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Net Zero Targets and GHG Emission Reduction in the UK and Norwegian Upstream Oil and Gas Industry:

A Comparative Assessment

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Abstract

The recent adoption by the UK and Norway of net zero and climate neutrality targets by 2050 has galvanised the upstream oil and gas industry in both countries to adopt GHG emission reduction targets for 2030 and 2050 for the first time. Meeting these targets, ensuring an appropriate sharing of costs between investors and taxpayers and preserving investor confidence will present a lasting challenge to governments and industry, especially in periods of low oil and gas prices. The scale of the challenge on the Norwegian Continental Shelf (NCS) is far greater than on more mature UK Continental Shelf (UKCS) since the remaining resource base is much larger, the expected future production decline is less severe and the emission intensity on the NCS is already much lower (10 kg CO_2e/boe) than on the UKCS (28 kgCO_2e/boe) due to the long history of tighter emission standards and offshore CO_2 taxation. Norway is expected to deliver future CO_2 emission reduction through an extension of its existing power-from-shore investment programme. The high cost of such new investment, borne mainly by the state via the tax system, is a political and social choice made by Norway to reduce upstream CO_2 emissions without giving up its commitment to develop its remaining resources of more than 50 bn boe and to preserve the source of its prosperity.

In the UK upstream, the new industry target to reduce GHG emissions by 50 per cent by 2030 may demand less new capital but it will require the integration of emission abatement into the OGA's MER UK strategy, well-designed economic incentives, including possibly carbon pricing and fiscal reform, and behavioural changes from operators. The relatively short remaining economic life of many mature fields and the dispersed nature of offshore power demand penalises both power-from-shore and CCS as routes to least-cost emission reduction but future integration with offshore renewable electricity generation may offer abatement opportunities at larger installations or new field developments. Methane emissions have for some years been a blind spot for government and industry on the UKCS, amounting to 1.6 mt CO_2e in 2018, three times higher than on the NCS. The UKCS has the potential to reduce methane emissions significantly from flaring, venting and leakage through better emission reporting, a more robust consents regime and changes to operating practices.

Units of measurement

bbl	barrel (1 cubic metre = 6.29 barrels)
boe	barrel oil equivalent
mboe	million barrels oil equivalent
kt CO_2	thousand tonnes CO_2
mt CO_2	million tonnes CO_2
mt CO_2e	million tonnes CO_2 equivalent
MJ/m^3	megajoules per cubic metre

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1. Introduction

The recent adoption of more stringent 'net zero' and 'climate neutrality' decarbonisation targets by 2050 by the governments of the UK and Norway have implications for all energy consumers but particularly for energy-intensive industrial sectors such as the upstream oil and gas industry. The political attention on upstream greenhouse gas (GHG) emissions and emission reductions is particularly acute in Norway where the sector accounts for about 15 per cent of GDP and 27 per cent of total national emissions. Even in the UK, where the upstream oil and gas sector is now a small part of the UK economy and accounts for only 4 per cent of total UK GHG emissions, the sector attracts disproportionate attention because of the opposition of some NGOs to the production of hydrocarbons, the presence of listed international oil companies and its relative importance to the Scottish economy.

In 2020, the upstream industry on both the UK Continental Shelf (UKCS) and the Norwegian Continental Shelf (NCS) responded to the political imperative to contribute to the new decarbonisation agenda by announcing GHG emission reduction targets for 2030 and beyond. The processes by which these new non-binding targets were agreed were quite different in the two countries. The Norwegian state has a direct equity participation on the NCS, via Equinor, Petoro and Gassco, a stable body of industry regulation on economic and environmental matters and a well-established regulator, the Norwegian Petroleum Directorate (NPD). In the UK, the government lacks such direct levers, assets are owned and operated by a diverse range of private companies, environmental regulation of offshore emissions has been less stringent and more fragmented and the new sector regulator, the Oil and Gas Authority (OGA), is primarily responsible for resource management, not decarbonisation. Furthermore, emissions on the NCS have been subject to a CO_2 tax since 1991 but the UK has so far not extended the limited scope of onshore carbon taxation to the UKCS. These fundamental differences between the UKCS and NCS ensure that the policies and measures to achieve lower emissions are likely to be very different.

Within weeks of the adoption of new emission reduction targets in Norway, the upstream industry in both countries was plunged into serious difficulty by the collapse of oil prices and the onset of the Covid-19 viral pandemic which restricted manning of offshore installations, disrupted routine operations and delayed projects under development. The financial impact has already been severe and discretionary expenditure and investment plans have been reduced for at least the remainder of 2020 and into 2021.

On both the UKCS and NCS, the expected net decline in production between 2020 and 2050 will make a deep contribution to the net zero target by 2050 but in both countries the industry has adopted targets for 2030 which will, if they are to be reached, require investment in existing facilities. By increasing the demand for new capital to reduce emissions, the question of who pays for lower upstream emissions (upstream investors or taxpayers) and how governments can preserve fiscal revenues, competitiveness and investor interest has come to the fore. There is now the prospect in both countries that such investment will not be made without further lasting changes to the tax regime, especially if lower oil and gas prices persist. Already, the Norwegian government has agreed temporary changes to the upstream fiscal regime intended to allow projects approaching approval to proceed, to maintain industry investment and to preserve jobs. In the UK, the upstream industry continues to search for a comprehensive 'sector deal' with government to address investment, taxation, jobs and emission reduction.

This paper addresses the issue of GHG emissions from upstream oil and gas activities (exploration, production, processing and transportation) and the scope for future abatement on the UKCS and NCS. It does not address the much wider issue how the offshore continental shelf, as a geographical area, may contribute to the energy transition and decarbonisation in Europe through the further development of carbon capture and storage (CCS), offshore wind generation and hydrogen production. Successful least-cost decarbonisation in NW Europe is likely to utilise some of the existing assets, skills and expertise of the offshore upstream oil and gas industry in the integration of offshore CO_2 storage, renewables and hydrogen production but this much broader energy transition lies beyond the narrower scope of this current paper.

2. UK and Norwegian Climate Change Commitments

In 2019-20, the governments of both the UK and Norway, Europe's two largest producers of oil and gas, adopted new, more demanding, domestic targets for the reduction of greenhouse gas (GHG) emissions. In June 2019, the UK became the first country to enshrine binding GHG emission reduction targets in domestic law in setting a target of 'net zero emissions' by 2050. In February 2020, Norway submitted a more ambitious target of a 50-55 per cent reduction in emissions by 2030 in its Nationally Determined Contribution (NDC) in the Paris Agreement process and re-iterated its 2050 goal of 'climate neutrality'. The two countries have been for many years among the most active in promoting international agreement designed to mitigate climate change. Both countries are Annex 1 signatories to the original UN Framework Climate Change Convention (UNFCCC) and continue to actively support an ambitious agenda to implement the Paris Agreement. Despite similarities in their approach to international action, there are notable differences between the UK and Norway in the design of their own domestic targets, their chosen domestic policies and instruments and the implications of their new targets for their upstream oil and gas industry. This reflects above all the fundamental differences in the size and importance of the upstream industry in the two countries and its share of national gross GHG emissions. Figure 1 provides a tabular summary of the main emissions data and targets for the two countries.

In Norway, in the years 2015-19, oil and gas extraction accounted for 10-17 per cent of GDP and 10-20 per cent of government revenues, depending on commodity market conditions. In the more diversified UK economy, upstream activity in the same period contributed only 0.6-0.8 per cent of Gross Value Added (GVA) and its net contribution to government finances has been marginal in this period of $30-70/bbl oil prices.[1] In Norway, the industry is responsible for 27 per cent of total GHG emissions (52 mt CO_2e) whereas in the UK its share is much lower at about 4 per cent of total emissions of 466 mt CO_2e.[2]

[1] In the five fiscal years 2015-16 to 2019-20, the upstream sector contributed only 0.1% of UK government tax revenues, reflecting low prices, lower tax rates since 2016 and the repayment to operators of Petroleum Revenue Tax (PRT) for field decommissioning.

[2] UNFCCC Greenhouse Gas Inventory data for 2018.

Figure 1: UK and Norway GHG Emissions and Climate Change Targets

million tonnes CO_2 equivalent	UK		Norway	
Total GHG emissions in 2018 (mt CO_2e)				
Emissions excluding LULUCF	465.9		52.0	
LULUCF emissions/removals	(10.0)		(23.7)	
Emissions including LULUCF	456.0		28.4	
% change from 1990 baseline	-43%		-31%	
Composition of emissions by gas 2018		% share		% share
CO2	380.9	82%	43.8	84%
CH4	51.9	11%	4.8	9%
N2O	19.2	4%	2.3	5%
Other GHGs	13.9	3%	1.1	2%
	465.9		52.0	
National GHG emission targets*				
2030 target (mt CO2e)	345		19 - 21	
% reduction v 1990	57%		50-55%	
2050 target	Net zero		90-95% reduction	
Total emissions within EU ETS in 2019	118.6		24.6	
% share of total GHG emissions	*25%*		*49%*	
Upstream EU ETS emissions (2019)	15.1		12.2	
Upstream oil and gas emissions 2018 (mt CO_2e)				
CO_2	17.2		13.7	
Methane	1.6		0.5	
Total GHGs	18.9		14.2	
% share of national emissions	*4%*		*27%*	
Offshore	16.0		11.8	
Onshore	2.9		2.4	
	18.9		14.2	
Combustion	13.1		12.7	
Flaring	4.4		0.9	
Venting	0.9		0.2	
Other fugitive	0.5		0.3	
	18.9		14.2	
Oil and gas production in 2019 (mboe)				
Oil	403		634	
Gas (gross)	268		725	
Total oil and gas	671		1359	
million boe/day	*1.84*		*3.72*	
GHG emission intensity in 2018 (kg CO2e/boe)	28.0		9.9	

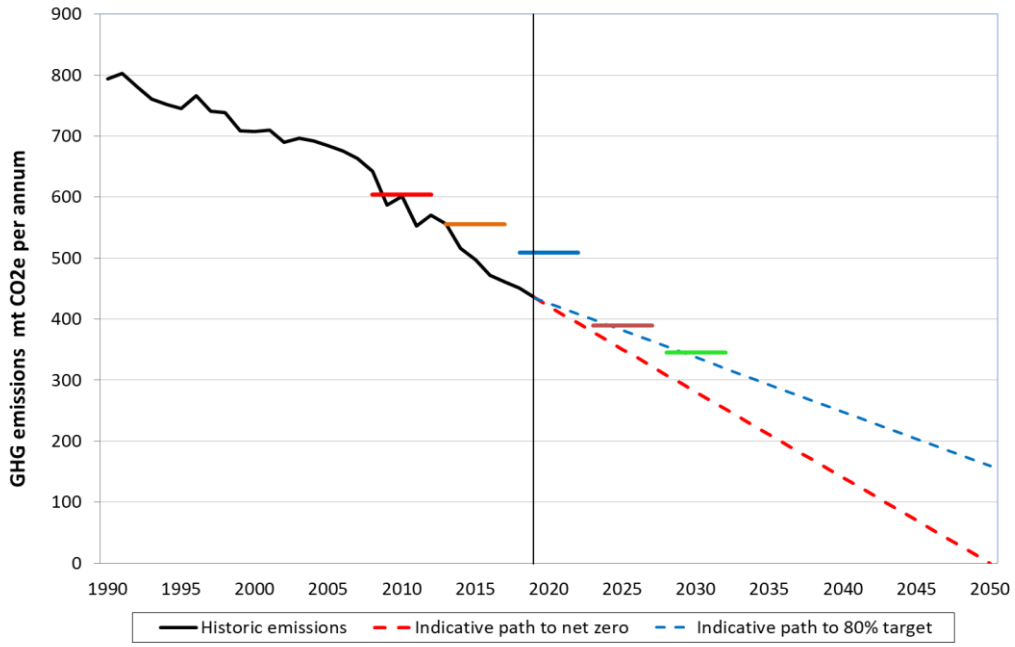
* UK targets are based on the 'net carbon account' (476 mt CO2e in 2018), not actual emissions.

