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Does carbon pricing really work?

An empirical evaluation of CO_2 emissions on both the Norwegian Continental Shelf and the UK Continental Shelf

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Acknowledgement

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I take full responsibility for any mistakes and omissions in the thesis.

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Eirill Aastorp Tangen

Abstract

Does carbon pricing reduce CO_2 emissions from the petroleum industry? This thesis studies the driving forces behind the CO_2 emissions per produced unit of both the UK and Norwegian offshore oil and gas extraction. One of the driving forces studied is the CO_2-price. For Norway, this include both the CO_2-tax and the EU ETS carbon permit price. In contrast, there is no carbon tax om oil and gas extraction in the UK. UK is only regulated by EU ETS when it comes to a CO_2-price.

We use field specific figures covering both the Norwegian and the UK continental shelfs when using panel data techniques for the period 1997-2015 and 2006-2015, respectively. This thesis is to some extent based on the modelling framework of Gavenas (2014) and Gavenas et al. (2015), which considered only the Norwegian Continental Shelf in the period 1997-2012.

In this thesis, we find no or little significant effect of the CO_2-price on emission intensity on neither NCS nor UKCS. The dummy variable for fields located on UKCS generally enters with high statistical significance. This suggest that there is a difference between fields located on UKCS and NCS when it comes to emission intensity. We expected that this dummy variable would capture some long-term effects of the Norwegian and UK CO_2-prices, which the CO_2-price variable was unable to capture. However, this dummy variable turned out to have the opposite effect, which may be due to deficiencies with the UK data.

We also find that the emissions intensity increases significantly as a field's production decreases. In addition, our estimations suggest that oil fields have higher emission intensities than gas fields, and that emission intensities decrease with the reserve size and increase with water depth. Most of our results support previous studies, such as Gavenas (2014) and Gavenas et al. (2015).

Sammendrag

Vil en karbonpris redusere utslipp av CO_2 fra olje- og gass utvinning på norsk og britisk sokkel? Denne oppgaven analyserer drivkreftene bak CO_2 utslipp per produsert mengde fra norsk og britisk olje- og gassutvinning. Karbonpris er en av drivkreftene vi har studert i denne oppgaven. For Norge inkluderer dette både en norsk karbonavgift og EU ETS sin kvotepris. UK har ikke en karbonavgift på olje- og gassutvinning, og er kun regulert av EU ETS sin kvotepris.

Sammenhengen mellom CO_2-utslipp og utslippsintensitet er estimert ved hjelp av panel data metoder. Vi bruker feltspesifikk data som dekker både norsk og britisk sokkel for henholdsvis periodene 1997-2015 og 2006-2015. Oppgaven er til en viss grad basert på metoden til Gavenas (2014) og Gavenas et al. (2015). De så kun på norsk sokkel i perioden 1997-2012.

Resultatene viser at en karbonpris har lav eller ingen effekt på utslippsintensitet på norsk og britisk sokkel. En dummy variabel for britiske felt, som generelt sett har høyt signifikans nivå, indikerer at det er en forskjell mellom felt på norsk og britisk sokkel når det kommer til utslippsintensitet. Det var forventet at denne dummy variabelen ville fange opp langsiktige effekter av ulik CO_2-pris på norsk og britisk sokkel, som CO_2-pris variabelen ikke klarte å fange opp. Denne dummy variabelen viste seg å ha motsatt fortegn av det som var forventet, noe som kan skyldes mangelfulle data for UK.

Vi finner også at utslippsintensiteten øker betydelig når produksjonen til et felt avtar. I tillegg, finner vi at oljefelt har høyere utslippsintensitet enn gassfelt, og at utslippsintensiteten avtar med reservestørrelse og øker med vanndybde. Mange av resultatene underbygger tidligere studier som for eksempel Gavenas (2014) og Gavenas et al. (2015).

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1. Introduction

1.1 Background

Climate change is a global challenge that requires action. In 2015, at the UN climate conference in Paris, an agreement was adopted, called *the Paris agreement*. This agreement aims to reduce global emissions of GHGs (greenhouse gases). Norway, together with EU, has a goal to reduce GHG emissions with at least 40 % within 2030 compared to their emission level in 1990 (Ministry of Finance 2016).

Oil and gas production are important for both the Norwegian and British economy. Norway is the largest producer of oil in Europe and UK is second largest (Hough 2017). However, atmospheric emissions of CO_2, and other GHGs that contribute to global climate effects, are an inevitable part of the production process. IOGP (International Association of Oil & Gas Producers) members reported 280 million tonnes of CO_2 emissions from their oil and gas production in 2015. This correspond to 129 kg CO_2 per thousand tonnes of oil equivalent (IOGP 2016). Thus, regulation of oil and gas production has gained increased attention in the climate debate in later years. This applies especially to Norway since the oil and gas industry is the main sources of GHG emissions in Norway. The second source of GHG emissions in Norway is the manufacturing sector, followed by the transport sector (SSB 2016). In UK, CO_2 emissions from the oil and gas industry stood for slightly more than 3 % of the total CO_2 emissions. And the largest emission source of CO_2 emissions in UK are energy supply, mainly electricity generation (Oil and Gas UK 2016).

Combustion of gas and diesel in turbines, which is quite energy demanding, followed by gas flaring are the main causes to CO_2 emissions from the petroleum industry (IOGP 2016). A country's emission level from the petroleum industry depends among other things other things on the size of the oil and gas extracted, and on what kind of measurements the country has implemented to reduce emissions. Norway introduced a tax on CO_2 emissions in 1991 to reduce their emissions of CO_2. The EU ETS (Emission Trading Scheme) started in 2005, and UK became member of this scheme from its beginning since they already were member of the EU (DERFRA 2006). The Norwegian petroleum industry joined the EU ETS in 2008 in addition to the already existing CO_2-tax (KonKraft 2016; Ministry of Finance 2016).

1.2 Problem statement and hypothesis

This thesis will be aiming to answer the following research questions:

What are the driving forces behind emission intensity on oil and gas fields on both the Norwegian Continental Shelf and the UK Continental Shelf? In particular, how does a CO_2-price affect emission intensity of oil and gas extraction?

We will compare and study emission intensities of oil and gas extraction on both the Norwegian and UK Continental Shelf's to identify the driving forces behind emission intensity. We have detailed field data for the period 1997-2015 for the Norwegian Continental Shelf and 2006-2015 for the UK Continental Shelf, respectively. The study partly builds on Gavenas (2014) and Gavenas et al. (2015) who studied emission intensities on the Norwegian Continental Shelf for the period 1997-2012. Carbon pricing is commonly believed to be one of Norway's most important instruments to reduce emissions of CO_2. In light of this, we are also particularly interested to see if a CO_2-price has a significant impact on emission intensity. Gavenas et al. (2015), finds a weak[1] negative relationship between the CO_2-price and emission intensities. To the best of my knowledge, UK has only had EU ETS in the period studied. Thus, we would like to invest if the great difference in the CO_2-price between Norway and UK have influenced emission intensity. A CO_2-price is one of many factors affecting CO_2 emissions. We will therefore also aim to answer the following sub-questions:

Are there differences between oil and gas fields with respect to emission intensity?
Does a field's emission intensity increase when its production declines from its peak production level?
Does the size of the field, gas flaring, water injection and water depth matter?

1.3 Structure

Section 2 contains background information that will enable the reader to understand more of the research conducted. Section 3 contains the theoretical framework provided to explain and substantiate CO_2-pricing to reduce CO_2 emission on the petroleum sector, and the difference between an emission tax and emission permit. Section 4 presents the data collected and variables used, before the methodology is presented. The method is by using panel data techniques. Section 5 presents the results of this analysis and discussion of the estimated results. Policy implication is briefly discussed at the end of this Section before we end with a conclusion in Section 6.

[1] At 10 % level of significance.

2. Background to topic

This Section will present the necessary background knowledge. First, a general background, current situation and a brief introduction of the regulatory framework will be presented. Secondly, a short presentation of climate policy, followed by a brief presentation of CO_2 emissions and emission sources from the petroleum industry. Fourth, a short presentation of electrification from land and fifth and lastly, previous research.

2.1 Brief history and current situation

The first oil well was drilled in 1859 in Pennsylvania. This laid the groundwork of the modern petroleum industry, and early in the 1960s it became known that the North Sea could contain oil and gas. As a result, and before the oil exploration started, Norway and UK agreed to divide the two continental shelves by the centreline principle in 1965. This was done to determine the ownership of the undersea resources when it came to exploration and extraction of natural resources (NOG 2010b). Because of the centreline between the NCS and UKCS, there are some fields that are Anglo-Norwegian, e.g. *Blane, Enoch, Frigg, Islay, Murchison* and *Statfjord*.[2]

The first discovery of oil on the Norwegian Continental Shelf was the *Balder* field in 1967. However it was not until the *Ekofisk* discovery in 1969, and it production start two years later, that the oil production on the NCS really began (NP 2017). This is said to be the largest offshore discovery at NCS followed by a number of large discoveries in following years (Ibid). The first major oil discovery on the UK Continental Shelf (UKCS) was the *Forties* oil field in 1971. The *Forties* field came in production in 1975, and is characterised as the largest oil field on the UKCS. *Forties* it is still in producing after 40 years of production (Whaley 2010).

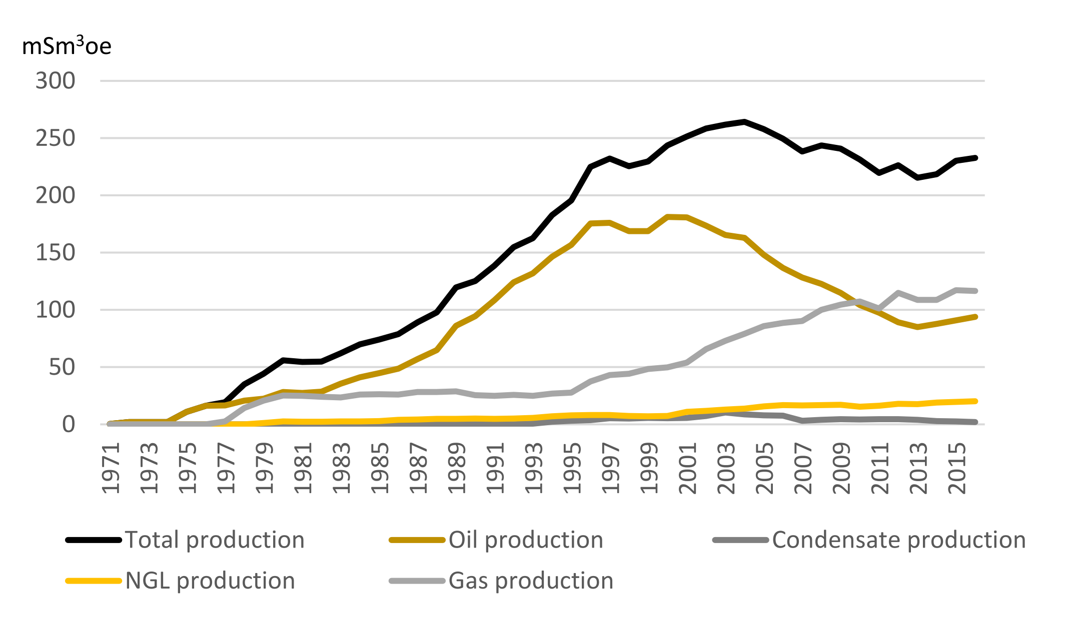
By the entrance of 2017, 83 offshore fields were in production on the Norwegian Continental Shelf (NCS). Of these 83 offshore fields, there are 47 oil fields, 26 gas and condensate fields and 10 oil and gas fields (NPD 2017b). Since the entrance of 2013 14 new fields have started their production. Four of these started producing during 2015 and two during 2016. These fields are called *Valemon, Bøyla, Knarr*, *Edvard Grieg*, *Ivar Aasen* and *Goliat*, respectively (NPD 2017c). From Figure 1 we see that the total production of oil and gas peaked in 2004 with slightly above 264 million standard cubic meter oil equivalents (mSm3oe). We also see that the oil and condensate production has steadily declined after the peak as new oil discoveries has not kept pace with existing fields maturing. We also see that the

[2] How these are treated in our analysis is described in Section 4.1.

production of NGL and gas are gradually increasing. Norway produced around 230 mSm3oe in 2015, which is a decrease of 12 % relative to their peak production level.

Troll is the largest oil producing field on the NCS, which started producing in 1995. It produced nearly 43 mSm3oe in 2015, which is around 18 % of the total production that same year (NPD 2017c). The *Troll* field peaked in 2003 with around 49 mSm3oe and stood for slightly above 16 % of the total production on NCS that year (Ibid). The largest producing oil field on the UKCS in 2015 was the *Buzzard* Oil field with an oil production of around 10 mSm3oe, which is around 10 % of the total production the same year (OGA 2016a). *Buzzard* started producing in 2007, and peaked in 2008 with around 12 mSm^{3}oe. This is slightly above 7 % of the total production in 2008 (Ibid).

Figure 1. Historical annual production on NCS (1971-2016).

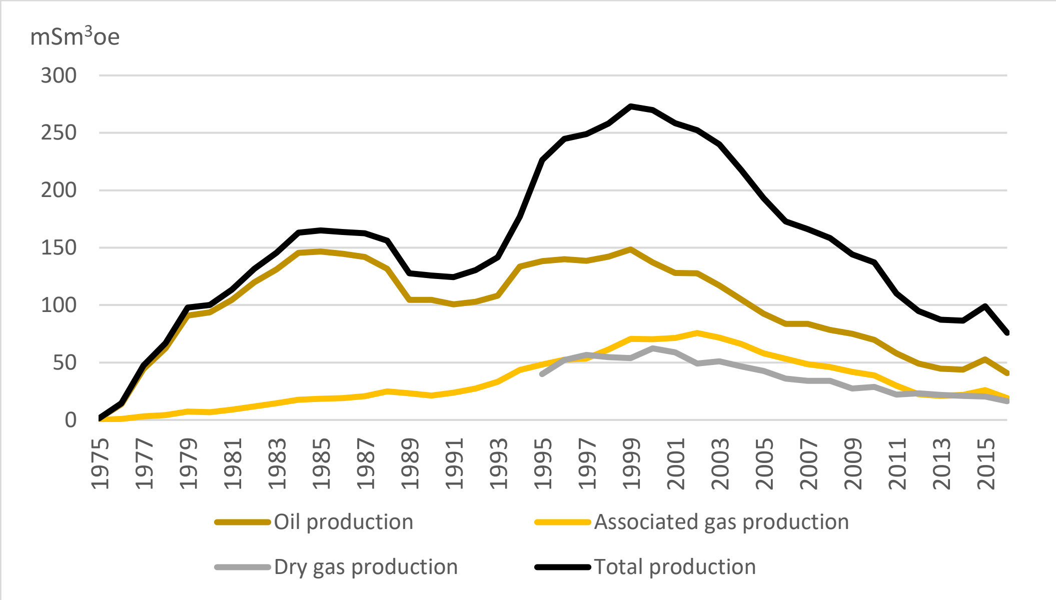


Source: Based on figures obtained from NPD (2017c).

320 offshore oil and gas fields were in production by the entrance of 2017 on the UKCS. The 320 offshore fields consisted of 169 oil fields, 115 gas fields and 36 condensate fields (OGA 2017). Since 2013, 38 new fields have started producing and eight of these started producing in 2015, namely *Peregrine*, *Ythan*, *Enochdhu*, *Godwin*, *Alma*, *Galia*, *Gladhan* and *Solitaire*. *Conwy*, *Solan*, *Crathes*, *Scolty*, *Laggan*, *Tormore*, *Alder*, *Aviat* and *Cygnus* started in 2016 (OGA 2016a).

Production of oil and gas on the UKCS has steadily declined since its peak in 1999, which shown in Figure 2. UK produced 99 mSm^{3}oe of oil and gas in 2015, falling about 64 % compared with the peak production level. In 2015 about 53 % of the total production was crude oil including condensate. The oil production including condensates in 2015 increased with around 20 % from 2014, while a 64 % decrease compared with 1999. While associated gas consisted of 26 % of the total production in 2015 falling about 63 % compared with the peak level, and dry natural gas consisted of 21 % of the total production in 2015 falling about 62 % compared with 1999. Gas that dissolved in the crude oil is knows as associated gas, and is a by-product of crude oil production (Smithson 2016). Associated gas is often flared, vented, used or injected back into the reservoir (IOGP 2016). Dry gas is natural gas with low or none contents of condensates or liquid hydrocarbons, consisting mostly of methane (CH_4) (Devold 2013; NPD 2017a). For both NCS and UKCS, there was a modest upturn in 2015. This might be due to new start-ups fields and developments.

Figure 2. Historical annual production on UKCS (1975-2016).



Source: Based on own calculations with figures obtained from OGA (2017).

2.2 Brief about the regulatory framework

The petroleum industry is important to both the Norwegian and the British economy. Thus, it is essential that the petroleum industry is well organised and is subject to a thoroughly prepared regulation to e.g. ensure efficient utilization of the petroleum resources. Thus, the Petroleum Act 1996 (Act of 29 November 1996 No. 72) is related to petroleum activity subject to the Norwegian jurisdiction. The Petroleum Act 1996, among other, states that the Norwegian state has the proprietary right to subsea petroleum deposits and resource management on the Norwegian Continental Shelf (The Petroleum Act 1996, s1(1-4)). The Norwegian Parliament has the legislative power and sets the framework for the petroleum activities on the NCS, including production licensing. A licence (or a production licence) gives an operator the right to explore and extract oil and gas within an agreed upon geographical area. In addition, must all petroleum activity receive licences subject to the Pollution Control Act (Act of 13 March 1981 No.6).

On the UKCS, the Oil and Gas Authority (OGA) regulates oil and gas exploration and development, and grant licenses to maximize the cost-effective recovery of the UK's petroleum resources according to the Petroleum Act 1998 (Act of 11th June 1998 c.17) and the Energy Act 2016 (Act of 12th May 2016 c. 20) (Hough 2017). However, licences cannot be issued without the consent of the Secretary of State (Petroleum Act 1998, s 3(1-4) & s 4(1-2)). This is because the Secretary of State for Business, Energy and Industrial Strategy (BEIS) has the overall responsibility over OGA. The Secretary of State also has the regulatory power relating to the environment such as climate change policy (Hough 2017).

2.3 Emissions from the petroleum sector

2.3.1 Emissions

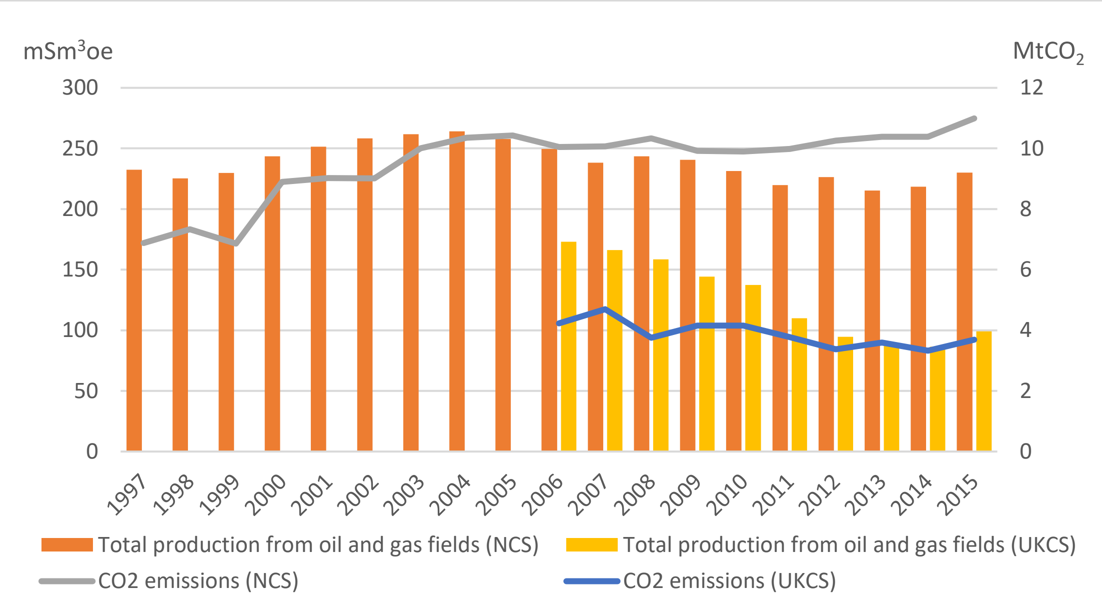
The oil and gas industry results in heavy emissions of GHGs, both during production and mostly during product combustion. In 2015, GHG emissions from oil and gas extraction on the NCS were 15.1 million tonnes CO_2-equivalents ($MtCO_2e$), of which 14.1 million tonnes were CO_2 emissions (NEA 2016; SSB 2016). The offshore oil and gas extraction emitted around 11 million tonnes CO_2 on the NCS (SSB 2016). The UKCS emitted 14.7 $MtCO_2e$ GHG emissions in 2015 from the petroleum industry, of which 13.2 million tonnes were CO_2 emissions (Oil and Gas UK 2016). Thus, the UKCS have more of other GHGs from their petroleum activity relative to NCS.

Most of the Norwegian CO_2 emissions come from the petroleum industry, which constitute slightly less than one third of their total CO_2 emissions. Most Norwegian electricity comes from hydropower. Other countries use electricity mostly generated on fossil fuels associated with CO_2 emissions. This contributes to the Norwegian petroleum activity's high share as an emission source compared to other petroleum producers around the Northern Sea area (NOG 2010a). On the UKCS, 3 % of UK's total CO_2 emissions are from the petroleum sector (Oil and Gas UK 2016). As UK still uses coal and fossil fuels for electricity generation, this contributes to the UK petroleum activity's low share as an emission source. But also because UK is a larger country with higher emissions relative to Norway, where national CO_2 emissions in 2015 was 405 $MtCO_2e$ in UK (DECC 2016), while Norway's national CO_2 was 44.7 $MtCO_2e$ (SSB 2016). In addition, the oil sector on the UKCS is smaller than on the NCS.

From Figure 3, we see that CO_2 emissions from oil and gas production increased slightly from 2014 to 2015 on both the NCS and UKCS, which is because of increased production in 2015 (Oil and Gas UK 2016). GHGs from oil and gas industry have increased significantly since 1997 on NCS since several new installations have started producing and many fields are approaching the last stage of production (declining phase), which is more energy intensive. While on the UKCS, the CO_2 emissions have steadily decreased as the production is gradually falling due to maturing fields.

The CO_2 emissions in Figure 3 are based on the reported emissions received from BEIS and NEA. The Norwegian emissions from the offshore oil and gas extraction, was around 11.9 $MtCO_2e$ in 2015, compared to the 14.2 $MtCO_2e$ from the petroleum industry, which includes onshore fields and terminals. It is uncertain why the emission data from UK are so different (13.2 $MtCO_2$ compared to nearly 4 $MtCO_2$ in Figure 3). The amount of 13.2 $MtCO_2$ most likely include emissions from both onshore fields and terminals. The emissions from UKCS in Figure 3 are received from BEIS. Further, BEIS have been contacted about this significant difference, and been asked about which kinds of emissions sources the reported emission figures cover. But we are still waiting on the reply.

Figure 3. Overall production and CO_2 emissions from offshore oil and gas extraction.



Source: Based on data from NPD, OGA & BEIS.

2.3.2 Emission sources

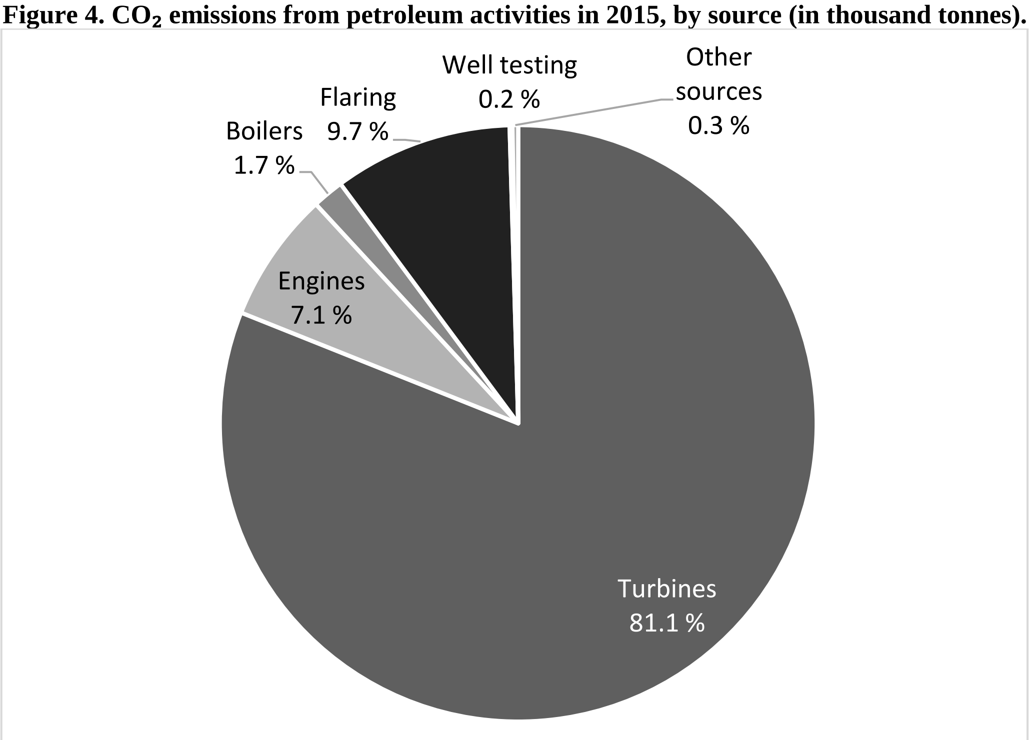
Emissions from the petroleum industry mainly come from combustion of natural gas and diesel in turbines to generate power and heat on installations when producing oil and gas offshore. Other sources are gas flaring[3] engines, boilers, venting, storing and transporting oil and gas. According to data from NPD, turbines caused 81 % of the CO_2 emissions from petroleum activities on the NCS in 2015. On the UKCS 75 % of the CO_2 emissions were due to fuel combustion to provide electrical power to run oil pumps, heating, etc., and to drive compressors to convert gas into liquid form for gas export (Oil and Gas UK 2016). Both on the NCS and the UKCS is gas flaring the second largest emission source.

[3] Gas flaring is post combustion to get rid of excess gas and oil by petroleum production, and involves disadvantages such as loss of resources and large CO_2 emissions (NOG 2016).

CO_2 emissions from the petroleum industry are largely based on each field and installations energy demand, but also on how energy efficient the installation is. Energy, i.e., power and heat, is needed to extract oil and gas. While gas flaring on the NCS mainly is maintained due to safety considerations in case of failures in the process (Devold 2013; NOG 2010a). According to the World Bank (2017), the UKCS flared 1 321 mSm^3 gas in 2015, while NCS flared 336 mSm^3 gas, which is considerably lower. This is equivalent to a flare intensity of 0.014 Sm^3 gas per Sm^3oe produced and 0.0014 Sm^3 gas per Sm^3oe produced, respectively. The flare intensity was around 13.6 tonnes of gas per thousand tonnes of hydrocarbon produced for the world average in 2015 (IOPG 2016).

On the NCS, gas flaring is limited according to regulations in the Petroleum Act 1996 (NOG 2016). On the UKCS, the regulation for flaring is strict and is subject to the Petroleum Act 1998. A consent is needed to flare, but the flaring regulation is somewhat "looser" than for the NCS. Still, gas flaring mainly is conducted due to safety reasons. However, the UKCS have several mature fields that are over 30 years old. These fields are designed to flare higher level of gas since the infrastructure to transport gas is lacking (Oil and Gas UK 2016).

Figure 4. CO_2 emissions from petroleum activities in 2015, by source (in thousand tonnes).



Source: Based on data from Norwegian Petroleum Directorate.

2.4 Electrification

Today, the offshore fields *Gjøa, Goliat, Ormen Lange, Troll* and *Valhall* on the NCS is electrified (KonKraft 2016). However, to the best of my knowledge, none of the oil and gas fields on the UKCS are electrified.

Electrification is a way to reduce emissions from the petroleum activity. Offshore gas turbines are replaced, fully or partly, with electricity transmitted with cables from land (ABB 2014). Emission reduction from electrification apply at least for emissions on the NCS, since electricity generations from hydropower does not cause CO_2 emissions. New big point source emissions with long lifetime can be avoided by electrifying new start up fields from the beginning, rather than later in its lifetime, which is cost reducing relative to do the electrification in a later stage in the oilfields lifetime (Ibid).

According to ECON Energi and SINTEF (1994), electrification on the NCS leads to less use of natural gas due to increased use of electricity generated from hydropower on the NCS. This causes an excess supply of natural gas and decreased export of hydropower. The excess supply of natural gas can either be exported,[4] injected back into the reservoir to increase oil extraction or be flared (Ibid). The two latter will increase the CO_2 emissions, while increased export of natural gas can reduce the use of more polluting energy sources e.g. oil and coal (ABB 2014). And according to ECON Energi and SINTEF (1994), decreased export of hydro power will lead to more use of natural gas (or of other more polluting energy sources) and less use of hydropower. Hence, the Norwegian emission reduction from electrification might lead to increased emissions abroad. However, same reasoning as above for increased export of natural gas apply here, where natural gas substitutes the use of more "dirty" power sources, which may reduce the emissions abroad. It is difficult to determine which of these two effects that is the greatest, and the net effect on global emissions are therefore hard to calculate (Ibid).

2.5 Climate Policy

Both the Norwegian and British climate policy are among other based upon the Kyoto protocol, the UN Framework Convention on Climate Change (UNFCCC) and on each Parliaments individual decisions.

In 1997, almost every country in the world signed UNFCCC's Kyoto Protocol, which was ratified in 2005. The goal with this agreement was to reduce the overall GHG emissions from developed countries with at least 5 % from 2008 to 2012 compared to the emission level in 1990, where EU committed to a 8 % emission reduction (Tietenberg 2006). However, US did not sign the agreement (which is one of

[4] Some fields do not have the constructions or solutions to export gas, and therefore use gas injection or flaring as a solution to excess gas (ECON Energi & SINTEF 1994).

the world's biggest emitter) and Canada ratified but withdrew later from the agreement. The EU Emission Trading Scheme (EU ETS) was introduced by EU to reach their Kyoto Protocol target.

