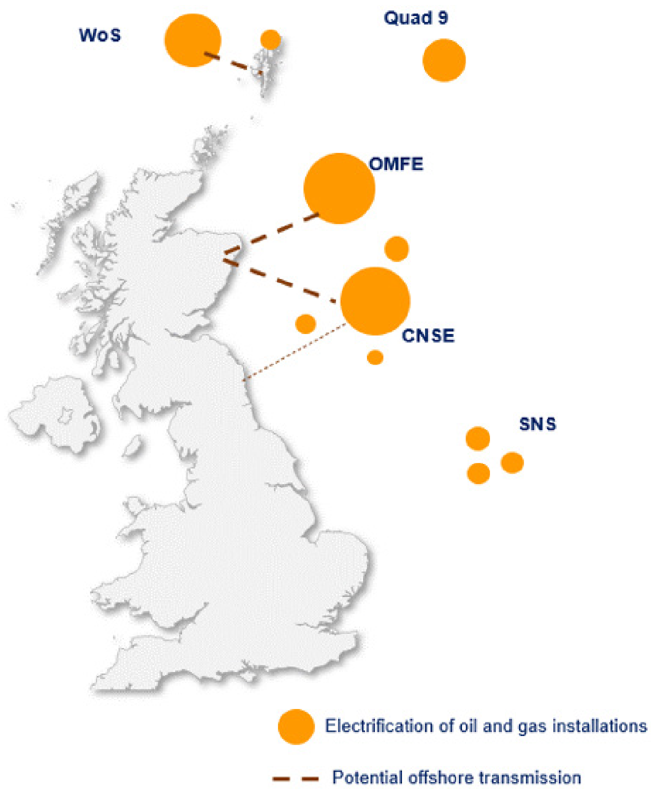
3.2 Regional breakdown of potential electrification projects

The UKCS has enormous potential to reduce emissions from offshore oil and gas installations and support the decarbonisation of the wider UK economy. The 2020 UKCS Energy Integration Report presented an overview of such opportunities and further refinement was presented in the 2021 Emissions Monitoring Report.

A number of initiatives were introduced in 2022 to support UKCS electrification. The NSTA electrification competition provided £1m towards three studies which demonstrated cost-efficient emission reductions of up to 87% could be achieved on offshore platforms. In August 2022 Crown Estate Scotland opened the Innovation and Targeted Oli and Gas (INTOG) offshore wind leasing process, a pioneering leasing round dedicated to decarbonising oil and gas facilities in Scottish waters while supporting offshore wind development.

Figure 14 shows the revised and up-to-date assessment of regions and installations with major potential projects for platform electrification. The schematic is not an exhaustive list of all abatement opportunities. Industry is already engaging in smaller-scale opportunities to reduce emissions from upstream operations such as flaring and venting reduction, leakage detection and repair of fugitive emissions, and upgrades to equipment to increase efficiency. The NSTA will continue to engage with operators and the supply chain to promote and increase the abatement potential in the UKCS.

Figure 14: UKCS schematic map of potential electrification projects of offshore oil and gas installations



3.3 Zero routine flaring

Abatement of flaring emissions is an additional action to achieve decarbonisation of the upstream industry in the UK.

The NSTA issued consolidated and updated guidance on flaring and venting outlining a tougher approach to drive down emissions in 2021. Amongst the main expectations, the guidance established that:

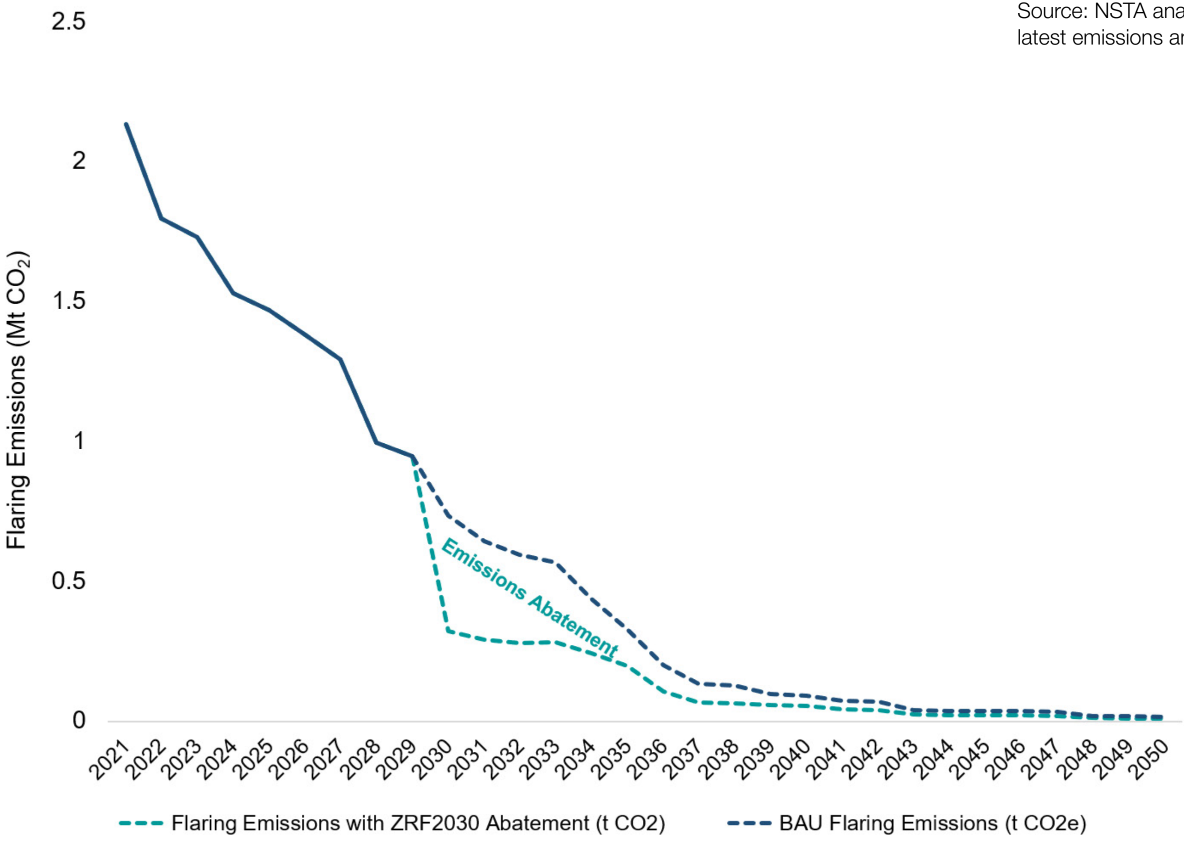
- All new oil and gas projects should be planned and developed based on zero routine flaring and venting.
- Zero routine flaring and venting for all fields should be implemented by 2030 at the latest.