Source: UNFCCC, BEIS, CCC, Statistics Norway, NPD, MInistry of Climate and Environment

2.1 UK's carbon budgets set framework for progressive decarbonisation

UK climate change policy and emission reduction targets are set within the framework of the Climate Change Act (CCA) 2008 and the treaty obligations assumed under the Paris Agreement in 2015. Under the provisions of the CCA, the UK sets a series of five-year carbon budgets, proposed by the advisory Committee on Climate Change (CCC) and approved by the government. The Fifth Carbon Budget (2028-32) is already legislated under the CCA and the CCC will publish its proposals for the Sixth Carbon Budget (2033-37) in December 2020. In reviewing the progress towards the carbon budget targets already legislated, before the Covid-19 pandemic, the CCC judged that government's existing policies would not be sufficient to meet either the Fourth Carbon Budget (2023-27) or the Fifth (2028-32[3]). At the time of the UK's departure from the EU, the UK's Fifth Carbon Budget, which set a reduction in GHG emissions of 57 per cent compared to 1990, was more demanding than the implied emission reduction targets for the UK in EU legislation. However, the EU is expected in 2021 to agree to raise its ambition for 2030 from a reduction of 40% to 55%, making UK and EU targets for 2030 more closely aligned.[4]

Figure 2: UK Carbon Budgets and Net Zero 2050 Target



Source: CCC Progress Report to Parliament 2020

The original CCA passed in 2008 set a target of an 80 per cent reduction in GHG emissions by 2050. In June 2019, the government approved the recommendation of the Climate Change Committee (CCC) that the UK should adopt in law a net zero GHG emissions target for 2050.[5] The CCC had recommended that this net zero target should apply to the entire UK economy, including aviation and shipping, and that it should be achieved entirely through domestic emissions reduction without relying on international carbon credits. The legislation approved by Parliament in June 2019 does not implement the CCC's recommendation entirely since it leaves open the possibility of using international carbon credits to meet the new net zero target and allows a review of the commitment in 2024.

The UK formally left the European Union on 31 January 2020 and will not be bound by EU climate change legislation and emission reduction targets after the end of the transition period on 31 December

[3] Climate Change Committee Progress Report to Parliament 2000
[4] European Commission communication 'Stepping up Europe's 2030 climate ambition', 17 September 2020.
[5] 'Net Zero: The UK's Contribution to Stopping Global Warming', CCC, May 2019

2020. However, it may choose to co-ordinate its policy and diplomatic efforts in this area with that of the EU beyond the end of the transition period. The EU-UK Withdrawal Agreement reached in 2019 requires a 'level playing field' in future trading relations but it does not require continued UK participation in the EU Emissions Trading Scheme (EU ETS). In June 2020, the UK government announced its intention to introduce a new UK ETS which could operate on a stand-alone basis or be linked to the EU ETS, possibly in conjunction with a new UK Carbon Emission Tax. The first phase of the UK ETS would run from 2021 to 2030 in parallel with Phase IV of the EU ETS, and would include a transitional auction reserve price of £15/tonne. The final form of the UK's new emission trading arrangements sector may not be finalised until new EU-UK trading arrangements are agreed.

The UK upstream oil and gas industry in 2018 was responsible for 18.9 mt CO_2e of GHG emissions, or about 18% of total industrial emissions. The new net zero target in 2050 does not include explicit targets for individual sectors but the CCC emphasises it will mean 'close to net zero' for all industrial sectors. It is a matter for the government, advised by the CCC, as to how it pursues decarbonisation and how the costs of the energy transition are to be fairly distributed between consumers, producers and taxpayers. Decarbonisation presents a severe challenge for all sectors but the public attention on emissions from hydrocarbons has ensured that the UK upstream oil and gas industry has been among the first sectors to present its emission reduction plans.

2.2 Norway: climate targets present greater challenge for government and industry

Norway's climate change commitments and targets are set by a combination of national legislation and targets, close coordination with the EU over emission reduction and its obligations in the Paris Agreement in 2015. After Norway ratified the Paris Agreement in 2016, the Storting adopted a resolution that Norway should be 'climate neutral' in 2030 but this was not enshrined in law. The Climate Change Act in 2017 requires a reduction in GHG emissions of 40 percent by 2030 and sets out an objective 'to become a low emission society' by 2050 by reducing emissions by 80-95% compared to 1990. In 2019, the government increased this target to a 90-95% reduction,[6] but so far this has not yet been translated into domestic law.

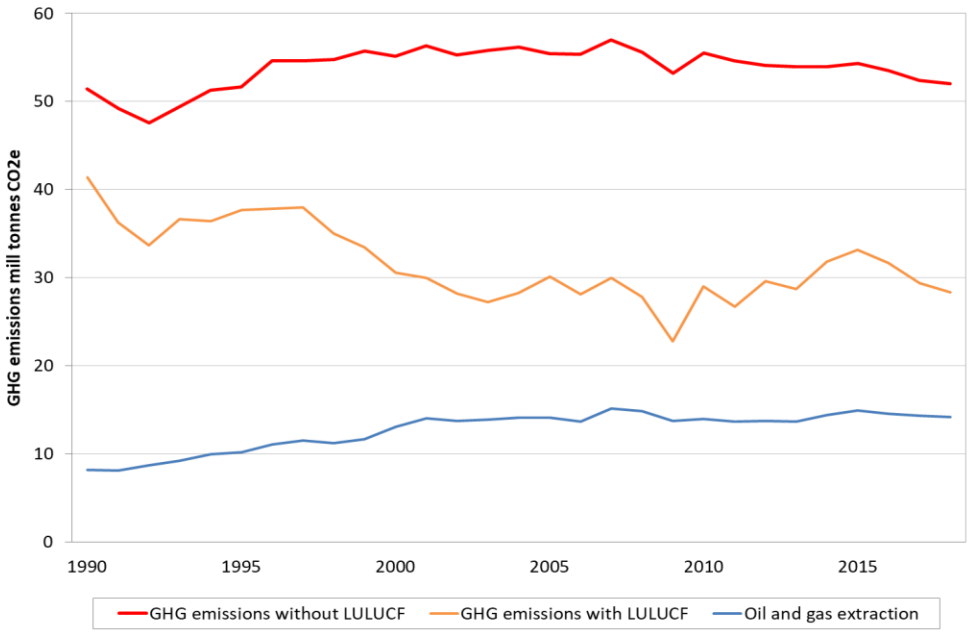
Even though Norway is not an EU member state, it closely co-ordinates its climate policy with the EU as a member of the European Economic Area (EEA). Indeed, Norwegian climate policy is developed and expressed by reference to the EU's targets and to its own obligations in the Paris Agreement. Almost 80 per cent of national CO_2 emissions are subject to the national CO_2 tax, which applies at the highest rate to aviation and to the upstream oil and gas industry, and almost half its emissions fall within the scope of the EU ETS. In 2019, Norway agreed to adopt the EU 2030 targets and its associated EU legislation.[7] Indeed, as the UK has dis-engaged from EU climate targets, Norway has aligned itself more closely with them. In February 2020, Norway was among the first countries to adopt a revised Nationally Determined Contribution (NDC) within the Paris Agreement, aiming for a reduction of 50-55% in GHG emissions by 2030 in anticipation of a similar future commitment by the EU.

Norway has earned a reputation as a leader in international climate change policy but it is highly unusual among developed Annex 1 countries in having total GHG emissions in 2018 (52 mt CO_2e) higher than in 1990 (51.5 mt CO_2e[8]). The evolution of Norway's reported emissions since 1990 is shown in Figure 3. One of the main reasons for the stability of emissions since 1990 was the progressive development of its offshore oil and gas resources. As oil and gas production rose from 2.2 mboed/ in 1990 to 3.9 mboe/d in 2018, GHG emissions from the sector increased from 8.2 mt CO2e to 14.2 mt CO_2e despite efforts to contain the rise. The upstream industry is today the largest source of national GHG emissions, accounting for 27 per cent of total emissions from 2015 to 2019. Offsetting relatively high per capita

[6] Norway's Fourth Biennial Report under UNFCCC, Norwegian Ministry of Climate and Environment, January 2020.
[7] EU Effort Sharing Regulation 2018/842 and EU LULUCF Regulation 2018/841
[8] UNFCCC data 1990-2018. Provisional emission data released by Statistics Norway in June 2020 show a slight decline in total GHG emissions in 2019 which would take total emissions slightly below the 1990 figure.

emissions in Norway is the carbon sink provided by its extensive and increasing forest cover which absorbed almost half its emissions in 2018 (24 mt CO_2e).

Figure 3: Norway Reported GHG Emissions 1990-2018



Source: UNFCC Greenhouse Gas Inventory database, 2020

In reducing its net carbon emissions, Norway has relied extensively in the past on developing its domestic carbon sink in forestry, on carbon trading and on contributing to accredited programmes in developing countries to abate emissions and to preserve natural sinks. In the future, this reliance on carbon trading and international credits is likely to continue as it seeks to achieve its long-term climate targets since it remains committed to developing its offshore oil and gas resources in a responsible manner. For Norway in particular, a successful completion of the stalled international negotiations over the Paris Agreement 'rule book', in particular Article 6 concerning carbon markets and international co-operation, is essential to the achievement of its longer-term 2050 goal of 'climate neutrality'. Since the future international carbon trading regime is not yet agreed, it is not possible to say by how much Norway will have to reduce its own GHG emissions to meet its stated aims. It is in this context, that the minority Norwegian government turned its attention in 2019 and 2020 to reducing emissions reduction at home and in particular in the upstream oil and gas sector.

3. UK and Norwegian Upstream Emissions: Sources and Composition

3.1 Upstream GHG emissions and emission intensity

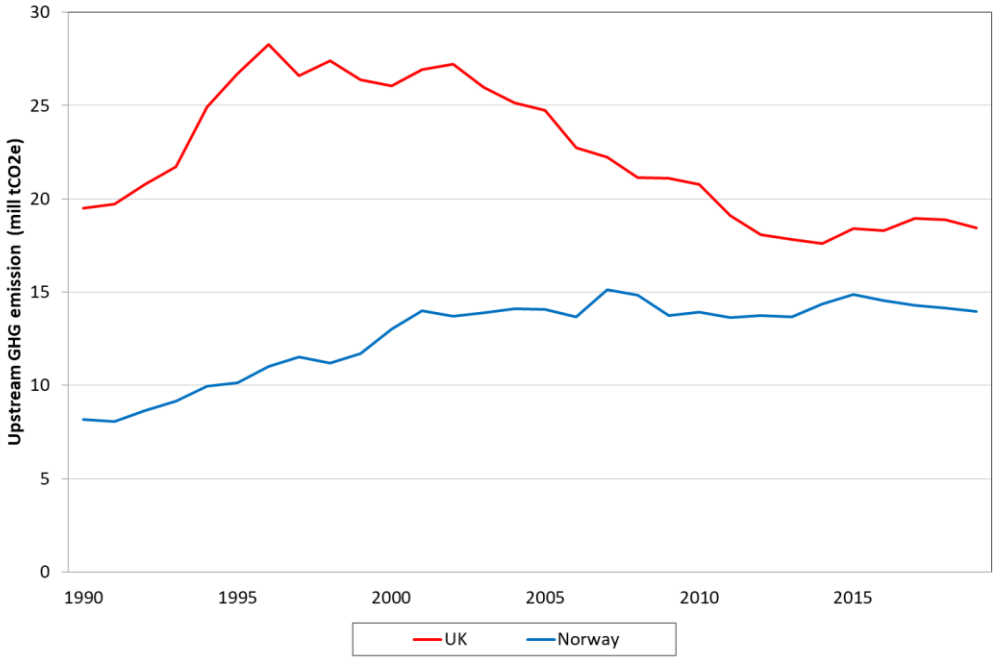
Upstream oil and gas activities, comprising exploration, production, transportation, processing and vessel loading, give rise to emissions of three GHGs: carbon dioxide (CO_2), methane (CH_4) and, in smaller quantities, nitrous oxide (N_2O). These emissions to the atmosphere arise principally from combustion of hydrocarbons for power generation and to drive compressors, pumps and engines, from flaring and venting and from unintended fugitive emissions. Flaring of gas, which takes place mainly at offshore oil fields for safety or operational reasons, causes emissions of CO_2 and methane through incomplete combustion. The more damaging venting of gas to the atmosphere is less common and occurs mainly at onshore oil and gas terminals.[9]

[9] Table E1, Digest of UK Energy Statistics (DUKES), BEIS, July 2020

In the UK and Norway, emissions of CO_2 and methane come from both offshore fixed and floating installations and from onshore terminals and plants used to process oil or natural gas. Emissions data are reported by operators to government or regulators and aggregate emissions within the national territory are then reported to the UNFCCC each year by sector and sub-sector according to definitions set out by the IPCC. Each GHG is ascribed a Global Warming Potential (GWP) so that all GHGs are reported on a consistent basis in CO_2 equivalent units. The GWPs used in the latest national and sectoral data to 2018 are from the Working Group 1 of the IPCC Fourth Assessment Report (AR4) 2007.[10]

Reported GHG emissions from all UK upstream operations were 18.86 million tonnes CO_2e ($mtCO_2e$) in 2018.[11] This represents about 4 per cent of total UK gross GHG emissions of 466 $mtCO_2e$. GHG emissions from the Norwegian upstream sector are reported to have been 14.16 $mtCO_2e$, accounting for about 28 per cent of total Norwegian gross emissions.[12] Figure 4 shows the evolution of upstream emissions for both countries since 1990. UK upstream emissions in recent years have been well below their peak of 26-28 $mtCO_2e$ per annum from 1996 to 2002 while NCS emissions have been stable at 14-15 $mtCO_2e$ since 2000. Figure 4 includes preliminary estimates for 2019 in both the UK and Norway, based on verified EU ETS CO_2 emissions. These estimates indicate a minor fall in 2019, to 18.5 $mtCO_2e$ in the UK and to 13.9 $mtCO_2e$ in Norway. Final emissions data for 2019 will be released in early 2021.