At the UN climate conference in Paris during 2015 (COP21), a global target to combat the climate challenges by reducing emission of GHGs and gaining climate neutrality, was agreed upon. The UN member states agreed to prevent the global average temperature increase to surpass 2 degrees Celsius (ºC) above pre-industrial level. The UN member states must also strive to limit the temperature increase to 1.5 degrees Celsius (ºC) (UNFCCC 2015). Thus, the Paris Agreement was adopted at the COP21 and entered into force on 4th November 2016. Today, 159 members of 197 have ratified, while 43 parties are considering ratifying (Ibid). The US ratified, but withdrew by the entrance of June 2017 following presidential changes.[5] The Paris agreement applies to all countries, even though developed countries are assumed to stand for most of the mitigation. All countries must establish a national plan for how to reduce GHG emissions and by how much (Ibid). Norway along with EU (and thus UK) have decided to reduce their emissions with 40 % within 2030 compared to their emission level in 1990 (Ministry of Finance 2016). This will happen through e.g. participation in the EU ETS and environmental taxation. Over 80 % of Norway's total GHG emission are regulated through these instruments (Ibid).

2.5.1 EU ETS

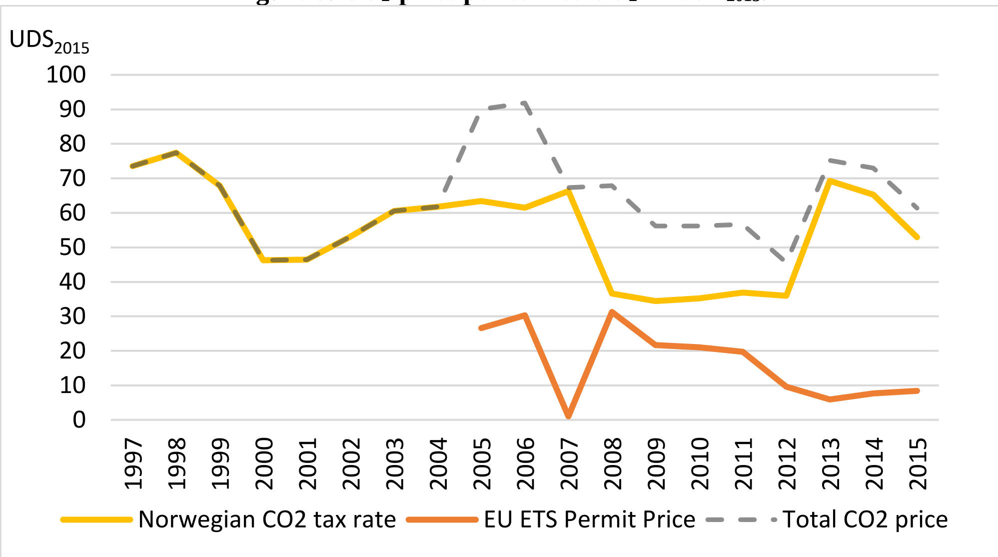
European Union Emission Trading System (EU ETS), along with CO_2-tax, is the main instrument to reduce CO_2 emissions, and is the world's largest carbon market for trading CO_2-permits according to KonKraft (2016). It covers 45 % and 50 % of the total GHGs emissions from the member countries and from Norway respectively (Ibid). The EU ETS was introduced in 2005, and applies for 31 countries: all member countries of EU plus Iceland, Liechtenstein and Norway (EC 2017a). Norway became connected with the EU ETS in 2008, and is subject to the same laws as the member countries of EU. The oil and gas industry, among other sectors, are obliged to participate in the ETS, while other sectors such as agriculture can voluntarily buy emission permits (Ibid). EU ETS creates a limit for pollution and emission through allowances or permits, where one permit gives a permission to emit one ton of CO_2. The number of permits in circulation correspond to the amount of CO_2 emitted according to the agreed upon climate target. Thus, the ETS regulates and sets a limit or a "cap" for how much CO_2 that can be emitted. This will be examined closer in Section 3.2.

EU ETS is divided into three phases. The first phase (2005-2007) was a trial phase due to missing emission figures, where almost all permits were distributed for free. In this phase, they managed to establish a carbon market and a carbon price (also called a CO_2-price) (EC 2017b). However, due to using estimates and not actual emission data, the supply of permits exceeded the demand after permits.

[5] https://www.theguardian.com/environment/2017/jun/01/donald-trump-confirms-us-will-quit-paris-climate-deal (Accessed 11.07.2017)

As a result, the permit price fell to zero in 2007 (Ibid). This can be seen in Figure 5. In the second phase (2008-2012), the proportion of free allocation of permits was reduced with around 10 %. With actual emission data from the first phase, the cap on permits was now reduced (Ibid). However, the economic crisis in 2008 led to lower emissions than anticipated, resulting in a low permit price due to a large excess supply of permits. EU ETS is now in its third phase (2013-2020). In contrary to the first and second phases, less permits are distributed for free, and there is more use of auctioning (EC 2017a). However, industries that are exposed to carbon leakage are still receiving permits for free. This is addressed closer in Section 3.5. From 2013, the Norwegian offshore petroleum industry received free permits for the first time due to EU's regulations.[6]

Figure 5. CO_2-price per tonnes CO_2 in USD_{2015}.



Source: Based on own calculations with figures obtained from Ministry of Finance.

2.5.2 Tax on CO_2 emissions

The CO_2-tax was introduced in Norway in 1991. The tax was applied to the oil and gas industry, in addition to other sectors, on the NCS. In 1991 this tax was NOK 0.60 per standard cubic meter oil equivalent (Sm^3oe) (KonKraft 2016; Larsen & Nesbakken 1997). The tax rate varies between sectors and is determined by the Ministry of Finance in the Norwegian Parliament, in contrast to tradable permits where the price is determined in the carbon market. Today, the CO_2-tax is NOK 1.04 per Sm^3oe which equals around NOK 444 per tonne CO_2.[7] The tax is levied at the production stage (where emissions are directly emitted), and is one of the main instrument to reduce CO_2 emissions from the oil and gas industry on the NCS (KonKraft 2016). The CO_2-tax is mainly imposed on industries or firms that are not obligated to comply with EU ETS. The EU ETS permit price is seen in context with the

[6] https://www.ssb.no/natur-og-miljo/artikler-og-publikasjoner/fire-av-ti-klimakvoter-gratis 30.02.2017
[7] http://www.statsbudsjettet.no/Statsbudsjettet-2017/Artikler/Avgiftssatser-2017/ 14.05.2017

CO_2-tax to primarily avoid firms paying twice for their CO_2 emissions, where the permit price will be subtracted from the CO_2-tax (KonKraft 2016; Ministry of Finance 2016). This relationship can be seen from the Figure 5 in Section 4.21. With an introduction of emission permits, we see that the CO_2-tax rate falls. Further, when the permit price falls, the CO_2-tax rate increases.

2.5.3 The Climate Change Programme

To achieve UK's commitment to the Kyoto Protocol of a 12.5 % emission reduction and national unilateral policy goal of 20 % emission reduction relative to 1990 levels by 2010, the UK established a Climate Change Programme by the ending of 2000 (Dahan et al. 2015; DERFRA 2006). As an aid to the Climate Change Programme, the UK established an emission trading scheme pilot prior to the EU ETS, known as UK Emission Trading Scheme (ETS), which entered into force in 2002. The UK ETS trading scheme played an important role for the EU ETS as it was largely based on the UK pilot scheme along with Denmark's pilot ETS that only considered the electricity sector (Dahan et al. 2015). By the entrance of 2002, the UK Government held an auction of a subsidy payment per tonnes abatement of CO_2-equivalents, where 32 firms entered. Participating firms could buy and sell needed and excessive respectively, and followed a Cap-and-Trade system (as the EU ETS). One of the goals for the UK ETS was to prepare and gain experiences of emission trading before participating in EU ETS. Another goal was to reduce GHG emission in a cost-effective way, where the emission reductions were compared to the 1998-2000 emission level. An additional goal with the introduction of the UK ETS, was to make London the location for the global emission permit market (Dahan et al. 2015; DERFRA 2006).

In contrast to EU ETS, participation of UK ETS was voluntary. Since most of the 32 participants were not energy intensive, the net gains from energy efficiency were sometimes negative (DERFRA 2006). Furthermore, the number of permits allocated declined as the EU ETS entered into force in 2005 since some of the participants were obligated to join the EU ETS. The UK ETS officially ended in 2006, and relevant participants were more or less taken over by the EU ETS in 2007 (DERFRA 2006). Hence, the UK ETS does not affect the data used in this analysis.

Another instrument to aid the Climate Change Programme, was the Climate Change Levy (CCL). The CCL was introduced in 2001, and is a type of environmental tax for British industry (Dahan et al. 2015; Smith & Swierzbinski 2007). The CCL is intended to give an incentive to increase energy efficiency, encourage to use renewable energy and to reduce CO_2 emissions (Ibid). This levy is a downstream tax based on fossil fuel users, i.e. industry use of coal, gas electricity and non-transport LPG (Pearce 2006). The levy does not apply the transport or household sector uses of fuels. Moreover, since the levy is downstream, electricity generation and extractors are exempted from the levy in addition to fuels used for non-energy use. Further, the CCL is like a single-stage excise resulting in higher electricity prices for those eligible, and is included in the electricity bill (Ibid). It seems like the CCL does not apply to extraction of oil and gas, and thus does not affect our UK data in this analysis. And to the best of my knowledge, there is no other regulation of CO_2 emissions than EU ETS on UKCS.

2.6 Previous research

Gavenas et al. (2015) study the driving forces behind CO_2 emission per produced unit of oil and gas extracted (emission intensity) on the NCS, and the effect of CO_2-prices on emission intensity using field specific figures during the period 1997-2012. They found among other, an indication of a negative relationship between the CO_2-price and emission intensity. They also found that the emission intensity increases substantially as a field declines from its' peak production. In their study, they also found that emission intensity is lower for gas production relative to oil production.

Fæhn et al. (2017) study how changes in Norwegian oil production would influence both the domestic and the global oil demand. Their main finding is that reduced oil extraction in Norway would probably lead to lower global CO_2 emissions. The reduced domestic oil production could be replaced by production elsewhere (abroad). However, even with an increase in production abroad, global emissions could still have a negative net effect, i.e. a reduction in domestic production will be greater than the increase in production abroad. This will lead to a decrease in global consumption, and thus a decrease in global emissions.

ECON Energi and SINTEF (1994) study the effect of the CO_2-tax on oil and gas extraction in Norway. The result of the analysis show that emission per unit oil and gas produced has been reduced with 8 % because of measurements implemented in the period 1991 to 1993. They conclude, however, that only a small part of the reduction can with certainty be traced back to the taxation. ECON Energi and SINTEF (1994) finds that the tax has a limited effect on the final phase of oil and gas extraction. The tax has, however, a bigger effect on the decisions about the development phase of a field, whether the field will be developed or not. Further, reduced domestic gas production because of undeveloped oil and gas fields, the Norwegian gas production is reduced because oil and gas fields are not developed, this will lead to a reduced export of gas and energy substitution with coal and oil resulting in higher emissions (ECON Energi & SINTEF 1994).

Larsen and Nesbakken (1997) has conducted an analysis of the effects of a CO_2-tax in Norwegian emissions, where they looked at CO_2 emissions from the petroleum sector, among other sectors. According to this analysis, CO_2-tax has had some effects on CO_2 emissions on the sectors studied, such as the petroleum sector. However, the emissions intensity in the petroleum sector was only reduced with 1.5 %.

3. Economic Theory

The most relevant economic theory and theoretical model when it comes to oil and gas industry will be presented in this section, which is based on Varian (1992) and (Storrøsten 2014). First, we will look at the globally optimal level of GHG emissions. Secondly, a review of economic instruments such as emission tax and tradable emission permits. Third, there will be a comparison of emission tax and tradable permits with and without uncertainties. Fourth, we will look at how a profit maximizing firm, which produces fossil fuels, behaves with an introduction of an emission tax or tradable emission permits in a competitive market. Lastly, there will be a short presentation of carbon leakage.

3.1 The optimal level of (CO_2) emission

Even though emissions of CO_2 are harmful to the environment, zero emissions are not economic efficient, as we shall see. Allowing some emissions can be beneficial when related to cost savings such as saved abatement costs. Nevertheless, emission reductions today will have benefit of less damage to the environment in the future.

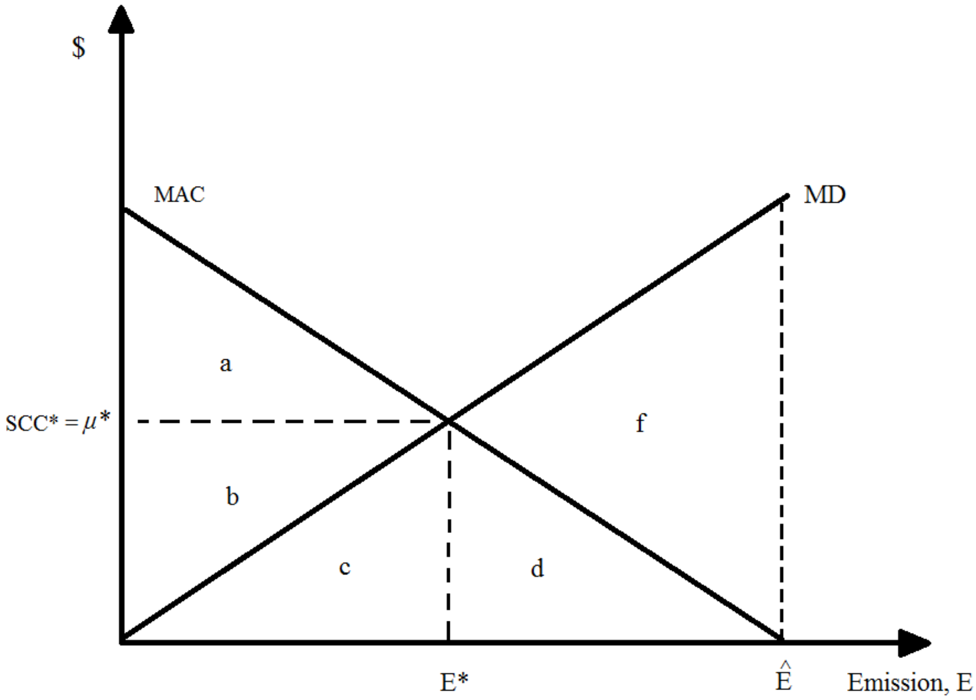
Rational firms behave in a way that maximize their private profits, hence minimize their private costs when producing goods and services. The production methods used to maximize profits are often those who generate harmful emissions (Perman et al. 2011). Emissions without regulations are shown as $\hat{E}$ in Figure 6. At this point, the total costs are the sum of damage costs (area *c*+*d*+*f*) and abatement costs, which at this point are equal to zero. Without regulation, it is cheap to reduce emissions by small amounts. However, the more emissions reduced already, the more it cost to reduce emissions further. Eventually it becomes very expensive to reduce emissions. Hence, the Marginal Abatement Costs (MACs), shown in Figure 6, increases as the emissions decreases.[8] As emissions of CO_2 increase, the damage cost related to pollution also increase. The Marginal Damage (MD) costs correspond to the additional costs applied to the society by a unit increase of CO_2 emissions (Ibid.)

The optimal level of emissions, denoted E^* in Figure 6, is found where MAC is equal to MD, thus where social net benefits are maximized and where total costs (abatement costs and damage costs) are minimized. If the actual emissions are greater than the optimal emission level, the MDs from emissions are greater than MACs of emitting. Hence, the emissions are too high per the optimal emission level and less emission will yield more net benefits. Conversely, if actual emissions are lower than the optimal emission level, the MDs from emissions are less than the MAC of emitting. Thus, there is too much

[8] Abatement costs mean whatever technology the firm has used to reduce its emission. However, CO_2 emissions are often hard to clean, and in this situation, abatement costs reflect emission reduction through e.g. less use of fossil fuels.

abatement and more emissions will yield more net benefits. Hence, zero emissions are not socially optimal.

Figure 6. The efficient level of emissions.



Source: Based on Figure 5.2 in Perman et al. (2011, p. 147).

At the optimal level, E^*, the sum of total damage costs (area *c*) and abatement costs (area d) is $c + d$. Area $d + f$ equals the reduced damage cost from going from $\hat{E}$ to E^*, where *f* is the net benefits. The intersection where MAC = MD is also where we find the optimal SCC (Social Costs of Carbon), represented as SCC^* in Figure 6. The SCC^* is equal to the shadow price of emission (μ^*). The shadow price represents the equilibrium price of (CO_2) emission and the optimal rate of emission tax, as we shall discuss in Section 3.2.1. The SCC represent the global discounted future damage costs of emitting one more unit of CO_2 emission, and can be found along the MD function (Rosendahl 2016b). The SCC depends on many variables such as climate change and impacts on climate change in the future, hence future population growth, economy growth and GHG emissions etc. Higher future development of GHG emissions and higher environmental effects of climate change will lead to a higher SCC. However, stricter regulations of GHG emissions will bring down the SCC. Thus, the SSC is given by:

$$SCC_{t=0} = \int_{t=0}^{t=\infty} \frac{\partial D_t}{\partial E_0} e^{-rt} dt, \qquad [1]$$

where todays emissions, E_0, may have an impact on future damage costs, D_t, and where *r* is the social discount rent (Rosendahl 2016b, p. 8). Lower discount rate will lead to a higher SCC (Rosendahl 2016b). Further, with a lower discount rate, future benefits of emission reductions today will matter more than if the discount rate were higher.

3.2 Economic instruments

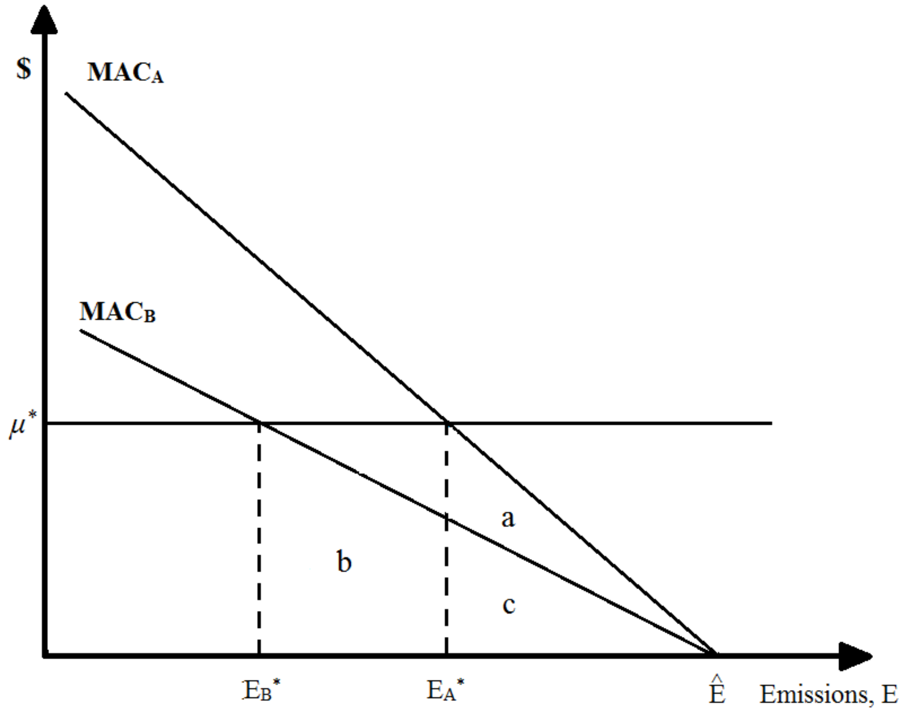
One way to achieve the optimal level of emissions is to implement economic instruments. Economic instruments (also called market based instruments) such as emission tax and tradable emission permits are incentive based instruments, unlike Command-and-Control instruments. Economic instruments give firms and consumers incentives to change their behaviour voluntarily. When implementing a climate policy, economic efficiency and cost effectiveness are often listed as two of the main criteria's. "*Greenhouse gas (GHG) emissions are externalities and represent the biggest market failure the world has seen."* - Stern (2008). Pollution creates a negative externality to the society and we therefore want an regulation to internalise this externality efficiently (Pigou 1920; Sandmo 1975). Pigouvian tax, which is a type of an emission tax, is used to internalise externality caused by pollution, and ensures the polluter-pays-principle (Bruvoll 2009). With perfect information, economic instruments can be constructed in a way that the market adjusts itself to the optimal emission level. Further, if the tax is set right, then producers' private costs will include the cost of the externality. However, in a permit market, where firms have to purchase permits to emit units of emissions, the externality is internalised through the existing emission permit market (Perman et al. 2011).

3.2.1 Emission tax

As mentioned in Section 2.4.2, a CO_2-tax was introduced in Norway in 1991, which included extraction of oil and gas. The principle behind the CO_2-tax is to reduce CO_2 emissions related to production of oil and gas, by increasing the input prices that contributes to such emissions. The tax should be set equal to the shadow price of emissions (μ^*) (cf. Figure 6), to internalize the externality, leading to an optimal emission level (Perman et al. 2011). Firms will reduce their level of emissions as long as their MAC is lower than the tax. However, if their MAC is greater than the tax, firms could reduce abatement costs by increasing emissions and paying lower tax.

Cost-effectiveness is a necessary condition for efficiency and requires that the marginal abatement costs are equal across emission sources or across firms. The tax rate is equal for all firms in the same sector, hence their marginal abatement costs are equal. This means that firms will adjust their individual emission level such that their marginal abatement cost is equal to the tax rate (Ibid). Introducing an emission tax on CO_2 per unit emissions at a constant rate (μ^*), will give rational firms incentive to reduce their emissions as long as MAC is less than the tax level. They will reduce their emissions until they end up in the intersection where MAC=MD (Ibid). In Figure 6, total tax payment equals the rectangle *b + c*. If the firm reduces more emissions than E^*, they will pay less taxes, but more abatement cost such that the total costs will be higher than necessary. The marginal abatement cost will be higher than the tax, which is unprofitable for the emitting firm. This is also shown in Figure 7.

Figure 7. Marginal abatement cost (MAC) curves for firm A and B.



Source: Based on Figure 6.1 in Perman et al. (2011, p. 180).

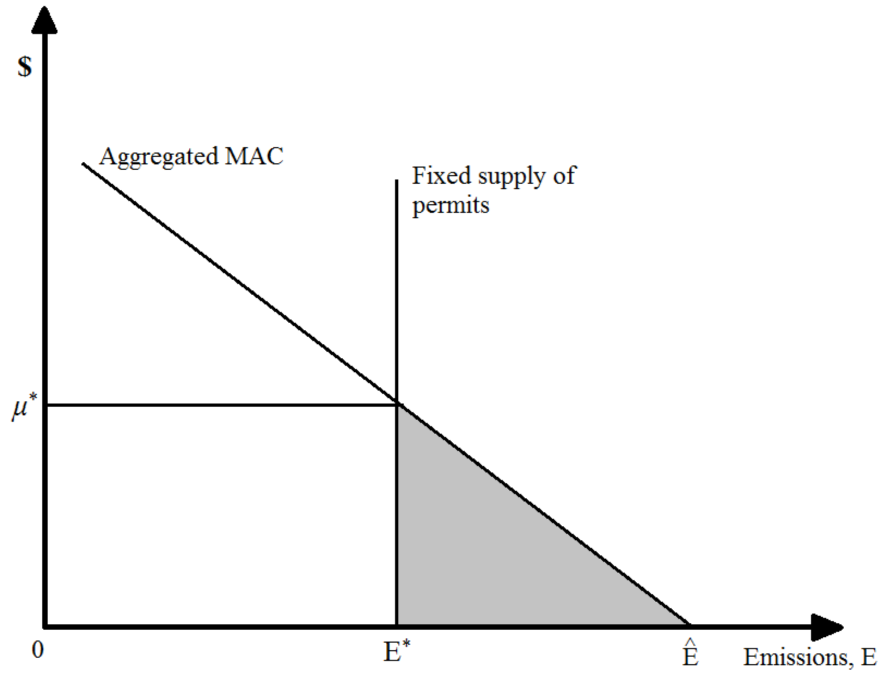
Let there be two firms, A and B, with different marginal abatement costs, represented as MAC_A and MAC_B in Figure 7. Assume that both firms have the same initial emission level halfway between E_A^* and E_B^*. If firm A with the highest MAC abates one unit less, and firm B with the lowest MAC abate one unit more, there will be a cost reduction while total abatement will be unchanged. As seen from the first order condition [6] in Section 3.4 and from Figure 7, marginal abatement costs will increase as the firm reduce its emissions. To ensure cost-effective ness, firm B will abate more than firm A until $MAC_A = MAC_B$. With a introduction of a tax (μ*), the two firms will abate until their MAC is equal the tax, as mentioned earlier, meaning that $\mu* = MAC_A = MAC_B$. Hence, the optimal emission level for firm A and B, will be E_A^* and E_B^*, respectively, which satisfy the least-cost condition. Area $a + c$ shows firm A's total abatement costs and area $b + c$ shows firm B's total abatement costs.

If the tax is wrongfully set, this can lead to efficiency losses due to emission levels that are at any other level than E^*, and the net benefits are no longer maximized (Weitzman 1974). However, we will still achieve cost-effectiveness since MAC_A=MAC_B. We will come back to this subject in Section 3.3. According to Bruvoll (2009), environmental taxes are in practice often levied lower or higher than the theoretical optimal taxation level.

3.2.2 The EU Emission Trading System

The Norwegian petroleum industry was included in the EU ETS in 2008, as mentioned in Section 2.4, together with the existing CO_2-tax, which was reduced when Norway became member of EU ETS. The ETS, also called cap-and-trade, tradable emission permit system, emissions quotas, tradable pollution quotas etc., is a system to control GHG emissions. The supply of permits decides the level of CO_2 emissions that can be emitted (Ellerman et al. 2016), and is measured in tonnes of CO_2 per year. Tradable emission permits give firms the right to emit a specific number of units of emissions. They can either be auctioned (sold) or distributed for free (e.g. grandfathered) to the polluting or emitting entity. Emitting firms are free to sell and buy permits at an agreed price, in contrast to the command-and-control instrument (Perman et al. 2011; Tol 2014). If emissions exceed a firm's number of permits, the firm must buy permits and hence pay the permit price for every extra unit of emission. If emissions are lower than a firm's number of permits, they can sell the residuary permits. Thus, this trade creates a market for emission permits and the permit price will, in this way, be generated in the market. The permit price will fluctuate according to how many available permits there are in the market. The possibility to sell residual permits creates an opportunity cost related to the decision whether to emit an extra unit or sell one unit of permit (Perman et al. 2011). Tradable permits are working in terms of quantities rather than prices as taxes do (Tol 2014). Figure 8 below illustrates the determination of the permit prices with aggregated emissions and aggregated MAC curve. Figure 8 is explained further below.

Figure 8. The determination of the permit price.



Source: Inspired by Figure 6.9 in Perman et al. (2011, p. 204).

Tradable emission permits can both minimize total abatement costs, achieve the desired level of emissions and provide flexibility on the choice of mechanisms used to achieve the environmental target

(Perman et al. 2011). Figure 8 shows the aggregated MAC curve for all emitting firms, which indicates the overall demand curve for emission permits, and overall emissions, denoted E. The total number of issued emission permits is represented by E^*, which indicate the total allowed emissions. Point E^* is the net demand for permits if the firms' aggregated emissions are to the right of E^*. Thus, the permit price is pushed upwards, and the emissions decreases.

While Figure 8 illustrate the determination of the permit price at an aggregated level, Figure 7 can be used to illustrate at determination of the optimal permit price level at firm level. We have that firms still have different MAC curves, respectively MAC_A and MAC_B, and face a permit price, μ. Each rational firm compares their MAC with the price of a permit. Both firms have received permits equal to halfway between E_A^* and E_B^*. Firm A has an emission level equal to E_A^* and firm B equal to emission level E_B^*. From Figure 7, we can see that firm A has a MAC greater than the permit price when its emission level is halfway between E_A^* and E_B^*, and will have an incentive to buy permits. A firm is not interested in buying permits after point $\hat{E}$. Firm B has a MAC that is lower than the permit price when its emission level is halfway between E_A^* and E_B^*, and will have an incentive to sell. This trade will continue until the permit price reaches the equilibrium permit price (μ^*), which equates MAC across all firms (Ibid). Hence, the cost-effectiveness condition is met, similarly to the emission tax.

3.3 A comparison of Emission Tax and Tradable Emission Permits

If the permits are auctioned, and there are not any uncertainties, the outcome from tradable permits are equivalent to the outcome from taxes (Tol 2014). Both emission tax and tradable permits are likely to generate dynamic efficiency effects, and will generate incentives to adopt and implement new technology to reduce emissions. The incentives created are tax savings and the possibility of selling permits to spare, as previously mentioned. Therefore, if adapting new technology will reduce the emitters total abatement cost, there will be an incentive to reduce emissions. There also are distributional impacts, where taxes and auctioned permits generate income for the government. Revenues from emission taxes and auctioned permits can contribute to reduce tax expenditures (e.g. on labour and income), while improving environmental quality and stimulating technological innovation. This is known as *Double dividend* (Perman et al. 2011). Where the first dividend is the environmental impact and the second dividend is removal of distortions in the labour market. However, if the tradable permits are distributed for free, they do not generate income for the government. If the government are to implement such policies, the emitters will have incentives to report lower emission than what they actually emit to pay less taxes or permits than what they are supposed to pay (Ferraro 2008). I.e., environmental policies will also generate cost for the government related the costs of controlling and monitoring emitters to ensure compliance (Romstad 2006).