Figure 15 presents updated projections of abatement potential from the zero routine flaring policy by 2030. The projections are based on future flared gas volumes provided by operators and informed by historic flaring consents applications and current levels of routine flaring.

It should be noted that the abatement estimates are a low case as operators are expected to reduce routine flaring from now until 2030. Moreover, several operators are currently engaging in flaring abatement and increased efficiency in equipment which reduces such emissions.

Figure 15: Annual estimated GHG emissions abatement from implementation of zero routine flaring in 2030

Source: NSTA analysis based on latest emissions and UKSS data.



4. Emissions performance benchmarking

Comparing the emissions performance of offshore facilities is challenging due to the differences in size of platforms, lifespan, operations handling and subsurface factors such as fluid and gas composition. These determinants vary widely between UKCS installations and have a significant impact on performance.

For this reason, it is common practice to use an intensity measure of emissions in order to compare the performance of installations, areas or nations – in other words a measure of the emissions associated with each barrel of oil equivalent (boe) produced.

There are commonly two different intensity measures – emissions intensity, which measures the overall amount of GHG gasses emitted to produce each boe; and carbon intensity which measures specifically the amount of CO_2 emitted to produce each boe. While emissions intensity is a more complete calculation it relies on detailed data and involves a more complex calculation therefore carbon intensity is frequently used, particularly in an international context where data for methane and other GHGs is difficult to obtain.

For completeness, both emissions intensity and carbon intensity are included in this report.

4.1 Offshore facilities emissions performance

In 2021 there were 110 offshore production facilities[3] with emissions ranging from under 100 $ktCO_2e$ to 500 $ktCO_2e$. 79% of facilities decreased their emissions between 2020 and 2021 with an average reduction of almost 40%. As a result, emissions across the 110 facilities fell nearly 31% on average.

Figure 16: Offshore facilities emissions change, 2020–2021

Source: EEMS.

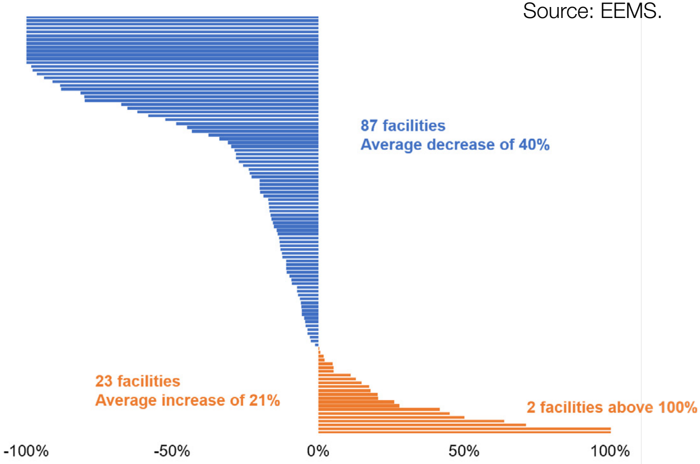
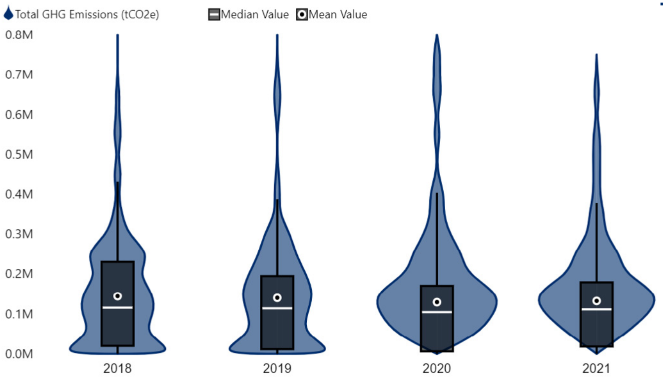


Figure 17 shows the distribution of offshore facility emissions between 2018 and 2021. The distribution has remained relatively stable except for an outlier installation with increasing emissions until 2020 and then a steep reduction in 2021. The distribution also shows that 75% of total offshore facilities have emissions below 200,000 tonnes of CO_2e (as marked by the top whisker of the boxplot). This means that the distribution of emissions per facility is heavily skewed with a relatively small number of high emitters.

[3] The statistics in this paragraph exclude two outlier points, installations that did not report emissions for two consecutive years and installations that have ceased production.

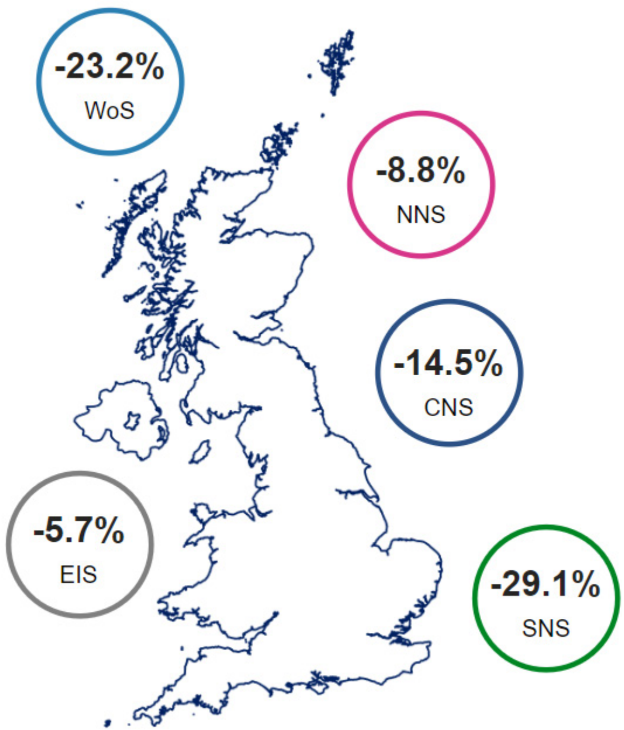
Figure 17: Offshore facilities CO_2e emissions distribution, 2018–2021



Source: EEMS.

Reductions in GHG emissions vary quite considerably across the different areas of the UKCS (Figure 18). While facilities in the Central North Sea (CNS) model the UKCS average, larger falls are demonstrated in the Southern North Sea (SNS) and the West of Shetland (WoS) and more moderate reductions can be seen in the Northern North Sea (NNS) and East Irish Sea (EIS).