Figure 4: UK and Norwegian Upstream GHG Emissions 1990-2019



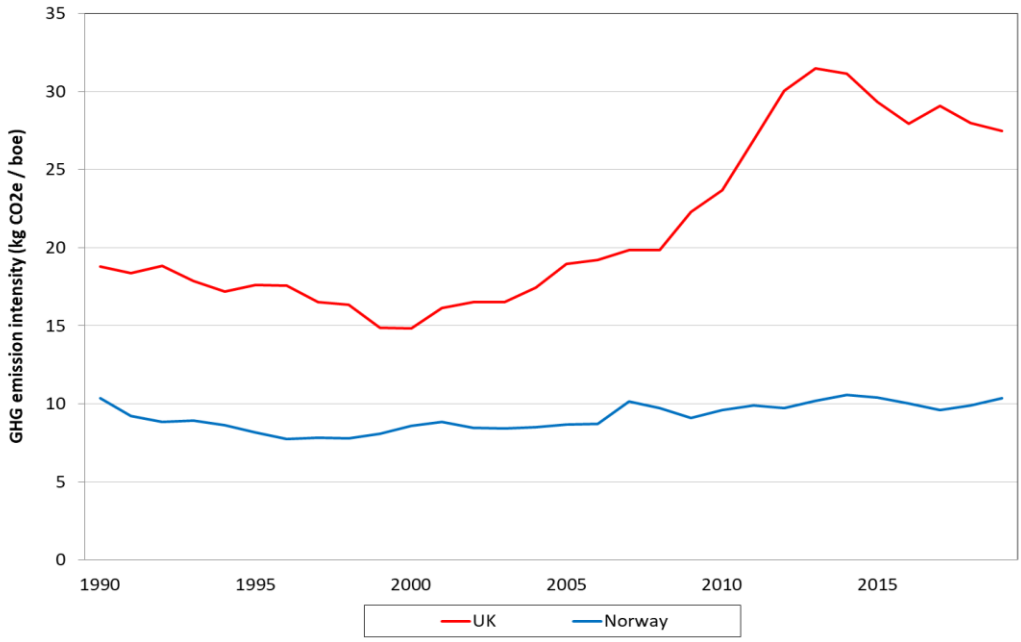
Source: BEIS, Norwegian Ministry of Environment

Once upstream GHG emissions in the UK and Norway are expressed relative to their production of oil and gas, the sharp difference in emission intensity becomes very evident. Figure 5 shows upstream emission intensity, expressed in kg CO_2e per boe produced, from 1990 to 2019. It shows that the emission intensity has been consistently higher on the UKCS than on the NCS. According to data gathered and published by the International Association of Oil and Gas Producers (IOGP), Norway has

[10] The IPCC's AR4 established a GWP for methane on a 100-year horizon of 25. Its Fifth Assessment Report (AR5) published in 2014 recommended raising its GWP_{100} to 28.
[11] National Atmospheric Emissions Inventory (NAEI) database, July 2020
[12] Statistics Norway, Emissions to Air, June 2020

been, and remains, one of the least emission-intensive producing countries in the world.[13] Figure 5 also highlights the adverse trend in emission intensity on the UKCS between 2000 and 2013, a period in which oil and gas output fell by 58 per cent. Total UKCS emissions declined in that period but emission intensity more than doubled from 15 kgCO_2e/boe to 31 kgCO_2e/boe. In the same period, NCS emission intensity also rose, from 8 kgCO_2e/boe to 10 kgCO_2e/boe, as output declined and stabilised thereafter.

Figure 5: UK and Norwegian Upstream GHG Emission Intensity 1990-2019



Source: BEIS, NAEI, EU ETS, Ministry of Environment

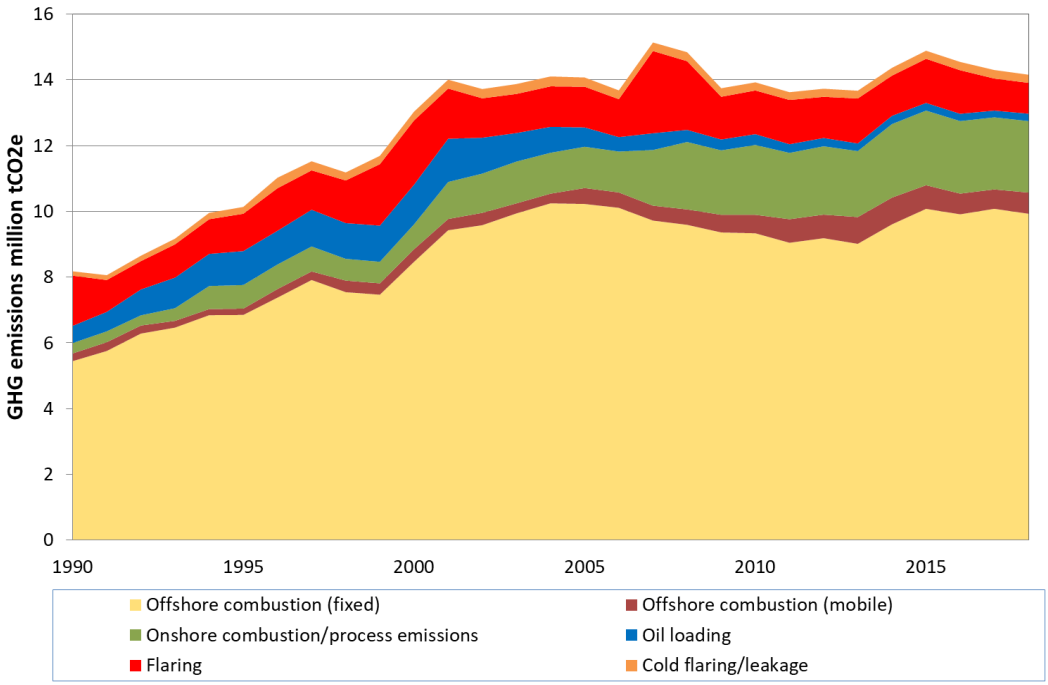
3.2 Norwegian upstream emissions

In Norway, emissions from 'stationary combustion' from turbines, engines and turbines and in connection with well testing accounted for 12.7 mt CO_2e, or 90 per cent, of total upstream GHG emissions in 2018.[14] The balance (1.5 mt CO_2e) came from flaring, process emissions at terminals, oil loading and cold venting and leakage, as illustrated in Figure 6. Emissions from flaring of gas offshore and onshore (0.9-1.3 mt CO_2e per annum) has varied in recent years with fluctuations in operations at major fields. Offshore facilities were the source of 83 per cent of total NCS GHG emissions; onshore oil facilities and gas processing plants[15] emitted 2.4 mt CO_2e from combustion, flaring and leakage. In recent years, combustion emissions at offshore installations and onshore terminals have been relatively stable at about 11.5 mt CO_2e, even when production was increasing, thanks in part to the connection of more offshore facilities to the onshore grid, displacing gas-based power generation offshore.

The corollary of the restrictions on flaring and venting on the NCS and the dominance of combustion as a source of GHG emissions on the NCS is that 96-97 per cent of reported emissions are of carbon dioxide. Methane emissions in 2018 amounted to 0.49 mt CO_2e, mainly as process emissions from 'cold flaring and leakage'. This represents an exceptionally low methane emission ratio of 0.03 per cent weight by international standards, reflecting what is widely regarded as a 'tight' upstream system with regulations and practices designed to minimise flaring, venting and fugitive emissions.

[13] IOGP atmospheric emissions survey database, 2020.
[14] Emissions to Air, GHGs by economic activity and pollutant, Statistics Norway, 2020 Norway
[15] The principal onshore gas processing plants at Karsto, Kollsnes, Nyhamna and Melkoya.

Figure 6: NCS GHG Emissions by Source 1990-2018



Source: Ministry of Environment, Statistics Norway

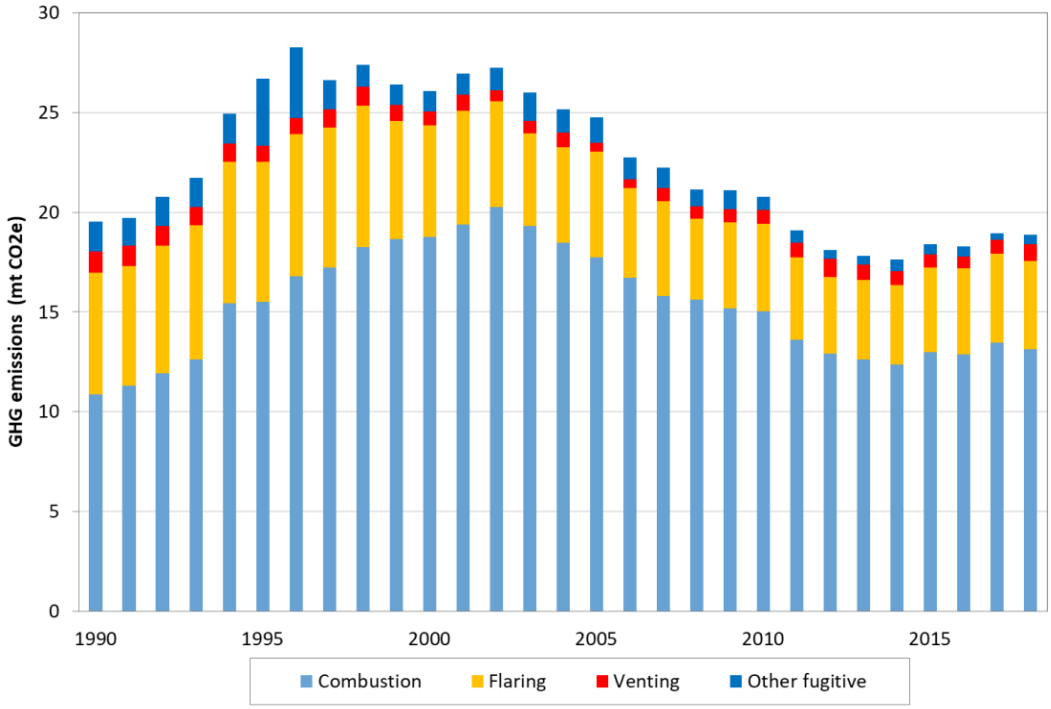
3.3 UK upstream emissions

The sources of UK upstream GHG emissions present a very different picture from that of the Norwegian Continental Shelf. In the UK, combustion is the largest source of emissions but flaring and venting emissions account for more than 25 per cent of total emissions because regulation has not been as stringent as in Norway. Figure 7 shows the source of UK emissions from 1990 to 2018, as reported in the national emission inventory. In recent years, combustion of gas and oil products (diesel and LPG) accounted for about 70 per cent of total GHG emissions (13.1 mt CO_2e in 2018). The remaining 30 per cent, categorised as 'fugitive emissions' came from flaring, venting and leakage. Flaring alone has been by far the largest non-combustion category, accounting for 4.4 mt CO_2e in 2018. The corollary of the significant proportion of non-combustion emissions on the UKCS is that methane accounts for a higher share (9 per cent) of total reported emissions than on the NCS. Total reported methane emissions in 2018 were 1.6 mt CO2e, more than three times the level reported on the NCS.

The detailed classification of emissions in the UK national inventory attributes all GHG emission to either oil or gas production despite the widespread co-production of oil and gas together at numerous UKCS oil and gas condensate fields.[16] Oil operations are reported to account for 73 per cent of all emissions in 2018, considerably higher than the 59 per cent share by energy content of oil in UKCS production. According to the NAEI data, UKCS oil production is much more emission-intensive (35 kg CO_2e/boe in 2018) than gas production (18 kg CO_2e/boe). This difference is certainly consistent with the lower energy-intensity of much of the gas-producing Southern North Sea (SNS) and the recent commissioning of more complex, energy-intensive oil fields. However, the extensive co-production of liquids and gas, especially in the Central North Sea (CNS), means that such estimates may not be entirely reliable.