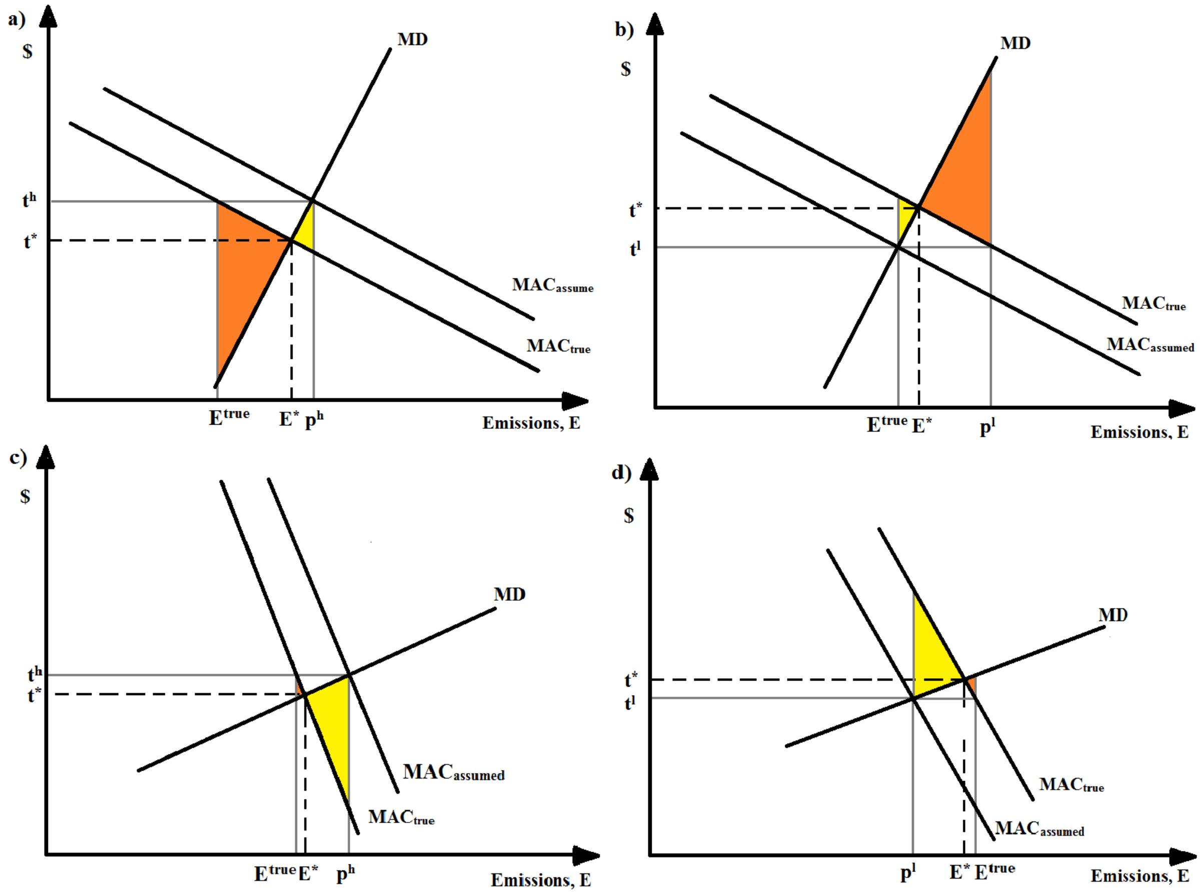
As previously shown, both emission tax and tradable permits leads to cost-effective abating. However, in practise, we might have both uncertainties and asymmetric information and other market failures (Tol 2014). Because of these uncertainties, and that MAC may change over time, an emission tax will not give us any guarantee about reaching the specific emission level. Thus, if a specific emission level is more important to achieve than a specific emission price, then tradable permits might be a better choice. However, if the target is based on today's economic situation, and what the society is expected to afford, the target might not fit the future movements in the economy. Then it might be better to use emission taxes if there no specific emission level we want to reach (Ibid).

3.3.1 Uncertainties about abatement costs

Achieving a desired level of emissions is easily accomplished if the aggregated MAC function is known, and can be reached at lowest costs. However, if the aggregated MAC function is unknown, an optimal tax level or optimal permit level is harder to achieve. With uncertainty in the MAC function, price-based and quantity-based instruments will differ (Tol 2014; Weitzman 1974). As mentioned previously, deviations from the optimal level can lead to efficiency losses. Both emission tax and tradable permits generate efficiency losses when environmental instrument are based on incorrect abatement costs, i.e., over- and underestimation of abatement costs (Tol 2014), shown in Figure 9. Polluting firms will in this case adjust in a non-optimal way. However, the magnitude of efficiency loss will differ depending on which instrument is chosen (Ibid).

In case (*a*), the regulator imposes an emission tax at rate t^h under an incorrect assumption of MAC, which is too high relative to the optimal tax rate at t^*. The emitting firms will emit as long as their true MAC is above the tax, and will therefore emit at E^{true}, which results in an efficiency loss equate to the green triangle. However, under a tradable permit scheme, the regulators will set a looser control, i.e., allocate too many permits relative to the optimal level under the assumption that t^h is the optimal price level. This results in a smaller efficiency loss (shown by the yellow triangle) compared with the efficiency loss from using an emission tax (shown by the dark orange triangle) (Tol 2014). By using the same reasoning as above, we can see that both an over- and underestimation of MAC will lead to efficiency losses. However, the magnitude of the efficiency loss will depend on which policy is implemented. The uncertainty about marginal abatement costs influences the costs of choosing wrong policy, while uncertainty about marginal damages are irrelevant because the firms only relate to marginal abatement costs.

Figure 9. Uncertainty about MAC, where
a) MAC overestimated b) MAC underestimated c) MAC overestimated d) MAC underestimated



Source: Based on Figure 7.3-7.6 in Perman et al. (2011, p. 237).

According to Weitzman (1974), under the uncertainty condition, these efficiency losses can be minimized by choosing the right policy. The efficiency losses are determined by the steepness of MD and MAC, where different steepness on MD and MAC results in greater disparity between optimal level and achieved level of emission (Tol 2014). This is illustrated by four cases in Figure 9. If the MD curve is flatter than the MAC curve, case (*c*) and (*d*), the regulators should choose taxes due to smaller efficiency loss than when permits are used, and vice versa if MD is steeper than MAC case (*a*) and (*b*). This is known as the Weitzman Theorem (Ibid), and is shown in Figure 9, where the dark orange triangles represent efficiency loss when taxes are used and the yellow triangles represent efficiency loss when permits are used. Should MAC and MD be equally steep, then it does not matter which policy the regulators should choose.

3.4 Theoretical model

3.4.1 Profit maximization

Economic theory states that firms behave in a profit maximizing, rational way (Pindyck et al. 2013; Varian 1992). However, according to Ariely (2010) people often behave in an irrational way. Leaders behind bigger firms might be more concerned about profitability in short term relative to long term, where they make decisions to satisfy shareholders and achieve promotions and/or bonuses at the expense of long-term profitability. However, leaders will have limited opportunities to prioritize other than long-term profit maximization. Firms that in long run do not prioritise profit maximization will most likely not survive (Pindyck et al. 2013). It is necessary to understand how firms behave when analysing the effects of environmental instruments, such as emission tax.

3.4.2 Profit maximizing firm with an introduction of an emission tax and tradable permits

To not overcomplicate the profit maximization theory, it's assumed that firms have identical costs functions, produce homogenous goods and wish to produce their products at lowest costs possible (Varian 1992). The profit maximizing level of emissions for firm i without regulations is denoted $\hat{E}$. We also assume perfect competition in all markets where there are n firms, both Norwegian and British, denoted $i \in N = \{1,2,\dots,n\}$.

Profit (π) equates the difference between total revenues, R, and total costs, C. The revenues are given at a market price, p, and multiplied with the amount of produce units, denoted q, such that $R(q) = pq_i$. All firms face the same market price and produce homogenous goods. The firm's costs depend on the number of produced units, q_i, and the firm's emission level, denoted e_i, because every unit produced causes emissions. These costs also include the firm's abatement costs. It's assumed that increased production brings up the costs as well as the marginal costs. Increased production also increases the emissions. As a firm reduces its emissions, its abatement costs and marginal abatement costs will increase. Thus, an upward sloping marginal costs function and an upward sloping marginal abatement cost function (with respect to abatement).

By introducing an emission tax or/and a tradable permit scheme, the firm's costs will also depend on the emission tax (denoted τ) or/and a permit price (denoted γ). Furthermore, the firm receives permits equal to σq, where q is the production and σ is the amount of emission permits per unit produced. Since the price on emissions vary between Norwegian and British firms, due to the Norwegian CO_2-tax, we set an index i on the tax (τ_i). For British firms, the tax is equal to zero.

We then get the following profit function:

$$\pi_i \equiv \max_{q_i,e_i}[pq_i - c_i(q_i,e_i) - e_i(\gamma + \tau_i) + \gamma\sigma q_i], \qquad [2]$$

This equation builds on the fundamental condition for profit maximization explained in Varian (1992), but it also include environmental regulation. The first term on the right-hand-side of [2], describes the firm's total revenues (pq_i) explained previously. The second term is the firm's cost function ($c_i(q_i,e_i)$). The third term is the firm's costs of being regulated by either an emission tax and/or emission permits ($e_i(\gamma + \tau_i)$), where $\gamma + \tau_i$ can be seen as the CO_2-price. The last term on the right-hand-side of [2] is the Output-Based Allocation (OBA) of permits (σq_i), due to carbon leakage (shortly described in Section 3.5), multiplied with the permit price, $\gamma\sigma q_i$. From [2], we see that the costs increase if production increase, and if emissions increase due to higher abatement costs. We also see that the costs related to paying the carbon price ($\gamma + \tau_i$) increases proportionally with emissions, hence, when there are no emissions, $e_i(\gamma + \tau_i)$ is zero.

Profit maximization for a competitive firm i is found where the marginal revenue equal marginal costs (Varian 1992), i.e., where change of production or emissions does not change the profit. This is found by the first order conditions with respect to q_i and e_i. We get the following first order condition with respect to quantity, q_i, for any firm $i \in N$,:

$$\frac{\partial \pi_i}{\partial q_i} = p - \frac{\partial c_i(q_i,e_i)}{\partial q_i} + \gamma\sigma = 0 \qquad [3]$$

This can be written as:

$$p = \frac{\partial c_i(q_i,e_i)}{\partial q_i} - \gamma\sigma \qquad [4]$$

From Equation [4], we see that an increased price will lead to increased production since the marginal costs increase with production, hence an upward trending MC-curve. We can also see that increased distribution of OBA will increase firm i's production because of increased prices. The first order condition with respect to emissions, e_i, for any firm $i \in N$, where the carbon price is equal to marginal costs of reducing emissions, is given by:

$$\frac{\partial \pi_i}{\partial e_i} = -\frac{\partial c_i(q_i,e_i)}{\partial e_i} - \gamma - \tau_i = 0 \qquad [5]$$

By rewriting, we get:

$$\gamma + \tau_i = -\frac{\partial c_i(q_i,e_i)}{\partial e_i} \qquad [6]$$

From [6] we see that the carbon price is equal to the firm's the marginal abatement cost. An increase in the carbon price will increase the marginal abatement costs indicating emission reductions. Decreased marginal costs due to higher emissions and lower marginal abatement costs will bring up the expenditures related to tax payments or permit purchases because of higher emissions. This can also be seen by Figure 7 in Section 3.2.1.

3.5 Carbon leakage

It is hard to achieve a global CO_2-price, even though we are well on the way with the Paris agreement. Due to different climate policies and different CO_2-prices across countries, a stricter domestic climate policy to reduce domestic CO_2 emissions might lead to increased CO_2 emissions in foreign countries without climate policy - where emitting is cheaper. This is known as carbon leakage[9], which means that the global emission reductions decrease. Another reason for carbon leakage is the comprehensive trade between countries, where domestic climate policy affects trade between the domestic country and foreign countries without climate policies. Intuitively, the carbon leakage would be reduced if more countries implement climate policies.

Carbon leakage happens through two main channels, namely energy markets and markets for energy intensive goods. The first channel goes through the international markets for fossil fuels where climate policies reduce domestic demand of fossil fuels. This brings down the price on fossil fuels which leads to increased demand and emissions abroad (Bye & Rosendahl 2012). The second channel happens by markets for energy intensive goods such as extraction of oil and gas, steel and concrete, where climate policies increase the domestic production costs for these energy intensive goods (Bye & Rosendahl 2012). The CO_2-price in oil and gas production could influence the leakage through both these two channels. We are first looking at carbon leakage though the second channel, then through the first channel. Figure 10 shows carbon leakages through the second channel.

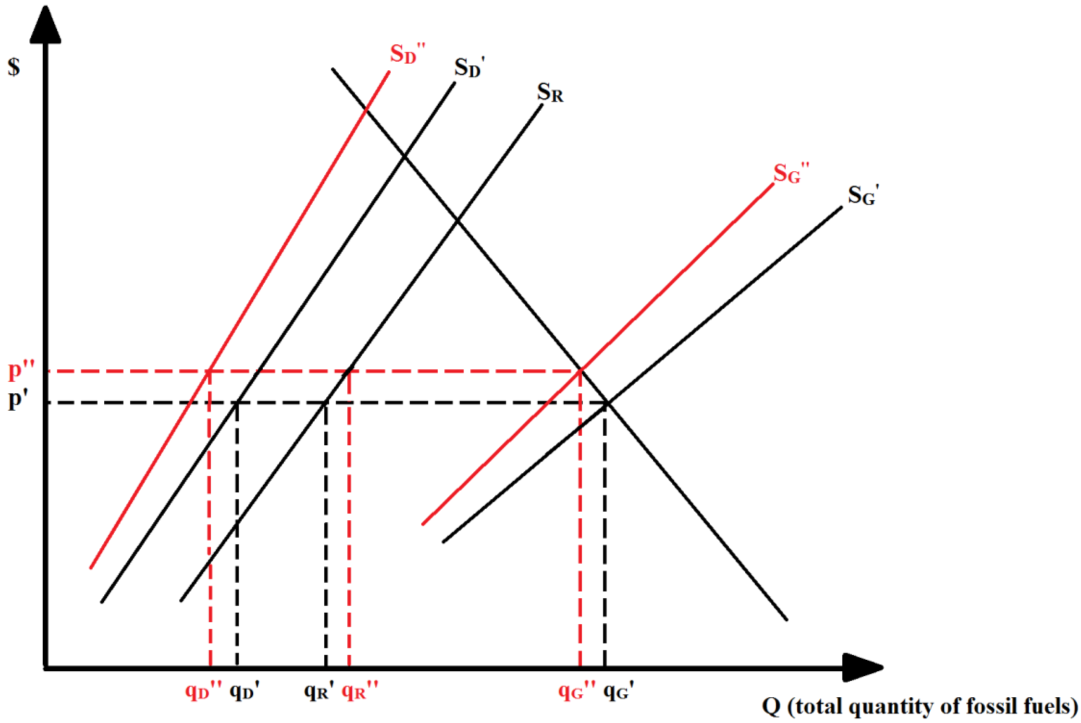
Let S_D, S_R and S_G denote domestic supply, supply in rest of the world (abroad) and global supply, and D_G denote global demand in Figure 10. The initial production without climate policy is represented by the black supply and demand curves. Here the initial price is shown by p' and the initial production level is denoted q', q_R' and q_G'. By implementing domestic climate policies towards fossil fuel extraction (we disregard climate policy towards other sectors here),[10] the domestic supply will shift inwards due to higher input prices in fossil fuel extraction. This will make an inward shift in the global supply as well, making the global fossil fuel prices to increase (p''), while the supply-curve for the rest of the world

[9] Carbon leakage is defined as $\frac{\Delta\,(Foreign\ emissions)}{-\,\Delta\,(Domestic\ emissions)} \cdot 100\ \%$ (Bye & Rosendahl 2012).

[10] In this paper, "domestic" and "abroad" is referred to as with and without climate policy respectively.

remains the same. This will reduce the firm's competitiveness and profitability. Thus, fossil fuel producers located abroad will gain increased competitiveness and profitability relative to domestic producers, which will increase production abroad as well as the CO_2 emissions related to production due to increased prices. This is shown in Figure 10 below. The new production of fossil fuels is shown by the red supply and demand curves and the red notations (Rosendahl 2016a). Hence, increased CO_2 emissions due to increased production abroad will lead to a positive carbon leakage.

Figure 10. Illustration of carbon leakage from the supply-side.



Source: Based on lecture notes from Rosendahl (2016a).

What determines the carbon leakage? Carbon leakage through energy intensive industries depends on increase in costs as a consequence of implementing climate policies, e.g. abatement costs. It also depends on trade intensity with countries without climate policy, and on how emission intensive the domestic country is relative to countries without climate policy (Bye & Rosendahl 2012; Rosendahl 2016a). The emission intensity on UKCS according to Oil and Gas UK (2016) and IOGP (2016), was around 166 kg per toe (tonnes oil equivalents) on average in 2015. The average on NCS was around 56 kg per toe in 2015 (NOG 2016). The IOGP (2016) report writes that the world average was around 130 kg CO_2 per toe. Hence, UK's average emission intensity is around 25 % higher than the world average and the Norwegian's average emission intensity is nearly half the size of the world average.

Some firms operate in industries that are more exposed to carbon leakage than other industries, such as energy intensive industries as mentioned above. In Norway, these firms receive a lower carbon tax than firms with low risk of carbon leakage. As mentioned in Section 2, until EU ETS phase 3, almost all permits were allocated for free. In phase 3 greater portions have to buy permits e.g. power sector (Bye & Rosendahl 2012). However, firms with high risk of carbon leakage, including the oil and gas industry, still receives free permits. This is approximately similar to output-based allocation (Bye & Rosendahl 2012; Böhringer et al. 2010). From Equation [2] we see that it is the firm *i*'s production level that determines the assignment of permits, where the quantity of allocated permits is proportional to the oil and gas produced (Böhringer et al. 2015). Böhringer et al. (2015) finds that the carbon leakage might be reduced by using OBA on one hand. But, on the other hand, it might also lead to increased global production due to increased demand of these goods. To reduce this second effect, they suggest a consumption tax along with the OBA.

Moreover, Bye and Rosendahl (2012) writes that climate politics which reduce domestic production of fossil fuels might also lead to negative carbon leakage through the energy market channel. Fæhn (2013) looks closer at this and finds that 50 % of the amount of reduced Norwegian oil production would be replaced with a lower global oil demand, while the other 50 % would be an increase in oil production abroad. As we see from Figure 10, reduced domestic supply will lead to increased fossil fuel prices which lead to reduced global consumption and production. Hence, the reduced domestic production ($q_D{}' - q_D{}''$) is greater than the effect from increased production abroad ($q_R{}'' - q_R{}'$). Thus, unless emissions from extraction (which are not shown in the figure) are much higher abroad, we have net effects equal to a negative carbon leakage. If this is the case, then allocation of free permits would give firms incentive to increase the fossil fuel production and consequently counteract the negative carbon leakage. In other words, this increased production might create a positive carbon leakage.

4. Data and methods

This chapter will present data collection and variables that will be used in this analysis. Then it will have a discussion of how different explanatory variables are expected to impact emission intensity, before presenting the method used to analyse emission intensity. Our research question is whether the CO_2-price has had an impact on emission intensity on the petroleum industry on both the UKCS and the NCS. The variables included and the methodology used in this analysis will to some extent follow the modelling framework of Gavenas et al. (2015), who only analysed Norwegian data.

4.1 Methods for data collection

The data contain 147 oil and gas fields, where 44 fields are on the NCS and 103 are on the UKCS, over a 19-year period from 1997 to 2015. We initially wanted to look at UK field level figures for the period from 1997 to 2015, but emission figures for UKCS were only accessible from 2006 to 2015, a 10-year period.

Annual CO_2 emission figures at field level on the NCS and on the UKCS have been obtained from the Norwegian Environment Agency (NEA 2016) and from the Department for Business, Energy and Industrial Strategy (BEIS), respectively. The calculated CO_2 emissions from the offshore sector cover emissions from both oil and gas production, and are reported in thousand tonnes and tonnes per year, respectively.

Annual production figures of oil and gas at field level on the UKCS have been obtained from the Oil and Gas Authority (OGA 2016a). Oil production is reported in standard cubic meters of oil equivalents (Sm^3oe), and associated gas and dry gas is reported in thousand standard cubic meters (kSm^3). Annual production figures of oil and gas at the field level on the NCS have been obtained from the Norwegian Petroleum Directorate (NPD 2017c). All production for NCS is reported in million standard cubic meters of oil equivalents (mSm^3oe). OGA distinguished between production of oil, associated gas and dry gas. The oil and associated gas production figures are from the same fields, while the dry gas production figures are from own gas fields. Some condensate fields, e.g. *Elgin*, report condensate in the oil stream.[11] This means that the data for oil production contain both oil and condensates. However, for dry gas fields the figures for gas and condensate production are reported separately, except for dry gas fields in the Southern North Sea where condensate is included in the dry gas stream.

[11 & 13] Based on personal communication with OGA via e-mail.

The associated gas stream includes both Natural Gas Liquids (NGLs)[12] and methane and according to OGA[13] it is only terminal figures[13] that give an accurate NGL production, and this is not allocated back to the fields. We had intended to treat NGL and condensate together with oil as done in Gavenas et al. (2015), but in light of the problem above, it is hard to separate the NGL figures from the associated gas figures. For this reason, we have chosen to aggregate the associated gas and dry gas figures. The production has been converted from mSm^3oe to Mtoe (million tonnes oil equivalents) by a conversion factor of 0.858 used by the Norwegian Petroleum Directorate and British Petroleum (BP). The Norwegian production figures is divided into four production types namely oil, gas, NGL and condensates for each and every field. Thus, to treat our Norwegian production data as comparable as possible with the British data, the oil production includes condensates while the gas production includes NGL's.

The Norwegian Oil and Gas Association (NOGA) and OGA have made annual gas flaring and water injection data for NCS and UKCS available to us, respectively. Gas flaring figures for NCS are reported in Sm^3 gas and in kSm^3 for UKCS. Water injection data are reported in Sm^3 water for both NCS and UKCS.

Field specific data for water depth, reservoir depth and reserve size on the NCS have been obtained from the NPD (2017d), while the same data have been obtained from different web sites for UKCS since OGA do only publish aggregate reserves and not field specific reserves.[14] However, reservoir depth figures for UKCS were hard to find for all fields, and hence reservoir depth is not included as an explanatory variable in our model. Water depth is reported in meters for NCS, and in meters and feet for UKCS. Figures reported in feet have been converted to meters by a conversion factor of 0.3048. Reserve sizes on the NCS are reported in mill. Sm^3oe, while for UKCS oil reserves are reported in both mill. tonnes and mill. Sm^3oe, while gas reserves are reported in both Ksm^3 and billion standard cubic feet (bscf). Oil reserves in Mtoe were converted to mSm^3oe by a conversion factor of 1.166 Sm^3. The gas reserves in bscf were converted to mSm^3oe by a conversion factor of 0.28317 Sm^3.[15]

[12] NGLs are associated hydrocarbons and a by-product of gas production that consist of ethane, propane, butane isobutane and pentane which are sold separately from natural gas (Devold 2013)
[13] When oil and gas is extracted, this is transported to the nearest or associated terminal (Devold 2013). Terminal figures means aggregated production figures from some particular fields.
[14] Sources used to find field level figures for water depth, reserve depth and reserve size: http://abarrelfull.wikidot.com/, http://www.offshore-technology.com/projects/region/europe/, http://www.subseaiq.com/data/default.aspx and http://www.databydesign.co.uk/energy/ukdata/fields/
[15] Both conversion factors used for reserve size is obtained from http://www.norskpetroleum.no/en/calculator/about-energy-calculator/

Spot crude oil prices Brent and Natural gas prices UK (Heren NBP Index) have been obtained from the BP Statistical Review (BP 2016), and converted from nominal USD to real USD in 2015 prices using the producer price index (PPI) for Industrial commodities less fuels.[16] The same procedure has been applied for the CO_2-prices, which have been obtained from several governmental documents from the Norwegian Ministry of Finance and European Environmental Agency.[17] The Norwegian gas prices have been obtained from Statistics Norway by dividing Norwegian gas export values on Norwegian gas export quantity. Then the prices have been converted from domestic prices into USD 2015 prices using annual exchange rates from the Central Bank of Norway (Central Bank of Norway 2017), and by applying the same deflator as for oil prices.

4.2 Data collected / Variables

Summary statistics for the variables used in this thesis are provided in Table 1 below. The table also contains information of unit of measurement for the variables and how the different variables are expected to affect emission intensity. The expected effect on emission intensity will be further discussed in Section 4.3.1.

Table 1. Summary statistics for the dataset with 1360 observations. Emission intensities with values less than 1 kg CO_2 per toe and above 1800 kg CO_2 per toe with production share values near zero are excluded.

Variable name	Description	Unit	Mean	St. Dev	Min	Max	Expected effect on emission intensity
em_int_{it}	Emission per unit of production for field *i* in year *t*	Kg CO_2 per toe	83.12	99.63	1.005	1590.62	Dependent variable
$prod\_share_{it}$	Production level as a percentage of peak production	Share	0.31	0.29	0	1	-
$gasres\_share_{it}$	Share of gas in the original recoverable reserves	Share	0.37	0.38	0	1	-
$gasprod\_share_{it}$	Share of gas in production minus *gasres_share*	Share	-0.09	0.33	-1.00	0.90	-
$gasflare\_share_{it}$	Gas flaring (Ksm^3) as a fraction of peak oil and gas production (Sm^3 oe)	Ratio	4.109	23.395	0	496.109	-
res_size_i	Size of original recoverable reserves	mSm^3oe	112.23	221.71	0.57	1762.00	+/-
w_depth_i	Water depth	Meter (m)	146.95	128.63	18.00	950.00	+
w_prod_{it}	Water production (Sm^3) as a fraction of peak oil and gas production (Sm^3 oe)	Ratio	2.07	20.41	0	333.58	+
w_inject_{it}	Water injection (Sm^3) as a fraction of peak oil and gas production (Sm^3 oe)	Ratio	0.70	2.96	0	56.85	+
$carb\_p_{it}$	Total carbon price for both UK and Norway	USD in 2015 prices per tonnes CO_2	37.38	24.88	1.01	77.43	-

[16] The PPI is obtained from http://www.bls.gov/data/home.htm. The PPI used in this paper is different from the PPI used in Gavenas (2014) and Gavenas et al. (2015). Since this paper addresses both NCS and UKCS, the PPI used is international.
[17] www.eea.europa.eu & http://www.statsbudsjettet.no/Statsbudsjettet-2013/ (Accessed: 28.01.2017)

oil_p_t	Crude oil Brent price	USD in 2015 per barrel	77.59	28.62	17.77	112.06	+/-
gas_p_{it}	Total gas price for both UK and Norway	USD in 2015 per Sm^3 gas	235.21	79.17	5.34	422.41	+/-
$time_t$	Time trend	Year	12.33	4.85	1	19	+/-
$start\_year_i$	Field's start-up year	Year	1993	11.50	1967	2015	+/-
d_elect_i	Dummy variable for electrified field's	1 or 0	0.04	0.19	0	1	-
$d\_gasfield_i$	Dummy variable for dry gas fields	1 or 0	0.19	0.39	0	1	-
$d\_confield_i$	Dummy variable for condensate fields	1 or 0	0.07	0.25	0	1	-
$d\_ukfield_i$	Dummy variable for fields located in UK	1 or 0	0.53	0.50	0	1	+

Satellite fields

The dataset covers all offshore oil and gas production in Norway and UK. However not all fields do report separate CO_2 emissions. This could e.g. be smaller fields, known as satellite fields, which are connected to bigger fields nearby where the operation of the satellite field takes place. There are 382 individual fields in UK and 86 individual fields in Norway with separate petroleum production figures, respectively, where 279 and 42 of these fields do not have separate emission figures. In order to do a proper analysis of emissions per unit of production, we have treated fields without emission figures as satellite fields. Further, we have tried to connect these satellite fields to a larger field nearby, i.e., a main field that have higher production than the satellite field.[18] Emissions from these satellite fields are assumed to be included in the emissions figures for the remaining 103 and 44 fields respectively. The Norwegian fields are tied based on the work of Gavenas (2014) and Gavenas et al. (2015), while the UK satellite fields were connected by help of OGA (2016b). *Ringhorne* was treated as a main field in Gavenas (2014). However, this field has not reported emissions according to figures received from NEA (2016), and are therefore treated as a satellite field. *Sleipner West* is tied to *Sleipner East*, however in this thesis they are treated as two separate fields in the period 2003-2015, as they both report own emission figures in this period. From 1997-2002, emission figures from *Sleipner West* is missing, resulting in treating *Sleipner East* and *Sleipner West* as one field in this period. There might still be some classification problems when it comes to the connection of these tied fields, as some satellite fields could be connected to other main fields than what we have understood it to be.

In section 2, we also mentioned that some fields are Anglo-Norwegian, meaning that they lie both on the UKCS and the NCS. Fields that are Anglo-Norwegian are *Blane, Enoch, Frigg, Islay, Murchison* and *Statfjord*. These fields are treated either as a Norwegian or as a British field depending on which country withholds the largest part of the production. This was decided by looking at a offshore infrastructure map (see Appendix A for Map 1 and Map 2), and by the production figures obtained from

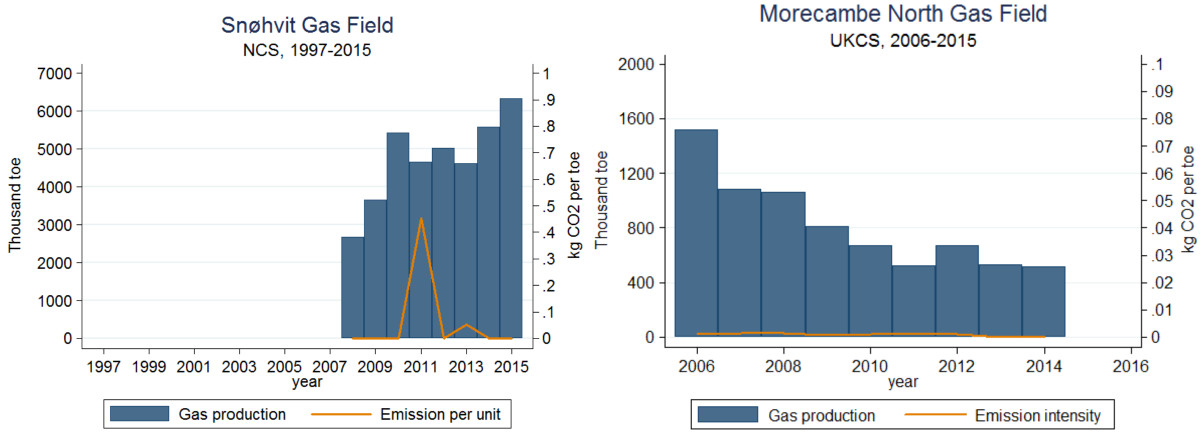
[18] The overview of the tied fields can be found in Appendix A.

OGA (2016a) and NPD (2017c). For those fields where the share of production between NCS and UKCS were almost equally divided, the country that reports these fields emission figures determined the field's nationality. Consequently, *Blane, Frigg* and *Statfjord* are treated as Norwegian fields, while *Enoch, Islay* and *Murchison* are treated as UK fields.

Emission intensity

Emission intensity, called em_int_{it}, is our dependent variable. The emission intensity for a given field for each year has been derived by dividing total annual emissions for all the connected fields by the annual sum of oil and gas production of the same fields. We log transformed the dependent variable, which we will come back to later. The emission intensity variable has some observation values equal to zero because some fields have zero reported emissions in some years. These values are mostly from gas fields such as the *Amethyst field, Banff field, Chiswick field, Hyde field, Lancelot field, Pickerill field, Ravenspurn North, Thames field, Windermere field, Snøhvit field* and *Morecambre North field*, where data for the two latter fields are displayed in Figure 11 below. As we can see, the *Snøhvit field* has very low emission intensity, peaking in 2020011 with almost 0.5 kg CO_2 per toe, and in most years, it is equal to zero. The *Morecame North field's* emission intensity peaked in 2008 with 0.0013 kg CO_2 per toe.

Figure 11. Emission intensity vs. gas production (including condensates) for Snøhvit and Morecame North Gas field.



Source: Based on own calculation with figures obtained from OGA, BEIS, NPD and NEA.