Figure 18: Regional breakdown of GHG emissions reductions in 2021



Source: EEMS.

4.2 Carbon intensity

Carbon dioxide emissions intensity (carbon intensity) is a performance metric that measures the amount of CO_2 emissions per barrel of oil equivalent (boe) produced. The NSTA uses data published by UK ETS (and previously the EU ETS) to calculate the measure in kilograms of CO_2 per boe (kgCO_2/boe).

Despite the decrease in CO_2 emissions in 2021, offshore and total carbon intensity (including terminals) increased slightly during the last year (Figure 19). This is due to production declining at a faster rate than carbon emissions during 2021. The net effect is higher carbon intensity in the basin as there are fewer units of production per unit of CO_2.

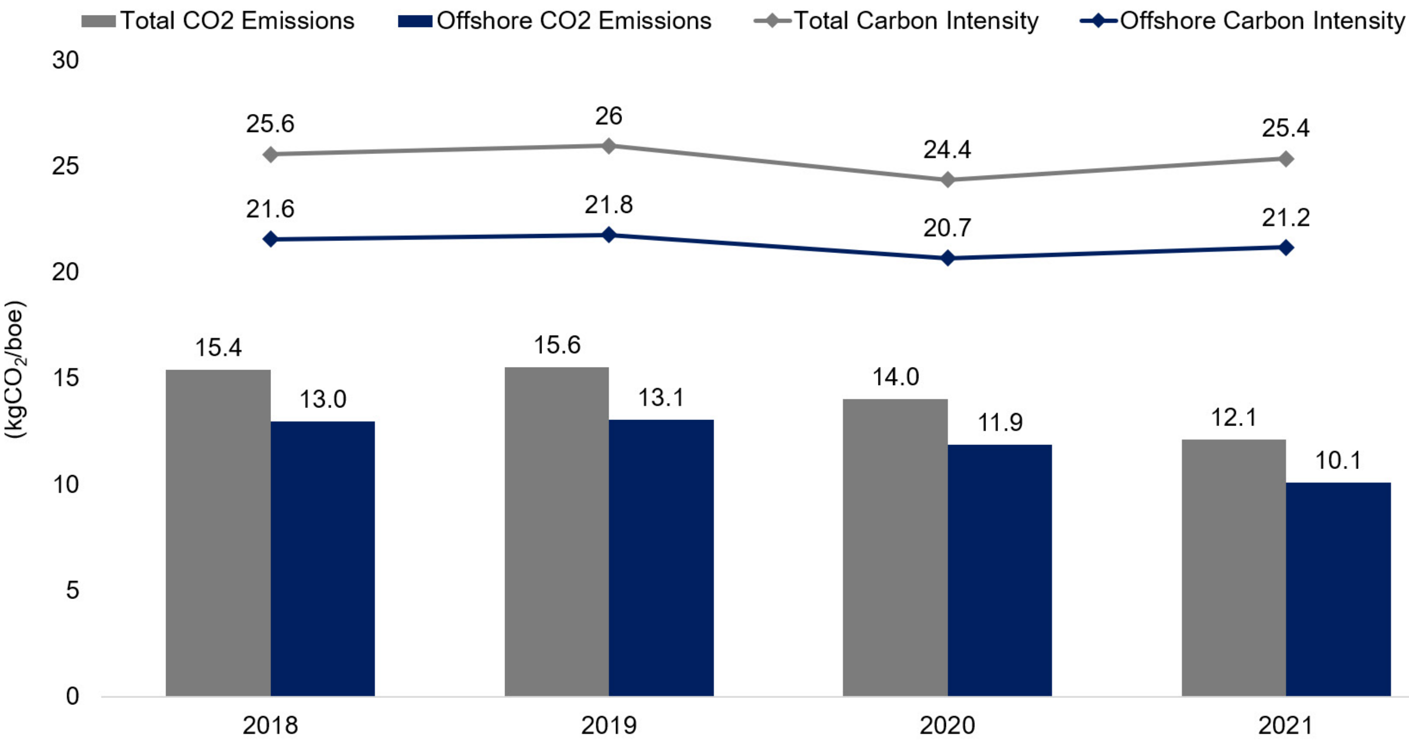
Note on offshore and total carbon intensity

Upstream carbon intensity is often calculated using only offshore emissions, however it is important to include emissions from onshore receiving terminals to capture all upstream emissions. Consequently, total carbon intensity includes both offshore facilities and onshore receiving terminals.

2021 UK upstream oil and gas carbon intensity (kgCO_2/boe)

	Offshore	Total (including onshore terminals)
CO_2 in scope of the UK ETS	21.2 CO_2: 10.1 Mt	25.4 CO_2: 12.1 Mt
Production: 478 MMboe		