[16] National Atmospheric Emissions Inventory database, July 2020

Figure 7: UK Upstream GHG Emissions by Source 1990-2018



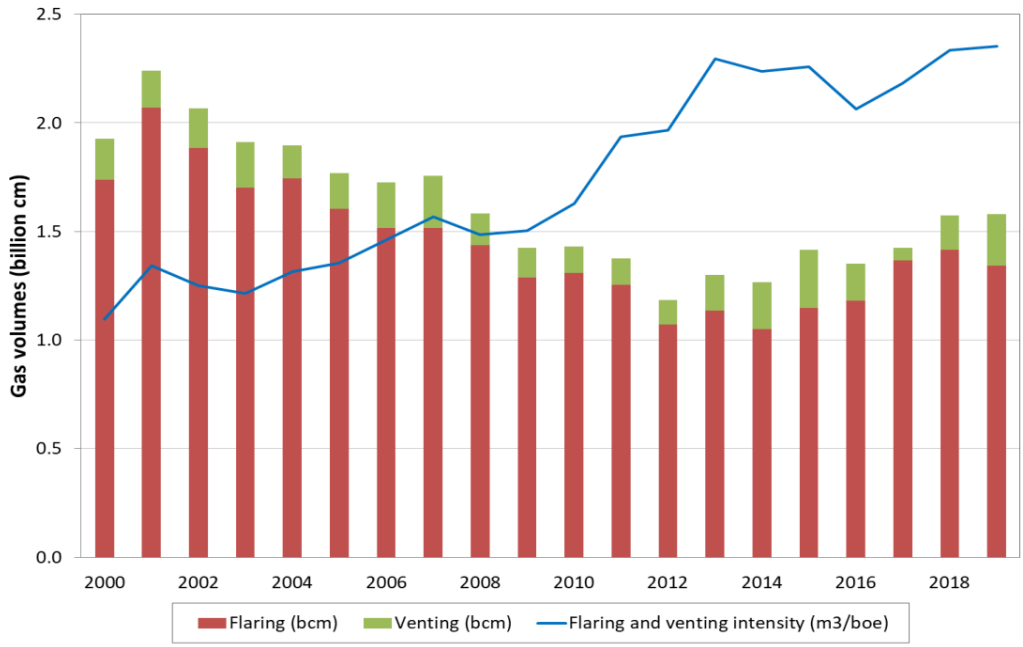
Source: UK National Atmospheric Emissions Inventory (NAEI)

The higher incidence of gas flaring at UKCS offshore facilities is to some extent a consequence of the greater dependence on gas for electricity generation on the platforms. The consequence of greater flaring and venting on the UKCS is the much higher reported methane emissions in the UK upstream than in Norway. Flaring will in some operating conditions be necessary for safety reasons but the scale of the difference suggests that something other than adherence to strict safety standards is responsible. Both activities on the UKCS require consent under the Petroleum Act 1998 and the operator must seek a permit issued by the OGA which will specify the volume and duration of the authorisation.

Figure 8 shows the volume of UKCS gas wasted or lost through flaring and venting between 2000 and 2019. In 2019, almost 1.6 bcm of gas, mainly methane, was flared (1.34 bcm) or vented (0.24 bcm). More than 90 per cent of flaring is of associated gas at offshore oil fields whereas most of the gas vented is from onshore terminals. Despite industry initiatives to reduce non-routine flaring[17], since 2012 the volume of gas flared or vented on the UKCS has risen steadily, broadly in line with production. The chart also shows clearly that the intensity of gas lost through flaring and venting has risen steadily over the last 20 years.

[17] For example, the World Bank's 'Zero Routine Flaring by 2030' initiative

Figure 8: UK Upstream Gas Flaring and Venting 2000-19



Source: DUKES 2020, BEIS

3.4 Data sources and data quality

The quality of measurement, reporting and verification (MRV) of GHG emissions in the UK and Norway is high by international standards but there is still a wide range of uncertainty surrounding some of the reported estimates of upstream emissions, notably of methane. Therefore, questions still arise over the accuracy, completeness and consistency of the published data, particularly in regard to fugitive emissions from flaring, venting and leakage. The verification by accredited entities within the EU ETS and the NCS CO_2 tax provide a higher degree of confidence in CO_2 emissions than for other GHGs. In both countries, operating companies are the principal primary source of emissions estimates which are later gathered and reproduced by the UK's National Atmospheric Emissions Inventory (NAEI) and by the Norwegian Environment Agency and Statistics Norway (SSB[18]). Some discrepancies remain between industry and public sector sources arising from differences in the scope of relevant domestic legislation, the classification of sub-sectors and activities, the reporting practices of operators and the extent of external verification. A list of statistical data sources is set out in the Sources and Bibliography.

In the UK, the EEMS industry reporting system to which operators submit suffers from some inconsistencies, the complexity of the classification of emission sources, the infrequency of submissions and a reliance on operators' self-reporting. An update of the 2008 EEMS guidance notes for operators is probably overdue to improve accuracy and consistency. In Norway, the publication by the NPD of monthly data on flaring, cold venting and fuel use for each upstream installation provides a higher degree of transparency over emission-related activities than in the UK. Recent changes to emission factors and to reporting guidelines have been responsible for a recent sharp decline in NOROG's reported annual methane emissions.[19] Although such changes may be justified, they tend to highlight questions about the robustness of reporting methodology and data accuracy in both countries. This attention on emission data quality can be expected to intensify since the industry has adopted new emission reduction targets.

[18] UK operators report emission data to OPRED/BEIS through the Environmental Emissions Monitoring System (EEMS). Norwegian operators report via the EPIM Environmental Hub (EEH) to NOROG; the Norwegian Environment Agency has powers to verify the operators' submissions.
[19] NOROG Environmental Report 2018

4. UKCS and NCS resource development and emission regulations

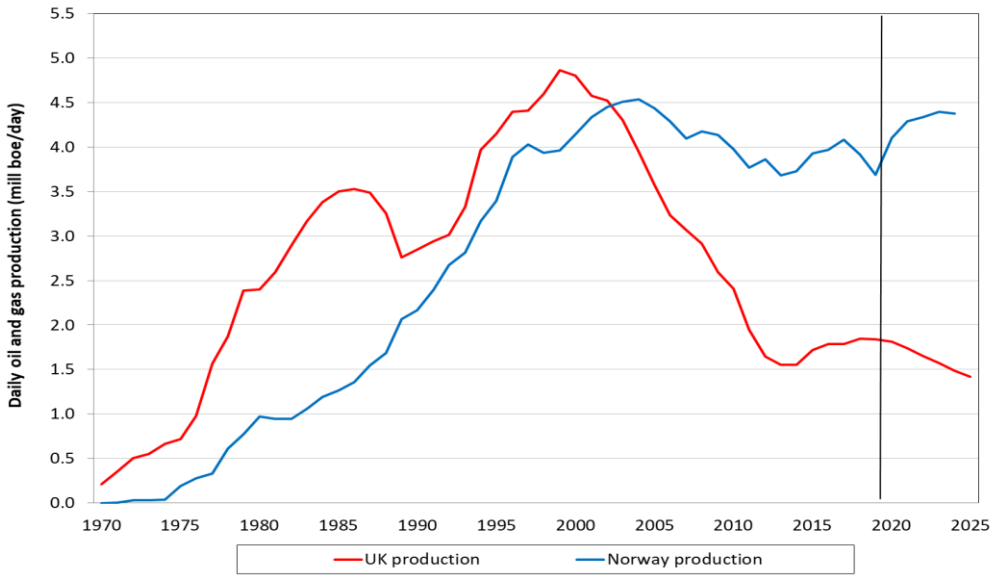
4.1 History of resource development

The scale and composition of GHG emissions from the UK and Norwegian upstream oil and gas sectors in 2020, and the scale of the task to reduce emissions in future, owe much to the contrasting history of offshore development and regulation in the two countries. The developmental differences between the UKCS and the NCS reflect not only geographical features such as the proximity of discovered resources to end-user markets, the depth of water and the more severe climate on the NCS but also to important political choices about the role of the state, the extent of economic regulation of infrastructure and the stringency of environmental regulation regarding emissions of local pollutants and GHGs to air and water.

After 1979, the UK adopted a market-led approach to development of the UK's offshore resources with minimal state intervention beyond the setting of licence obligations. In the early phase of UKCS development, field approvals were granted which permitted, in many cases, flaring and venting of gas for safety or operational reasons. In contrast, Norway chose at the very beginning to carefully guide resource development of the NCS through state ownership in Statoil (now Equinor), a strong commitment to recover, not to flare or vent, natural gas and stringent regulations on local and GHG emissions from offshore facilities. These early political decisions have had a lasting impact on historical upstream GHG emissions and they continue to influence the options and opportunities for emission reduction in the future because of the long-lived nature of most infrastructure assets.

Broadly speaking, resource development on the UKCS preceded development on the NCS by about a decade. Offshore production technology developed quickly in the 1970s and 1980s, led by the operating experience in the UK North Sea, towards smaller, lighter and more energy-efficient installations. Each generation of offshore production technology tended to mark an improvement in resource recovery and energy efficiency. Given the long-lived nature of offshore assets and the difficulty and cost of retrofitting later improvements, the choice of production system prevailing at the time of the initial field development application effectively determined the extent of emissions over the life of the field and the associated infrastructure. Norwegian projects may have to some extent benefited from lessons learned on the UKCS but it was primarily the tougher regulations on flaring and venting, the introduction of the offshore carbon tax in 1991 and electrification of many offshore facilities which ensured that very low emission intensity was embedded in NCS operations from almost the very beginning.

Figure 9: UK and Norway Oil and Gas Production 1970-2025



Source: BEIS, OGA projections, NPD, 2020

Figure 9 shows the annual history of oil and gas production from the UKCS and NCS from 1970 to 2019 and official short-term projections of output to 2024-25 published at the beginning of 2020, before the onset of the Covid-19 pandemic. The long-term decline in UK production since 2000 was reversed between 2013 and 2018 but the OGA expects the decline to resume again in 2020 and to fall to 1.4 mboe/d (gross) in 2025. At the end of 2019, remaining 2P reserves of oil and gas on the UKCS were estimated to be 5.3 billion boe and the range of future recoverable resources remains in the lower half of the long-standing range of 10-20 billion boe.

On the NCS, total hydrocarbon production peaked at 4.5 mboe/d in 2014 and declined gradually to 3.7 mboe/d in 2019. Before the onset of the Covid-19 pandemic, the NPD expected output to rise to a new peak of 4.4 mb/d in 2023-24 as output from the giant Johan Sverdrup field increased but we expect these projections may be revised down somewhat in future. At the end of 2019, remaining reserves of oil and gas on the NCS were estimated at 27 billion boe and total remaining recoverable resources were put at 52 billion boe. Both remaining reserves and resources on the NCS are roughly five times greater than those on the more mature UKCS and successive Norwegian government have so far remained committed to their development.

4.2 Emission regulation framework in UK and Norway

Climate change, or 'global warming', was not prominent in UK or Norwegian government legislation and regulation of offshore resource development before the mid-1980s. Early legislation in both countries comprised a framework Petroleum Act and pollution control laws focused principally on the local environment and operational safety. In Norway, the greater emphasis on the economic recovery of natural gas in field development approvals and severe restrictions on flaring and venting of gas had the effect of reducing CO_2 and methane emissions. However, climate change abatement was not the explicit aim of Norwegian legislation before the release of the Brundtland Commission report on 'sustainable development' in 1987.[20] Norway adopted explicit policies to discourage upstream CO_2 emissions very much earlier than the UK. In 1991, Norway introduced the first upstream carbon tax on all CO_2 emissions from offshore installations to supplement controls on local emissions and flaring. By contrast, the UK has preferred to rely on emission trading and the EU ETS on the UKCS, and has never applied a tax on emissions to the upstream sector.

In Norway, GHG emissions from activities which come within the scope of petroleum legislation are regulated under the Petroleum Act, the CO_2 Tax Act, the GHG Emission Trading Act and the Pollution Control Act which requires operators to use the best available technology (BAT), to apply for a permit for any emissions to air and to observe specific emissions limits. Any operator submitting a Plan for Development and Operation (PDO) to the Ministry of Petroleum and Energy (MPE) for approval must submit a summary of the energy needs and an assessment of the costs of supplying power from the onshore rather than from offshore gas turbines. Once a field or installation is in operation, the operator is also required to report all emissions to air and water to a national database created and administered by the Norwegian Oil Industry Association (NOROG[21]).