Since the models are specified in natural logarithms, we have to decide what to do when zero values for the emission intensity are encountered (when the emission intensity approaches zero, the corresponding log-transformed values approaches minus infinity). To deal with this problem, we tried two alternatives. The first alternative was to drop all observations with emission intensity values less than 1 kg CO_2 per toe to avoid that our empirical results are too influenced by emission intensity values near zero. The second alternative was to follow Gavenas et al. (2015) and replace all emissions intensity values less than 1 kg CO_2 per toe by 1 kg CO_2 per toe, and then to include these imputed observations in the log transformation. Both these two alternatives will affect the interpretation of the results to be reported in Section 5. For robustness, we will apply both alternatives. Since the emission intensity values less than 1 kg CO_2 per toe largely are gas fields, this might lead to a skewness in the estimated results for the gas reserves variable. Hence, when gas fields with emission intensity less than 1 kg CO_2 per toe is omitted from the model, the average emission intensity for gas fields are higher than they actually are. The second alternative is therefore the preferred method when dealing with emission intensity values less than one. However, it may seem like there is a few gaps in the UKCS emission figures. Reported emissions that are equal to zero might actually be positive. According to Oil and Gas UK (2016), CO_2 emission per unit production is 166 kg per toe in 2015, while our figures show 46 kg per toe on average. The Norwegian average in 2015 was 56 kg CO_2 per toe. This indicates that the emission intensity on UKCS is 3 times larger than the emission intensity on NCS. This may be due to missing emission figures from UKCS. This is a reason for preferring alternative one.

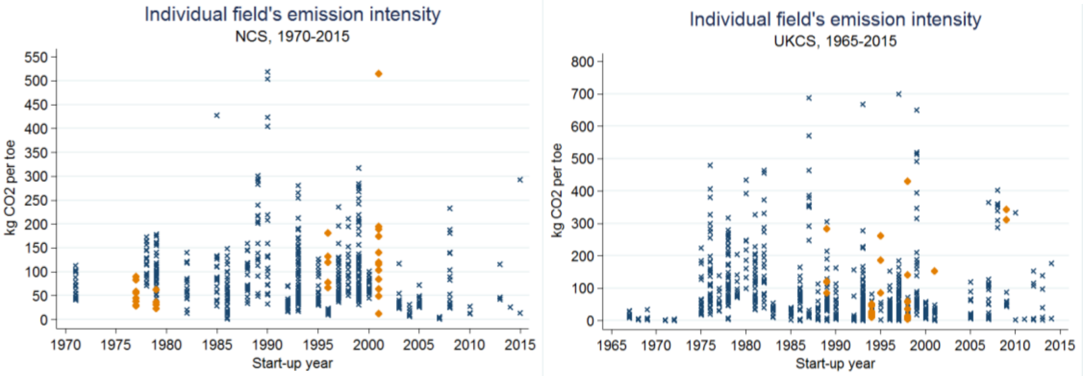
We also excluded four observations that had very high emission intensities and very low annual production level relative to the peak production level. This could be emissions due to the first year of a field's production, or it could be related to termination of the field, which results in high emission intensities (we will come back to this later). These were *Glitne* in year 2013 (2473 kg CO_2 per toe), *Beatrice* in year 2015 (1207 kg CO_2 per toe), *Norne* in year 1997 (2138 kg per toe) and *Pierce* in year 2014 (1885 kg CO_2 per toe). *Foinaven* does also have very high emission intensity level (1590 kg CO_2 per toe) in 2013, but are not dropped since production share of peak production is higher (26 %). When excluding observations with emission intensity values less than one, and the four observations mentioned above, there were some changes for summary statistics for the emission intensity. The changes for the means, standard deviations, minimum values and maximum values. There were only minor changes in mean and in standard deviation for the rest of the variables, see Appendix B for statistics table for alternative 2.

The start-up year ($start\_year_i$) for an offshore field is often different from other operating years when it comes to emission intensity. Emission intensity could be influence by several operations before production starts, such as drilling operations for oil and gas wells, casing the wells, making flow paths to guide the oil and gas from the surroundings above the reservoir, to flow into the production pipe and other activities (Devold 2013, pp.13 & 29-32). As an example, a field might be in its final stages of well drilling in the start of the year, and not start production until the end of that same year. We have therefore followed Gavenas et al. (2015), and excluded observations corresponding to cases where a field's first year of production constitutes less than 20 % of peak production. Using this procedure, 37 observations on UKCS and 19 observations on NCS are excluded. We also include the field's start-up year to see if this variable has a significant effect on emission intensity.

Production as a share of peak production

The Norwegian and UK fields consist of several mature fields in their declining phase. Oil and gas production in UK reached its peak in the late 1990s according to the data obtained from OGA (2016a), while Norway reached its peak in 2004 (NPD 2017c). In Figure 12 we see the fields' emission intensities combined with their start-up years. Both oil and gas fields are included. From this figure, we see that UK had lower emission intensity for fields starting up in the period around 1970 as compared to Norwegian fields. Fields in the UK had relatively higher emission intensity in the period 1975-1987 than Norwegian fields.

Figure 12. Individual field's start-up year combined with emission intensity for the period 1997-2015 and 2006-2015 for NCS and UKCS respectively. Dark orange observations denote fields with termination before 2015.



Source: Based on own calculations using the data obtained from NEA, NPD and OGA.

The fields on both NCS and UKCS are in different operating phases. On NCS, 9 of 44 fields started up after 2006, whereas 15 of 103 fields on UKCS started up after 2006. Of the 44 and 103 fields, 6 and 8 fields terminated their production before 2015, respectively. Further, 18 Norwegian fields and 80 British fields produced petroleum the entire period. As a field's production increases, the natural pressure in the well and reservoir declines due decreased mass in the reservoir. As the natural pressure declines more energy is used to increase oil production by increasing the pressure in the reservoir or wells by e.g. water or gas injection (Devold 2013). The energy also increases because of increased resistance due to friction in the wells that will cause a pressure drop (Ibid). The use of more energy increases emission intensity. In light of this, we have generated a variable, which is the annual production level as a share of peak production in the field's lifetime. Thus, this variable, labelled *prod_share*, reflects which operating phase each field is in each year. We are particular interested in this variable as it entered with a highly significant effect in Gavenas et al. (2015). We have, like Gavenas et al. (2015), specified a third order polynomial in this variable. Thus, $prod\_share^2$ and $prod\_share^3$ are also included as regressors. The specification yields a flexible relationship between the emission intensity and the production as a share of peak production. For this calculation, we only use production figures for the main field.

Reserve size, water depth, share of gas in original reserves and the share of gas in production

We also use figures for the main field for other field specific variables such as reserve size (*res_size_i*), water depth (*w_depth_i*) and share of gas in original reserves (*$gasres\_share_i$*). The latter has been derived by dividing the gas reserves by the total original reserves. One exception is *Sleipner East + Sleipner West*, where we calculated the share of production and share of gas in original reserves based on the overall production for the two fields. The recoverable reserves are summed up, while the water depth was based on the average of the two fields. The variable *gasprod_share* is given as the annual share of gas in the field's total production less the share of gas in original petroleum reserves.

Water production, gas flaring and water injection

Produced water as a fraction of peak annual oil and gas production (*w_prod_{it}*) is calculated by dividing water production by peak oil and gas production. The same method applies for gas flaring (*$gasflare\_share_{it}$*) and water injection (*w_inject_{it}*).

Time trend variable

A linear time trend variable, called *$time_t$*, is used to capture trend in emission intensities across time. Time specific effects affect fields uniformly, but vary over time. We assume that emission intensity is not time specific, but the process, which generates the changes in emission intensity, extends across time. This may be technological progress leading to more energy-efficient extraction process, or that operators first choose to operate on fields that require less energy, and wait until later to operate on more complex fields that require more energy to extract oil and gas (Gavenas et al. 2015). Thus, the expected sign of this variable could be both positive and negative.

Prices

As mentioned are both the CO_2-price and the natural gas price different for Norway and the UK. When estimating for the NCS and UKCS together, the total CO_2-price for both UK and Norway is used as the Norwegian CO_2-price is the sum of EU ETS permit price and the Norwegian CO_2-tax, while the UK CO_2-price is just the EU ETS permit price. Investments are likely to follow the oil price and the natural gas price. The CO_2-price is said to be an important measurement to reduce CO_2 emissions, which also might affect investments. As seen in Section 3, a CO_2-price will be a cost for the petroleum industry. Thus, it will give the petroleum industry incentives to reduce emissions (ECON Energi & SINTEF 1994). All the three price variables, *$carb\_p_{it}$*, *oil_p_{it}* and *gas_p_{it}* are log transformed.

To allow heterogeneity in the effect of a change in the CO_2-price between UK and Norway we generated a new variable, which is given as *$d\_ukfield_i$* x *$lncarb\_p_{it}$*, where *d_ukfield* is a dummy for fields located on the UKCS (see below). Thus, two variables, i.e., *$d\_ukfield_i$* x *$lncarb\_p_{it}$* and *$lncarb\_p_{it}$* are now used to specify the effects of the CO_2-prices.

Consider the following linear combination:

$$lnpcarb\_new_{it} = \beta_1 lncarb\_p_{it} + \beta_2 (d\_ukfield_i \cdot lncarb\_p_{it}) \qquad [7]$$

For Norway, the emission intensity elasticity with respect to the carbon price is given by the parameter β_1, whereas the corresponding elasticity for UK is given by $\beta_1+\beta_2$.

Dummy variables

We control for different gas and CO_2-prices for the NCS and the UKCS. However, there might be other uncontrollable differences between fields located on NCS and on UKCS, such as different use of technology, different culture between operators that affects how the fields are operated, different geological conditions and different regulatory conditions outside the CO_2-price. Therefore we created a dummy variable called $d\_ukfield_i$, to control for these effects. This dummy variable is equal to 1 for fields on the UKCS, and equal to 0 otherwise.

UK has several dry gas and condensate fields that do not produce any oil. To mark what type the field is, we generated one dummy for gas fields called $d\_gasfield_i$, and one dummy for condensate field called $d\_confield_i$, which is equal to 1 for gas and condensate fields respectively. Norway has few "clean" dry gas and condensate fields. However, a field is treated as a dry gas or condensate field if it consisted of more or equal to 90 % of gas or condensate, respectively. The dummy variable for gas fields may be somewhat redundant as we have an explanatory variable, which control for the share of gas in the original reserves, as mentioned above. We will come back to this in Section 5. We therefore choose not to include this dummy variable in the specification of the main model.

The dummy variable called d_elect_i is equal to 1 for electrified fields and equal to 0 otherwise. As mentioned in Section 2, four fields are electrified on the NCS. *Troll*, which is an oil field, consists of two fields where the biggest field produces dry gas and is electrified. However, in the production and emission figures received from NOG and NEA respectively, the two *Troll fields* were treated as one field. It is not clear whether fields on UKCS are electrified or not. We therefore chose not to include this dummy variable in the specification of the main model.

Lagged and smooth prices

For robustness, we also tried to replace the ordinary log transformed prices with, respectively, lagged (called *lagged_lncarb_price, lagged_lnoil_price* and *lagged_lngas_price*) and smoothed log transformed prices (called *smlncarb, smlnoil* and *smlngas*). This was done to see if there were more significant effects of the prices on emission intensity using these new variables. One opens up for that it takes some time the emission intensities are responding to a change in the prices. When it comes to the smoothed prices, we apply the following formula:

$$smp_i = \frac{1}{5}\sum_{t=T}^{T-4} \beta_i \ln(price_i)_t \qquad [8]$$

Where $i \in$ {oil price, gas price, carbon price}. However, there were only minor changes using the new type of variables. These will therefore not be used in the subsequent analysis.

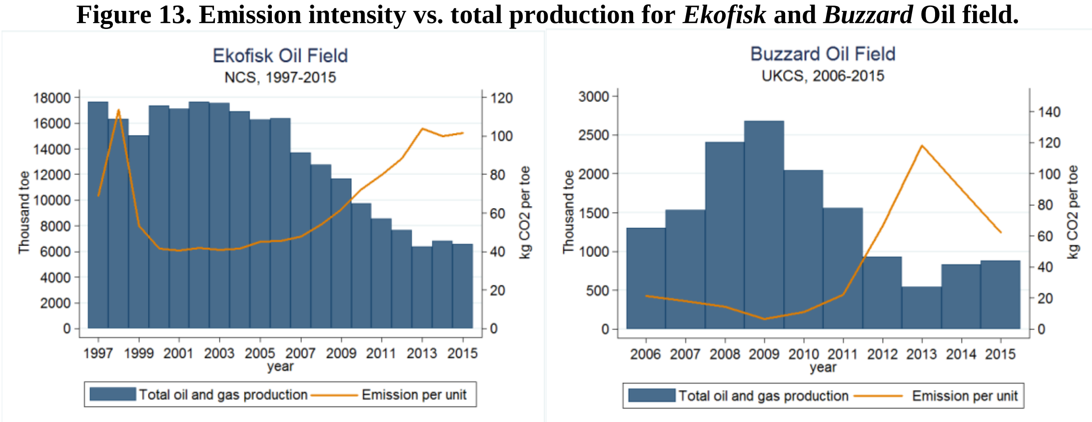
4.3 Model specification and expected signs

In this subsection, we will first discuss expected signs to the variable used in this analysis in Section 4.3.1, followed by a discussion of the model specification of the original and main model in Sections 4.3.2 and 4.3.3, respectively. Section 4.3.3 also include a description of how we obtain our main model.

4.3.1 Expected signs

A field's production level as share of peak production ($prod\_share_{it}$) is assumed to have a negative effect on emission intensity. Since the production level varies in different operational phases, we expect that the emission intensity also varies accordingly. Oil and gas extraction is energy intensive, and as mentioned above, the start-up phase requires more energy per produced unit of oil and gas and thus yields higher emission intensity. The same applies in the declining phase, where energy used per produced unit increases due to declining natural pressure in the reservoir (Fæhn et al. 2017). Figure 13 illustrate our assumption. It shows emission intensity and total oil and gas production profiles for some years of two of the largest oil fields: one on NCS and one on UKCS. The focus is on the declining phase.

Figure 13. Emission intensity vs. total production for *Ekofisk* and *Buzzard* Oil field.



Source: Based on own calculation with figures obtained from OGA, BEIS, NPD and NEA.

We expect both the initial and the declining phase to have low production levels as a percentage of peak production level and high emission intensities. As the production declines, the field require more energy to extract oil and gas due to lower natural pressure (pressure drop) in the reservoir. Thus, the closer the field is to its peak production level in its declining phase, the less energy used per unit produced and hence, the less emission per unit produced (Gavenas et al. 2015). We therefore expect this variable to enter with a negative sign as seen in Table 1.

Water production (w_prod_{it}) is a by-product when extracting oil and gas (Forskningsrådet 2012; IOGP 2016), which increases in the declining phase of extraction. Increased water production requires more energy when extracting oil and gas due to separating water from the liquid hydrocarbons, and when cleaning the water before discharging it to sea (Devold 2013). This energy demanding process leads to higher emission intensity. We therefore assume water production to enter with a positive sign. However, water production is negatively correlated with production share, and it might be caught up by the production share variable ($prod\_share_{it}$) such that it could be discussed whether w_prod_{it} should be included in the model or not. In light of this, we therefore run some estimation where both variables are included in the model, and some estimation where water production is excluded, which will be further discussed in Section 4.3.3.

Water depth (w_depth_i) is assumed to have positive effect on emission intensity. The deeper the water is the more energy is used when drilling wells and extracting oil and gas. This variable is log transformed and is called lnw_depth_{it}.

Oil and gas fields contains more oil and gas than what are being produced, as production generally stops when the operational costs on the field exceeds the production value (KonKraft 2016). The world average oil recovery rate, i.e. the oil produced relative to the oil in the original reserves, is around 40 %, indicating that 60 % of oil and gas is left in the reservoir (Devold 2013). The recovery rate depends among other on the natural pressure in the reservoir (Ibid). Oil fields on the NCS is said to have higher average oil recovery compared with oil fields in other parts of the world, with a recovery rate of 47 %. [19] They have a goal to increase this rate up to at least 60 % (KonKraft 2016). There are several ways to increase the recovery of oil, where water, gas or – in some cases CO_2, is used to increase pressure by injecting it into the reservoir. This could increase the recovery rate up to 70 % (Devold 2013). However, water injection (w_inject_{it}) requires energy, where increased water injection leads to increased emission intensity due to increased use of energy. We therefore expect the w_inject_{it} variable to enter with a positive sign. However, there is a negative correlation between water injection and the production share variables. As for water production, water injection relates more to the declining phase when the natural pressure in the reservoir decreases. Thus, the production share variables could capture this effect and there could be a discussion whether the w_inject_{it} should be included in the model.

[19] http://www.npd.no/no/Tema/Okt-utvinning/Temaartikler/Gode-muligheter-for-a-fa-ut-mer-olje/ (Accessed: 15.07.2017)

As the recoverable reserves (*res_size*$_i$) decrease in the declining phase, the less natural pressure remains in the reservoir. To extract oil in the reservoir with lower pressure, as mentioned above, more artificial pressure is needed to increase the oil recovery. This requires more energy, and the bigger the original reserve sizes are the more artificial pressure needed in the declining phase. Hence, a field's reserve size is therefore assumed to have a positive effect on emission intensity. However, Gavenas et al. (2015) assume a negative sign on the effects of reserve size, and base their assumptions on historically figures for NCS where fields with smaller reserve sizes have had higher emission intensities (Fæhn 2013). Moreover, with *w_inject*$_{it}$ that control for the first effect (which is a positive effect on emission intensity), we assume that the *res_size*$_i$ only capture the last effect, and enter with a negative sign. This indicator variable is log transformed and called *lnres_size*$_i$.

A pressure drop would not be as problematic for gas fields as it is for oil fields. This is because natural gas flows more easily relative to oil, in addition to having high compression and expansion energy (Devold 2013). When the natural pressure in the gas reservoir drops due to increased gas production, the remaining gas in the reservoir would have the opportunity to expand. Gas expanding releases energy that increase the reservoir pressure to a certain degree and reduce the pressure drop as long as the remaining gas has opportunity to expand (Smithson 2016). The recovery rate for gas fields with only natural drive mechanisms (such as the one explained above), is around 60-80 %, which is much higher than oil fields without artificial pressure.[20] Thus, there is a lower energy demand relative to oil fields since the need for artificial pressure is lower or absent for gas fields. In addition, gas fields have lower water production relative to oil fields. This suggest that gas fields have lower energy demands relative to oil streams when it comes to separation and processing (Gavenas et. al 2015). Furthermore, Gavenas et al. (2015) finds that emission intensity increases with the share of oil in the original oil and gas reserves, and their estimations suggest that a pure gas field has twice as low emission intensity as a pure oil field. According to our figures, gas fields on UKCS seem to have lower CO_2 emissions than oil fields as well. In light of this, we assume that gas fields have lower emissions than oil fields, hence that *gasres_share*$_{it}$, *d_gasfield*$_i$ and *gasprod_share*$_{it}$ enters with a negative sign. However, since *gasres_share*$_{it}$ and *d_gasfield*$_i$ are positively correlated, there could be a discussion whether both variables should be included in the main model. The share of gas produced (*gasprod_share*$_{it}$) capture the effect of a field's running oil and gas production, i.e. gas extraction from the reservoir relative to oil and gas extraction on emission intensity (Gavenas et al. 2015). The *gasres_share*$_{it}$ capture the effect of the share of gas in a field's original reserves on emission intensity (Ibid). In addition, since *gasprod_share*$_{it}$ is the share of gas in production minus *gasres_share*$_{it}$, this makes these two variables less correlated.

[20] http://utog.no/default.asp?id=659&t=Boring-og-produksjon (Accessed: 15.07.2017)

Condensate is a product between oil and gas (Devold 2013). We assume condensate production to have lower CO_2 emissions than oil fields, and hence, the indicator variable for condensate production is expected to enter with a negative sign.

The largest gas fields on NCS are electrified from land. This results in less use of fossil fuels because electrified fields use electricity from land to replace offshore gas or diesel turbines, fully or partly (ABB 2014). Gavenas et al. (2015) finds a highly negative significant effect for electrified fields, which suggest that electrified fields have lower emission intensity than non-electrified fields. The indicator variable for electrified fields (d_elect_i) are therefore assumed to enter with a negative sign.

The more mature the field is the more energy demanding it is due to less natural pressure in the reservoir. Following the same reasoning as above, the start-up year ($start\_year_i$) could be expected to have a positive effect on emission intensity. However, this variable could also capture new fields with new technology or more energy efficient equipment's, which would have a negative effect on emission intensity. Thus, this variable could also enter with a negative sign.

Gas flaring is the second biggest source of CO_2 emissions from the petroleum activity on both NCS, as mentioned in Section 2.2.2, and both NCS and UKCS have restrictions on gas flaring. However, gas is still flared due to safety measurements and lacking of gas infrastructure. The indicator variable for gas flaring is therefore expected to have a positive effect on emission intensity.

Both the oil and gas prices can have a positive and negative effect on emission intensity Since oil and gas are both inputs and outputs, they could have both a positive and a negative effect on emission intensity. First, let's look at the case where oil is an input. If the oil price increase, this is equivalent to increased production costs for the operator. Then the operators would want to reduce the use of oil, maybe use more environmental friendly inputs instead, and invest in more energy efficient technology that leads to lower emissions. The reduced use of oil would reduce emissions and thus emission intensity. Then, let's us look at the case where oil is an output. In this case, increased oil prices would lead to more investments both in less profitable and mature fields, which often have higher emissions because it is more energy demanding to extract petroleum (Fæhn et al. 2017). Thus, the expected sign is uncertain. The same reasoning applies for gas prices. If the gas price increases, the operators want to develop more gas fields, which might be more expensive to develop than oil fields. However, the operators also want to reduce the use of gas as this is used as an input. Which of these two effects that is strongest is hard to determine.

The CO_2-price is said to be one of the most important measurements to reduce CO_2 emissions on both NCS and UKCS (KonKraft 2016; NOG 2016; Oil and Gas UK 2016). In 2015, the total Norwegian CO_2-price was around \$ 61 per tonne CO_2, where the EU ETS permit prices was around \$ 8. The Norwegian CO_2-price has and continue to result in measurements that reduces emissions on NCS according to NOG (2016). According to economic theory (cf. Section 3) an emission tax or emission permit price will lead to reduced emissions. It will also be a cost-effective measurement. The CO_2-price is assumed to affect operators' investment decisions because the CO_2-price entails a cost for the petroleum industry (ECON Energi & SINTEF 1994). Moreover, Gavenas et al. (2015) finds a weak negative statistical significance for the CO_2-price, suggesting that the CO_2-price has a negative effect on the emission intensity. Thus, the CO_2-price is expected to have a negative effect on emission intensity.

The dummy for fields located on UKCS ($d\_ukfield_i$), could partly capture the effect of different CO_2-prices that the CO_2-price variable might be unable to capture, and partly capture other differences between NCS and UKCS such as technology differences. The emission intensity on UKCS, according to Oil and Gas UK (2016) and IOGP (2016), was around 166 kg per toe on average in 2015. This is quite higher than on NCS, where the average was around 56 kg per toe in 2015 (Norsk olje og gass rapport). According to Gavenas et al. (2015) the Norwegian average in 2012 was around 55 kg CO_2. This is slightly less than the average in 2015. The IOGP (2016) report writes that the average emission intensity in Europe was 91 kg per toe in 2015, while the world average was around 130 kg CO_2 per toe. However, according to the emission data obtained from BEIS, the average emission intensity is much lower than 166 kg per toe (as mentioned above). The reason for this significant difference is unclear. Hence, the indicator variable for *d_ukfield* might enter with a negative sign instead of positive.

4.3.2 Original model

Our first strategy is to test a model that includes all variables as discussed in Section 4.1 and 4.2, and then to end up with a main model. The process of how the main model was chosen is discussed in the next subsection.

A main challenge is to find a good model of emission intensity for Norway and UK. How should the heterogeneity between Norway and UK look like in our model: should we consider one model with equal coefficient values for both Norwegian and British fields, or start with two models with different coefficient values for each continental shelf? There is possible to do both. In this thesis, we included both NCS and UKCS in the same model for both the original and the main model. Additional estimations were also run, where we look at NCS and UKCS separately, that consider heterogeneity through different coefficients for NCS and UKCS.

To test which functional form we should use, we tried both a linear functional form (lin-lin model) and a log transformed functional form (log-log model). Based on different diagnostic tests, addressing among other issue normality, the log-log specification seems preferable. When using a logarithmic transformation, the estimated coefficients can be interpreted as elasticities (Gujarati & Porter 2009, p. 594). We therefore chose to use the log-log for the subsequent analysis. All variables were taken log transformed, except the dummy and the "share" variables. By assuming a log-log form, our model with emission intensity as dependent variable is given as follows:

$$\begin{aligned} log(em\_int_{it}) = \; & \beta_0 + \beta_1 prod\_share_{it} + \beta_2 (prod\_share_{it})^2 + \beta_3 (prod\_share_{it})^3 \\ & + \beta_4\, gasres\_share_i + \beta_5\, gasprod\_share_{it} + \beta_6 \ln(res\_size_i) \\ & + \beta_7 \ln(w\_depth_i) + \beta_8\, \mathrm{w}\_prod_{it} + \beta_9\, w\_inject_{it} + \beta_{10}\, gasflare\_share_{it} \\ & + \beta_{11}\, ln(carb\_p_{it}) + \beta_{12} \ln(oil\_p_t) + \beta_{13}\, ln(gas\_p_{it}) + \beta_{14}\, start\_year_i \\ & + \beta_{15}\, d\_elect_i + \beta_{16}\, d\_ukfield_i + \beta_{17}\, d\_gasfield_i + \beta_{18}\, d\_confield_i \\ & + \beta_{19}\, time_t + a_i + u_{it} \end{aligned} \qquad [9]$$

Where a_i is the unobserved heterogeneous effects and u_{it} is the error term often called idiosyncratic error term, since it varies across subjects and across time (Wooldridge 2014, p.372). The unobserved effect, a_i, represents some factors influencing emission intensity that are constant over time (in addition to time-invariant variables). The unobserved effect also captures several factors such as the field's location on the continental shelf, historical factors, where fields may have different emission intensities for historical reasons (Wooldridge 2014, p. 372). There might also be different policies between the two countries, where different operators may report emissions differently, or have different attitudes towards profit maximizing and environmental sustainability.

There are differences across fields and between fields on NCS and UKCS, which is subscripted by i where $i = 1, \dots, N$. The subscript t indexes time periods where $t = 1, \dots, T$. Variables with subscript i are time-invariant and depend only on field specific characteristics, such as reserve size and water depth. Variables with subscript t, such as oil price, are time-variant and field-invariant. This means that they do not vary across fields in a specific time period. Variables which vary across fields and time therefore are indexed with subscript it. As mentioned in Section 3.4, the CO_2-price varies both across time and across fields due to different CO_2-prices in Norway and in UK due to the CO_2-tax in Norway. This variable therefore has subscript it, as opposed to what was the case in Gavenas (2014) and Gavenas et al. (2015). The same reasoning goes for the gas price, as it also differs between Norway and UK.

4.3.3 Main model

The main model is obtained by using stepwise backwards regression. Stepwise backwards regression is a term for variable elimination, i.e., starting out with a model that include all possible variables and polynomials then dropping non-significant variables one by one based on t-tests (Gujarati & Porter 2009, p. 354). We tested several model variants with different composition of the explanatory variables of our original model above, and have gone from a general to a more specified model. By looking at the difference between the estimated coefficients of the variables, p-values, R^2, standard errors and F-test results every time we drop a variable, we arrived at our main model, [10]. Analysis of this model followed the same log transformation as described under the original model (cf. [9]). The signs of the expected effect of the variables are the same as with the original model. This model is specified using data for both countries.

$$\log(em\_int_{it}) = \beta_0 + \beta_1 prod\_share_{it} + \beta_2(prod\_share_{it})^2 + \beta_3(prod\_share_{it})^3 + \beta_4 gasres\_share_i + \beta_5 \ln(res\_size_i) + \beta_6 \ln(w\_depth_i) + \beta_7 w\_inject_{it} + \beta_8 ln(carb\_p_{it}) + \beta_9 \ln(oil\_p_t) + \beta_{10} ln(gas\_p_{it}) + \beta_{11} d\_ukfield_i + a_i + u_{it} \quad [10]$$

As mentioned in Section 4.2, $gasres\_share_{it}$ and $d\_gasfields_i$ are correlated. Thus, the dummy for gas fields might be redundant as it captures the same effects as the $gasres\_share_{it}$. There is therefore a question whether this dummy variable should be included in the main model. Since there are few pure gas fields that only produce gas, and mostly mixed fields (e.g. oil and gas) on the NCS, and many pure gas fields on the UKCS, the $gasres\_share_{it}$ variable is included in the main model while the dummy for gas fields ($d\_gasfield_i$) is excluded from the main model. When excluding this dummy variable from the main model, the dummy for condensate fields ($d\_confield_i$) is no longer significant in any of the tests. Moreover, there is no pure condensate fields on the NCS. In light of this, the dummy for condensate fields is therefore excluded from the main model.

The dummy variable for electrified fields (d_elect_i) is excluded from the main model. The reason for this is because of missing observation on UKCS, but also because we drop observations for which *em_int* is less than one. These observations includes most of the emission intensity values for electrified fields on NCS.

As we mentioned above, the production share variable ($prod\_share_{it}$) is correlated with water production (w_prod_{it}) and with water injection (w_inject_{it}). In Table 1, we see that the production share variable is defined as the production level as a share of peak production level. A field emission intensity is expected to increase in the declining phase and towards depletion, because of higher energy demand due to measurements to increase the recovery rate. Water production and the use of water injection increases as a field production declines (cf. Section 4.2), and hence increased emission intensity due to increased energy use. Since this effect on emission intensity, from both water production and from water injection, might be captured by the production share variable such that the two former variables may be redundant in this model. When performing the stepwise backwards regression method, we found that the estimated effect of w_prod_{it} was generally not statistical significant, while w_inject_{it} was. Furthermore, water injection was not studies in Gavenas et al. (2015). We are therefore interested to see how this will affect emission intensity. The w_inject_{it} was therefore included above w_prod_{it}. However, we did run some additional estimations where w_inject_{it} and w_prod_{it} are both excluded and included, and where $prod\_share_{it}$ is excluded, to get a more precise picture of how these to former variables influences emission intensity.

The estimated effect of start-up phase (*$start\_year_i$*) and gas flaring (*$gasflare\_share_{it}$*) were generally not statistical significant, and thus therefore not included in the main model. However, we want to look more into the gas flaring variable as this effect was not studied in Gavenas et al. (2015). We therefore ran an additional estimation for the main model with gas flaring.