Figure 19: Offshore and total carbon intensity and CO_2 emissions, 2018–2021



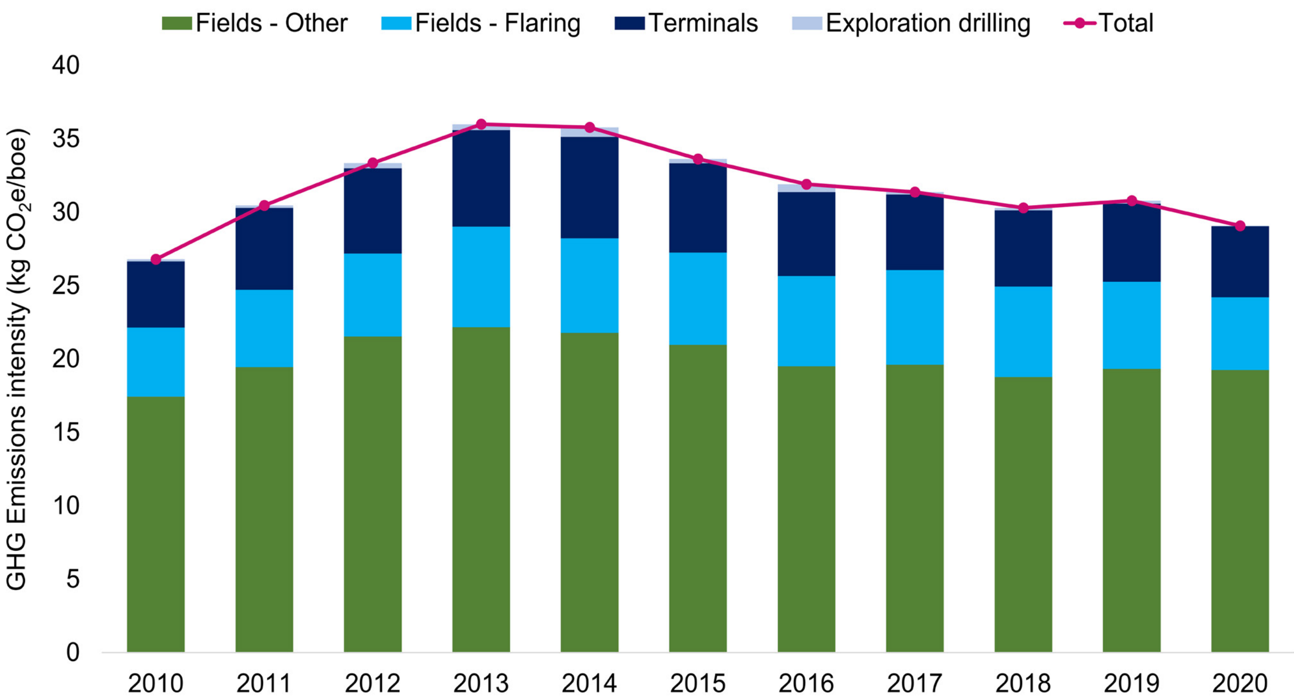
Source: EU ETS, UK ETS

4.3. Overall GHG emissions intensity

In contrast to the carbon intensity measure presented in the previous section, GHG emissions intensity is a performance metric that captures emissions from all GHGs in upstream oil and gas activities. This means emissions intensity relates emissions from not only CO_2, but also CH_4 (methane) and N_2O (nitrous oxide) to oil and gas production in barrels of oil equivalent.

The NSTA expects official figures to show that total upstream GHG emissions intensity increased slightly between 2020 and 2021 from 29.1 to around 29.9 kgCO_2e/boe, however this remains below 2018 levels. This change was due to production declining at a faster rate than GHG emissions during 2021.

Figure 20: UKCS GHG emissions intensity by source and total, 2018–2020



Source: NAEI, BEIS

4.4. Carbon emissions intensity and GHG emissions intensity of offshore assets

Performance on emissions intensity and carbon emissions intensity measures can vary significantly between UKCS assets due to size, age and type of installation.

Figure 21a shows in general terms that on average larger and older assets have a larger emissions intensity than newer smaller assets. The same is true when measuring carbon emissions intensity.

There are also regional differences. In 2021, the NNS and EIS had the highest carbon intensity of all regions at 35.1 and 37.1 kgCO_2/boe respectively. This is followed by the CNS with 22.2; WoS with 13.7; and SNS with 10.6.

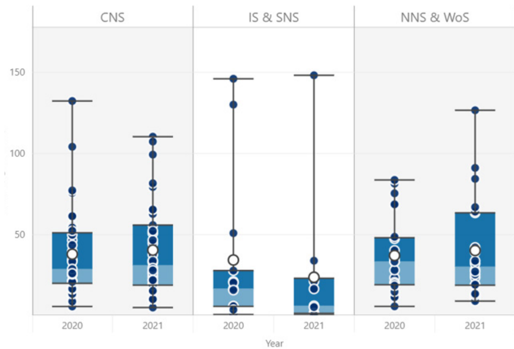
Detailed analysis on carbon intensity and emissions intensity is available in more detail in the NSTA's interactive emissions dashboard that accompanies this report.

Figure 21a: GHG emissions intensity breakdown by installation type and year

Installation Age	Small Platform	Floating	Large Platform
0-10 Years	6	19	12
11-25 Years	24	39	31
> 25 Years	23	45	62

*Numbers are in kgCO_2e/boe

Figure 21b: UKCS distribution of GHG emissions intensity by region, 2020–2021



Source: NAEI, BEIS

4.5. Flaring and venting benchmarking

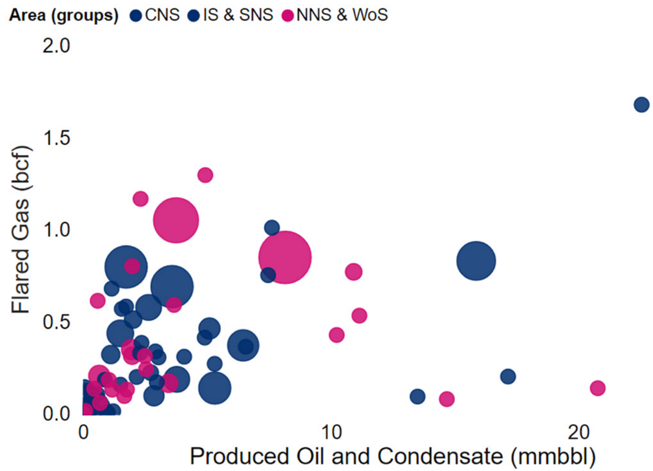
Operators report flaring and venting volumes to the NSTA's PPRS system, which can be used to monitor progress on reducing emissions.

Flaring and venting volumes and gas composition varies throughout the UKCS. Reservoir fluids and topside processes are amongst the main determinants behind the differences. As Figure 22a shows, there is a positive correlation between volumes of flared and vented gas, and oil and condensates production.

In general, CNS has larger volumes of flaring and oil production compared with other regions (Figure 22a). However, the NNS and WoS regions show a split with a group of hubs having lower flaring and production volumes compared with the CNS, and a second group with higher volumes. Venting volumes appear to be strongly correlated with production and flaring volumes.

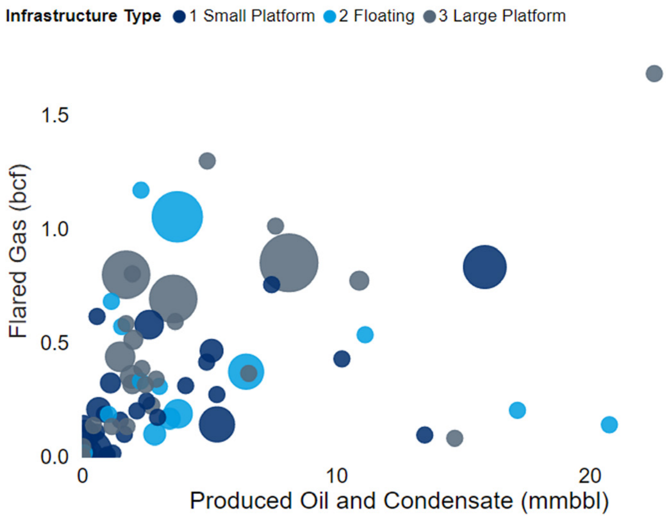
Looking at infrastructure types, platforms (Figure 22b), floating facilities and small platforms have smaller volumes of flared and vented gas compared to large platforms.