In 2019, the CO_2 tax on upstream activities stood at NOK 1.08/m^3 for the combustion of gas, equivalent to NOK 462/tonne CO_2 or €47/tonne CO_2. This was raised to NOK 1.15/m^3 in 2020. NCS operators are also within the scope of the EU ETS where the cost of allowances (EUAs) in 2019 added a further €24/tonne CO_2. The effect of the CO_2 tax since 1991 has been to encourage energy efficiency in facilities design and the supply of low-carbon power from shore, to reduce gas flaring and to support the development of CCS. However, the quantitative impact of the CO_2 tax on NCS upstream emissions is not easy to assess, particular since 2008 when Norway joined the EU ETS. In 2019, in reporting its emissions to the UNFCCC, Norway estimated the combined effect of the tax and the EU ETS would reduce NCS emissions in 2020 by 7 mt CO_2.

[20] 'Our Common Future', World Commission on Environment and Development, 1987.
[21] EPIM Environment Hub (EEH)

There are two CCS projects in operation on the NCS capturing and storing CO_2 emitted from upstream operations. Since 1996, about 1 mt CO_2 per annum has been separated during gas processing on the Sleipner Vest field and stored in the subsea Utsira formation. At the Snohvit field supplying the Melkoya LNG plant, CO_2 has been captured and re-injected since 2008, reducing emissions by about 0.7 mt per annum. The Northern Lights CCS project, approved by Equinor, Shell and Total and awaiting government sanction, would provide storage in an offshore aquifer near the Troll field but in its first phase would store CO_2 captured at onshore industrial plants, not from existing upstream operations.

The UK has sought to strike a balance between development of its offshore resources and environmental protection through a comprehensive array of domestic legislation, supplemented by the transposition of EU legislation on environmental and offshore safety such as the Habitats Directive (1992) and the Offshore Safety Directive (2013) and international agreements such as the OSPAR Convention. Plans for offshore development are subject to a Strategic Environmental Assessment (SEA) and individual projects are required to submit an environmental statement. Permits must be issued for any offshore combustion under the Prevention and Control of Pollution Regulations. Flaring and venting of gas requires a permit under the Petroleum Act 1998 and the Energy Act 1976 respectively. Overall, the current regulatory framework in the UK regarding emissions to air presents a comprehensive picture but one that is more complicated and fragmented than in Norway because it comprises successive regulations of different origin and involves numerous governmental and non-governmental bodies in policy formation, regulation and enforcement.

In October 2016, almost all the legal responsibilities and powers of the government energy department were passed by the Energy Act 2016 to a new industry-funded regulator, the Oil and Gas Authority (OGA[22]). The reform was intended to achieve a new statutory objective of 'maximizing the economic recovery of UK oil and gas resources in UK waters' or MER UK. The OGA is the licensing authority for exploration, production, carbon storage and gas storage and offloading activities. It does not have any responsibility for environmental regulation or decommissioning which remains with the government's Department for Business, Energy and Industrial Strategy (BEIS) and its agency, the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED). Offshore safety continues to be the responsibility of the Energy Division of the Health and Safety Executive (HSE).

Under the constitutional settlement over powers granted to the 'devolved administrations', the offshore oil and gas industry remains the responsibility of the UK government even though about 90 per cent of UKCS reserves and production lie within what are, geographically speaking, Scottish waters. In constitutional parlance, offshore oil and gas is a 'reserved matter' for the UK government in Westminster. However, regulation of onshore facilities such as oil and gas terminals falls under either the Environment Agency (EA) in England and Wales, or, in Scotland, under the Scottish Environmental Protection Agency (SEPA).

Emissions for upstream installations are subject to the conditions set within the required permits for combustion, flaring and venting and by the requirements of the EU ETS for those facilities which fall within its scope. The OGA issues permits for both flaring and venting and is responsible for the development of policy concerning both activities. The adoption of the net zero target in 2050 has extended the role of the OGA into the area of atmospheric GHG emissions. After a public consultation in mid-2000, the OGA is expected to propose a revision of its MER UK Strategy to incorporate the net zero target and consideration and monitoring of atmospheric emissions in its regulatory activities and in the supervision of UKCS operators.[23] Revision to the current MER Strategy will require amendment to existing legislation but it is not expected to give the OGA new legal powers. If this is confirmed, the OGA will not have powers to mandate investment by operators in emission reduction but it will be required to incorporate consideration of future emissions into the exercise of its existing powers.

[22] 'Gas Production from the UKCS: An Assessment of Resources, Economics and Regulatory Reform', OIES, 2019 offers a summary of the regulatory changes pp 14-15.

[23] '2020 OGA Strategy Review', OGA, 6 May 2020. The OGA held a 12-week consultation in May-July 2020. An announcement on the outcome and the expected revision of its Strategy is expected in late-2020.

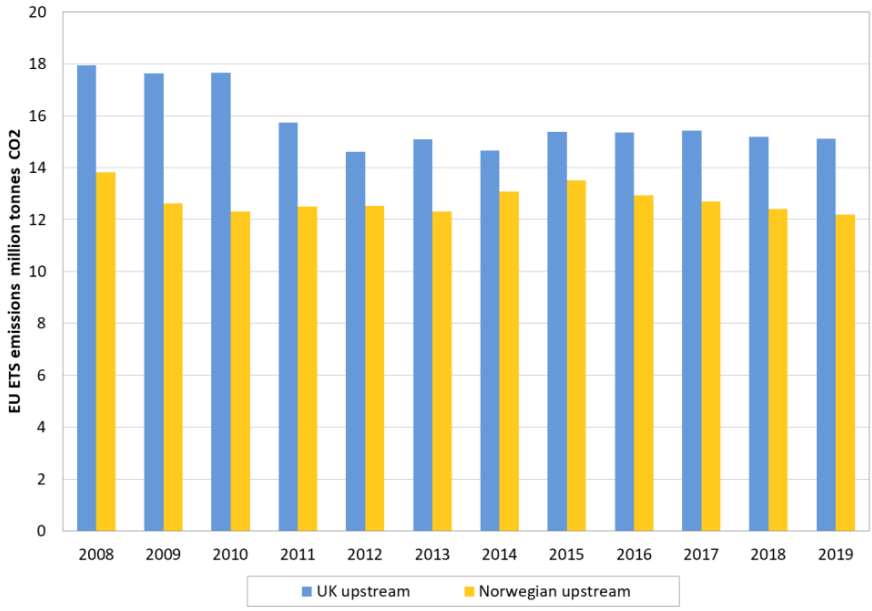
4.3 EU Emissions Trading Scheme (EU ETS)

The UK participated in the EU ETS from the first trading period in 2005-07. Norway introduced its own national ETS in 2005 to supplement its domestic CO_2 tax and modified it in 2007 and 2009 to become compatible with the EU ETS. The two schemes were linked in Phase II (2008-12) and were fully harmonised in Phase III (2013-20) even though Norway relied to a greater extent on auctions rather than free allocations and did not issue free allowances to offshore electricity generation as occurred in the EU ETS.

The EU ETS covers a much greater share of gross GHG emissions in Norway than in the UK largely because of the much greater relative size of the upstream sector in the economy. In 2019, emissions from stationary installations in the EU ETS in Norway (24.6 mt CO_2e) represented almost half of all national GHG emissions, whereas in the UK (118.6 mt CO_2e) they accounted for about 25 per cent of the national total. Not only is the 'traded sector' within the EU ETS larger in Norway than in the UK but the domestic Norwegian CO_2 tax also covers about 80 per cent of national CO_2 emissions.

The EU ETS covers only three of the six GHGs: CO_2, nitrous oxide (N_2O) and perfluorocarbons. Significantly, it excludes the second most common GHG in upstream oil and gas operations, methane. From a statistical point of view, the significance of the EU ETS regulations is that they provide a legal basis for the monitoring, reporting and verification (MRV) of emissions data. Verified emissions within the EU ETS account for 80-85 per cent of total estimated upstream GHG emissions and represent the most reliable elements in overall GHG estimates. In Norway, 2019, verified emissions from a total of 33 upstream installations within the EU ETS, excluding the Mongstad refinery, amounted to 12.2 mt CO_2 or 85 per cent of total sectoral GHG emissions. In the UK, verified emissions from 103 EU ETS installations, both offshore and onshore, were responsible for 15.1 mt CO_2e or 80 per cent of total upstream GHG emissions. Figure 10 shows verified emissions from upstream installations in the two countries from 2008 to 2019.

Figure 10: EU ETS Emissions from UK and Norwegian Upstream 2008-2019



Source: EU ETS Registry (EUTL)

UK upstream emitters are more numerous and smaller in size than in Norway; average emissions from UK upstream installations are less than 150 kt CO_2e compared to 370 kt CO_2e in Norway. Among offshore facilities, the largest emission sources on the UKCS (Britannia, Beryl Alpha, Elgin PUQ and the Glen Lyon FPSO) each emitted about 400 kt CO_2 in 2019. On the NCS, the largest emitters (Asgard, Oseberg, Gullfaks, Sleipner, Statfjord and Troll) were each responsible for 700-1100 kt CO_2 in 2019. The difference between the UKCS and NCS in the distribution of emissions today reflects the greater

maturity of the UKCS, the smaller size of developed fields on the UKCS and a legacy of UKCS offshore infrastructure development which did not promote shared facilities or hubs. The greater scale of emissions at large offshore hubs on the NCS has helped to mitigate the high cost of the recent trend towards retrofitting platform electrification. In contrast, the smaller scale of emissions at typical UKCS installations may have adverse consequences in future for emission reduction costs per tonne of CO_2 abated and the prospects for electrification in particular.

4.4 Electrification of offshore operations

Power is needed on offshore facilities for a variety of purposes which vary between fields and through the life of a field: reservoir pressure maintenance, processing and transportation of hydrocarbons and re-injection of produced water and gas. As conventional fields are depleted, the energy intensity of production tends to rise. Throughout the history of the UKCS, fields have normally been developed using produced fuel gas to generate power offshore, rather than laying subsea cables from the onshore network.[24] The UK has developed more than 13 GW of offshore wind capacity, including in areas close to upstream operations, but there has so far been no connection between the two activities. By contrast, in the Norwegian sector, since 2005 a rising proportion of offshore power demand has been met by 'power from shore' supplied through connections to the onshore network where low-carbon hydroelectricity accounts for more than 97 per cent of power generation.

In 1996, the Norwegian government required new field developments or major re-developments to consider possible supply of power from the onshore grid in order to reduce CO_2 and NOx emissions. The first power-from-shore project was the compression project on Troll A installed in 2005 which supplied 80 MW to two new platform compressors through a new high-voltage subsea DC cable. However, by 2007-08, the NPD and the Norwegian Water Resources and Energy Administration (NVE) concluded that retrofitting of power from shore to replace all the 4.3 GW of offshore generating capacity was not an economic way of reducing CO_2 emissions; there was no surplus hydro power to supply offshore demand and the options were 'neither simple nor cheap'.[25]

In the last decade, there has been fundamental re-appraisal of power from shore on the NCS. Technological advance in the transmission of alternating current (AC) over greater distances has extended the scope of power-from-shore but the principal change has been in domestic political sentiment in the context of ever more ambitious national decarbonisation targets. No longer is it considered politically feasible or acceptable to emit additional CO_2 in developing new resources if low-carbon power is available through connection to the onshore grid. The discovery of the giant Johan Sverdrup oil field in 2010 was followed by technical and political consideration of the field development options. The Storting approved the project in 2015 on condition that all power was supplied from shore and that there were no CO_2 emissions from offshore combustion; the additional capital costs would be borne by the field partners and the government. Since then, all new field development applications, with the exception of the remote, delayed Johan Castberg FPSO project in the Barents Sea have had to include power from shore to win approval.

In mid-2020, there are eight offshore NCS fields powered from shore.[26] A further eight fields will be connected to the onshore grid when Phase 2 of the Johan Sverdrup project is completed in 2022-23, five of which in the Utsira High area of the North Sea will be connected to a new offshore power hub. According to the NPD, when the Utsira High power-from-shore project is completed and all sixteen fields are connected, the total CO_2 emission savings will be 3.2 mt CO_2 per annum. Six other power-from-shore projects are at an advanced stage of the planning process. The NPD estimates that by 2025, more than half of total NCS production will be powered from shore and annual avoided CO_2 emissions will rise to almost 5 mt CO_2.

[24] The Beatrice oil field, now decommissioned, in the Moray Firth was connected to the onshore network in 1986 to supplement its own gas-fired generation.
[25] Gunnar Berge: Electrification of the Shelf, Norwegian Petroleum Directorate, May 2007.
[26] 'Almost half Norwegian production will soon be run on power from shore', NPD June 2020. The fields are Troll, Gjoa, Vega, Ormen Lange, Valhall, Hod, Goliat and Johan Sverdrup.