The time trend (*$time_t$*) is not included in the main model. This indicator variable was weakly significant, but when *$start\_year_i$* was omitted from the model, *$time_t$* become statistical insignificant. In addition, the time trend variable could capture some of effects on emission intensity that the price effects otherwise could capture. To get a more precise picture of the three price variables influence emission intensity, we decided to exclude the time trend variable in the main model.

4.4 Data and estimation issues

Our data have not been obtained by random sampling because we are analysing all offshore fields that report emission and production figures on both NCS and UKCS within these time periods. The probability to be included in this sample within the periods studied for NCS and UKCS, respectively, is equal for all fields independent from their emission intensity. Fields with missing emission figures have been treated as satellite fields. As mentioned in Section 4.2, there could still be some classification problems when it comes to the connection of these tied fields, as some satellite fields can be connected to other main fields than what we have understood it to be. Based on this, however, our sample is representative for the population.

There could also be a problem with including irrelevant variables that may result in imprecise but correct estimates. The imprecision will increase as more irrelevant variables are included in the regression model, which have consequences for the variances of the estimators (Wooldridge 2014, p. 76). However, this problem will be reduced in the main model as we use the stepwise backwards regression method explained above to simplify the model in Section 4.3.3.

Furthermore, as mentioned in Sections 4.1, 4.2 and 4.3.3, some variables, such as reservoir depth, are not included due to lack of information. Thus, there might be omitted variables that are important for this analysis. If the omitted variables are correlated with the variables included in the analysis, then there might be a problem with omitted variables bias if the omitted (Wooldridge 2014, pp. 76-77). In Gavenas et al. (2015) the reservoir depth was positively correlated with the share of gas in the original reserves. However, in practice, there will always be one or more relevant explanatory variables that are omitted. This is because we either do not have the knowledge about these variables influencing the dependent variable, the necessary figures are not available or accessible or some other reasons. To include all relevant variables may therefore be impossible. We should instead try to include as many accessible relevant variables as possible.

4.5 Methodology

The methodology for this analysis is based on econometric models for panel data. They are applied on data for both Norwegian and British offshore fields within the periods 1997-2015 and 2006 – 2015, respectively. Especially when estimating the effect of a CO_2-price on the emission intensity it would have been valuable to have longer time series for the fields on UKCS. The observable results after implementing a policy might take some time to emerge, because it takes some time before agents change their behaviour. Our data set is unbalanced, where some subjects (fields) has different number of observations due to different start-up years. We also have a short panel data, meaning that we have more oil and gas fields than time periods, i.e. the number of subjects is greater than the number of time periods (Gujarati & Porter 2009, p. 593). There are 147 fields and a period over 19 years as mentioned above in Section 4.1.

One simple technique for analysing panel data is by pooling the two data sets of Norwegian and UK fields of 1360 observations and estimating a "grand" regression, known as Pooled OLS. Other panel data techniques are methods for estimating panel data models containing Fixed Effects or Random effects (Gujarati & Porter 2009, pp. 593-594). The methodology will to a large extent follow the modelling framework of Gavenas et al. (2015), which only considered Norwegian data.

As the Pooled OLS (POLS) is used to estimate a "grand" regression, it assumes all coefficients to be equal (Gujarati & Porter 2009, p. 594). Furthermore, it disregards any systematic unobserved heterogeneity between observations from different populations. This may be viewed as a strict assumption, since there is not likely that the observations from one population are generated the same way as observations from another population. For example, fields on UKCS are most likely not behaving equivalently to the fields on NCS.

With equation [9] and [10] in mind, for the Pooled OLS (POLS) estimator to be consistent, we assume that $cov\ (\varepsilon_{it}, x_{it}) = 0\ \ \forall\ i \in N, \forall\ t\ \in T$, where $\varepsilon_{it} = a_i + u_{it}$ and x_{it} is our explanatory variables. In order for the estimator to be unbiased, we require that the gross error term is uncorrelated with our explanatory variables (Wooldridge 2014). In large samples, we generally only require OLS to be consistent, since fulfilling the two assumptions of both an unbiased and a consistent estimator are quite strict and difficult to maintain. Furthermore, in reality we often have correlation between one or more of our explanatory variables and the unobserved effects ($cov\ (a_i, x_{it}) \neq 0$), such that $cov\ (\varepsilon_{it}, x_{it}) \neq 0\ \ \forall\ i \in N, \forall\ t\ \in T$, making POLS both biased and inconsistent and thus an unfit as an estimator of the parameters in the equation at hand (Gujarati & Porter 2009 , p. 595).

As the POLS estimator pool all observations and estimate a "grand" regression, the estimator treats all field specific observations as equal (Gujarati & Porter 2009). The Fixed Effects (FE) estimator treats all the field specific observations differently by "removing the field specific unobserved effects". The FE estimator calculates an average of the dependent variable (emission intensities) for a given observation unit (field), but across time, and removes the a_i resulting in mean corrected values ("de-meaned" values) (Wooldridge 2014, p.388). One of the disadvantages of the FE estimator is that it removes all variables that are time-invariant and thus cannot yield any estimate of time-invariant variables on the dependent variable (Gujarati & Porter 2009, pp. 600-601). The RE estimator on the other hand, allows us to estimate the effect of time-invariant variables on the dependent variable. It assumes that $E[cov(a_i, x_{it})] = 0$ and that $\mathcal{E}_{it}$ are not correlated with any of the explanatory variables (Wooldridge 2014, pp. 395-397). Under the assumption that $cov(a_i, x_{it}) = 0$ is true, the estimated standard errors under RE are smaller than those under FE.

The Hausman test is used to test whether both FE and RE are consistent and thus appropriate estimators. If the unobserved effects (a_i) are not correlated with any of the explanatory variables included in the model, then $\mathcal{E}_{it}$ is not correlated with the explanatory variables as a_i is component of $\mathcal{E}_{it}$ and the RE estimator is a consistent, unbiased and an appropriate estimator (Gujarati & Porter 2009, p. 603). In this case the RE estimator is preferred to the FE estimator as the RE estimator is generally more efficient, especially if the panel data are short in the time dimension (Wooldridge 2014). Even though in the case where the POLS estimator is the one with the best statistical properties, the RE estimator is consistent and appropriate to use. However, if the true model is the FE model, the RE estimator is no longer consistent. The Breuch-Pagan Lagrange Multiplier test can also be used to see if the RE specification is appropriate. It tests whether there are any substantial observation unit specific effects ($var(a_i) = 0$) present that capture unobserved heterogeneous effects. Such effects will potentially result in endogeneity if ignored (Wooldridge 2014).

5. Results and Discussion

Until now, we have review the most relevant background material, theory about CO_2-pricing, and the methodology used for our econometric analysis. This section first presents some descriptive information about the development of the CO_2-price variables and emission intensity. This is to get a better knowledge of our data that will help us with further understanding when discussing the results. Secondly, the results from the statistical tests for both our original model and main model are presented, followed by a discussion of the results for what influences emission intensity when it comes to oil and gas extraction. Lastly, policy implications are presented.

5.1 Descriptive information about prices and emission intensity

5.1.1 Prices

The coefficient of variation (CV),[21] which is the standard deviation divided by the mean, tells us that the oil and gas price have varied more or less equal. The CO_2-price seems to be more volatile than the other two prices, with a CV of 0.67 relative to 0.37 for the oil price and 0.34 for the gas price. The CO_2-price has a negative correlation with the oil price, while low positive correlation with the gas price. The CO_2-price is further discussed below.

5.1.2 Emission intensity

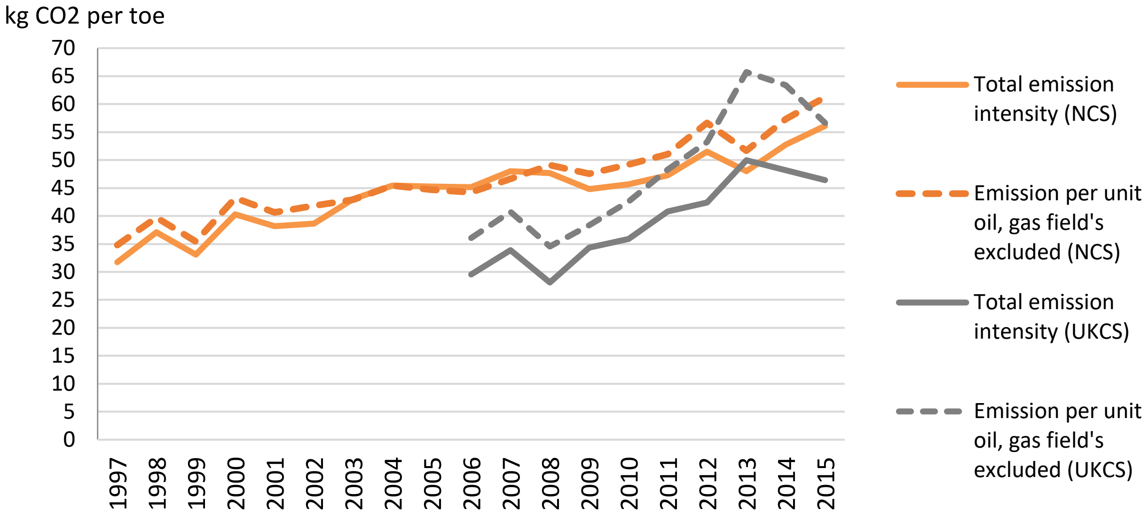
In Figure 4 in Section 2.3, we see that the emission development over time is different for the two countries where Norway has had an increasing trend since the 1990 and UK has had a falling trend since 1990. However, from Figure 14 we see that the emission intensities for both countries are trending upwards. In 2015, the world average emission intensity was around 129 kg CO_2 per tonnes oil equivalent (toe) (IOGP 2016, p. 20), whereas the Norwegian and UK average were 56 kg and 46 kg CO_2 per toe, respectively.[22]

From Figure 14, we see that average emission intensity where dry gas fields are excluded, meaning both dry gas and condensate from these fields are excluded, is higher than if dry gas and condensate fields are included. There is even a greater disparity for the UK fields, as there are several more gas fields on UKCS than on NCS. This corresponds to our assumption in Section 4.3.1 about gas production having a negative effect on emission intensity relative to oil production. Around 2013 there was an increase in emission intensity on UKCS while a decrease in emission intensity on NCS. As seen from Figure 5 of

[21] We use CV instead of standard deviation due to different price units.
[22] 113 kg and 83 kg according to STATA. The difference in calculations is explained below.

the movement of the carbon price in Section 2.4.1, there was an increase in the Norwegian CO_2-tax from 2012 to 2013, while the EU ETS permit price had gradually decreased from 2011. As mentioned before, the EU ETS permit price moved towards zero in 2007 followed by an increase in 2008. Furthermore, from Figure 14 we see that the emission intensity on UKCS had an increase in 2007 and then a decrease in 2008. As for Norway, there was a small increase in the CO_2-tax in 2007 followed by a fall in the CO_2-tax in 2008 when Norway became member of EU ETS. This builds up our argument for the negative effect the CO_2-price has on emission intensity.

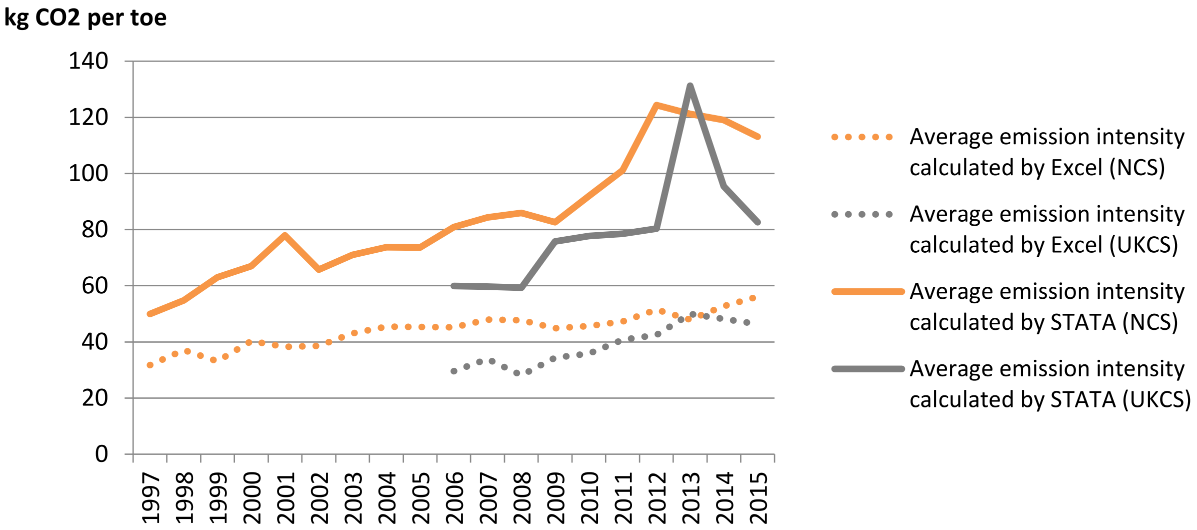
Figure 14. Overall emission intensity with and without dry gas production for both NCS (1997-2015) and UKCS (2006-2015).



Source: Calculated by Excel and based on data obtained from BEIS and NEA.

Figure 15 shows average emission intensity calculated by STATA for both Norway and UK, respectively, together with the overall emission intensity, which is also shown in Figure 14. STATA calculates the unweighted emission intensity by taking the average emission intensity across all fields for each year. Thus, fields with very high/low emission intensity increase/decrease the average emission intensity value significantly even if production from such fields are very low. The overall emission intensity is calculated by dividing total emissions for a particular year by total production for the same year. The two different methods to calculate average emission intensity give quite different results, as we see from Figure 15. The main reason for this is the negative correlation between production share (*prod_share*) and emission intensity (*em_int*). When a field's production gradually declines, the emission intensity tends to increase. In Figure 15, extremely high emission intensity values (values above 2000 kg CO_2 per toe) and emission intensity values less than 1 kg CO_2 are excluded (cf. Section 4.2).

Figure 15. Difference in calculations of emission intensity for NCS (1997-2015) and for UKCS (2006-2015).



Source: Based on data obtained from BEIS and NEA.

5.2 Econometric analysis of the determinants of emission intensity for both the original and main model.

Looking at various factors that influence emission intensity, we started analysing the data by running a POLS regression with clustered robust standard errors[23] on both alternatives, and on both the original and main model to confirm whether POLS is consistent, especially with respect to the standard errors. A main concern when using panel data is heteroskedasticity and serial correlation, since our first suspicion is cluster effect due to repeated observations. Clustered robust standard errors are often used as a remedy since they are robust to both serial correlation and heteroskedasticity (Wooldridge 2014).

The Breusch and Pagan Lagrangian multiplier test in our sample rejects that $var(u) = 0$, which indicate that $var(u) > 0$. Thus, there is evidence of substantial individual heterogeneity such that POLS is not an appropriate model to use for this sample. We therefore run both the FE and the RE estimators with cluster robust standard errors. According to the Hausman test, the unobserved effects (a_i) are not correlated with any of the explanatory variables in our model on a 5 % level of significance. This suggest that RE is a consistent estimator and therefore preferred to FE. The Hauseman test follows a χ^2 (Chi-squared) distribution with 9 degrees of freedom. We have seven time-invariant variables (*gasres_share*, *lnw_depth*, *start_year*, *d_ukfield*, *d_gasfield*, *d_confield*¸ *d_elect*) that we are interested to estimate the effect of. Six of these enter significantly under POLS and RE. Thus, RE is preferred here as it allows us to estimate the effects of both time varying and time invariant variables. For robustness, we also ran

[23] To see if our model has clusters we looked at the interclass correlation. This showed a correlation of 0.63, which indicates clusters. In addition, both the Breusch-Pagan / Cook-Weisberg test for heteroskedasticity, White's test, Scatterplot and the Wooldridge test for autocorrelation in panel data, indicates presence of both heteroskedasticity and auto correlation. We therefore use cluster robust standard errors as a remedy.

additional regressions for both the original and main model by using the Maximum-likelihood random-effects estimator (MLE)[24] and both the FE and RE models with an AR (1) disturbance since autocorrelation in the genuine errors seems to be present. There were not considerably large differences between these estimators and the (pure) RE and FE estimators. The MLE estimator and the RE and FE with an AR (1) disturbance were therefore not considered for further testing, other than for the comparison with the original and main model. The investigation of alternative estimators was in addition carried out for both alternative one and two (cf. Section 4.2). The comparison is shown in Appendix C (Tables C.1, C.7, C.8 and C.15).

As mentioned in Section 4.3, the production share variables may capture some of the effect of water production and water injection on emission intensity. To obtain a better picture of what influence emission intensity, we therefore ran additional estimations for both the original and main model where water injection and water production were excluded. We also run estimations where the three production share variables were excluded and the water injection and production were included. Three additional estimation tests were carried out for both the original and the main models considering the three price variables, where our main interest was the CO_2-price.

The discussion in the next sections are mainly based on the Random Effects model as this performed better in statistical tests and allows for estimating the effects of our time invariant variables as mentioned above.

5.3 Main results from the original model

Table 2 shows the results for the original model using Random Effects and Fixed Effects estimators, where the standard errors are lower with RE than with FE. As seen from Section 4.3.2, the original model includes all explanatory variables we find relevant and where data are accessible. It also shows separate regressions for the UKCS and the NCS with the RE estimator. From this table, we see that production level as a share of peak production and its second and third order terms enter significantly for the RE estimator, as well as the gas reserves, water injection, water depth, time and all dummy variables. However, the three different prices are not significant and neither are fields' reserve size, gas flare and water production. As mentioned in Section 4.3.2, we can interpret the coefficients to the explanatory variables in logarithmic form as elasticities. How we interpret coefficient where the explanatory variables are not in logarithmic form is described for both models below.

[24] The MLE and RE estimators essentially yields the same results, however in our case when the data are unbalanced and the number of observation units is small (e.g. equal to 147), there are marginal differences between these two estimators. The MLE estimator assume among others that the error term is normally distributed. According to our normality tests, there are some non-normalities which makes us prefer RE to MLE.

Table 2. Estimation results from original model with ln(em_int) as dependent variable. Emission intensities with values less than 1 kg CO_2 per toe and above 1800 kg CO_2 per toe with production share values near zero are excluded.

Variable name	RE model	FE model	RE_{UKCS}	RE_{NCS}
prod_share	**-4.61*** **	**-4.95*** **	**-3.85*** **	**-5.37*** **
	(0.92 / 0.00)	(1.02 / 0.00)	(1.33/0.00)	(1.37/0.00)
$prod\_share^2$	**4.68** **	**4.85** **	**3.80**	**6.37** **
	(1.87 / 0.01)	(1.99 / 0.02)	(3.26/0.24)	(2.51/0.01)
$prod\_share^3$	**-1.97***	**-1.94***	**-2.03**	**-2.81** **
	(1.11 / 0.08)	(1.17 / 0.10)	(2.13/0.34)	(1.37/0.04)
gasres_share	**-0.75** **		**-0.22**	**-0.20**
	(0.34 /0.03)		(0.43/0.60)	(0.52/0.71)
gasprod_share	**-0.19**	**-0.10**	**-0.06**	**-0.22**
	(0.21 / 0.38)	(0.24 /0.68)	(0.35/0.86)	(0.26/0.41)
gasflare_share	**0.00**	**0.00**	**0.00**	**0.06*** **
	(0.00 / 0.24)	(0.00 / 0.35)	(0.00/0.23)	(0.02/0.01)
lnres	**-0.09**		**-0.15***	**0.06**
	(0.07/ 0.18)		(0.08/0.07)	(0.10/0.55)
lnw_depth	**0.34*** **		**0.27**	**-0.13**
	(0.13 / 0.01)		(0.21/0.21)	(0.23/0.56)
w_prod	**0.00**	**0.01*** **	**-0.00**	**0.30** **
	(0.00 / 0.48)	(0.00 / 0.00)	(0.00/0.34)	(0.12/0.01)
w_inject	**4.26*** **	**3.77** **	**4.17*** **	**13.82** **
	(1.46 / 0.00)	(1.50 / 0.01)	(1.26/0.00)	(5.42/0.01)
lngas_p	**-0.05**	**-0.10**	**-0.03**	**-0.04**
	(0.13 / 0.69)	(0.13 / 0.43)	(0.16/0.83)	(0.13/0.74)
lnoil_p	**0.07**	**0.10**	**0.11**	**0.03**
	(0.11 / 0.53)	(0.12 / 0.38)	(0.14/0.42)	(0.10/0.78)
lncarb_p	**-0.02**	**-0.02**	**-0.02**	**-0.00**
	(0.02 / 0.35)	(0.02 / 0.38)	(0.02/0.47)	(0.09/0.97)
time	**0.01***	**0.01**	**0.02***	**0.01**
	(0.01 / 0.10)	(0.01 / 0.29)	(0.01/0.10)	(0.01/0.24)
start_year	**0.01**		**0.01**	**0.02**
	(0.01 / 0.45)		(0.01/0.56)	(0.01/0.22)
d_elect	**-1.21*** **		**0.00**	**-1.36*** **
	(0.41 / 0.00)		(0.00/.)	(0.47/0.00)
d_ukfield	**-1.01*** **			
	(0.17 / 0.00)			
d_confield	**-0.81** **		**-1.20*** **	**0.00**
	(0.35 / 0.02)		(0.37/0.00)	(0.00/.)
d_gasfield	**-1.10*** **		**-1.96*** **	**-0.38**
	(0.39 / 0.00)		(0.45/0.00)	(0.43/0.38)
Constant	**-7.23**	**4.76*** **	**-7.85**	**-30.45**
	(15.03/ 0.63)	(0.42 / 0.00)	(19.30/0.68)	(29.13/0.30)
No. of observations	1,365	1,365	797	568
No. of observation unites	143	142	100	43
R^2	0.501	0.0482	0.559	0.500
Sigma_u	0.760	0.980	0.730	0.539
Sigma_e	0.522	0.522	0.621	0.326
Rho	0.680	0.879	0.580	0.732

Notes: * p<0.1; ** p<0.05; *** p<0.01; robust standard errors & p-values in parentheses.

The RE model and the FE model have quite similar estimated results; first and foremost, for the production share variables, the share of gas production, gas flaring, water injection and the price variables. Water production is highly positive significant in the FE model, while not significant in the RE model. When we look at the estimated variance to the random effects (Sigma_u due to a_i) and the estimated variance to the genuine error term also called noise (Sigma_e due to u_{it})[25], we see that *Sigma_e* is equal for both the RE and the FE models, while the *Sigma_u*, is higher for the FE estimator. If we have more "noise" than "random effects" we might have a problem with our model, however this is not the case here. The overall R^2 is higher for the RE than for the FE, which agrees with the Hausman test preferring the RE estimator over the FE estimator.

All the production share variables (*prod_share*, *prod_share²*, *prod_share³*) enter significantly, where the first order term is highly negative significant which corresponds to our expectation. When we look at how the production share influence emissions intensity, we look at all the three production share variables together. Hence, when deriving the *em_int* with respect to production share, we obtain $em\_int = A \cdot e^{(\widehat{\beta_1} \cdot prod\_share + \widehat{\beta_2} \cdot prod\_share^2 + \widehat{\beta_3} \cdot prod\_share^3)}$, holding all other variables constant. Since *prod_share* has values between 0 and 1, comparing non-peak production with peak production, the formula above shows percentage change when production declines from its peak production level. Thus, a field's emission intensity increases with 2.4 % when a field's production declines from its peak production with one percentage point, i.e. from 1 to 0.99. If production share increases with one percentage point from 0.49 to 0.5, emission intensity decreases with 3.6 % and when a field's production declines from its peak production with 10 %, i.e. from 1 to 0.90, emission intensity increases with 21 %. This result corresponds to the findings reported in Gavenas et al. (2015) for NCS in the period 1997-2012. Reasons for increased emission intensity when production declines are increased water injection and water production associated with depletion of oil production (the latter also applies for gas production but to a lesser degree). Even though production declines, energy is still used when water is produced, or to increase the recovery rate by water injection as mentioned in Section 4.3. When we look at the NCS and UKCS separately, we see that water production is positive significant for the NCS. This suggest that increased water production increases emission intensity because of increased energy consumption.

Water injection enters very significantly and with a positive value; hence, emission intensity increases as the field production declines and more water injection is used. Increased water injection implies more energy used per unit extracted, hence higher emission intensity. Water injections only apply to oil fields, which support Gavenas et al. (2015) findings that oil fields have higher emission intensity relative to gas fields. If we look at Norway and UK separately, we see that water injection still is significant for both countries. As mentioned, water injection is used to increase a field's profitability by increasing the

[25] Recall Section 4.5 where we stated that $\varepsilon_{it} = a_i + u_{it}$.

recovery rate of oil. It is possible that water injection is also a factor that the operators adjust to reduce emission intensity. If this is the case and the CO_2-price increases, the operators will use less water injection. By including water injection, the estimated effect of the CO_2-price on emission intensity will be smaller than in reality, because some of this effect is captured by the water injection variable. When this variable is excluded from the model, the time trend variable becomes insignificant and both the oil and CO_2-price becomes less significant. Otherwise, there are no substantial changes for the other variables.

The gas share of original reserves seems to be highly negative significant as well with an estimated coefficient of -0.75, where emission intensity decreases with the share of gas in a field's original reserves. Hence, the negative effect on emission intensity corresponds to our expectations. As *prod_share*, the *gasres_share* has values from 0 to 1, with a value equal to 1 indicating that there is only gas in a field's original reserves (a pure gas field), while 0 means that there is only oil in a fields original reserves (a pure oil field). The estimated coefficient implies that emission intensity decreases with increased share of gas of a field's original reserves. Since the dummy variables have values equal to 0 or 1, we cannot interpret the estimated dummy parameters as semi-elasticities (i.e. relative changes) (Gujarati & Porter 2009, p.298). Halvorsen and Palmquist (1980) referred to in Gujarati and Porter (2009, p. 298) suggest that the *Y*'s (here *lnem_int*) semi-elasticity with respect to the linear dummy variables in our regression, can be obtained by the following method:

$$(e^{\widehat{\beta_i}} - 1) \cdot 100 \qquad \textbf{[11]}$$

By using this formula we have that ($e^{-0.75}$-1) · 100 = -53 % indicating that a purely gas field has about twice as low emission intensity as a purely oil field, which agrees with the findings in Gavenas et al. (2015). By using the same formula and the estimated coefficients in Table 2, we have that emission intensity is 20 % lower for pure gas fields than for pure oil fields on the UKCS. For the NCS we have that emission intensity is 18 % lower for pure gas fields than for pure oil fields. It is surprising that the coefficient is lower for both UKCS and NCS when estimated separately than for UKCS and NCS estimated together. It is hard to explain why this is the case.

Gavenas et al. (2015) found *gasprod_share* to be statistical significant. However, our regression does not find this variable significant. This might be because the effect of this variable is captured by the production share variables instead.

Gas flaring is not statistical significant when data from both the UKCS and the NCS are included. However, we see that this variable is highly positive significant for the NCS and insignificant for the UKCS. The NCS is subject to strict regulation when it comes to gas flaring. The flaring rules for the UKCS are somewhat looser. It is required that operators receive consent to flare, however the UKCS has several mature fields that are over 30 years old. They are designed to flare most of the gas instead of e.g. injecting it back to the reservoir (Oil and Gas UK 2016). Even though the UKCS has higher levels of flaring per produced unit than the NCS (cf. Section 2), gas flaring does not affect the emission intensity according to our estimations. Looser flaring regulation on the UKCS might lead to increased unburnt methane gas (CH_4), which decreases the amount of CO_2 emission reported relative to if there were no unburnt methane gas. This may affect our gas flaring variable since our dependent variable only includes CO_2 emissions. According to the UK Oil and Gas Environmental report for 2016, 34 % of emissions from gas flaring consisted of methane (Oil and Gas UK 2016, p. 23).

Water depth is highly positive significant as expected. Moreover, as seen from Table 2, we have that when the water depth increases with 1 %, the emission intensity increases with 0.34 %. The deeper the ocean, the more energy is used to extract oil and gas since the oil and gas must be lifted higher, and injected water must be pumped further down. For the NCS, we have a negative estimated effect on emission intensity, but it is not statistically significant. There could be differences between the UKCS and NCS when it comes to how their wells are drilled (horizontally vs. vertically), or perhaps when it comes to wear and tear of pipes and wells (Devold 2013). Modern wells are drilled horizontally to reach distant parts of the reservoir to increase production (Devold 2013; NPD 2011).

The time trend variable, *time*, is weakly significant with a positive value, which indicates that there are some external effects affecting emission intensity over time. This might be price effects that otherwise would be picked up by the price variables. The variable *time* is positively correlated with *lnoil_p* and *lncarb_p*, and negatively correlated with *lngas_p*. When we look at the UKCS and NCS separately, we see that the time trend variable is only statistical significant for the UKCS. The estimated effect is also positive, as in the original model, indicating that the time trend is even stronger for the UKCS than for the NCS. One reason for the time trend variable not being significant for the NCS may be two contradictory effects; such as depletion of oil and gas and technological progress. Thus, for the significant different between the NCS and the UKCS, this might be that the two continental shelfs use different technologies. We also know that UK's production peaked earlier than the Norwegian production, hence depletion and the production share variables might capture some of the effect on the NCS.

All the dummy variables are significant in the model where both UKCS and NCS are included, and the estimated values are negative. Thus, if we look at electrified fields (*d_elect*) we have a negative significant value, with an estimated coefficient equal to -1.21. By taking the antilog of -1.21, subtracting 1 from this and then multiply by 100, we get a percentage change of -70.18. This suggests that there is a 70 % decrease in emission intensity for electrified fields. As mentioned in Section 4.2, this dummy variable only applies to four gas fields on the NCS, and is therefore not included in the main model. From Table 2 above (and from Table C.5) we see that there are no electrified fields on the UKCS because the p-value is missing denoted with a ".", making the estimated coefficient equal to zero. For NCS the variable is statistically significant for NCS with an estimated coefficient of -1.36. This gives us a decrease in emission intensity of 74 % for the NCS.

The dummy for dry gas fields (*d_gasfield*) is statistically significant at a 1 % level of significance, both for the original model and the model estimated with data only for UKCS. Using Eq. [11] above, we have that dry gas fields have 67 % lower emission intensity than oil fields when both continental shelfs are included, and that gas fields on the UKCS has 86 % lower emission intensity than oil fields. The findings that gas fields have lower CO_2 emissions than oil fields correspond to the results above. The dummy for dry gas fields is not statistically significant for NCS. As seen from Section 2.1.1, we see that the category for type of offshore field is different for the NCS and UKCS,[26] where NCS have more mixed types where oil fields also included gas production. This feature pulls down emissions for these fields compared to oil fields without gas production.