Figure 22a: Volumes of flared and vented gas* compared with oil production by UKCS area, 2021



*Size of the bubble is volume of vented HC gas

Figure 22b: Breakdown by installation type, 2021



*Size of the bubble is volume of vented HC gas

To aid the comparison of the performance of installations, flaring and venting volumes can be represented per barrel of oil equivalent produced to give a flaring intensity or hydrocarbon venting intensity measure.

In 2021 offshore flaring intensity was 90.2 scf/bbl, down 4.5% relative to 2020 levels of 94.4 scf/bbl. Offshore hydrocarbon venting intensity however showed an increase from 1.3 scf/bbl to 1.6 scf/bbl 2021, driven by spikes from gas vented for safety reasons in two pipelines in early 2021.

Flaring intensity and hydrocarbon venting intensity can be explored in more detail in the NSTA emissions benchmarking dashboard that accompanies this report.

5. International benchmarking of the UKCS carbon intensity

The NSTA's work on the carbon footprint of gas (May 2020) looked at emissions at the point of consumption, i.e., including emissions from processes like transportation and liquefied natural gas (LNG) regasification, showed that the carbon footprint of consuming domestically produced gas is less than half that of imported LNG. This international benchmarking instead looks only at the production emissions.

A comparison of UKCS offshore carbon intensity with other producing countries using data sourced from Rystad Energy is shown in Figure 23a.

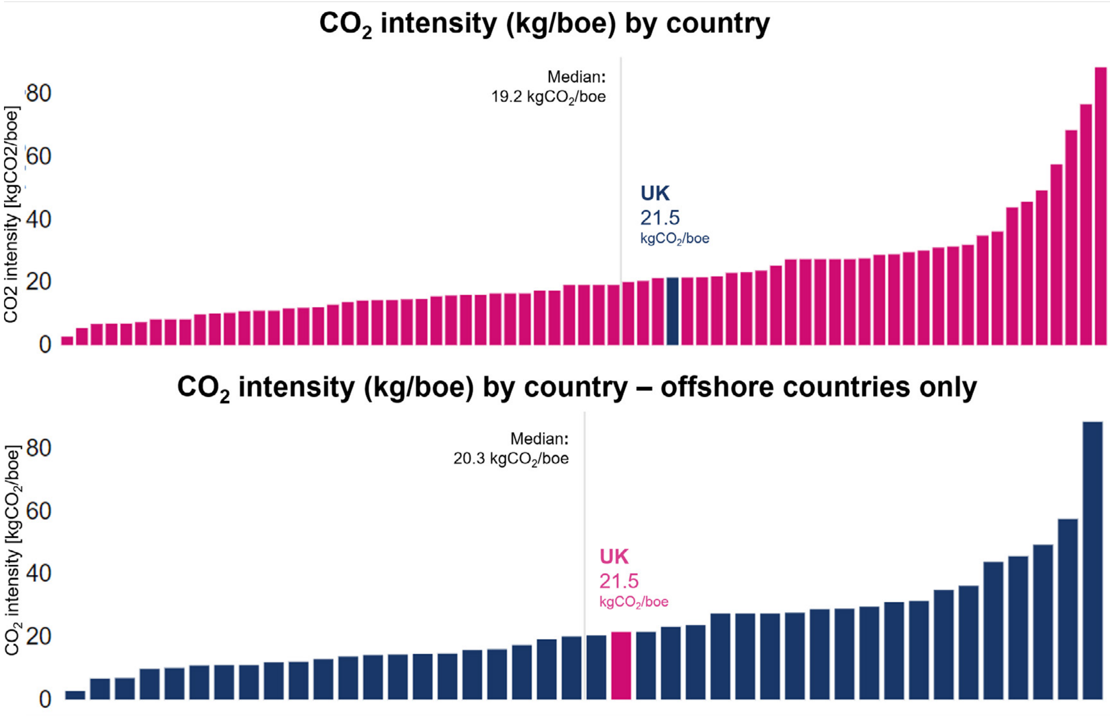
According to the Rystad data and methodology, the UK's carbon intensity has remained constant between 2020 and 2021 at 21.5 $kgCO_2$/boe. Of the 71 countries included in the analysis, 39.3% reduced their carbon intensity between 2020 and 2021, while 26.8% of the countries increased.

The UK's carbon intensity of 21.5 $kgCO_2$/boe in 2021 places the UK slightly higher than the median position of 19.2 $kgCO_2$/boe. This is heavily influenced by factors like age of basin, geology and so forth, but shows clearly there is still room for improvement in the UKCS.

Figure 23b compares the UK against emissions from other predominantly offshore producing countries. This again shows the UK in a mid-table position, slightly above the median point of 20.3 $kgCO_2$/boe.

Carbon intensities at country level conceal the great extent of in-country variation in carbon intensity at field level. Some of this variation is related to the phase in the life cycle of each field, with late-life carbon intensity rising exponentially as production rates decline and as cessation of production approaches.

Figure 23 (a/b): 2021 Carbon intensity by country, global and peer group comparison



Source:
Rystad Energy - August 2022

To note:

- Data excludes emissions from onshore terminals.
- Direct comparisons with analysis published in the EMR 2021 are not possible due to revisions to the 2020 data subsequent to the NSTA publication.

6. Conclusion and next steps

The importance of a secure and stable energy supply has become more apparent than ever. As we transition away from fossil fuels, it is crucial we work to produce domestic oil and gas as cleanly as possible. The UKCS upstream oil and gas industry has made encouraging early progress in its efforts to cut emissions and meet NSTD targets.

Total emissions fell by 21.5% between 2018 and 2021 with a 14.6% decline in 2021 alone due both to production falls but also the sector's proactive steps to reduce emissions, and the NSTA's regulatory and stewardship approach. The revised Strategy and integrated net zero regulation has resulted in tangible action being taken; for example, the activation of flare gas recovery systems on platforms and upgrades to equipment to increase efficiency. The 2021 period was also marked by disruption due to the COVID-19 pandemic with several installations shut down permanently while others reduced offshore activity levels due to maintenance, with a knock-on impact on emissions. With maintenance programmes concluding and further facilities returning to pre-pandemic production levels, associated emissions are expected to rise briefly in 2022, before falling again in 2024 and onwards.