In the UK, progress on developing power from shore and possible integration of offshore renewables generation and offshore oil and gas production has been much slower. Progressive decarbonisation of power supplied to the UK onshore grid has made power from shore more attractive as a route to offshore emission reduction but technical and economic obstacles still need to be overcome. A recent major joint study by UK regulators identified platform electrification as a critical element in offshore emission reduction and scope in future for integration of oil and gas production with CCS, renewables and hydrogen generation as part of the UK's energy transition[27]. At present, there are no firm proposals for full or partial electrification of existing or prospective new developments on the UKCS but it is possible that in future new developments may be subject to approval conditions regarding the carbon-intensity of power consumed in the production phase.

5. UK and Norwegian Emission Reduction Targets and Investment

5.1 UK upstream industry targets

In 2020, the upstream industry in both the UK and Norway adopted new emission reduction targets for 2030 but these targets emerged in very different ways. For most of the period between 2014 and 2019, the focus of the UK upstream industry had been on cost reduction, portfolio restructuring and on meeting the demands of the new regulatory regime introduced in 2015 to promote MER UK. Emissions performance, beyond compliance with the EU ETS, was not seen as a priority issue by most operators. By 2018, the industry had improved its operating and financial performance and had adjusted its behaviour to comply with the operational and reporting guidance issued by the new OGA. The adoption by the government of the new net zero target in June 2019 and public pressure from the OGA finally brought the issue to the attention of all operators, galvanising the industry into a collective response in June 2020.

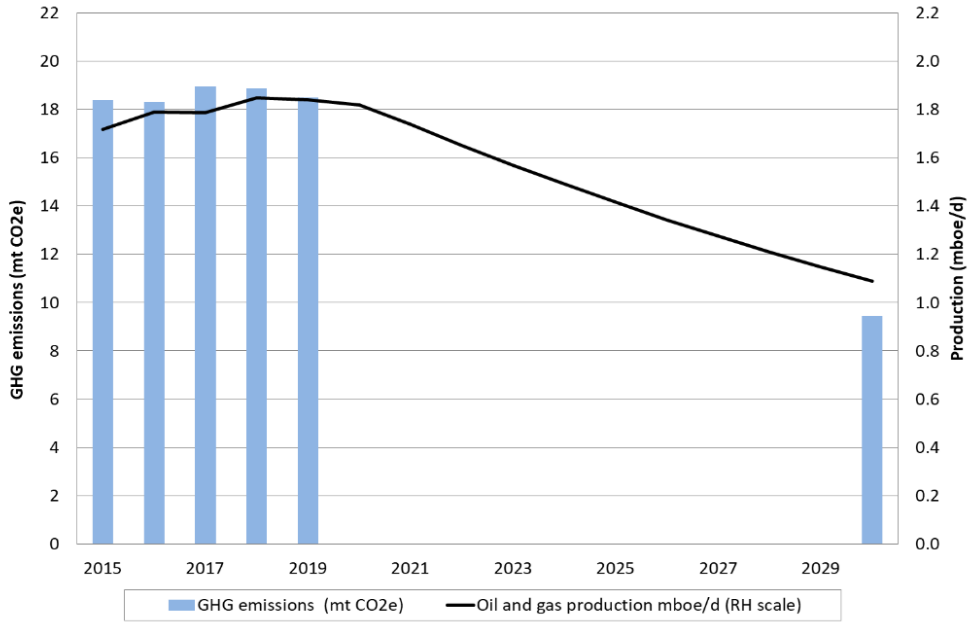
In September 2019, OGUK, the upstream industry association, released its 'Roadmap to 2035: Blueprint for Net Zero' which affirmed its 'support' for the net zero target and emphasised that the industry possessed the skills, infrastructure and expertise to help the UK to meet its net zero ambition.[28] It also called for a tripartite approach with the government and the OGA to reconcile energy security, the economic contribution of the sector and the new net zero target. However, it did not quantify the scope of emissions reduction the upstream industry was willing or able to make.

In January 2020, the new Chairman of the OGA, Tim Eggar, warned the industry that it needed to make much faster progress in reducing GHG emissions from its own operations.[29] In language reminiscent of that often used by environmental NGOs, the OGA chairman said the industry was 'at risk of losing its social licence to operate' if it could not demonstrate that it is part of the solution to tackling climate change. He called on the industry to set 'clear measurable GHG emission targets' and to reduce its methane emissions in particular.

In response to this political pressure, in June 2020, OGUK published its 'Pathway to a Net Zero Basin: Production Emission Targets' which sets out, for the first time, targets for reducing emissions from the entire UK upstream sector by 2030 and 2040 and to aim for a 'net zero basin' by 2050.[30] From its own baseline of 18.3 mt CO_2e in 2018, OGUK committed the industry to reducing its total GHG emissions by 50 per cent by 2030 and by 90 per cent by 2040 to just 1.8 mt CO_2e. There is no intermediate target for emissions in 2025. The expected 'natural decline' of UKCS production is projected to deliver 50-67 per cent of the projected net reduction in emissions of 9 mt CO_2e between 2018 and 2030, leaving industry to deliver the remaining 3-5 mt CO2 through changing practices and investment. The target and the most recent projections of UK production by the OGA are illustrated in Figure 11 below.

[27] 'UKCS Energy Integration: Final Report' OGA, August 2020.
[28] Roadmap to 2035: Blueprint for Net Zero', OGUK 4 September 2019
[29] OGA Chairman's speech to industry leaders in Aberdeen on 15 January 2020, OGA.
[30] 'Pathway to a Net Zero Basin: Production Emission Targets', Oil & Gas UK, June 2020

Figure 11: UKCS Industry 2030 Emission Reduction Target



Sources: BEIS, OGUK, OGA production projections, 2020

OGUK classified the intended reduction in emissions in three generic categories but did not quantify the expected contribution in each category over the period to either 2030 or 2040:

- operational improvement
- reduced flaring and venting
- capital investment to decarbonise production operations

OGUK cites improvements in energy efficiency of turbine operations, reduced use of diesel in dual-fuel turbines, valve replacement and re-sizing of pumps as examples of operational improvements. Regarding flaring and venting, OGUK is developing a Methane Action Plan to phase out routine flaring and venting offshore and has set a target of a 30 per cent reduction in flaring emissions, over and above natural decline, by 2030.[31] Among contributions to lower emissions through investment, OGUK mentions full or partial electrification of new offshore production and increased use of electrical power at existing onshore terminals and processing plants as the most promising options.

The industry's emission targets for 2030 and 2040 appear, at first sight, to be ambitious unless one takes a very pessimistic view of the economic viability of the UKCS in the 2020s and assumes a sharp acceleration of decommissioning and few new developments. OGUK does not disclose its assumptions about which prospects and fields will be developed in future, nor the timing of the decommissioning of existing fields, facilities and terminals. However, the proposed reduction of 50 per cent in GHG emissions between 2018 and 2030 is greater than the decline in oil and gas production of 41 per cent projected over the same period by the OGA in February 2020. If OGUK has assumed the same production decline to 2030, then the emission reduction target implies a reduction in emission intensity per boe produced of about 15 per cent in the 12-year period. Given the observed tendency for energy and emission intensity to increase as fields are depleted, a reduction of this magnitude is likely be achievable only by investment in emission abatement at some existing facilities, not simply much lower emission intensity on new development due to enter production before 2030.

[31] In 2018, OGUK estimates offshore flaring of 1.2 mt of gas generated 3 mt of CO_2 emissions.

These emission reduction targets for 2030 and 2040 are described by OGUK as 'aspirational'. They are not binding on the industry. They represent a collective aspiration for the industry and do not apply to individual UKCS operators or to particular assets. Nor is there any target before 2030 despite the perceived scope to reduce emissions from flaring and venting at relatively low cost. The targets are not binding on individual operators but the OGA announced that it will incorporate them into its data benchmarking to monitor industry progress.[32] The OGA will have access to confidential operating and emissions data on emissions but how will it seek to influence operators' behaviour and investment, and how will it balance the potentially competing objectives of MER UK and emission reduction?

At present, there are no published estimates of the capital and operating costs of meeting these targets. OGUK acknowledges that some of the routes to achieving the targets are not yet commercially feasible but reveals that emission abatement costs for 'incremental operational improvements' are lower than the cost of larger emission reductions requiring investment. It also highlighted the expected wide range of abatement costs in the upstream since they are very sensitive to individual field size and maturity, platform design, remaining recoverable reserves and opportunities for sharing of utilities with adjacent facilities.

'Pathway to a Net Zero Basin' represents a pragmatic response to the challenge laid down by the OGA but leaves key issues unanswered. OGUK makes clear its view that meeting these targets 'will require a tripartite approach between industry, regulators and the government underpinned by an effective commercial, fiscal and regulatory framework'. In other words, without such an approach and such a framework, the emission reduction targets may not be met. At a time of renewed financial pressure, the industry will be seeking clarity from the government on the future offshore carbon emission regime and the tax treatment of emission reduction capital expenditure. The publication of the Energy White Paper the Treasury's Net Zero Review in late 2020 to consider 'how the transition will be funded and where the costs will fall' may be critical for the upstream sector and its hopes for a 'sector deal'. From the OGA, operators will be seeking clear guidance as to how emission reduction targets will sit alongside existing obligations of asset stewardship under MER UK.

5.2 Norwegian upstream industry targets

In the first half of 2020, the Norwegian industry went through an extraordinary combination of events: the announcement by Equinor of ambitious new emission reduction targets on the NCS, the collapse in oil and gas prices, the voluntary restriction of oil output to support prices for the first time in 18 years and disruption to NCS operations caused by the Covid-19 virus. The sharp deterioration in industry finances so soon after the announcement of an ambitious emission reduction and investment programme provoked a period of intense domestic political debate over a proposed industry stimulus package and reform of the upstream tax regime. In June, the government finally announced a temporary tax relief package intended to avert the deferral of capital projects and to maintain the industry's decarbonisation commitment.[33]

Equinor occupies a pre-eminent and privileged position in the Norwegian upstream industry since 67% of its equity is owned by the state, represented by the Ministry of Petroleum and Energy. It is the largest equity producer of oil and gas, accounting for one third (1.24 mboe/d) of all NCS production in 2019 but it is also operator of more than 75% of NCS production. Equinor also markets the entire output of Petoro, the wholly state-owned company which holds the state's direct financial interest (SDFI) in producing fields.

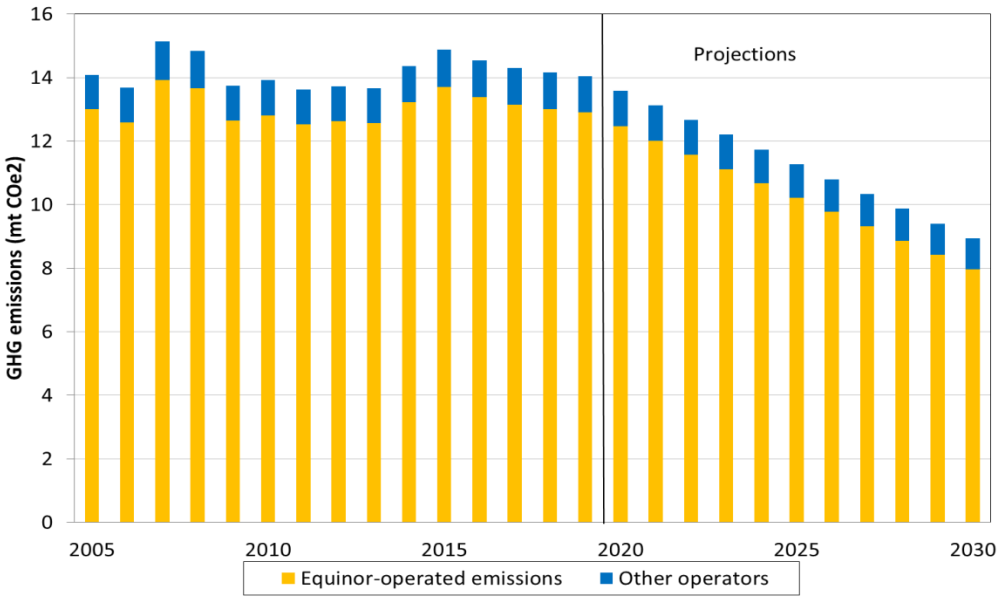
In January 2020, after consultation with the government and partners, Equinor announced an ambitious target to reduce GHG emissions from its operated NCS fields and onshore plants by 40 per cent by 2030, 70% by 2040 and 'towards near zero' by 2050. The baseline for the reduction is 2005 when emissions were about 13 mt CO_2, similar to its operated emissions in 2018. Scope 1 and Scope2 emissions of both CO_2 and methane are included in the target reduction. The company expects this

[32] 'OGA to track and monitor industry progress towards new emissions targets', OGA, 16 June 2020
[33] 'Norway tax package could help unlock $40 billion projects boom', Upstream, 2 July 2020.

reduction can be achieved through platform electrification, energy efficiency improvements, and new investment in offshore wind, CCS and hydrogen. Equinor estimates that the new target will deliver a reduction in its total NCS operated emissions of more than 5 mt CO_2e by 2030. If the target is achieved, and emission intensity at upstream facilities not operated by Equinor were to remain constant, it is estimated that total NCS GHG emissions would fall from 14.2 mt CO_2 in 2018 to about 9 mt CO_2 in 2030, as illustrated in Figure 12 below. This would imply a further reduction in the GHG emission intensity of total NCS oil and gas output to 7 kg CO_2e/boe in 2030 based on current NPD projections of output in 2030.[34]

The contributions to the NCS emission reduction targets from renewable generation and CCS, which may serve mainly onshore industrial emission reduction, are not yet known since they will depend on firmer capital cost estimates, joint investment with other companies and the willingness of the Norwegian government and other public entities such as Enova to finance some of the capital expenditure. As the incoming Equinor CEO, Anders Opedal, has said, there will have to be a significant re-allocation of capital to achieve the decarbonisation targets. Equinor estimates that achieving the 2030 target will require investment by Equinor and its partners (including state-owned Petoro) of an estimated NOK 50 billion or about NOK 5 bn per annum. In the period 2015-19, total industry capex on the NCS has been NOK 125-175 bn per annum but in 2020 this is expected to fall to about NOK 100 bn. There is currently a risk that an extended period of low oil prices in 2020-21 may cause some emission reduction investment to be delayed.