When it comes to the dummy for condensate field (*d_confield*), we see the same pattern as for gas fields. This analysis suggests that condensate fields have 56 % lower emission intensity than oil fields. For the UKCS, condensate fields have an even stronger effect on emission intensity, where these fields have 86 % lower emission intensity than oil fields. On UKCS, there are 13 condensate fields of the 103 fields as opposed to NCS, which has no pure condensate fields.

The negative dummy coefficient of -1.01 for *d_ukfield* indicates a difference between the UKCS and the NCS. After following the same method as above, we get a percentage change of – 63.58. This suggests that the UKCS has 64 % lower emission intensity than the NCS when controlling for other variables. From Figure 14 above, we see that even when gas fields are excluded, emission intensity is lower on the UKCS than on the NCS until the years 2013-2015.

An interesting finding is that the estimated coefficients attached to oil and gas price consistently have the opposite sign of each other. This is interesting as the gas price traditionally follows the oil price. Hence, when the oil price has a positive sign, the gas price has a negative sign. These two prices have a correlation of 0.68, which is quite high.[27] However, both variables enter insignificantly.

The CO_2-price was expected to enter with a negative effect, and more so for Norway than for UK. This estimated coefficient is negative, but statistically insignificant as were the case for the oil and gas prices. By including UK figures in our panel data, we expected to reveal an increased significance of the CO_2-price because it is larger variation in the CO_2-price when UKCS is included in addition to NCS. However, as we see from Table 2 (and Table C.1 in Appendix C), the effect of the CO_2-price for each

[26] UKCS has three categories; Oil fields, dry gas fields and condensate fields. NCS has four categories; Oil fields, dry gas fields, dry gas and condensate fields and lastly, dry gas and oil fields.
[27] A correlation matrix is attached to Appendix B.

model (and each estimator in Table C.1) is quite similar. It is possible that the dummy variable for fields located on UKCS could capture some of the effect that otherwise would be captured by the CO_2-price variable. The indicator variable for UK fields enters then with the opposite sign than what could be expected. If the relationship between emission intensity and the CO_2-price is convex, it could be that the CO_2-price is too low, such that the firms do not really care about it. Thus, the indicator variable enters insignificantly. According to economic theory (cf. Section 3.2), a lower price than what is optimal will give less incentives to reduce emissions. It may be easier to influence investments than production with a CO_2-price, but its effect on emission intensity might be harder to capture because it is hard to capture a direct effect of CO_2-price on investments in technology or equipment that results in lower emissions. We therefor run an estimation with lagged prices, which we will come back to later in Section 5.4. Even though the estimated effect of CO_2-price on emission intensity is not statistically significant, it still may have had an effect. Consider for instance the *Sleipner East* field, where CO_2 is separated from the natural gas produced. Instead of releasing it into the atmosphere, they reinject it into the reservoir and store it.[28] This decision of storing the CO_2 in the reservoir has been claimed to be a result of the CO_2-tax. It was more profitable to re-inject it and store the CO_2 than to release it into the atmosphere and pay a CO_2-tax per unit CO_2 (Barstad 2016). However, these effects are hard to capture by the CO_2 variable because we do not have a good control group. Moreover, investing in technology or equipment that reduce CO_2 emissions, or operating with CO_2 capture and storage as at the *Sleipner East* field mentioned above, might not result in immediate effects that will be captured by the CO_2-price variable. This is because investments and technology improvements such as energy efficient technology often takes time before they come into operation.

5.4 Main results from main model

The main model is based on the original model and has been chosen by stepwise backwards regression based on p-values, but some variables with low p-values are kept as we find them interesting and relevant such as the three price variables (cf. Section 4). Table 3 presents the main results of different regression models with emission intensity as the dependent variable. From this table, we see that production level as a share of peak production and its second and third order terms are significant, as well as the share of gas in recoverable reserves, reserve size, water injection, water depth and the dummy for fields located in UK. The three different prices seem to enter insignificantly according to our regression. When we look at the $prod\_share^2$ and *gasres_share*, they are more significant in this model compared with the original model, while the three price variables are slightly less significant here than in the original model. The estimated parameters of the different variables and their significance levels are quite similar to those

[28] https://www.statoil.com/en/what-we-do/norwegian-continental-shelf-platforms/sleipner.html (Accessed: 18.05.2017)

obtained applying RE estimator on the original model, and there is no change in signs. As with the original model, the results are quite similar for both the RE and the FE model. This may correspond with the Hausman test, where the FE model was rejected over the RE model. All significant time-variant variables in the RE model are significant in the FE model, but some to a less degree.

The estimated variance to the genuine error term is equal for both the RE and the FE model, and is also equal to the variance in the original model. The estimated variance to the random effects is also here higher for the FE than for the RE, but as for the original model, sigma_u is greater than sigma_e. The overall R^2 is higher for the RE than for the FE, which agrees with the Hausman test preferring the RE estimator over the FE estimator.

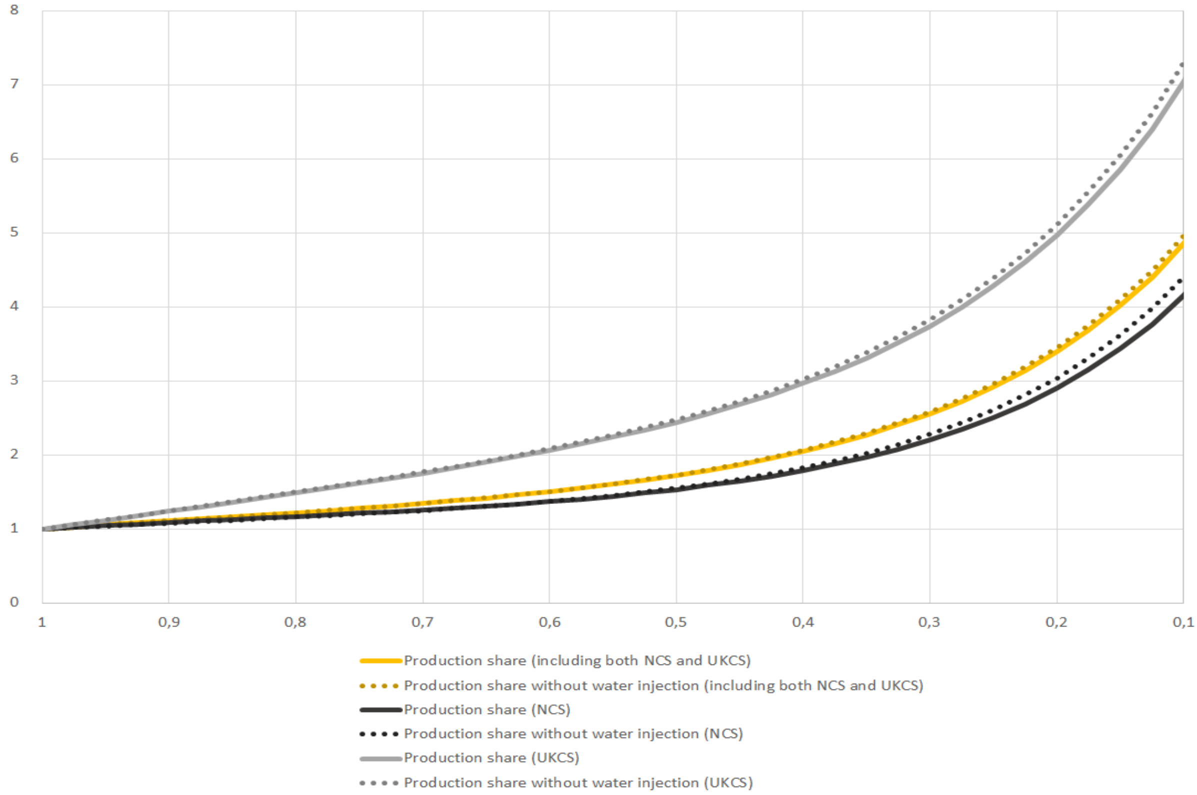
Table 3. Estimation results from main model with ln(em_int) as dependent variable. Emission intensities with values less than 1 kg CO_2 per toe and above 1800 kg CO_2 per toe (together) with production share values near zero are excluded

Variable name	RE model	FE model	RE_{UKCS}	RE_{NCS}
prod_share	**-4.95*** **	**-5.20*** **	**-4.59*** **	**-5.02*** **
	(0.92/0.00)	(0.98/0.00)	(1.32/0.00)	(1.35/0.00)
$prod\_share^2$	**4.93*** **	**5.07** **	**4.41**	**5.39** **
	(1.89/0.01)	(1.97/0.01)	(3.28/0.18)	(2.53/0.03)
$prod\_share^3$	**-2.02* **	**-2.01* **	**-2.17**	**-2.24**
	(1.13/0.07)	(1.17/0.09)	(2.14/0.31)	(1.41/0.11)
gasres_share	**-1.70*** **		**-1.62*** **	**-0.99*** **
	(0.26/0.00)		(0.31/0.00)	(0.37/0.01)
lnres_size	**-0.14** **		**-0.20** **	**0.04**
	(0.07/0.04)		(0.08/0.02)	(0.10/0.71)
lnw_depth	**0.42*** **		**0.61*** **	**-0.21**
	(0.16/0.01)		(0.19/0.00)	(0.30/0.48)
w_inject	**4.20*** **	**3.81** **	**4.06*** **	**19.55*** **
	(1.45/0.00)	(1.51/0.01)	(1.32/0.00)	(7.15/0.01)
lnoil_p	**0.10**	**0.13**	**0.09**	**0.09**
	(0.11/0.33)	(0.11/0.26)	(0.15/0.55)	(0.10/0.36)
lngas_p	**-0.03**	**-0.09**	**-0.02**	**-0.00**
	(0.13/0.79)	(0.14/0.53)	(0.17/0.91)	(0.13/0.99)
lncarb_p	**-0.03**	**-0.02**	**-0.02**	**-0.08**
	(0.02/0.25)	(0.02/0.29)	(0.02/0.28)	(0.09/0.42)
d_ukfield	**-1.12*** **			
	(0.16/0.00)			
Constant	**4.07*** **	**4.75*** **	**2.21** **	**5.65*** **
	(0.86/0.00)	(0.41/0.00)	(1.04/0.03)	(1.28/0.00)
No. of observations	1,365	1,365	797	568
No. of observation units	143	143	100	43
R^2	0.454	0.0507	0.366	0.501
Sigma_u	0.824	1.411	0.639	0.818
Sigma_e	0.522	0.522	0.340	0.621
Rho	0.713	0.880	0.780	0.634

Notes: * p<0.1; ** p<0.05; *** p<0.01; Robust standard errors & p-values in parenthesis.

The relationship between a field's production level as a share of its peak production level and emission intensity is shown in Figure 16, based on the estimated parameters from the main model. This figure shows that emission intensity increases when production as a share of peak decreases, which corresponds to Figure 13 in Section 4.3.1 for some selected fields. If the production share decreases from 0.6 to 0.5, the emission intensity increases with 11 %, and if the production share decreases from 0.3 to 0.2 the emission, intensity increases with 32 %. This indicates increasing emission intensity as production level declines from its peak production level.

Figure 16. The relationship between annual production level as a share of peak production level and annual emission per unit of production (normalized to 1 for an easier comparison).



Source: Based on estimated parameters from Table 3.

When we look at UK and Norway separately, we see that the third order term in the production share no longer is significant for both countries. For UKCS neither the second order term nor the third order term enters significantly. However, from Figure 16, we see that the emission intensity is greater for UK than for Norway when production share declines, and the model which includes both continental shelves is in-between, but closer to the NCS. If production share is 0.5 and emission intensity is 2, this means that the total emissions are just the same as at peak since the emission intensity is twice as large and the production is half as big. Thus, for UKCS when production share is equal to 0.5 and the emission intensity is equal to 2.5, this means that total emission increases even though oil and gas production on the UKCS falls. They produce less, but the emissions increase. For the NCS, the emission intensity is equal to 1.6 meaning that total emissions are lower than before, and decreases as production falls. An explanation for this difference might be that the UKCS and NCS use different technology where one might use more energy than the other, or differences when it comes to injections in the declining phase. According to our water injection figures, water injection is used more on the UKCS than on the NCS. Water injection is used to increase the recovery rate in a field's declining phase, as mentioned previously, and thus, is associated with higher emission intensity due to increased energy demand. Whether gas or water injection is more efficient to increase the proportion of extraction depends on field specific factors, such as how the wells are drilled, what kind of type the reservoir is and on what kind of gas that are used.[29] If associated gas is used to inject, that otherwise would be burned or flared, this would require less energy than extracting new gas with the main goal to inject it back to the reservoir to an oil field. However, Figure 16 visualizes the difference between production share when water injection is included and excluded, where the difference is marginal.

The water depth has gone from insignificant in the original model to highly positive significant for UK in the main model. From Table 3, we have that a 1 % increase in water depth leads to a 0.61 % increase in emission intensity, and that UKCS has larger coefficient than NCS. As mentioned under Section 5.3, horizontal wells are drilled on modern fields to increase production. Since the UKCS have more mature fields than the NCS, there is possible that the UKCS have older or different wells and pipes than on the NCS, which could affect emission intensity. There could also be geological differences between NCS and UKCS. For example, emission intensity could depend on the reservoir type, as some reservoir types might damage the pipes in a larger extent than other reservoir types. Sand particle size, shape, hardness and density among other play a significant role for erosion of subsea wells and pipeline. Naz et al. (2016) and Parsi et al. (2014) write that sand production in oil and gas productions can lead to blockage of the wells and pipelines. It is therefore reasonable to think that reservoirs with high content of sand or rocks relative to e.g. chalk, will wear out or even damage the pipes faster. This could be an interesting issue for further investigation.

The gas share of original reserves has becoming even more negatively significant compared to the original model. Hence, the emission intensity decreases as the share of gas produced increases. By using the same formula as above, we get that pure gas fields have nearly 82 % lower emission intensity than pure oil fields $((e^{-1.70} - 1 \cdot 100) = -81.73)$. This is a much bigger difference than for the original model. This might be because the dummy for dry gas fields is excluded from the main model, in addition to the dummy for electrified fields. Around 25 % of the electrified fields observations are omitted due to alternative one where emission intensity values less than 1 kg CO_2 per toe are omitted (cf. Section 4.2). For instance, for the Snøhvit field one has eight years of reported emissions where the emission intensity

[29] http://www.npd.no/en/Topics/Improved-Recovery/Temaartikler/Well-filled-toolbox-for-improved-oil-recovery/ (Accessed: 15.07.2017)

is less than 1 kg CO_2 per toe. These observations are omitted from the regression. It could also be that some of the effect of the gas share in the original model is captured by other variables such as the *gasprod_share*, which is not included in the main model due to its insignificance. The gas share of original reserves has become highly negatively significant for both UKCS and NCS. For fields on NCS, pure gas fields have nearly 63 % lower emission intensity than pure oil fields. For the UKCS, pure gas fields have around 80 % lower emission intensity than pure oil fields. An explanation for lower emissions from gas fields on UKCS relative to gas fields on NCS might be that UK has more pure gas and condensate fields than Norway (as mentioned above in Section 5.3). Further, these fields have quite low emission figures relative to gas fields on the NCS and thus, pull the average emission intensity further down for the gas fields on the UKCS.

The reserve size has also become more negatively significant for both the main model and for the UKCS. A reason for this might be that this variable now captures the effects that otherwise the variables *start_year* and *gasprod_share* would capture. In addition, UK has several large gas fields which both have lower emissions due to its larger size and due to the type of field. However, the share of gas in original reserves controls for the latter effect. The former effects are captured by reserve sizes. Neither Gavenas (2014) nor Gavenas et al. (2015) did find any statistical significance for the indicator variable for a field's reserve size in their study.

The estimates of the coefficients attached to the three prices have not changed much from the original model. The estimates of the gas and oil price parameters have the opposite sign of each other, where the oil and gas price affect emission intensity in a positive and negative way, respectively. However, both the estimates are insignificant. As mentioned above, oil and gas are both inputs and outputs. The expected immediate effect on production and hence on emission intensity by the oil or gas price sign is uncertain, and insignificant results is not surprising. Another reason for the statistical insignificance might be that the effect on emission intensity that otherwise would be captured by the price variables, is captured by the production share variables. As these variables capture a field's life time, they may also capture other external effects that otherwise could have been captured by the price variables.

The CO_2-price enters slightly more significant for all models, but is still insignificant. The same reasoning for the original model applies here when it comes to discussing why the CO_2-price turns out to be statistically insignificant. According to Larsen and Nesbakken (1997), Norway is constantly developing with new technologies and changes in prices, income, environment and economic structure i.e., producer and consumer behaviour. This makes it hard to say if a CO_2-price alone has led to lower CO_2 emissions. From Table 3, we see that the estimated effect for the dummy variable for fields located on the UKCS is highly negatively significant with a value of -1.12. Thus, fields on the UKCS have around 67 % lower emission intensity than fields on the NCS. Also for the main model, this variable may capture some of the effects that otherwise would have been captured by the CO_2-price variable since fields located on the UKCS have different gas and CO_2-prices than fields located on the NCS. However, the indicator dummy for fields in UK was expected to be positive due to a lower CO_2-price in UK. Moreover, maybe if we had managed to control for all heterogeneity between the UKCS and the NCS, the genuine CO_2-price effect on the emission intensity would have been easier to isolate.

To test whether there are some historical factors such as investment that affect emission intensity, we ran additional estimations with both lagged and smoothed prices in addition to creating a new CO_2-price variable to see if there were effects on emission intensity that the ordinary CO_2-price variable was unable to pick up. These estimations are discussed in Section 5.4.1.

An overview over the expected and estimated actual effects of the emission intensity is presented in Table 4 below. The table also contains information on how statistically significant the estimates are for both the original model and main model.

Table 4. An overview of expected and actual effect on emission intensity along with significance level.

Variable name	Expected effect on emission intensity	Actual effect on emission intensity	Statistical significance level Original model	 Main model
em_int_{it}	Dependent variable	Dependent variable	Dependent variable	Dependent variable
$prod\_share_{it}$	-	-	***	***
$gasres\_share_{it}$	-	-	**	***
$gasprod\_share_{it}$	-	-		
$gasflare\_share_{it}$	+	+		
res_size_{i}	+/-	-		**
w_depth_{i}	+	+	***	***
w_prod_{it}	+	+		
w_inject_{it}	+	+	***	***
$carb\_p_{it}$	-	-		
oil_p_{t}	+/-	+		
gas_p_{it}	+/-	-		
$time_{i}$	+/-	+	*	
$start\_year_{i}$	+/-	+		
d_elect_{i}	-	-	***	
$d\_gasfield_{i}$	-	-	***	
$d\_confield_{i}$	-	-	**	
$d\_ukfield_{i}$	+	-	***	***

Notes: * p<0.1; ** p<0.05; *** p<0.01

5.4.1 Additional estimations

As mentioned above, we ran additional estimations without water injection and water production, and some without the production share variables, with water production and water injection to obtain a better picture of what influences emission intensity. The primary interest was to see if any of the effects related to prices changed. These results from these tests are shown in Tables C.2 and C.9 in Appendix C. When the production share variables are omitted, the results from the original model and main model are quite similar, especially when it comes to the effects of share of gas reserves, water injection, water production and the gas price. In Table C.2, we see that share of produced gas enters weakly significant with a negative value and that reserve size enters with a highly significant and negative estimate. In the main model, cf. Table C.9, reserve size is not statistically significant when the production share variables are excluded, in contrast to what was the case in the original model. The water depth is generally significant in the original model for all estimators and most of the tables presented in Appendix C.1, but is only significant when the production share variables are included in the main model. From the original model, we also see that the estimated effects of the time trend and start-up year variables are, respectively, highly positive and negative significant when the production share variables are omitted. A reason for this is that the production share would for an average field decline as time goes by. The emissions would increase as the production declines as due to less natural pressure in the reservoir and more energy used due to water injection as explained above. This effect of increased emission when production declines is then instead captured by other variables such as the time trend and start-up year. However, we are not going much deeper into the discussion of the estimation without production share variables, since these variables are viewed as highly relevant for this analysis.

When we look at water injection and water production we see that water injection is overall significant in both the original and the main model. Water production is not significant in any of the cases in the original model (Table C.2). While in the main model, water production is significant if water injection is excluded from the model (cf. Table C.9). On both UKCS and NCS, there are, as mentioned earlier, many mature fields. Older pipelines and wells are more worn than newly build wells and pipelines, which could lead to emission leakages due to erosion and corrosion. Moreover, water production and water injection contributes to corrosion since water reacts with steel and thus the pipelines surface according to Nyborg (2005). This effect might be hard to capture by the water production and water injection variables, as there may be time lags involved.

Lagged and smoothed prices

As mentioned earlier, emission intensity may be influenced by factors such as investment, which the log transformed price variables are unable to capture. We therefore ran estimations with both lagged prices and smoothed prices which replaced the ordinary log transformed prices. The lagged price variable has one-year lag, while the smoothed price variable is smoothed over a five-year period (cf. Section 4.2). These estimations for the main model are presented, respectively, in Table C.11 and C.12 in Appendix C.

By including lagged prices in the main model (*lagged_lncarb_price*, *lagged_lnoil_price*, *lagged_lngas_price*), we obtain just marginal changes except for the estimated effect of the third order term in the polynomial of the production share, $prod\_share^3$, which becomes more significant than what was the case for the RE model in Table 3. When estimating with smoothed price variables (*smlncarb*, *smlnoil*, *smlngas*) the $prod\_share^3$ are becoming insignificant. For both estimations, we see that the

CO_2-price changes sign from negative to positive, but are still insignificant. The lagged prices enter more significantly than the initial prices in Table 3, where the lagged CO_2-price has a p-value of 0.13 relative to 0.25. The smoothed CO_2-price are less significant than the initial CO_2-price with a p-value of 0.46 relative to 0.25. However, both prices enter insignificantly.

When we look at UK and Norway separately, we see that the estimate of the lagged oil price has become weakly significant and positive for NCS, while the lagged gas and CO_2 price are insignificant. We also see that none of the estimated smoothed prices are statistical significant, both when looking at the estimation of NCS and UKCS together and separate. The estimated positive effect of the CO_2-prices on the emission intensity on the NCS is not what was expected. It might be that it captures that the UKCS generally has lower emissions than the NCS, and thus having a positive effect on emission intensity.

The results for the original model are quite similar to the main model and is therefore not discussed further in this analysis. The estimation results for the original model are presented in Table C.4 and C.5 in Appendix C.

The new CO_2-price variable

We also want to investigate if fields located on the NCS and the UKCS have different CO_2-price coefficient when estimating for both countries together for both the original and main model. In addition to lagged and smoothed prices, we ran some estimations where we created a new CO_2-price variable that a priori allows the CO2-price to have different effects depending on whether a field is located on the UKCS or the NCS. This model could be implemented in several ways. One way is by generating two variables where the first variable is created by multiplying the log transformed CO2-price with a dummy variable for fields located on the UKCS and the second variable is the log transformed CO_2-price multiplied with fields located on the NCS. A second way is to create one variable where the log transformed CO_2-price is multiplied with the dummy for fields located on UKCS. The latter alternative has been chosen for this analysis (cf. Section 4.2). We have that this new CO_2-price, called *lnpcarb_new*, determines that the effect of *lncarb_p* declares the effect on emission intensity for fields located on NCS. For UKCS it is the sum of the effects of the variables *lnpcarb_new* and *lncarb_p*. The estimation results for the main model can be found in Table C.13 in Appendix C. There are no substantial differences from the initial main model when it comes to the other variables in the regression. The CO_2-price becomes even less insignificant (from p-value equal to 0.25 to 0.43) when estimating with *lnpcarb_new*. The estimated coefficient of the new CO_2-price variable is 0.05, while the estimate of *lncarb_p* is -0.08. The sum of these two estimates gives us a negative estimated effect (-0.03) on emission intensity. However, both these two variables are highly insignificant when the dummy for fields located on the UKCS are included. When the dummy for fields on UKCS are excluded, the new CO_2-price variable became highly significant with a negative value and the original CO_2-price variable (*lncarb_p*) became highly significant with a positive value indicating that the CO_2-price affects emission intensity differently for Norway and UK. When the *d_ukfield* is excluded from the regression, we get a total effect for UK that is either zero or negative. For Norway, however, the CO_2-price influences emission intensity positively. This is in contrast to our expectation of how the CO_2-price should affect emission intensity. This positive significance may emerge because the CO_2-price now captures the effect that the UKCS generally has lower emissions than the NCS according to our figures (cf. Figure 14). The differences between fields on the UKCS and NCS might also be due to differences across operators, which may be due to different cultures, operation techniques, technology etc. For instance, it is not unlikely that some operators consider the environment to a larger degree than others, or that some operators have more revenue to invest in more energy efficient equipment. This can be controlled for by adding operators as a variable, since we have knowledge of which operators that operates on which fields.

We see the same pattern for the original model as the main model, both when the dummy for UKCS located fields are included and excluded from the regression. The estimated results from the original model are presented in Table C.6.

Gas flaring

Gas flaring stood for nearly 10 % of the CO_2 emission on both the NCS and the UKCS (Oil and Gas UK 2016; SSB 2016). As mentioned earlier, this is the second largest emission source after combustion of diesel and gas in turbines and engines. In addition to contributing with CO_2 emissions, gas flaring waste valuable non-renewable resources that could contribute to economic growth. The Norwegian government has implemented a prohibition on gas flaring except for safety measurements, as mentioned previously. To get a more precise picture of the driving forces of emission intensity from petroleum activity, we therefore ran an additional estimation for the main model with gas flaring as an additional explanatory variable. The overall results are however quite similar to those obtained for the initial main model, where the comparison is shown in Table C.14. The gas flaring variable is also here only significant for the NCS with an estimated coefficient of 0.07. When gas flaring is included for the NCS, neither water depth nor reserve size retains its significance.

Alternative 2

As mentioned at an earlier stage, we ran an alternative estimation for both models where emission intensity values less than 1 kg CO_2 per toe were replaced with the value 1. This because we were particularly interested to see what happened to the share of gas in the original reservoir. The estimated results are found in Table C.15. With the share of gas variable in mind, the negative effect is even stronger for this alternative relative to the first alternative, with an estimated coefficient of -2.98 relative to -1.70 (cf. Table 3). By using Eq. [11] above, we get that gas fields have nearly 95 % lower emission intensity than oil fields. The difference between oil and gas fields are now even more pronounced. We also found this effect for the original model (see Table C.7). Under this alternative, the observations that otherwise are omitted in the regression are now included. These observations are to a large extent connected to gas fields making the difference between oil and gas fields even larger. We also see that the reserve size goes from entering significantly at the 5 % level of significance to being insignificant. This might be due to a contradicting effect since more small gas fields with low emissions now are included in the regression rather than being omitted. This works against the effect that smaller fields have higher emission and thus, making this variable insignificant.

5.5 Policy implications

From Section 3, we saw how the CO_2-price works according to economic theory. If the CO_2-price is optimally set, this will lead to innovative behaviour and decreased emissions in a cost-effective way. The findings from the current analysis may give increased empirical knowledge about how the CO_2-price work in practice and how it influences emission intensity for the petroleum industry. It may also give increased knowledge to other factors influencing emission intensity such as a fields production level as a share of its peak production level, water injection, the share of gas in original reserves, electrification etc.

As mentioned in Section 2, most CO_2 emissions in the petroleum industry come from combustion of gas and diesel in turbines and engines and gas flaring. One method to reduce CO_2 emissions from this sector is by investing in more energy efficient measurements such as replacing processors, turbines and engines (NEA 2015). This may be expensive, and direct regulation of such equipment may be less cost effective than to regulate the CO_2-price.

Increasing the CO_2-price, either the CO_2-tax or the EU ETS permit price, will reduce emissions according to economic theory (cf. Section 3.2). Today, the CO_2-tax rate on the NCS is set to 1.04 NOK per Sm^3 gas or litre oil.[30] According to our regressions, the CO_2- price was not significant in either of the two models. There might be several reasons for this result as is discussed above. However, even though the CO_2-price is not statistical significant in our estimations, this does not necessarily mean that the CO_2-price have had no impact on CO_2 emissions. It is possible that the introduction of e.g. CO_2-tax on NCS increased awareness around this topic, as it is said for the *Sleipner field*, and has indirect put more cost-effective projects to reduce CO_2 emissions into action. There is a possibility that the estimated CO_2-price effect would had a more significant influence on emission intensity if we could compare with the period before the CO_2-price was introduced, both on the UKCS and on the NCS, or if we had a control group as mentioned in Section 5.3.

[30] https://www.regjeringen.no/no/tema/okonomi-og-budsjett/skatter-og-avgifter/avgiftssatser-2017/id2514838/ (Accessed: 01.08.2017)

The production share variables were generally significant across models and estimation results in this analysis. This suggest that the start-up phase and declining phase have higher emission intensity relative to the peak production level. As Gavenas et al. (2015) suggest, terminating mature fields earlier would contribute to lower emission intensity, but if it is reasonable for the government to demand earlier termination depends also on profitability of the field. Earlier termination may induce loss of profits, which is hard to accept for a rational firm. Our estimations also suggest that water injection has a significant effect on emission intensity, and this variable is tied to the production share as discussed above. Earlier termination may also lead to less use of water injection.

Another suggestion for reducing emission intensity may be to implement restrictions on the use of water injection. However, this follows the same counter-argument as for earlier termination of mature fields as the recovery rate may go down and be detrimental to the operators' profitability. This policy will also be less cost-effective than increasing the CO_2-price. However, according to economic theory, a direct regulation in addition to an optimal CO_2-price could lead to efficiency loss since the operators (emitters) will adjust in a non-optimal way where the operators will abate more than necessary. However, if implementing a higher tax is politically challenging, which results in a lower tax than the optimal tax-level, it could be argued that a direct regulation could be a solution in addition to a CO_2-price that is lower than the optimal level. An example of this is electrification, where offshore fields are connected to the electrical network on land to reduce CO_2 emissions. This applies especially to new installations to avoid reconstruction costs from existing installations. In addition, if the installation is stationed far from land, this might be an expensive operation and requiring electrification may therefore be less cost effective. Troll A, Gjøa, Goliat, Snøhvit, Ormen Lange and Valhall are all electrified from land. Martin Linge and Johan Sverdrup, which is approved for production, are also decided to be electrified. There is also decided a solution area with power from land for the fields Edvard Grieg, Ivar Aasen and Gina Krog (KonKraft 2016). We have however not been able to find information of electrified fields on the UKCS continental shelf.

Our estimations suggest that emission intensity is higher for oil fields with small reserve size and significant water depth. A question is if this finding has any policy implications. A controversial direct regulation is to be more restrictive when giving out licenses to such fields and to prevent development of them. This follows the same counter-argument as for earlier termination of mature fields and restrictions on water injection. Hence, this policy measurement is not recommended because adjusting the CO_2-price may be more cost-effective than restrictions on such fields mentioned above.