NSTA projections show that in a BAU scenario, industry is on track the meet the NSTD 2025 and 2027 emission reduction targets of 10% and 25% respectively. Meeting the 2030 target of 50% reduction will require much greater ambition with electrification of offshore facilities a key driver, the NSTA expects two electrification projects to be commissioned by 2027. Meeting the NSTD targets is the absolute minimum the NSTA expects from industry and is essential to maintain its social licence to operate. A robust regulatory approach will be taken to drive further emission reductions and to ensure GHG emission intensities continue to reduce and bring the UKCS in line with high performing countries.

The NSTA is working closely with industry and government to progress new oil and gas projects, bolstering the UK's security of indigenous supply and providing options in the years ahead with a new offshore petroleum licensing round expected to open later in 2022. This vital work will not compromise the emissions reduction targets in the NSTD. The government's upcoming climate compatibility checkpoint will be considered ahead of any future licensing rounds, and the NSTA will apply its effective net zero test prior to approving new projects, including the revised Field Development Plan guidance.

The NSTA is also pushing industry to reduce emissions from existing production activities and requires all licensees to write and implement Emission Reduction Action Plans (ERAPs) and submit revised Standard Economic Templates (SETs) to assess future operations with respect to emissions and production. The NSTA published revised flaring and venting guidance in 2021, which stipulates that companies are expected to achieve zero routine flaring and venting by 2030, or sooner, contributing to total flared volumes falling by 20% in 2021 with venting falling by 22% over the same period.

As the sector presses ahead with decarbonisation projects in the coming years, the NSTA will continue to both manage and track performance, including through the annual Stewardship Survey, performance monitoring and benchmarking, tier reviews, the publication of new and revised guidance, and yearly Emissions Monitoring Reports.

Annex: Emissions Monitoring Report 2022 methodology

This document provides additional technical details and sources to accompany the analysis in the NSTA's 2022 Emissions Monitoring Report.

A. IPCC data – upstream oil and gas categories

GHG emissions from the UK upstream oil and gas industry can be extracted from the NAEIdataset using the following relevant Intergovernmental Panel on Climate Change (IPCC) categories:

1A1cii – Manufacture of solid fuels and other energy industries

Source	Fuel Group	Activity Name
Gas terminal – fuel combustion	Petroleum	Gas oil
Oil terminal – fuel combustion	Petroleum	Gas oil
Upstream Gas Production – fuel combustion	Petroleum	Gas oil
Upstream Oil Production – fuel combustion	Petroleum	Gas oil
Gas terminal – fuel combustion	Gaseous fuels	Natural gas

Source	Fuel Group	Activity Name
Oil terminal – fuel combustion	Gaseous fuels	Natural gas
Upstream Gas Production – fuel combustion	Gaseous fuels	Natural gas
Upstream Oil Production – fuel combustion	Gaseous fuels	Natural gas

1B2a1 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Upstream Oil Production – Offshore Well Testing	Other emissions	Exploration drilling – amount of gas flared
Onshore Oil Well Exploration (conventional)	Other emissions	Number of wells per year

1B2a2 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Onshore Oil Production (conventional)	Other emissions	Crude oil
Oil Terminal – Direct Process	Other emissions	Non-fuel combustion
Oil Terminal – Other Fugitives	Other emissions	Non-fuel combustion
Upstream Oil Production – fugitive emissions	Other emissions	Non-fuel combustion
Upstream Oil Production – direct process emissions	Other emissions	Non-fuel combustion
Petroleum processes	Other emissions	Oil production

1B2a2 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Oil transport fugitives – pipelines (onshore)	Other emissions	Crude oil
Oil transport fugitives – road tankers	Other emissions	Crude oil

Source	Fuel Group	Activity Name
Upstream Oil Production – Offshore Oil Loading	Other emissions	Crude oil
Upstream Oil Production – Onshore Oil Loading	Other emissions	Crude oil

1B2a4 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Upstream Oil Production – Oil terminal storage	Other emissions	Non-fuel combustion

1B2b1 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Upstream Gas Production – Offshore Well Testing	Other emissions	Exploration drilling – amount of gas flared
Well exploration (unconventional gas) – all sources	Other emissions	Non-fuel combustion

1B2b3 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Gas Terminal – Direct Process	Other emissions	Non-fuel combustion
Gas Terminal – Other Fugitives	Other emissions	Non-fuel combustion
Upstream Gas Production – fugitive emissions	Other emissions	Non-fuel combustion
Upstream Gas Production – direct process emissions	Other emissions	Non-fuel combustion

1B2b4 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Upstream Gas Production – Gas terminal storage	Other emissions	Non-fuel combustion

1B2c1i – Upstream oil and gas - venting

Source	Fuel Group	Activity Name
Oil Terminal – Venting	Other emissions	Non-fuel combustion
Upstream Oil Production – venting	Other emissions	Non-fuel combustion

1B2c1ii - Upstream oil and gas - venting

Source	Fuel Group	Activity Name
Gas Terminal – Venting	Other emissions	Non-fuel combustion
Upstream Gas Production – venting	Other emissions	Non-fuel combustion

1B2c2i – Upstream oil and gas - flaring

Source	Fuel Group	Activity Name
Oil Terminal – Gas Flaring	Other emissions	Non-fuel combustion
Onshore oil Production – gas flaring	Other emissions	Non-fuel combustion
Upstream Oil Production – flaring	Other emissions	Non-fuel combustion

1B2c2ii – Upstream oil and gas - flaring

Source	Fuel Group	Activity Name
Gas Terminal – Gas Flaring	Other emissions	Non-fuel combustion
Upstream Gas Production – flaring	Other emissions	Non-fuel combustion

IPCC – NAEI data caveat

A caveat associated with using the NAEI dataset is that the total includes emissions from combined heat and power (CHP) plants adjacent to upstream facilities at Sullom Voe Terminal. The NSTA does not consider these facilities to be part of the UK upstream oil and gas industry. Unfortunately, these values can't be removed from the dataset. The total emissions from this facility are estimated to comprise a very small proportion of the total dataset.