Figure 12: Indicative NCS Emissions Based on Equinor Target in 2030



Source: Statistics Norway, Equinor projections

Equinor's domestic emission reduction target forms a central element in its new corporate climate change ambition, announced in February 2020, which itself is set within the context of the Paris Agreement.[35] The wider corporate objective is to reduce the net carbon intensity, from production to final consumption, of its energy production by at least 50 per cent by 2050 and to achieve 'carbon-neutral global operations by 2030'. This will entail a rapid expansion of renewable energy capacity, mainly outside Norway, and a progressive re-shaping of its worldwide upstream portfolio 'in line with

[34] 'The Shelf in 2019', released by the NPD in January 2020, projected output in 2030 of 3.45 mboe/d, down from 3.9 mboe/d in 2018.
[35] Equinor Capital Markets Day, February 2020

the Paris Agreement'. At present, approximately 30 % of its oil and gas reserves and 40% of its equity production is outside Norway.

In its new climate change targets, Equinor combines absolute emission reduction targets for operated assets in Norway with a global corporate target expressed in terms of 'carbon-neutrality' in 2030 and 'net carbon intensity' in 2050. Emission reduction in existing and planned NCS operations is expected to contribute to both domestic and global targets up to 2030 through completion of Phase 2 of the Johan Sverdrup field development, extended platform electrification, and an expected decline in NCS output after 2024. The constant dilemma on this ambitious path to 2050 will be how to phase its decarbonisation investment while retaining investor confidence and how to strike a balance in investment between hydrocarbons and low-carbon energy, between Norwegian and international upstream operations, and between existing operations and new developments.

Equinor claims that investments to achieve the NCS 2030 target will be NPV-neutral or NPV-positive in corporate financial terms but, as it acknowledges, this assessment is dependent on 'positive decisions in the licences' to approve the investment and on future EU carbon prices and Norwegian government taxation. NCS decarbonisation promises to be a constant feature of the regular contact between Equinor and the Ministry of Petroleum and Energy on licensing strategy, taxation and investment.

The company has sought to assure investors that such emission reduction investment 'will strengthen competitiveness'. The impact on Norway's competitive position as a supplier of pipeline gas to Europe and crude oil to world markets will depend, in part at least, on whether climate-conscious importing countries adopt measures which reward suppliers of oil and gas with lower emission intensity and penalise those with higher emission intensity, and whether its competitors respond to reduce their emission intensity. Norway is already the lowest-emission supplier of gas to the EU and the UK and among the lowest emission suppliers of oil but this advantage confers no direct economic benefit to Norway beyond reduced compliance costs on CO2 emissions within the EU ETS. Without additional border instruments such as carbon border taxes or importer certification schemes applying to upstream emissions of CO2, methane or total GHG emissions, there is clearly a risk that some future emission reduction investment will not be financially remunerated in a conventional sense. The benefits may eventually lie more in retaining domestic political and public support for oil and gas exploration and production on the NCS and in winning international support and co-operation for more ambitious international climate change abatement targets within the Paris Agreement process.

5.3 UKCS emission abatement options

The technical routes to lower upstream emissions of CO_2 and methane are well known and understood: improved energy efficiency, fuel switching in combustion, electrification of offshore operations, a reduction in flaring and venting and the capture and storage of CO_2 emissions. What is undecided is how to prioritise these options according to their expected GHG abatement costs, whether emission reduction should be incentivised through higher carbon prices or required through more stringent emissions standards, and who will bear the costs. The dilemma for government and the OGA is that upstream capital is highly mobile and that GHG emission reduction needs to be achieved without undermining investor confidence in the UKCS if the benefits of UKCS production are to be retained.

As part of its Net Zero Technical Report, published in May 2019, the CCC outlined the main abatement options to 2050 for the UK upstream oil and gas sector compared to other major industrial sectors.[36] Reliable assessment of the cost of GHG abatement in a natural resources sector needs to take account of progressive resource depletion over time. The CCC-commissioned analysis established a baseline for emissions from offshore oil and gas which projects a progressive decline from 18.8 mt in 2018 to 10 mt in 2030 and 3.2 mt in 2050. The analysis identified the reduction in gas flaring and venting in the upstream and reduced methane leakage in the entire gas chain through leak detection and repair (LDAR) as the least-cost abatement options. In contrast, the costs of abating emissions from

[36] 'Net Zero Technical Report, Committee on Climate Change, May 2019. The CCC commissioned 'Assessment of Options to Reduce Emissions from Fossil Fuel Production and Fugitive Emissions' from Element Energy.

combustion in the upstream through electrification or CCS and reducing them to just 0.5 mt CO_2e in 2050 were the highest estimated levelised abatement costs in any UK industrial sector.

In 2018, UKCS offshore installations generated about 21 TWh of power from fuel gas and diesel and emitted about 10 mt of CO_2 in doing so. The typical carbon intensity of offshore generation from fuel gas in an open cycle gas turbine is 450-500 gCO_2/kWh, compared to average onshore generation of about 200 gCO_2/kWh. The opportunity to reduce UK emissions by replacing offshore generation with power from shore or with offshore renewables is now more evident than ever but economic and technical obstacles to retrofitting existing installation remain. Oil and gas installations need firm power supply, so onshore or offshore renewables may offer only a partial source of supply and will need back-up supply from shore or from thermal generation.

The UK has already developed 13 GW of offshore wind generation capacity, some of it adjacent to existing oil and gas fields, and this may rise to 30-40 GW by the 2030s. Yet there has been no integration of offshore wind generation with offshore upstream oil and gas operations. This is now beginning to change as the potential of providing renewable power to offshore facilities from new wind projects is now being explored. For example, the OGA is currently engaged with industry in exploring the possible electrification in the Central North Sea (CNS) of existing long-life platforms with new offshore wind farms with a sharing of the emissions benefits and transmission costs savings.[37]

The recent joint study on UKCS energy integration led by the OGA looked at electrification of oil and gas facilities through power from shore or from offshore renewables, concluding that 'electrification is an essential response of the oil and gas industry to net zero'.[38] It concludes that electrification using offshore renewables is a more attractive option than power from shore. The study estimated that if all existing 'brownfield' installations with at least 15 years of remaining life and half of all future 'greenfield' oil and gas projects were electrified, then GHG emissions would be reduced by 2-3 mt CO_2e per annum[39] through the 2030s. The first contribution to lower emissions was envisaged in 2026. The study estimates that the power demand from such brownfield and greenfield projects would together support the construction of about 2 GW of new offshore wind power capacity.

The OGA study found that the economics of electrification were critically dependent on electricity and carbon prices and that, *at current prices*, power from shore would be unattractive on the UKCS. Electrifying operations using offshore wind power offers better prospects, according to the OGA report. The recommendations of the joint study are that operators should collaborate on sourcing power directly from offshore renewables, not from shore, and that governments should consider introducing a carbon price on offshore emissions from power generation similar to the CPF already in place for onshore generation and possibly electricity tariff exemptions to promote offshore electrification.

The economic and technical obstacles to power from shore on the UKCS cited by the OGUK[40] are indeed numerous and substantial. Progress is unlikely unless there is reform of carbon pricing, taxation and regulation. The recent deferral of the Rosebank and Clair South oil projects west of Shetland, an area where electrification of new developments was under consideration, sets back the prospects of greenfield electrification on the UKCS for the immediate future.

5.4 UK flaring and venting emission abatement

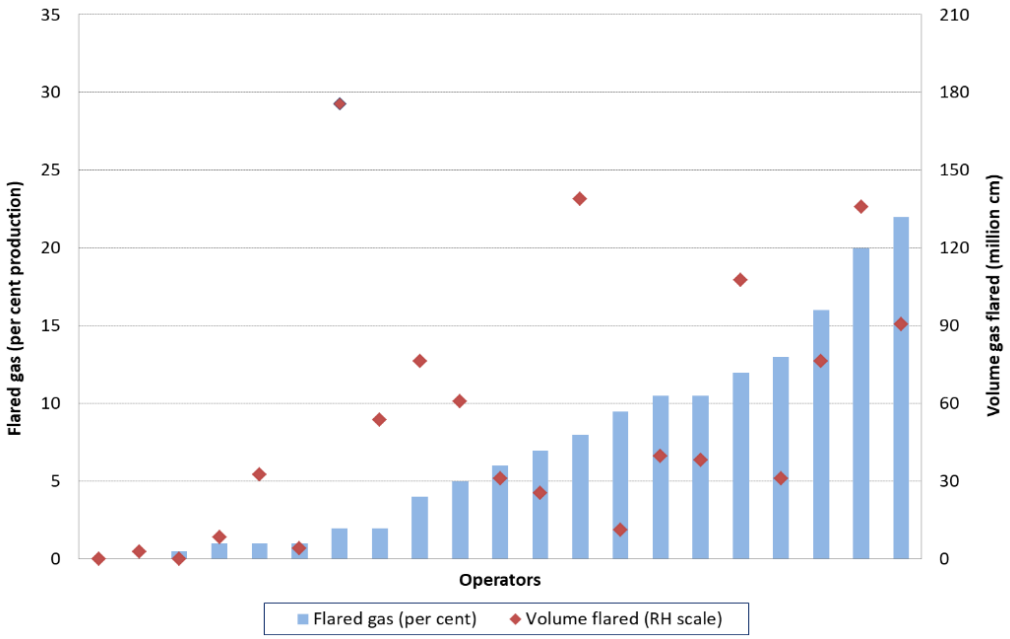
The adverse trend in volumes of gas flared or vented on the UKCS in recent years described in Chapter 3 (Figure 8) and the much higher flaring intensity on the UKCS compared to the NCS strongly indicate the scope for reducing CO_2 and methane emissions at moderate cost. At some facilities, there appears to be an excessive level of routine flaring, or a tolerance of routine flaring among operators and regulators, perhaps because operational safety is so often invoked as a reason that it should continue.

[37] 'OGA hosts Central North Sea platform electrification talks' August 2020
[38] 'UKCS Energy Integration: Final Report', OGA, August 2020.
[39] UKCS Energy Integration: Final Report, OGA, August 2020. This a two-part joint report on the entire offshore sector commissioned by BEIS, the Crown Estate, Ofgem and the OGA.
[40] 'Pathway to a Net Zero Basin: Production Emission and Targets', OGUK, 2020, pp 25-27

It is hard to avoid the conclusion that emissions from flaring and venting were to some neglected by the industry and the OGA between 2015 and 2019 as their focus was on improving production efficiency. A significant improvement may be achievable very quickly without the need for major investment but simply through a change in operational culture and effective intervention of the OGA.

The problem of flaring and venting emissions is not a ubiquitous feature of UKCS operations. The OGA's own emission benchmarking has revealed the wide variation in flaring intensity among UKCS operators. The volume of gas flared is concentrated among a relatively small number of operators and installations, some of which are identifiable from the publicly available EEMS database. Figure 13 shows the flaring intensity and the volume of gas flared by 21 unnamed operators on the UKCS in 2019. The total volumes of gas flared by these operators is estimated to have been 1.1 bcm or 85 per cent of the total volume reportedly flared on the UKCS in 2019. Several operators reported zero flared volumes yet two reported that more than 20 per cent of their gross production was flared. It is not known whether such flaring was the consequence of unexpected short-lived operational problems or extended over a longer period, what part safety played in the extent of flaring, nor whether any of these operators breached their flaring consents in 2019. At present, operators have some discretion over how they categorise their emissions in reporting them to the EEMS database and it appears that operators do not report in a consistent or uniform manner. The first stage of effective abatement should be to improve the reporting of emissions of CO_2 and methane from flaring and venting at onshore and offshore facilities.