6. Conclusion

The purpose of this thesis was to assess the driving forces behind CO_2 emission intensities of oil and gas extraction on both Norwegian Continental Shelf (NCS) and UK Continental Shelf (UKCS). We were specifically interested in how the CO_2-price have influenced emission intensity of oil and gas extraction as this is said to be one of the most important measurement to reduce CO_2 emissions on the NCS. By using panel data with a sample of 147 offshore fields, of which 44 fields are from NCS and 103 from UKCS. We studied the periods 1997-2015 and 2006-2015 for NCS and UKCS, respectively. We estimated the driving forces by mainly using a Random Effects model for panel data regression. We ran both an original model, which included all variables we found relevant, and a main model, which included only 11 of 19 variables from the original model. In addition to these two models, we also ran five additional estimations. The results in this analysis support several of earlier findings such as Gavenas (2014) and Gavenas et al. (2015).

6.1 Main findings

The first main finding is that the CO_2-price was not significant in either of the two models. However, it could be the case that the CO_2-price has had some indirect effect on emission intensity when it comes to e.g. investments and increased awareness around CO_2 emissions on the offshore petroleum industry. The dummy variable for fields located on UKCS generally enters with high statistical significance, suggesting that there is a difference between fields located on UKCS and NCS when it comes to emission intensity. In this analysis, we expected that the dummy for fields located on UKCS, would capture long-term effects of different CO_2-price for NCS and UKCS that the CO_2-price indicator variable was unable to capture. However, this turned out to have the opposite effect on emission intensity. As mentioned in Section 4.2, the emissions from UKCS are probably higher than the emission data indicates as there is as substantial difference between the obtained emission figures and the emission reported in both IOGP (2016) and Oil and Gas UK (2016). Further, when estimating with heterogeneous CO_2-price effects, the CO_2-price influenced emission intensity positively on NCS when excluding the dummy variable for fields located on UKCS. However, the CO_2-price probably captures the differences between UKCS and NCS since the dummy is not included.

Our second main finding is that offshore fields tend to have higher emissions in its declining phase relative to their peak production level, and the effect is even stronger for fields on UKCS than on NCS. Further, water injection enters with a significant effect on emission intensity, which strengthens the former conclusion.

Our third main finding is that gas fields tends to have lower emissions than oil fields since emission intensity tends to increase with the share of oil in a field's original reserve. We also find this when most electrified fields, which are mostly gas fields, are excluded from the model. This finding supports the findings of Gavenas et al. (2015). Also here is the effect even stronger for fields located on UKCS, where gas fields have 80 % lower emission intensity than oil fields on the UKCS. On the NCS, gas fields have 63 % lower emission intensity than oil fields.

In contradiction to Gavenas (2014) and Gavenas et al. (2015), suggest our estimation results that smaller fields have higher emission intensity. In addition, our estimations suggest that fields with significant water depth have higher emission intensity.

According to our estimations, gas flaring seemed to only be statistical significant for fields on the NCS, while not on the UKCS. The time trend only enters weakly positive significant in the original model. Further, neither the share of oil in the field's running production nor start-up year turned statistical significant. We also found a weak indication of a positive effect on emission intensity on the NCS when it comes to a lagged oil price. However, generally there was no statistical evidence of the oil and gas prices affecting emission intensity.

6.2 Limitation of the study

As mentioned before, there is significant difference between the emissions intensity based on data obtained from BEIS (2017) and the emission intensity reported in Oil and Gas UK (2016) and IOGP (2016). This may indicate that the emission data for UK is inadequate.

Further, we encountered some emission intensity values less than 1 kg CO_2 per toe, where we tried two alternatives to deal with this problem. The first alternative was to drop emission intensity values less than one, and the second alternative was to replace the values less than one with one (cf. Section 4.2). Thus, it could be argued either to use a different functional form than taking the natural logarithm, or to use a different method than the two alternatives mentioned above to avoid this estimation issue.

Another limitation of this study was in relation to connecting the satellite fields to their main fields. Hence, there could be some characteristic error when connecting these fields. Thus, the estimation results would have been more accurate if each offshore field, both satellite and main field had reported emissions.

6.3 Suggestion for further research

Only available emission figures for UKCS were in the period 2006-2015. To get a better understanding of the driving forces behind CO_2 emission intensities on UKCS, study of data across a longer time may be of suggestion. Moreover, a longer period studied also applies for the NCS, where we have studied the years 1997-2015. If Norwegian CO_2 emission figures before 1991 were available, we could compare before and after the introduction of the Norwegian CO_2-tax to obtain a more precise picture of the CO_2-price.

Another possible approach is to include other GHGs such as methane since most natural gas consists of methane. Emission of methane may be relevant to study as methane is the second largest GHG after CO_2. In 2015, emitted methane from offshore oil and gas extraction were 28 947 tonnes and 41 200 tonnes on NCS and UKCS, respectively (NOG 2016; Oil and Gas UK 2016; SSB 2016). Methane stood for 5 % and 7 % of the total GHG emissions from offshore oil and gas extraction, while CO_2 stood for 95 % and 90 % of the GHG emissions, respectively (Oil and Gas UK 2016; SSB 2016).

It is also possible to include other explanatory variables such as the amount invested in each field or whether the reservoir type or well type (horizontal vs. vertical wells) influence emission intensity. Alternatively, to look into the use of energy-efficient technology at field level, as this thesis did not consider technological characteristics as explanatory variables. Further, it is also possible to distinguish between different sources of CO_2 emission from the petroleum industry to a greater extent, such as combustion of gas or diesel in turbines.

7. References

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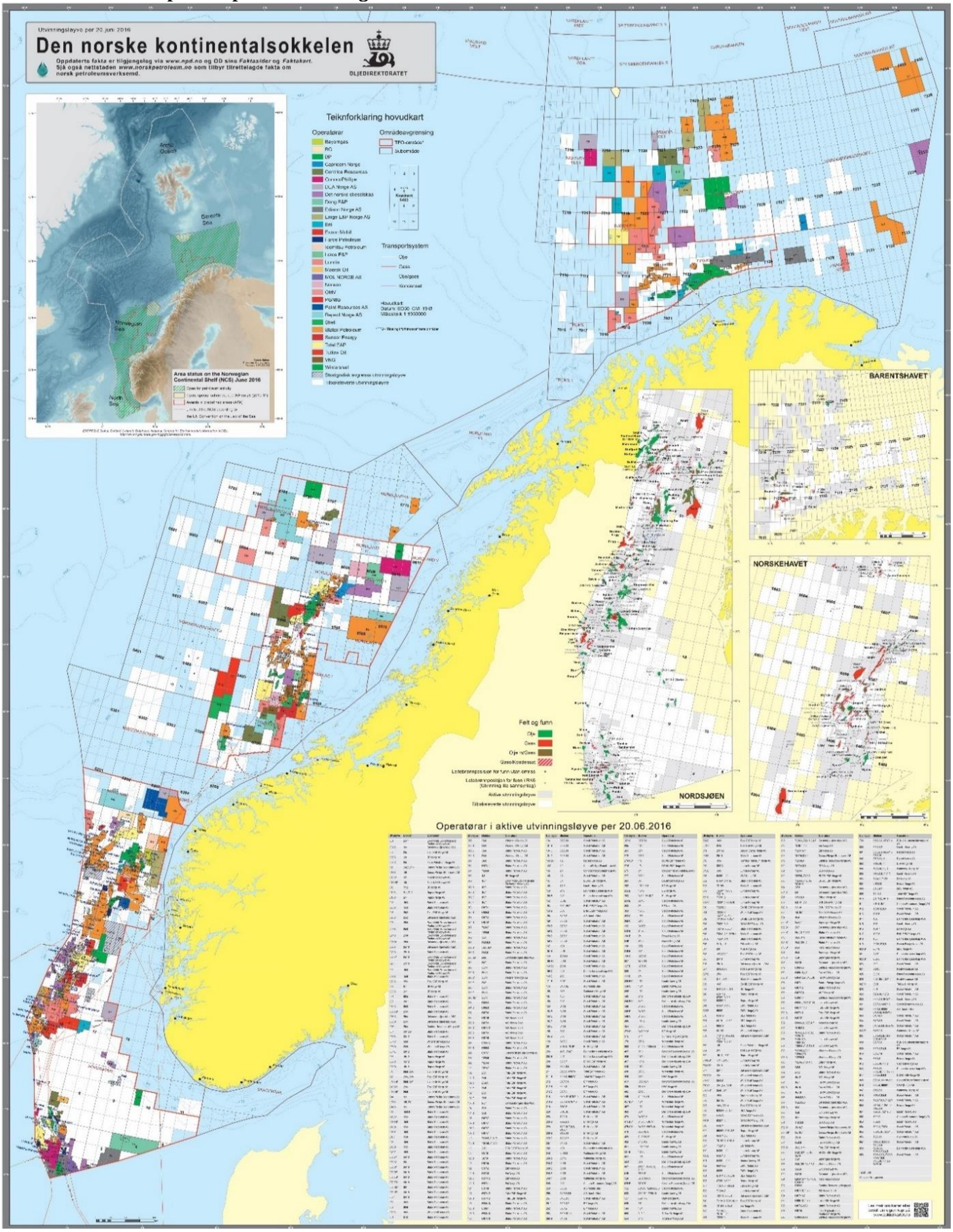
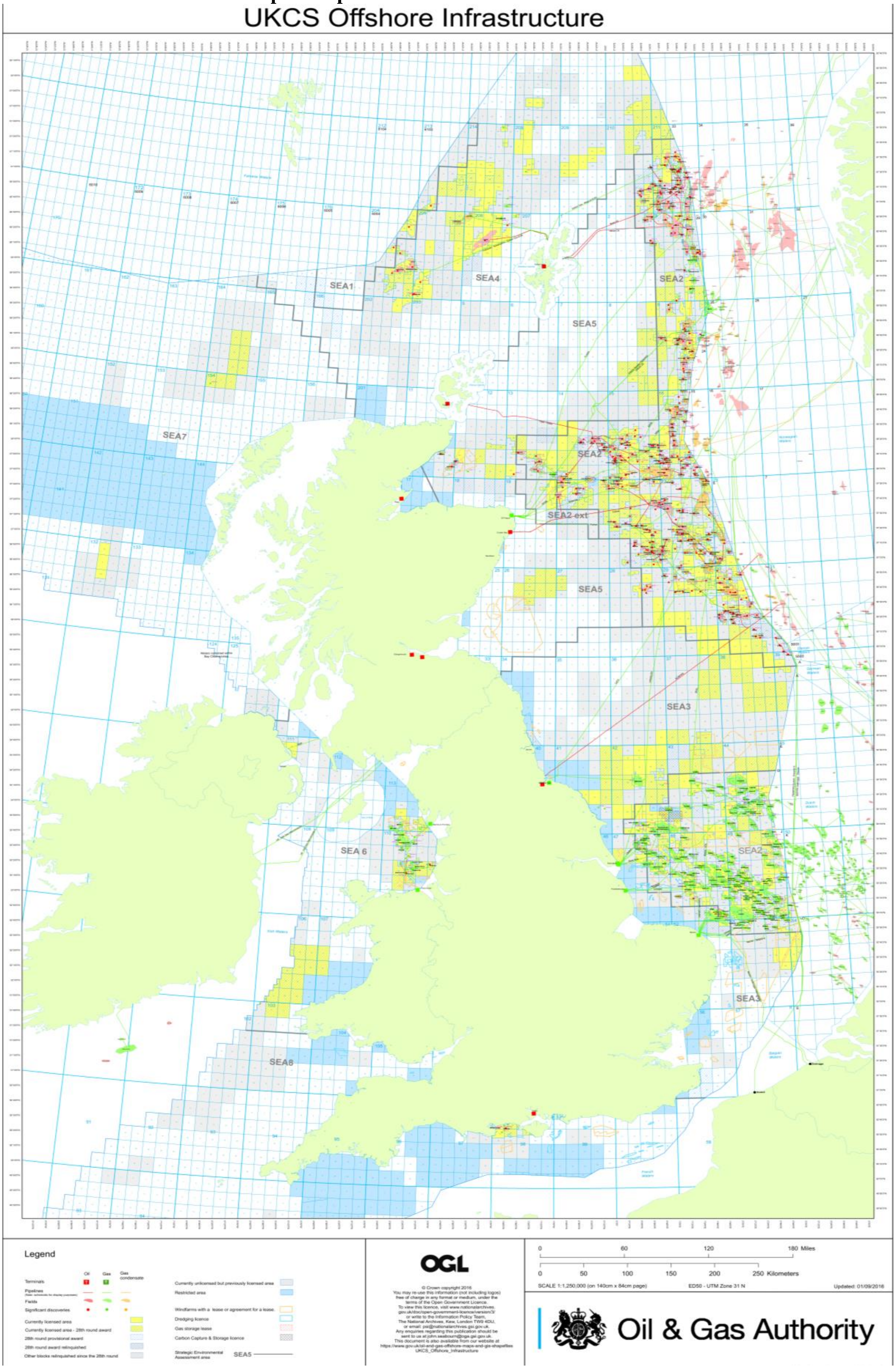
Appendix A
A.1 Maps

Map 1. Map of the Norwegian Continental Shelf's Infrastructure



Source: http://www.npd.no/en/Maps/Map-of-the-NCS/ (2016)

Map 2. Map of the UKCS's infrastructure



Source: https://www.gov.uk/guidance/oil-and-gas-offshore-maps-and-gis-shapefiles (2016)

A.2 Tied fields

Table A 1. Overview over tied fields on NCS.

Main field's	Satellite field's	Start Year	N
Albuskjell		1979	2
Alvheim	Vilje, Volund, Bøyla	2008	8
Balder	Jotun, Jette, Ringhorne	1999	17
Brage		1993	19
Brynhild		2014	1
Cod		1977	2
Draugen		1993	19
Edda	Tommeliten-Gamma	1979	2
Ekofisk	West Ekofisk	1971	19
Eldfisk	Embla	1979	19
Frigg	Lille-Frigg, Frigg on UKCS, East Frigg, Frøy	1977	8
Gjøa	Vega, Vega South	2010	5
Glitne		2001	12
Grane	Svalin	2003	13
Gullfaks	Gimle, Tordis East, Borg, Visund South, Gullfaks South	1986	19
Gyda		1990	19
Heidrun		1995	19
Heimdal	Atla, Huldra, Skirne, Vale	1985	19
Knarr		2015	1
Kristin	Tyrihans	2005	10
Kvitebjørn		2004	11
Njord	Hyme	1997	19
Norne	Alve, Marulk, Urd, Skuld	1997	18
Ormen Lange		2007	8
Oseberg	Tune	1988	19
Oseberg Sør		2000	16
Oseberg Øst		1999	17
Skarv		2013	3
Sleipner East + West (1997-2002)	Gungne, Sleipner East, Sleipner West, Gudrun	1993	19
Sleiper East (2003-2015)	Gungne, Sigyn	1993	13
Snorre	Vigdis	1992	19
Snøhvit		2007	8
Statfjord	Sygna, Statfjord North, Statfjord East, Statfjord on UKCS	1979	19
Tor		1978	19
Troll	Fram, Fram H	1995	19
Ula	Blane, Tambar, Oselvar	1986	19
Valemon		2015	1
Valhall	Hod	1982	19
Varg		1998	1
Veslefrikk		1989	19
Visund		1999	16
Volve		2008	8
Yme		1996	5
Åsgård	Mikkel, Morvin, Yttergryta	1999	16

Table A 2. Overview over tied fields on UKCS.

Main Field's	Satellite Field's	Start Year	N
AH001	Hamish, Ivanhoe, Renee, Rob Roy, Rubie	1989	4
Alba		1994	10
Alwyn North	Ellon, Forvie, Grant, Islay, Jura, Nuggets	1987	10
Amethyst	Amethyst East & West, Helvellyn, Rose	1990	10
Anasuria	Cook, Guillemot A, Teal, Teal South	1996	10
Arbroath		1990	10
Armada	Drake, Flemming, Gaupe, Hawkings, Maria, Rev, Seymour	1997	10
Athena		2012	3
Auk	Auk North	1975	10
Babbage	Beauly, Brenda, Burghley, Glamis, Nicol, Stirling	2010	5
Balmoral		1986	10
Banff	Kyle	1999	10
Beatrice	Jacky, Lybster	1981	9
Beryl	Buckland, Loirston, Ness, Nevis, Skene	1976	10
Brae Central	Brae North, South & West, Birch, Enoch, Larch, Miller, Sycamore, Kingfisher	1989	10
Brae East	Beinn, Braemar, Devenick	1993	10
Breagh		2013	3
Brent	Penguin East, Penguin West	1981	10
Bbritannia	Andrew, Brodgar, Caledonia, Callanish, Cyrus, Enochdhu, Farragon, Kinnoull,	1998	10
Bruce	Keith, Rhum	1993	10
Buchan	Hannay	1981	10
Buzzard		2007	9
Captain		1997	10
Chestnut		2008	7
Chiswick	Kew	2007	8
Clair		2005	10
Claymore	Scapa	1977	10
Cleeton	Apollo, Eris, Mercury, Minerva, Neptune, Whittle	1988	10
Clipper	Barque, Barque South, Carrack, Cutter, Galleon, Skiff, Valiant North & South, Vanguard, Viscount, Vulcan	1995	10
Clipper South		2012	4
Clyde	Medwin, Nethan	1987	10
Cormorant North	Causeway, Cormorant East, Falcon, Fionn, Kestrel	1982	10
Cormorant South	Pelican	1979	10
Curlew	Curlew Central,	1997	10
Don S.W. &W.	Conrie, Don South West, Don West, Ythan	1989	10
Donan	Balloch, Lochranza	2007	10
Douglas	Douglas West, Hamilton, Hamilton North, Hamilton East, Lennox,	1996	10
Dunbar		1994	9
Dunlin	Dunlin South West, Merlin, Osprey	1978	10
Eider	Otter	1988	10

Elgin	Franklin, Glenelg	2001	10
Ensign		2012	4
Erskine		1997	10
Ettrick	Blackbird	2009	6
Everest		1993	10
Fife	Angus, Fergus, Flora	1995	3
Foinaven		1997	10
Forties	Bacchus, Maule, Tonto	1975	10
Fulmar	Halley, Leven, Orion	1982	10
Gannet A	Gannet B, C, D, E, F & G	1993	10
Golden Eagle	Peregrine,	2014	2
Goldeneye	Atlantic, Cromarty	2004	4
Gryphon	Maclure, tullich	1993	9
Guillemot W & NW	Bittern, Clapham, Machar, Madoes, Mirren, Monan, Pict, Saxon	2000	10
Harding		1996	10
Heather	Broom	1978	10
Hewett	Delilah	1969	10
Huntington		2013	3
Hyde		1993	9
Indefatigable	Baird, Beaufort, Bell, Bessemer, Caravel, Inde South, Shamrock, Wenlock	1971	10
Jade		2001	10
Janice	Affleck, James	1999	10
Kittiwake	Gadwall, Goosander, Grouse, Mallard	1990	10
Lancelot	Durango, Malory, Mordred, Waveney	1993	10
Leadon		2001	1
Leman	Brigantine A, B, C & D, Boyle, Brown, Callisto, Callisto North, Camelot Central South & North, Camelot CA, Corvette, Europa, Davy, Davy East & North, Ganymede, Leman South, Tristan NW	1968	10
Lomond		1993	10
Macculloch		1997	9
Magnus	South Magnus	1983	10
Markham	Grove, Stamford	1992	10
Marnock	Arthur, Egret, Heron, Mungo, Orwell, Skua, Thurne, Wensum, Wissey, Wren, Yare	1998	10
Montrose	Arkwright, Brechin, Carnoustie, Wood	1976	10
Morecame North	Dalton, Millom, Rhyl	1994	9
Morecambe South	Bains, Calder	1985	10
Murchison	Playfair	1980	10
Murdoch	Boulton, Boultonh, Caister Bunter, Caister Carboniferous, Cavendish, Hawksley, Hunter, Katy, Kelvin, Keth, Mcadam, Munro, Murdochk, Rita, Schooner, Topaz	1993	10
Nelson	Bardolino, Howe	1994	10
Ninian	Columba BD & E, Lyell, Strathspey	1978	10
Pickerill	Juliet	1992	10
Pierce		1999	9
Piper	Chanter, Iona, Tweedsmuir, Tweedsmuir South	1976	10

Ravenspurn North	Ravenspurn South, Johnston,	1989	10
Ross	Blake	1999	10
Rough Production	Rough Storage	1985	10
Saltire		1993	10
Schiehallion	Loyal	1998	9
Scott	Rochelle, Telford	1993	10
Sean	Sean East	1986	10
Shearwater	Merganser, Scoter, Starling,	2000	10
Shelley		2009	2
Tartan	Duart, Galley, Highlander, Petronella	1981	10
Tern	Hudson	1989	10
Thames	Bure, Bure West, Gawain, Horne	1986	10
Thistle	Deveron	1978	10
Tiffany	Thelma, Toni	1993	10
Trent	Garrow, Kilmar North	1993	10
Tyne North	Tyne South	1996	9
Viking B	Alison, Alison KX, Ann, Annabel, Audrey, Mimas, Saturn, Tethys, Valkyrie, Vampire, Victor, Victoria, Vixen	1972	10
West Sole	Anglia, Ceres, Excalibur, Galahad, Guinevere, Hoton, Newsham, Seven Seas	1967	10
Windermere		1997	10
Wingate		2011	5
York		2013	3

Appendix B

B.1 Correlation matrix

Table B 1. Alternative 1: Correlation matrix for variables in linear form (obs=1365)

	em_int	prod_share	prod_share^2	prod_share^3	gasres_share	gasprod_ share	w_inject	res_size	w_depth	water	oil_p	gas_p	carb_p	gasflare _share	time	start_year	d_elect	d_gasfield	d_confield	d_ukfield
em_int	1.0000																			
prod_share	-0.2507	1.0000																		
prod_share^2	-0.2095	0.9601	1.0000																	
prod_share^3	-0.1850	0.9013	0.9847	1.0000																
gasres_share	-0.3121	0.0895	0.0756	0.0670	1.0000															
gasprod_share	0.0564	-0.1242	-0.1323	-0.1233	-0.3592	1.0000														
w_inject	0.2356	-0.1202	-0.0961	-0.0822	-0.0411	0.0485	1.0000													
res_size	-0.1058	0.3019	0.2960	0.2782	0.0923	-0.0549	-0.0828	1.0000												
w_depth	0.0255	0.3272	0.3191	0.3006	-0.0983	-0.1083	-0.0682	0.2909	1.0000											
water	-0.0392	-0.0354	-0.0454	-0.0439	0.0234	0.0191	-0.0145	-0.0241	0.0046	1.0000										
oil_p	0.0934	-0.3041	-0.2949	-0.2758	0.0346	0.1585	0.0721	-0.1616	-0.0768	0.0455	1.0000									
gas_p	0.1132	-0.0108	-0.0409	-0.0523	0.0224	0.0193	-0.0022	0.0631	0.1348	-0.0018	0.6828	1.0000								
carb_p	0.0039	0.4103	0.3607	0.3192	-0.0386	-0.2066	-0.1099	0.3287	0.3108	-0.0657	-0.3653	0.2554	1.0000							
gasflare_share	0.1372	-0.0075	-0.0002	0.0050	-0.0774	0.0104	0.0782	-0.0595	-0.0099	-0.0071	0.0392	-0.0278	-0.0973	1.0000						
time	0.1410	-0.3557	-0.3269	-0.2950	0.0412	0.1843	0.0627	-0.1797	-0.0750	0.0252	0.6306	0.3760	-0.4643	0.0207	1.0000					
start_year	-0.0530	0.4247	0.3804	0.3440	0.0156	-0.0766	-0.0298	-0.1307	0.2933	0.0276	0.0524	0.1285	0.0761	0.0056	0.1109	1.0000				
d_elect	-0.1064	0.2743	0.2977	0.2967	0.2132	-0.1042	-0.0363	0.6436	0.4833	-0.0137	-0.0281	0.0873	0.1659	-0.0251	-0.0229	0.1498	1.0000			
d_gasfield	-0.2172	-0.0512	-0.0482	-0.0426	0.7372	-0.1475	0.0502	-0.1142	-0.2454	-0.0449	0.0502	-0.0180	-0.1055	-0.0596	0.0579	-0.1316	0.0254	1.0000		
d_confield	-0.1697	-0.0217	-0.0551	-0.0679	0.2275	0.0975	-0.0689	-0.1024	-0.1029	-0.0112	0.0947	-0.0464	-0.2302	-0.0238	0.1075	0.1613	-0.0449	-0.1305	1.0000	
d_ukfield	-0.0315	-0.4390	-0.3928	-0.3518	0.0416	0.2269	0.1249	-0.3563	-0.3393	0.0725	0.3996	-0.2278	-0.9199	0.1109	0.4212	-0.1025	-0.1806	0.1092	0.2487	1.0000

Table B 2. Alternative 1: Correlation matrix for variables in logarithmic form (obs=1365)

	lnem_int	prod_share	prod_share^2	prod_share^3	gasres_share	gasprod_share	w_inject	lnres	lnw_depth	water	lnoil_p	lngas_p	lncarb_p	gasflare_share	time	start_year	d_elect	d_gasfield	d_confield	d_ukfield
lnem_int	1.0000																			
prod_share	-0.2141	1.0000																		
prod_s2	-0.1892	0.9601	1.0000																	
prod_s3	-0.1755	0.9013	0.9847	1.0000																
gasres_share	-0.5323	0.0895	0.0756	0.0670	1.0000															
gasprod_share	0.0005	-0.1242	-0.1323	-0.1233	-0.3592	1.0000														
w_inject	0.1694	-0.1202	-0.0961	-0.0822	-0.0411	0.0485	1.0000													
lnres	0.0354	0.2525	0.2204	0.1942	-0.0115	-0.0596	-0.1132	1.0000												
lnw_depth	0.3175	0.2703	0.2657	0.2491	-0.3603	-0.0725	-0.0900	0.3766	1.0000											
water	-0.0372	-0.0354	-0.0454	-0.0439	0.0234	0.0191	-0.0145	0.0090	0.0366	1.0000										
lnoil_p	-0.0289	-0.3166	-0.3103	-0.2913	0.0315	0.1666	0.0777	-0.2118	-0.1131	0.0460	1.0000									
lngas_p	0.0708	-0.0017	-0.0331	-0.0444	0.0583	0.0216	0.0106	0.0936	0.0405	0.0077	0.5449	1.0000								
lncarb_p	0.1692	0.3261	0.2889	0.2575	-0.0355	-0.1710	-0.0771	0.3677	0.2702	-0.0548	-0.3156	0.1574	1.0000							
gasflare_share	0.1165	-0.0075	-0.0002	0.0050	-0.0774	0.0104	0.0782	-0.1314	0.0209	-0.0071	0.0478	-0.0092	-0.0809	1.0000						
time	0.0089	-0.3557	-0.3269	-0.2950	0.0412	0.1843	0.0627	-0.2377	-0.1097	0.0252	0.6842	0.3309	-0.3549	0.0207	1.0000					
start_year	-0.0775	0.4247	0.3804	0.3440	0.0156	-0.0766	-0.0298	-0.3125	0.2784	0.0276	0.0633	0.1111	0.0688	0.0056	0.1109	1.0000				
d_elect	-0.1719	0.2743	0.2977	0.2967	0.2132	-0.1042	-0.0363	0.2803	0.3076	-0.0137	-0.0360	0.0592	0.1341	-0.0251	-0.0229	0.1498	1.0000			
d_gasfield	-0.4751	-0.0512	-0.0482	-0.0426	0.7372	-0.1475	0.0502	-0.1589	-0.5545	-0.0449	0.0495	0.0112	-0.0865	-0.0596	0.0579	-0.1316	0.0254	1.0000		
d_confield	-0.2333	-0.0217	-0.0551	-0.0679	0.2275	0.0975	-0.0689	-0.0859	-0.0452	-0.0112	0.1044	-0.0068	-0.1890	-0.0238	0.1075	0.1613	-0.0449	-0.1305	1.0000	
d_ukfield	-0.2269	-0.4390	-0.3928	-0.3518	0.0416	0.2269	0.1249	-0.4957	-0.3600	0.0725	0.4343	-0.1422	-0.7437	0.1109	0.4212	-0.1025	-0.1806	0.1092	0.2487	1.0000

Table B 3. Alternative 2: Correlation matrix for variables in linear form (obs=1483)

	em_int	prod_share	prod_share^2	prod_share^3	gasres_share	gasprod_share	w_inject	res_size	w_depth	water	oil_p	gas_p	carb_p	gasflare_share	time	start_year	d_elect	d_gasfield	d_confield	d_ukfield
em_int	1.0000																			
prod_share	-0.2408	1.0000																		
prod_s2	-0.2021	0.9608	1.0000																	
prod_s3	-0.1795	0.9029	0.9849	1.0000																
gasres_share	-0.3660	0.0864	0.0772	0.0726	1.0000															
gasprod_share	0.0646	-0.1176	-0.1296	-0.1240	-0.3479	1.0000														
w_inject	0.2429	-0.1178	-0.0943	-0.0809	-0.0653	0.0508	1.0000													
res_size	-0.0796	0.2919	0.2841	0.2651	0.0401	-0.0483	-0.0758	1.0000												
w_depth	0.0603	0.3232	0.3143	0.2941	-0.1568	-0.0941	-0.0540	0.3092	1.0000											
water	-0.0328	-0.0349	-0.0446	-0.0431	0.0099	0.0201	-0.0130	-0.0217	0.0086	1.0000										
oil_p	0.0682	-0.2820	-0.2729	-0.2547	0.0695	0.1466	0.0640	-0.1664	-0.0840	0.0421	1.0000									
gas_p	0.1096	-0.0008	-0.0319	-0.0447	0.0193	0.0200	-0.0025	0.0687	0.1478	-0.0018	0.6798	1.0000								
carb_p	0.0412	0.3899	0.3397	0.2979	-0.1044	-0.1886	-0.0964	0.3456	0.3493	-0.0597	-0.3624	0.2594	1.0000							
gasflare_share	0.1442	-0.0088	-0.0020	0.0026	-0.0896	0.0125	0.0810	-0.0543	-0.0016	-0.0060	0.0339	-0.0268	-0.0862	1.0000						
time	0.1104	-0.3233	-0.2896	-0.2570	0.0860	0.1697	0.0536	-0.1860	-0.0830	0.0217	0.6147	0.3588	-0.4689	0.0150	1.0000					
start_year	-0.0755	0.4331	0.3948	0.3601	0.0565	-0.0821	-0.0353	-0.1315	0.2737	0.0238	0.0636	0.1287	0.0593	0.0001	0.1263	1.0000				
d_elect	-0.1117	0.2858	0.3041	0.2983	0.2045	-0.0956	-0.0381	0.5899	0.4974	-0.0149	-0.0117	0.1222	0.1929	-0.0267	-0.0011	0.1809	1.0000			
d_gasfield	-0.1658	0.0064	-0.0271	-0.0422	0.1932	0.0733	-0.0681	-0.1036	-0.0917	-0.0073	0.0932	-0.0470	-0.2167	-0.0231	0.0927	0.1713	-0.0503	1.0000		
d_confield	-0.2823	-0.0421	-0.0352	-0.0263	0.7789	-0.1454	0.0127	-0.1409	-0.2794	-0.0521	0.0832	-0.0123	-0.1630	-0.0735	0.1075	-0.0705	0.0735	-0.1594	1.0000	
d_ukfield	-0.0714	-0.4182	-0.3728	-0.3319	0.1141	0.2060	0.1096	-0.3748	-0.3785	0.0661	0.3952	-0.2312	-0.9182	0.0988	0.4182	-0.0870	-0.2083	0.2414	0.1705	1.0000

Table B 4. Alternative 2: Correlation matrix for variables in logarithmic form (obs=1483)

	lnem_int	prod_share	prod_share^2	prod_share^3	gasres_share	gasprod_share	w_inject	lnres	lnw_depth	water	lnoil_p	lngas_p	lncarb_p	gasflare_share	time	start_year	d_elect	d_gasfield	d_confield	d_ukfield
lnem_int	1.0000																			
prod_share	-0.1126	1.0000																		
prod_s2	-0.0996	0.9606	1.0000																	
prod_s3	-0.0965	0.9025	0.9848	1.0000																
gasres_share	-0.5661	0.0901	0.0768	0.0704	1.0000															
gasprod_share	0.0455	-0.1201	-0.1309	-0.1245	-0.3500	1.0000														
w_inject	0.1342	-0.1190	-0.0949	-0.0812	-0.0617	0.0513	1.0000													
lnres	0.1827	0.2327	0.1995	0.1731	-0.0876	-0.0444	-0.0978	1.0000												
lnw_depth	0.4237	0.2520	0.2485	0.2308	-0.4370	-0.0538	-0.0640	0.4121	1.0000											
water	-0.0024	-0.0352	-0.0448	-0.0433	0.0121	0.0203	-0.0133	0.0130	0.0418	1.0000										
lnoil_p	-0.0959	-0.3015	-0.2949	-0.2761	0.0681	0.1541	0.0708	-0.2205	-0.1324	0.0433	1.0000									
lngas_p	0.0280	-0.0010	-0.0325	-0.0440	0.0604	0.0208	0.0092	0.0893	0.0375	0.0072	0.5479	1.0000								
lncarb_p	0.1936	0.3040	0.2676	0.2368	-0.0792	-0.1575	-0.0694	0.3765	0.2956	-0.0500	-0.3129	0.1565	1.0000							
gasflare_share	0.0964	-0.0088	-0.0016	0.0032	-0.0876	0.0127	0.0805	-0.1175	0.0333	-0.0062	0.0430	-0.0095	-0.0728	1.0000						
time	-0.0484	-0.3276	-0.2967	-0.2651	0.0732	0.1716	0.0563	-0.2440	-0.1243	0.0229	0.6738	0.3247	-0.3547	0.0168	1.0000					
start_year	-0.1015	0.4290	0.3896	0.3546	0.0464	-0.0831	-0.0335	-0.3214	0.2412	0.0249	0.0712	0.1080	0.0496	0.0016	0.1226	1.0000				
d_elect	-0.0877	0.2725	0.2926	0.2886	0.1918	-0.0978	-0.0356	0.2811	0.3113	-0.0137	-0.0266	0.0706	0.1421	-0.0247	-0.0132	0.1556	1.0000			
d_gasfield	-0.1380	0.0066	-0.0267	-0.0417	0.2023	0.0740	-0.0691	-0.0865	-0.0225	-0.0077	0.1047	-0.0082	-0.1732	-0.0239	0.0965	0.1752	-0.0470	1.0000		
d_confield	-0.5626	-0.0437	-0.0413	-0.0340	0.7711	-0.1441	0.0190	-0.2182	-0.6097	-0.0508	0.0842	0.0193	-0.1283	-0.0709	0.0920	-0.0888	0.0331	-0.1557	1.0000	
d_ukfield	-0.2742	-0.4133	-0.3688	-0.3286	0.1119	0.2063	0.1110	-0.5128	-0.4005	0.0668	0.4368	-0.1379	-0.7331	0.1000	0.4195	-0.0820	-0.1925	0.2441	0.1713	1.0000

B.1.2 Descriptives

Table B. 1. Alternative 2: Summary statistics with 1483 observations. Emission intensities with values less than 1 kg CO_2 per toe is replaced with the value of 1. Emission intensities above 1800 kg CO_2 per toe with production share values near zero are excluded.