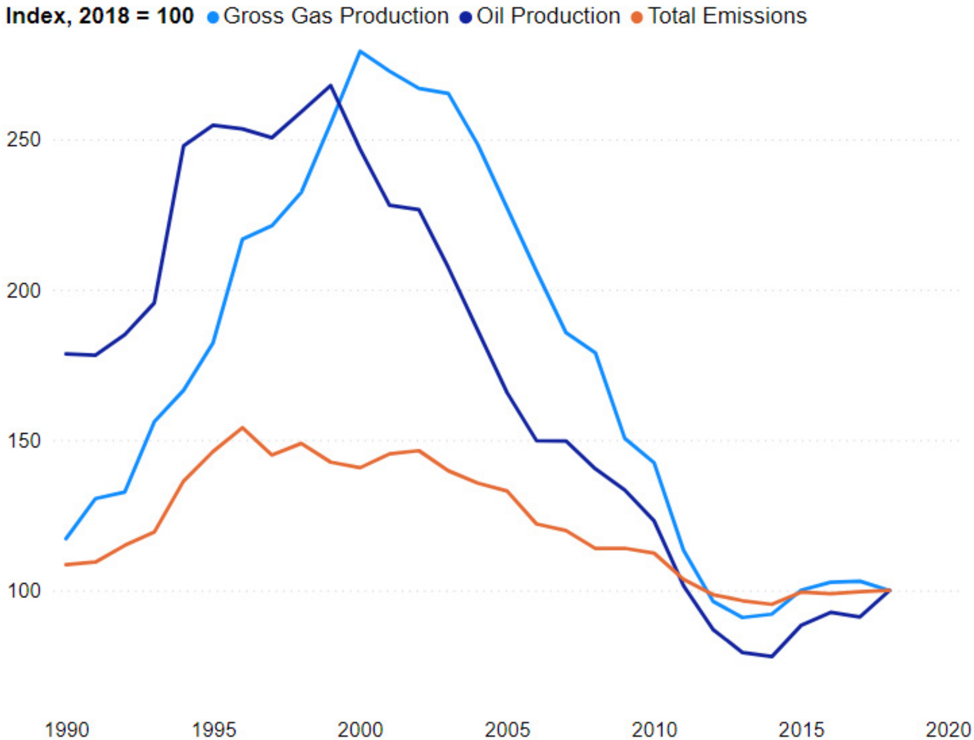
B. Global warming potential factors

Non-carbon dioxide GHGs have been converted to carbon dioxide equivalent (CO_2e) units using global warming potential (GWP) factors presented in the IPCC's Fifth Assessment Report (AR5) (table 8.7, page 714). The GWP factors used are without inclusion of climate-carbon feedbacks (no cc fb) and over a 100-year timescale.

Greenhouse gas	GWP 100 $_{\text{(cc fb)}}$
Carbon Dioxide (CO_2)	1
Methane (CH_4)	28
Nitrous Oxide (N_2O)	265

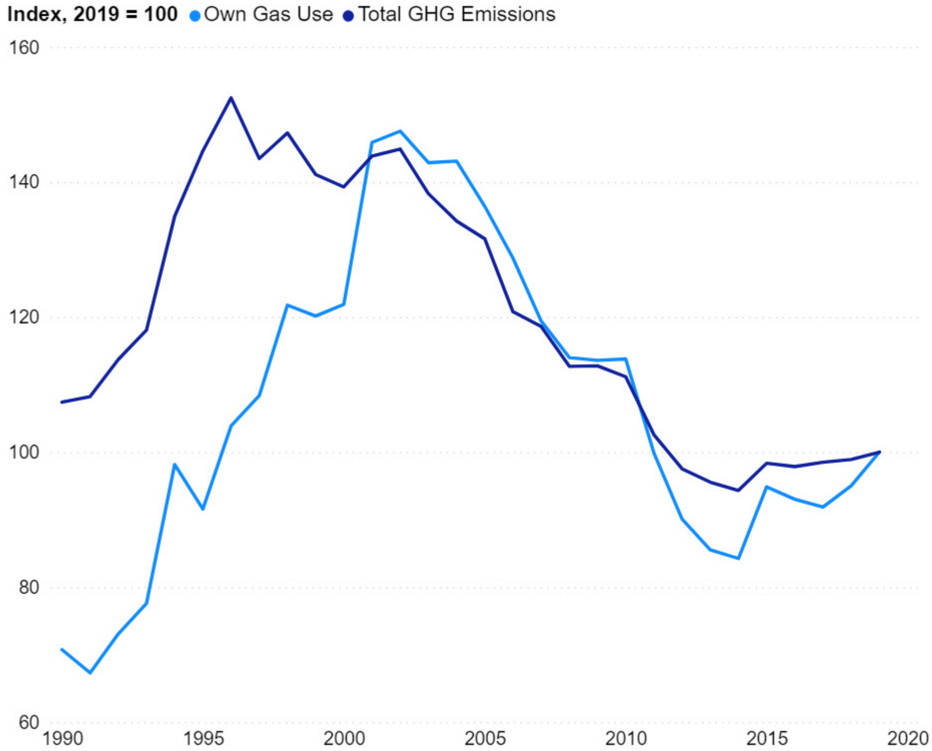
C. Relationship between emissions and oil and gas production

Figure 24 shows the relative change of UK Upstream Oil and Gas GHG emissions and production from 1990 to 2018.



D. Relationship between gas utilisation and overall emissions

Figure 25 shows the relative change of upstream utilisation of produced gas and overall emissions from 1990 to 2019. The two track each other well from around 2000 onwards.