Figure 13: UKCS Flaring Intensity and Volumes by Operator in 2019



Source: OGA Emission Benchmarking, 2020

The OGA has responsibility under the Petroleum Act for issuing permits for flaring and venting of gas but has no responsibilities for environmental legislation, which remains with BEIS/OPRED, or for safety legislation, which remains primarily with the Health and Safety Executive (HSE[41]). The HSE has taken the lead in recent years on the worrying incidence of offshore gas leaks, treating it as a matter of safety, not an environmental matter. The OGA's current public policy position on flaring and venting is short and somewhat vague, citing the aim of ensuring that the consents regime is consistent with both MER

[41] BEIS and the HSE jointly formed the Offshore Safety Directive Regulator to act as the Competent Authority under the EU Offshore Safety Directive but the HSE's Energy Division remains the principal safety regulator.

UK and government emission targets but failing to explain how they are to be reconciled or how responsibilities are divided between the OGA and BEIS. The issue of the monitoring of operators' emissions under existing permits and the circumstances in which permits would be withdrawn are not publicly set out by the OGA. It would not be surprising to see a restatement of this OGA policy position soon as the OGA revises its MER UK Strategy and possible also a review with BEIS and HSE of how the three entities can establish a tighter emissions regime without compromising safety. In September 2020, the OGA announced that it was extending its benchmarking to include GHG emissions from flaring and venting as part of its monitoring of asset stewardship.[42] At present, this falls short of a much tougher stance but such a change may follow if industry does not take up the challenge.

In June 2020, the OGUK announced that it is developing a Methane Action Plan to be released later in 2020. This may include a specific methane emission reduction target within the wider GHG target. As the OGA has acknowledged, reducing emissions from flaring and venting will require some changes to operators' procedures and behavior, for example, by curtailing production occasionally or re-starting production more slowly to avoid excessive emissions. Encouraged by the OGA and perhaps by new internal performance measures, a new, younger generation of asset managers may be willing to implement such 'cultural change' in operational control rooms to give greater weight to emissions in their decisions.

5.5 Norwegian investment in electrification

Electrification of the offshore industry is the only feasible and credible route for Norway if it wishes to achieve its GHG emission reduction targets and to continue to develop its remaining oil and gas resources estimated to be 52 billion boe. It is an expensive route to decarbonisation which began in 2005, when the first power from shore project at Troll B was commissioned, and has already begun to accelerate as new projects have been approved. Already electrification is going beyond conventional power from shore to include, for the first time, power from floating wind turbines to offshore oil and gas platforms.

Electrification of both phases of the Johan Sverdrup field, which came on stream in October 2019, will bring about a significant fall in emission intensity between 2020 and 2024 but it will also contribute in phase 2 to an absolute reduction in CO_2 emissions at other fields since the subsea power network laid to serve the Johan Sverdrup project will be extended to five adjacent fields in the Utsira High area by 2022-23.[43]

In April 2020, the MPE approved the 88 MW Hywind Tampen project, the world's first floating offshore wind project, which will connect pre-constructed wind turbines to the Snorre and Gullfaks platforms and are expected to supply 35 per cent of their power demand. After commissioning in late 2022, CO_2 emissions will be reduced by 0.2 mt per annum. The expected capital cost of the project is NOK 5 bn. The decision to proceed was made possible by a grant of NOK 2.3bn by Enova, the state-owned company committed to promoting innovative renewable technology, and a further NOK 566 m from the business-funded NOx Fund.

In June 2020, after approval to the temporary tax relief package, partners at the Sleipner field submitted revised plans to partially electrify the Sleipner field centre through a connection to the Gina Krog field in the Utsira High area. The project will include connections to adjacent fields Gudrun, Sigyn, Gugne and Utgard. The total cost of the project is estimated to be NOK 1.5bn, part of which will also be financed by the NOx Fund. If approved, the project is expected to be completed at the end of 2022.

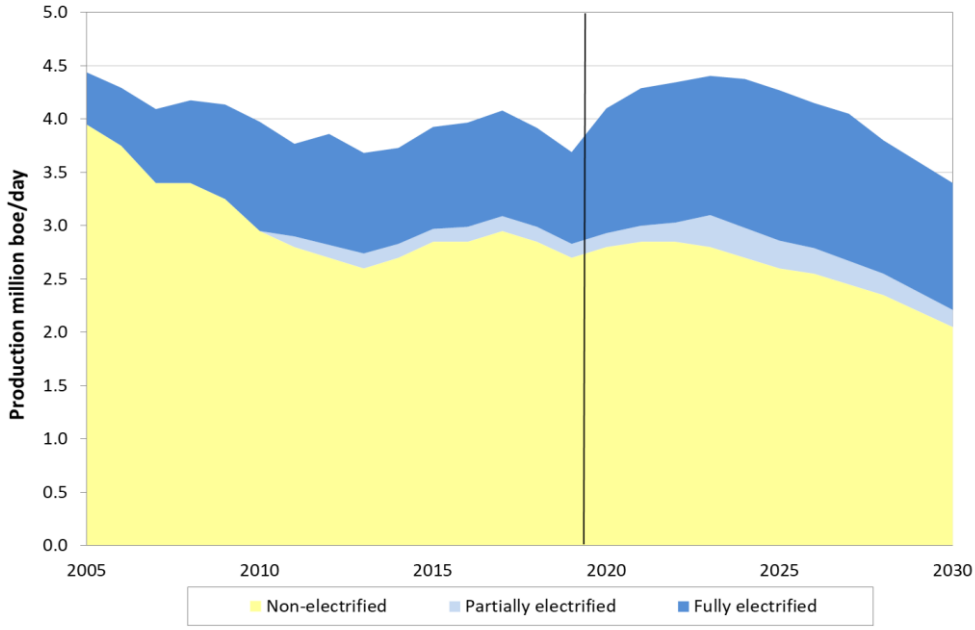
The proposed electrification of the Equinor-operated Troll B and Troll C platforms is currently at the FEED stage and a decision whether to proceed is expected in late 2020 or 2021. The expected CO_2 emission reduction is put at 450,000 tonnes per annum. There are also two other significant

[42] 'OGA turns attention to flaring and venting of greenhouse gases', OGA press release, 28 September 2020.

[43] The five fields are Edvard Grieg, Ivar Aasen, Gina Krog, Solveig and Hanz. The Martin Linge field, which is under development but delayed, will be supplied with power directly from shore and Duva and Nova will be connected to the already fully electrified Gjoa field.

electrification projects in the planning phase. Equinor is considering full or partial electrification of the remote onshore facility at Melkoya which emits almost 1 mt CO_2 per annum. This would require the construction of a major new onshore power line but the facility might still need back-up generation when the onshore network is constrained. In July, Equinor also awarded a FEED contract for partial electrification of the Oseberg field centre and Oseberg South by connecting the facilities to the onshore power grid, linked to an expansion of gas capacity. No schedule for an investment decision has yet been disclosed.

Figure 14: Estimated NCS Oil and Gas Production by Power Source 2005-2030



Source: Shelf in 2019, NPD 2020, Equinor and author's estimates

The NPD estimates that, after completion of Johan Sverdrup Phase 2 and the extension of power from shore to the Utsira High area, offshore CO_2 emissions on the NCS, including fields already electrified, will be 3.2 mt lower than they would have been otherwise. If the other projects under consideration at Sleipner, Troll, Oseberg and Melkoya, were to be realised, it estimates that almost half the production on the NCS would be supplied with power from shore by 2025 and CO_2 emissions would be 4.9 mt per annum lower than otherwise. Figure 14 illustrates the expected trend towards electrification in the 2020s, exceeding 40 per cent in mid-decade, based on current project commitments. The NPD estimates that the projects under consideration all have CO_2 abatement costs less than NOK 1500/tonne CO_2 but there is believed to be a wide range of abatement costs from one project to another. The capital costs are high but some financing is available from state-owned or public sources to alleviate the burden on existing investors. The projects can be expected to impair investors' future financial returns but the tax system will ensure that the state bears the principal financial burden through lower future tax receipts.

6. Summary and Conclusions

Before the adoption of upstream industry-wide emission reduction targets in 2020, it was expected that GHG emissions in both the UK and Norway would decline progressively in the coming decades. Resource depletion and declining production would have been accompanied by a fall in gross emissions on the UKCS by 2050 of 75-90% from a baseline in 2018 and on the NCS of 50-70%, depending on assumptions about future oil and gas prices, resource discoveries, costs and taxation. The larger and less mature resource base on the NCS is expected to ensure greater economic longevity and the continuation of production well beyond 2050.

The UKCS and NCS present two very different prospects for decarbonisation in the 2020s towards the respective new industry GHG emissions targets in 2030. The scale of the challenge presented by the upstream emission reduction targets by 2030 is greater in Norway than it is in the UK since the expected natural decline in output is slower on the NCS and NCS emission intensity (10 kg CO_2/boe) is already much lower than in the UK (28 kg CO_2e/boe) due to the legacy of more stringent emission regulation and the upstream CO_2 tax. In Norway, further platform electrification through power-from-shore represents a high-cost but secure route to delivering the targeted reduction of about 35 per cent by 2030. This is a political and social choice made by Norway to contribute to climate change abatement without giving up its long-standing commitment to develop its remaining offshore resources of more than 50 billion boe and to preserve the source of its prosperity.

State participation on the NCS provides the means to deliver effectively the 2030 targets set out by both Equinor and the Norwegian government. The legal basis, the policy instruments and the institutional arrangements are already in place. Capital commitments made so far will not be sufficient to achieve the target but a sustained programme of electrification investment and the natural decline in production after 2024 make the 2030 target feasible, albeit at a high financial cost. The relatively high current rates of tax on the NCS will ensure that the government, directly or indirectly, will bear the lion's share of the cost of upstream decarbonisation. The temporary tax relief package approved in June 2020 to maintain investment in resource development and electrification in 2020-21 highlights the importance of the tax system in ensuring that the costs of decarbonisation are shared appropriately between the taxpayer and investors and that private investor confidence in the NCS is not undermined. The potential impact of the new target on exploration and development economics in the remote, high-cost Barents Sea may entail some difficult decisions in future about which resources are developed.

On the more mature UKCS, resource depletion and steadily declining production are expected to deliver more than half the intended reduction of 50 per cent or 9 mtCO_2e in total GHG emissions between 2018 and 2030. The existing pattern of emissions strongly suggest that they could be reduced by 2-3 mt CO_2 per annum at moderate cost through improved energy efficiency and reduced flaring, venting and leakage of gas, without major investment. However, at present, there are no clear economic incentives or policy instruments in place to achieve it. Methane emissions have been a blind spot for regulators and industry on the UKCS for many years but the political context has now changed decisively. Improved emission reporting, a more effective OGA consents regime for flaring and venting and changes to operational priorities should together offer low-cost abatement opportunities achievable by 2025. Early action on methane emissions could also do much to establish the industry's credentials as its assets and expertise may be an important part of the UK's longer-term energy transition involving CO_2 storage, offshore renewables and hydrogen production.

At present, electrification through power-from-shore and CCS appear very costly options for emission abatement on the UKCS given the limited life of remaining recoverable resources (10-20 bn boe) and the dispersed nature of offshore power demand. Power from offshore renewables may be economically feasible in future in parts of the UKCS, such as the Central North Sea or West of Shetland, within a new carbon pricing and fiscal regime.

Carbon pricing and fiscal reform are likely to be critical to UK upstream decarbonisation, as in onshore energy-intensive sectors. Without changes to the UKCS tax system, there is a heightened risk that the demand for new capital for decarbonisation will simply lead to earlier decommissioning of late-life fields and infrastructure and the stranding of undeveloped discovered resources. Successful UKCS

decarbonisation will demand a change of behaviour from some UKCS operators, the integration of emission abatement into the OGA's MER UK strategy and well-designed economic incentives. As a producing province entirely dependent on a wide range of private investors, the economic viability of the UKCS is more sensitive to financial returns and its international competiveness than the NCS. The industry has done a good job of bringing down its operating costs since 2015 but future investment in resource development and emission abatement will remain vulnerable to protracted periods of low oil and gas prices.

The emission intensity of Norwegian oil and gas production is already among the lowest in the world. UK gas production has a carbon footprint which is significantly lower than that of most imported LNG and possibly also lower than some sources of long-distance pipeline supply, so it is essential from a global perspective that policy efforts to decarbonise UKCS and NCS operations do not undermine their competitiveness and increase imports from more carbon emission-intensive sources.

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