E. Business as usual baseline emissions projections methodology

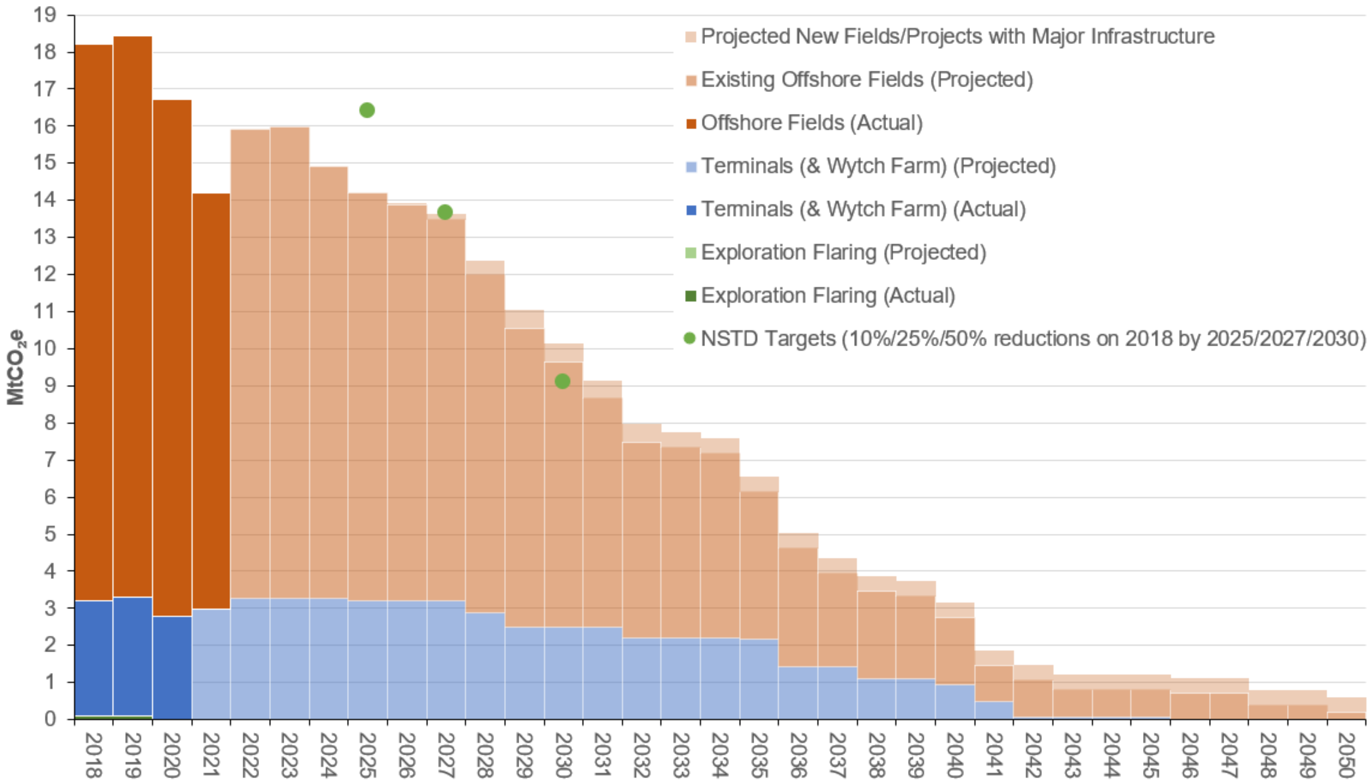
The NSTA has updated its bottom-up BAU projection of the sector's GHG emissions based on recent historical emissions data for all onshore and offshore installations using BEIS EEMS. Expected cessation of production dates are based on assessments of recent UKSS data for each installation. An allowance has also been made for a small number of major new developments which would materially increase GHG emissions. Inclusion of a new field in this list is without prejudice to BEIS or the NSTA granting consent to development.

For existing offshore installations which are expected to be in use after 2021 the NSTA has been guided by EEMS data for 2019–2021. For onshore terminals and Wytch Farm projections we have based this on verified CO_2 emissions for 2019 and 2020 from the EU ETS and for 2021 from the UK ETS with historic data for other GHGs for these facilities coming from the websites of the Environment Agency and Scottish Environment Protection Agency.

Emissions from exploration flaring are assumed to decline at 5% a year starting from 2020 levels as reported in the NAEI.

Current projections reflect best estimates of future emissions on a BAU basis, that is, without decarbonisation measures such as platform electrification and elimination of routine flaring.

The BAU projection of GHGs is summarised in the following chart:



Major updates to the BAU emissions projections this year include:

- Baseline emissions for 2018 have been revised down owing to updates in NAEI data.
- The use of AR5 without climate-carbon feedback GWPs in place of AR5 with climate feedback GWPs to calculate emissions in CO_2 equivalent (CO_2e) terms (see About Data section above).
- Recently approved projects that were previously categorised as new fields have been moved into existing offshore fields. The result is a shift to the right in the projected new fields emissions compared to last year.
- Cessation of production dates have been updated to reflect information from the latest UKSS.
- Projected emissions for a small number of recent and new installations are based on operators' emissions forecasts collected for the first time in the UKSS, as well as environmental statements for the developments.

It is important to note that the BAU emissions projections are not a forecast of upstream oil and gas GHG emissions and should not be used as such. The projections are based on an analytical approach that sets out to project historic data into the future. In this sense, the emissions projections are subject to high levels of uncertainty and are underpinned by the assumptions made on cessation of production dates and other relevant variables previously outlined.

F. Technical deployment scenarios for electrification abatement of oil and gas installations

The NSTA has produced a low, central and high case assessment of the sector's GHG technical abatement potential from the electrification of offshore facilities. This has been based on the following:

- A detailed list of installations being considered for electrification and whether the installation is estimated to be fully or partially electrified.
- Installation level power demand data calculated from data submitted to EEMS.
- Recent emissions histories for relevant installations and expected cessation of production dates based on latest UKSS data for each installation.
- Projected UK electricity grid emissions factors, sourced from the latest available data from BEIS (Data Table 1).
- Assumptions of 70% abatement for a fully electrified installation and 42% for a partially electrified installation.
- Variables between each of the modelled cases are:
  - Installations in scope
  - Whether facilities are fully or partially electrified
  - Projected UK electricity grid emission factors
  - Variations to power source between grid and offshore renewables

Methodology updates to the technical deployment scenarios this year include:

- Installation cessation of production dates are assumed to be fixed and consistent with the BAU baseline emissions projections.
- The low and central case assume first power in 2028, while the high case assumes first power in 2027.
- The list of potential installations and assets considered in the scenarios has been refined to reflect the most up-to-date data regarding electrification projects.

It is important to note that as with the BAU emissions projections the abatement potential estimated in the technical scenarios is not a forecast and should not be used as such. The scenarios are based on the NSTA's best understanding of the scope of projects that could be electrified and makes assumptions that are intended to capture a range of potential future deployment levels. In this sense, the technical abatement scenarios are subject to high levels of uncertainty

G. Flaring emissions abatement potential methodology

The NSTA has produced a projection of emissions abatement from the cessation of routine flaring by 2030. This estimate is acknowledged to be very much a low case as work is already being performed to cut routine flaring before 2030 by operators.
The methodology for estimated abatement via zero-routine flaring by 2030 is:

- Calculate historic trends of routine flaring per installation using NSTA flaring consents application data.
- Using this, assign each facility a predicted proportion of routine flaring going forwards.
- Produce a projection of flaring emissions out to 2050 using flare profiles provided in the UKSS and flare volume to CO_2 emission factors.
- Aggregate future installation level emissions attributed to routine flaring and subtract this from the total flaring emissions profile.

North Sea Transition Authority

North Sea oil and gas industry pledged

to halve emissions by 2030

Industry initiatives supported by NSTA action drive

early progress

Industry is

on track

to meet the 2025 and 2027 emissions targets

Bold measures will be needed to hit the 2030 goal of halving emissions

Four-fifths of offshore facilities cut emissions between 2020 and 2021

NSTA will continue to robustly **manage** and **track** performance