Variable Name	Unit	St. Dev	Mean	Min	Max	N
em_int	Kg CO_2 per toe	98.13	76.59	1	1590.62	1484
prod_share	Share	0.30	0.32	0	1	1510
gasres_share	Share	0.28	0.19	0	1	1510
gasprod_share	Share	0.26	0.14	0	1	1510
gasflare_share	Ratio	0.39	0.41	0	1	1862
res_size	mSm^3oe	0.32	-0.09	-1	0.90	1846
w_inject	Ratio	22.46	3.79	0	496.11	1493
w_depth	Meter (m)	216.18	107.79	0.57	1762	1862
w_prod	Ratio	0.03	0.01	0	0.57	1483
oil_p	USD in 2015 per barrel	128.79	142.07	18	950	1862
gas_p	USD in 2015 per Sm^3 gas	19.60	1.93	0	333.58	1498
carb_p	USD in 2015 prices per tonnes CO_2	28.30	78.37	17.77	112.06	1862
time	Year	78.01	235.32	5.34	422.41	1862
start_year	Year	24.81	36.24	1.01	77.43	1862
d_elect	1 or 0	4.79	0.04	1	19	1862
d_gasfield	1 or 0	11.40	1993	1967	2015	1862
d_confield	1 or 0	0.20	0.04	0	1	1862
d_ukfield	1 or 0	0.42	0.23	0	1	1862
em_int	Kg CO_2 per toe	0.26	0.07	0	1	1862
prod_share	Share	0.50	0.55	0	1	1862

Table B. 2. Alternative 1: Initial summary statistics with 1488 observations.

Variable name	Unit	St.dev	Mean	Min	Max	N
em_int	Kg CO_2 per toe	139.16	81.50	0	2472.52	1488
prod_share	Share	0.30	0.31	0	1	1514
gasres_share	Share	0.39	0.41	0	1	1866
gasprod_share	Share	.32	-0.09	-1	0.90	1850
gasflare_share	Ratio	22.43	3.79	0	496.11	1497
res_size	mSm^3oe	215.97	107.68	0.57	1762	1866
w_inject	Ratio	2.94	0.67	0	56.85	1487
w_depth	Meter (m)	128.80	142.10	18	950	1866
w_prod	Ratio	19.58	1.93	0	333.58	1502
oil_p	USD in 2015 per barrel	28.31	78.36	17.77	112.06	1866
gas_p	USD in 2015 per Sm^3 gas	78.06	235.31	5.34	422.41	1866
carb_p	USD in 2015 prices per tonnes CO_2	24.84	36.25	1.01	77.43	1866
time	Year	4.80	12.48	1	19	1866
start_year	Year	11.39	1994	1967	2015	1866
d_elect	1 or 0	0.20	0.04	0	1	1866
d_gasfield	1 or 0	0.42	0.23	0	1	1866
d_confield	1 or 0	0.26	0.07	0	1	1866
d_ukfield	1 or 0	0.50	0.55	0	1	1866

Table B. 3. Alternative 2: Initial summary statistics with 1488 observations.

Variable Name	Unit	St. Dev	Mean	Min	Max	N
em_int	Kg CO_2 per toe	139.12	81.56	1	2472.52	1488
prod_share	Share	0.30	0.31	0	1	1514
gasres_share	Share	0.39	0.41	0	1	1866
gasprod_share	Share	0.32	-0.09	-1	0.90	1850
gasflare_share	Ratio	22.43	3.79	0	496.11	1497
res_size	mSm^3oe	215.97	107.68	0.57	1762	1866
w_inject	Ratio	2.94	0.67	0	56.85	1487
w_depth	Meter (m)	128.80	142.10	18	950	1866
w_prod	Ratio	19.58	1.93	0	333.58	1502
oil_p	USD in 2015 per barrel	28.31	78.36	17.77	112.06	1866
gas_p	USD in 2015 per Sm^3 gas	78.06	235.31	5.34	422.41	1866
carb_p	USD in 2015 prices per tonnes CO_2	24.84	36.25	1.01	77.43	1866
time	Year	4.80	12.48	1	19	1866
start_year	Year	11.39	1993.51	1967	2015	1866
d_elect	1 or 0	0.20	0.041	0	1	1866
d_gasfield	1 or 0	0.42	0.23	0	1	1866
d_confield	1 or 0	0.26	0.07	0	1	1866
d_ukfield	1 or 0	0.50	0.55	0	1	1866

Appendix C

C.1 Original model regressions with Alt. 1.

Table C.1. Comparing of regression models where em_int <1 is dropped.

Variable name	RE model	FE model	MLE model	RE AR(1) model	FE AR(1) model
prod_share	-4.61***	-4.95***	-4.62***	-4.61***	-4.95***
	(0.92 / 0.00)	(1.02 / 0.00)	(0.63 / 0.00)	(0.70 / 0.00)	(0.80 / 0.00)
prod_share^2	4.68**	4.85**	4.69***	4.68***	4.85***
	(1.87 / 0.01)	(1.99 / 0.02)	(1.41 / 0.00)	(1.56 / 0.00)	(1.71 / 0.00)
prod_share^3	-1.97*	-1.94*	-1.97**	-1.97**	-1.94**
	(1.11 / 0.08)	(1.17 / 0.10)	(0.92 / 0.03)	(0.99 / 0.03)	(1.08 / 0.04)
gasres_share	-0.75**		-0.75**	-0.75**	
	(0.34 /0.03)		(0.35 / 0.03)	(0.32 / 0.05)	
gasprod_share	-0.19	-0.10	-0.18	-0.19	-0.10
	(0.21 / 0.38)	(0.24 /0.68)	(0.15 / 0.21)	(0.15 / 0.20)	(0.15 / 0.52)
gasflare_share	0.00	0.00	0.00**	0.00**	0.00
	(0.00 / 0.24)	(0.00 / 0.35)	(0.00 / 0.03)	(0.00 / 0.03)	(0.00/ 0.18)
lnres_size	-0.09		-0.09	-0.09	
	(0.07/ 0.18)		(0.06 / 0.15)	(0.06 / 0.11)	
lnw_depth	0.34***		0.35**	0.34**	
	(0.13 / 0.01)		(0.15 / 0.02)	(0.15 / 0.02)	
w_prod	0.00	0.01***	0.00	0.00	0.00
	(0.00 / 0.48)	(0.00 / 0.00)	(0.00 / 0.76)	(0.00 / 0.79)	(0.00 / 0.17)
w_inject	4.26***	3.77**	4.24***	4.26***	3.77***
	(1.46 / 0.00)	(1.50 / 0.01)	(0.79 / 0.00)	(0.80 / 0.00)	(0.84 / 0.00)
lngas_p	-0.05	-0.10	-0.05	-0.05	-0.10
	(0.13 / 0.69)	(0.13 / 0.43)	(0.10 / 0.59)	(0.09 / 0.61)	(0.11 / 0.33)
lnoil_p	0.07	0.10	0.07	0.07	0.10
	(0.11 / 0.53)	(0.12 / 0.38)	(0.09 / 0.40)	(0.09 / 0.41)	(0.09 / 0.26)
lncarb_p	-0.02	-0.02	-0.02	-0.02	-0.02
	(0.02 / 0.35)	(0.02 / 0.38)	(0.02 / 0.31)	(0.02 / 0.31)	(0.02 / 0.33)
time	0.01*	0.01	0.01**	0.01**	0.01*
	(0.01 / 0.10)	(0.01 / 0.29)	(0.01 / 0.02)	(0.01 / 0.02)	(0.01 / 0.10)
d_elect	-1.21***		-1.21**	-1.21**	
	(0.41 / 0.00)		(0.55 / 0.03)	(0.54 / 0.02)	
d_ukfield	-1.01***		-1.01***	-1.01***	
	(0.17 / 0.00)		(0.19 / 0.00)	(0.18 / 0.00)	
start_year	0.01		0.01	0.01	
	(0.01 / 0.45)		(0.01 / 0.46)	(0.01 / 0.46)	
d_confield	-0.81**		-0.81***	-0.81***	
	(0.35 / 0.02)		(0.31 / 0.01)	(0.31 / 0.01)	
d_gasfield	-1.10***		-1.10***	-1.10***	
	(0.39 / 0.00)		(0.35 / 0.00)	(0.35 / 0.00)	
Constant	-7.23	4.76***	-7.60	-7.23	4.76***
	(15.03/ 0.63)	(0.42 / 0.00)	(15.87 / 0.63)	(15.59 / 0.64)	(0.31 / 0.00)
Observations	1,365	1,365	1,365	1,365	1,222
Number of id	143	143	143	143	143
R^2	0.501	0.048		0.501	0.048
Sigma_u	0.760	0.980	0.783	0.760	0.980
Sigma_e	0.522	0.522	0.521	0.522	0.522
Rho	0.680	0.879	0.694	0.680	0.879

Notes: * p<0.1; ** p<0.05; *** p<0.01; robust st.errors & p-values in parentheses.

Table C. 2. Comparing the original model with/without production share, water production and water injection

Variables	Original model	Models with RE estimator						
prod_share	-4.61***	-4.70***	-4.60***	-4.70***				
	(0.00)	(0.00)	(0.00)	(0.00)				
prod_share^2	4.68**	4.78**	4.67**	4.77**				
	(0.01)	(0.01)	(0.01)	(0.01)				
prod_share^3	-1.97*	-2.01*	-1.97*	-2.01*				
	(0.08)	(0.08)	(0.08)	(0.08)				
gasres_share	-0.75**	-0.79**	-0.74**	-0.78**	-0.83**	-0.88**	-0.82**	-0.87**
	(0.03)	(0.02)	(0.03)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)
gasprod_share	-0.19	-0.15	-0.19	-0.15	-0.52*	-0.48	-0.52*	-0.48
	(0.38)	(0.55)	(0.38)	(0.55)	(0.06)	(0.12)	(0.06)	(0.12)
gasflare_share	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.25)	(0.24)	(0.25)
lnres_size	-0.09	-0.09	-0.09	-0.09	-0.21***	-0.21***	-0.21***	-0.21***
	(0.17)	(0.18)	(0.17)	(0.18)	(0.00)	(0.00)	(0.00)	(0.00)
lnw_depth	0.34***	0.34**	0.35***	0.34***	0.38***	0.37***	0.38***	0.37***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)	(0.00)	(0.00)
w_prod	0.00	0.00			0.00	0.00		
	(0.48)	(0.37)			(0.53)	(0.44)		
w_inject	4.26***		4.27***		4.98***		4.99***	
	(0.00)		(0.00)		(0.01)		(0.01)	
lnoil_p	0.07	0.07	0.07	0.07	0.15	0.15	0.15	0.15
	(0.53)	(0.54)	(0.53)	(0.54)	(0.21)	(0.22)	(0.21)	(0.22)
lngas_p	-0.05	-0.05	-0.05	-0.05	-0.10	-0.10	-0.10	-0.10
	(0.69)	(0.69)	(0.70)	(0.70)	(0.45)	(0.43)	(0.45)	(0.43)
lncarb_p	-0.02	-0.02	-0.02	-0.02	-0.02	-0.01	-0.02	-0.01
	(0.35)	(0.44)	(0.35)	(0.44)	(0.49)	(0.60)	(0.48)	(0.60)
time	0.01*	0.01	0.01*	0.01	0.06***	0.06***	0.06***	0.06***
	(0.10)	(0.11)	(0.10)	(0.11)	(0.00)	(0.00)	(0.00)	(0.00)
start_year	0.01	0.01	0.01	0.01	-0.03***	-0.03***	-0.03***	-0.03***
	(0.45)	(0.41)	(0.44)	(0.40)	(0.00)	(0.00)	(0.00)	(0.00)
d_confield	-0.81**	-0.84**	-0.81**	-0.85**	-0.78**	-0.82**	-0.79**	-0.83**
	(0.02)	(0.02)	(0.02)	(0.01)	(0.04)	(0.03)	(0.03)	(0.02)
d_gasfield	-1.10***	-1.08***	-1.11***	-1.09***	-1.23***	-1.21***	-1.24***	-1.22***
	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
d_ukfield	-1.01***	-0.98***	-1.01***	-0.98***	-0.91***	-0.87***	-0.91***	-0.87***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
d_elect	-1.21***	-1.19***	-1.22***	-1.20***	-1.39***	-1.37***	-1.40***	-1.38***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Constant	-7.23	-8.51	-7.32	-8.63	68.29***	68.44***	68.15***	68.27***
	(0.63)	(0.58)	(0.63)	(0.58)	(0.00)	(0.00)	(0.00)	(0.00)
No. of observations	1,365	569	1,365	1,366	1,365	1,366	1,365	1,366
No. of observation unites	143	43	143	143	143	143	143	143

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 3. Original model: Comparing RE models for UKCS and NCS with/without water production and water injection

Variables	Models with RE estimator					
	UKCS			NCS		
prod_share	-3.69***	-3.70***	-3.85***	-5.29***	-4.76***	-4.82***
	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)
$prod\_share^2$	3.37	3.40	3.54	6.29**	5.13**	4.96*
	(0.30)	(0.30)	(0.28)	(0.01)	(0.04)	(0.07)
$prod\_share^3$	-1.73	-1.75	-1.81	-2.81**	-2.13	-1.95
	(0.42)	(0.41)	(0.40)	(0.04)	(0.14)	(0.20)
gasres_share	-0.20	-0.24	-0.27	-0.16	-0.33	-0.45
	(0.64)	(0.57)	(0.55)	(0.77)	(0.54)	(0.42)
gasprod_share	-0.04	-0.05	0.05	-0.26	-0.27	-0.31
	(0.91)	(0.89)	(0.91)	(0.31)	(0.28)	(0.22)
gasflare_share	0.00	0.00	0.00	0.00	0.00	0.00
	(0.24)	(0.24)	(0.23)	(0.21)	(0.21)	(0.20)
lnw_depth	0.28	0.27	0.27	-0.13	-0.11	-0.12
	(0.20)	(0.21)	(0.24)	(0.58)	(0.62)	(0.60)
w_inject	4.22***	4.22***		14.31***	19.65***	
	(0.00)	(0.00)		(0.01)	(0.01)	
w_prod	-0.00			0.32***		
	(0.33)			(0.00)		
lnres_size	-0.17*	-0.17*	-0.17*	0.06	0.07	0.06
	(0.05)	(0.05)	(0.06)	(0.53)	(0.50)	(0.55)
time	0.02	0.02	0.02	0.01	0.01	0.01
	(0.11)	(0.11)	(0.13)	(0.40)	(0.25)	(0.21)
d_confield	-1.22***	-1.20***	-1.24***	0.00	0.00	0.00
	(0.00)	(0.00)	(0.00)	(.)	(.)	(.)
d_gasfield	-2.00***	-1.97***	-1.94***	-0.43	-0.42	-0.40
	(0.00)	(0.00)	(0.00)	(0.33)	(0.34)	(0.36)
d_elect	0.00	0.00	0.00	-1.45***	-1.41***	-1.37***
	(.)	(.)	(.)	(0.00)	(0.00)	(0.01)
lnoil_p	0.12	0.12	0.12	0.06	0.06	0.03
	(0.41)	(0.41)	(0.42)	(0.60)	(0.58)	(0.75)
lngas_p	-0.03	-0.03	-0.04	-0.04	-0.02	0.04
	(0.84)	(0.83)	(0.81)	(0.75)	(0.88)	(0.78)
lncarb_p	-0.02	-0.02	-0.01	-0.07	-0.09	-0.09
	(0.43)	(0.43)	(0.53)	(0.45)	(0.36)	(0.40)
start_year	0.00	0.00	0.01	0.02	0.02	0.02
	(0.63)	(0.64)	(0.57)	(0.17)	(0.22)	(0.23)
Constant	-6.06	-5.69	-7.73	-35.15	-30.74	-30.69
	(0.75)	(0.77)	(0.70)	(0.23)	(0.29)	(0.30)
No. of observations	797	797	797	568	568	569
No. of observation unites	100	100	100	43	43	43

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 4. Original model: comparing original model with models with lagged prices (RE estimates)

Variable name	Original model	Models with lagged prices					
		UKCS and NCS together	UKCS	NCS	UKCS and NCS together	UKCS	NCS
prod_share	-4.61***	-5.06***	-4.44***	-5.74***			
	(0.00)	(0.00)	(0.00)	(0.00)			
prod_share^2	4.68**	5.62***	4.66	7.27***			
	(0.01)	(0.00)	(0.16)	(0.01)			
prod_share^3	-1.97*	-2.54**	-2.45	-3.38**			
	(0.08)	(0.02)	(0.25)	(0.02)			
gasres_share	-0.75**	-0.68**	-0.15	-0.15	-0.75**	-0.04	-0.01
	(0.03)	(0.05)	(0.74)	(0.77)	(0.03)	(0.93)	(0.98)
gasprod_share	-0.19	-0.19	0.03	-0.29	-0.49*	-0.18	-0.55*
	(0.38)	(0.39)	(0.94)	(0.23)	(0.06)	(0.64)	(0.09)
gasflare_share	0.00	0.00	0.00	0.06**	0.00	0.00	0.07***
	(0.24)	(0.21)	(0.23)	(0.01)	(0.25)	(0.24)	(0.00)
lnw_depth	0.34***	0.35***	0.32	-0.12	0.39***	0.27	0.04
	(0.01)	(0.01)	(0.12)	(0.60)	(0.00)	(0.17)	(0.87)
w_prod	0.00	0.00	-0.00	0.30**	0.00	-0.00	0.28**
	(0.48)	(0.28)	(0.56)	(0.02)	(0.28)	(0.46)	(0.04)
w_inject	4.26***	4.77***	4.60***	14.00***	5.15***	4.89***	23.13***
	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)	(0.00)	(0.00)
lnres_size	-0.09	-0.09	-0.16*	0.04	-0.21***	-0.22***	-0.18**
	(0.17)	(0.17)	(0.06)	(0.69)	(0.00)	(0.00)	(0.04)
lnoil_p	0.07						
	(0.53)						
lngas_p	-0.05						
	(0.69)						
lncarb_p	-0.02						
	(0.35)						
time	0.01*	0.01	0.02	0.01	0.06***	0.06***	0.05***
	(0.10)	(0.19)	(0.15)	(0.22)	(0.00)	(0.00)	(0.00)
start_year	0.01	0.01	0.01	0.01	-0.03***	-0.03***	-0.04***
	(0.45)	(0.48)	(0.54)	(0.31)	(0.00)	(0.00)	(0.00)
d_confield	-0.81**	-0.83**	-1.20***	0.00	-0.77**	-1.28***	0.00
	(0.02)	(0.03)	(0.00)	(.)	(0.05)	(0.00)	(.)
d_gasfield	-1.10***	-1.08***	-1.88***	-0.41	-1.20***	-2.32***	-0.32
	(0.00)	(0.00)	(0.00)	(0.32)	(0.00)	(0.00)	(0.41)
d_ukfield	-1.01***	-0.93***			-0.83***	0.00	0.00
	(0.00)	(0.00)			(0.00)	(.)	(.)
d_elect	-1.21***	-1.20***	0.00	-1.32***	-1.40***	0.00	-1.38***
	(0.00)	(0.00)	(.)	(0.00)	(0.00)	(.)	(0.00)
lagged_lngas_ price		-0.09	0.03	0.01	-0.15	-0.07	-0.01
		(0.44)	(0.84)	(0.93)	(0.25)	(0.68)	(0.94)
lagged_lncarb _price		0.03	0.03	0.02	0.03	0.03	-0.02
		(0.16)	(0.24)	(0.81)	(0.19)	(0.21)	(0.86)
lagged_lnoil_ price		0.04	-0.20	-0.03	0.11	0.02	-0.02
		(0.80)	(0.43)	(0.74)	(0.44)	(0.95)	(0.86)
Constant	-7.23	-6.54	-8.40	-23.62	69.66***	57.11***	76.64***
	(0.63)	(0.68)	(0.68)	(0.41)	(0.00)	(0.00)	(0.00)
No. of observations	1,365	1,241	698	543	1,241	698	543
No. of observation unites	143	138	95	43	138	95	43

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 5. Original model: comparing original model with models with smoothed prices (RE estimates)

Variable name	Original model	Models with smoothed prices					
		UKCS and NCS together	UKCS	NCS	UKCS and NCS together	UKCS	NCS
prod_share	-4.61***	-4.44***	-3.94***	-5.37***			
	(0.00)	(0.00)	(0.00)	(0.00)			
prod_share^2	4.68**	4.37**	4.09	6.33**			
	(0.01)	(0.02)	(0.21)	(0.01)			
prod_share^3	-1.97*	-1.82	-2.24	-2.77**			
	(0.08)	(0.10)	(0.29)	(0.05)			
gasres_share	-0.75**	-0.66*	-0.21	-0.04	-0.82**	-0.17	-0.00
	(0.03)	(0.06)	(0.62)	(0.94)	(0.02)	(0.66)	(1.00)
gasprod_share	-0.19	-0.15	-0.05	-0.22	-0.49*	-0.28	-0.51
	(0.38)	(0.48)	(0.90)	(0.40)	(0.07)	(0.45)	(0.15)
gasflare_share	0.00	0.00	0.00	0.07***	0.00	0.00	0.07***
	(0.24)	(0.22)	(0.22)	(0.01)	(0.19)	(0.17)	(0.00)
lnres_size	-0.09	-0.10	-0.15*	0.04	-0.20***	-0.21***	-0.16*
	(0.17)	(0.15)	(0.07)	(0.69)	(0.00)	(0.00)	(0.10)
lnw_depth	0.34***	0.34***	0.26	-0.15	0.38***	0.20	0.01
	(0.01)	(0.01)	(0.22)	(0.52)	(0.00)	(0.31)	(0.95)
w_prod	0.00	0.00	-0.00	0.31***	0.00	-0.00	0.33**
	(0.48)	(0.49)	(0.34)	(0.01)	(0.51)	(0.37)	(0.01)
w_inject	4.26***	4.20***	4.12***	13.71**	4.90***	4.66***	23.44***
	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)	(0.00)	(0.00)
lnoil_p	0.07						
	(0.53)						
lngas_p	-0.05						
	(0.69)						
lncarb_p	-0.02						
	(0.35)						
time	0.01*	0.02**	0.03*	0.01	0.07***	0.07***	0.04***
	(0.10)	(0.03)	(0.08)	(0.41)	(0.00)	(0.00)	(0.00)
start_year	0.01	0.00	0.01	0.02	-0.03***	-0.03***	-0.03***
	(0.45)	(0.53)	(0.55)	(0.30)	(0.00)	(0.00)	(0.01)
d_confield	-0.81**	-0.85**	-1.20***	0.00	-0.78**	-1.28***	0.00
	(0.02)	(0.02)	(0.00)	(.)	(0.04)	(0.00)	(.)
d_gasfield	-1.10***	-1.19***	-1.97***	-0.48	-1.24***	-2.37***	-0.31
	(0.00)	(0.00)	(0.00)	(0.28)	(0.00)	(0.00)	(0.46)
d_ukfield	-1.01***	-0.90***			-0.60**	0.00	0.00
	(0.00)	(0.00)			(0.01)	(.)	(.)
d_elect	-1.21***	-1.20***	0.00	-1.37***	-1.38***	0.00	-1.44***
	(0.00)	(0.00)	(.)	(0.00)	(0.00)	(.)	(0.00)
smlnoil		-0.03	-0.32	-0.11	-0.03	-0.33	0.12
		(0.78)	(0.48)	(0.79)	(0.81)	(0.49)	(0.81)
smlngas		-0.12	-0.07	0.18	-0.08	-0.04	-0.04
		(0.13)	(0.45)	(0.74)	(0.44)	(0.68)	(0.95)
smlncarb		0.06	0.08	0.01	0.14	0.17*	0.02
		(0.46)	(0.32)	(0.97)	(0.12)	(0.07)	(0.95)
Constant	-7.23	-4.72	-6.45	-26.77	68.23***	57.80***	68.13***
	(0.63)	(0.75)	(0.74)	(0.37)	(0.00)	(0.00)	(0.01)
No. of observations	1,365	1,363	797	566	1,363	797	566
No. of observation unites	143	142	100	42	142	100	42

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C.6. Original model: Comparing the original model with models allowing for heterogeneous CO_2-price effects between UK and Norway (RE estimates)

Variable name	Original model	Models with heterogeneous CO_2-price effects			
prod_share	-4.61***	-4.61***	-4.57***		
	(0.00)	(0.00)	(0.00)		
prod_share^2	4.68**	4.70**	4.58**		
	(0.01)	(0.01)	(0.01)		
prod_share^3	-1.97*	-1.99*	-1.90*		
	(0.08)	(0.07)	(0.09)		
gasres_share	-0.75**	-0.74**	-0.73**	-0.82**	-0.81**
	(0.03)	(0.03)	(0.03)	(0.02)	(0.02)
gasprod_share	-0.19	-0.19	-0.20	-0.52*	-0.53*
	(0.38)	(0.38)	(0.35)	(0.06)	(0.05)
gasflare_share	0.00	0.00	0.00	0.00	0.00
	(0.24)	(0.24)	(0.25)	(0.24)	(0.24)
lnw_depth	0.34***	0.34***	0.36***	0.38***	0.39***
	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)
w_prod	0.00	0.00	0.00	0.00	0.00
	(0.48)	(0.49)	(0.57)	(0.53)	(0.60)
w_inject	4.26***	4.26***	4.25***	4.98***	4.97***
	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)
lnres_size	-0.09	-0.09	-0.08	-0.21***	-0.19***
	(0.17)	(0.17)	(0.24)	(0.00)	(0.00)
lnoil_p	0.07	0.07	0.06	0.14	0.14
	(0.53)	(0.54)	(0.57)	(0.22)	(0.23)
lngas_p	-0.05	-0.05	-0.04	-0.10	-0.09
	(0.69)	(0.69)	(0.76)	(0.45)	(0.50)
lncarb_p	-0.02	-0.10	0.20***	-0.11	0.18***
	(0.35)	(0.31)	(0.00)	(0.39)	(0.00)
time	0.01*	0.01*	0.01	0.06***	0.06***
	(0.10)	(0.09)	(0.11)	(0.00)	(0.00)
start_year	0.01	0.01	0.01	-0.03***	-0.03***
	(0.45)	(0.45)	(0.36)	(0.00)	(0.00)
d_confield	-0.81**	-0.81**	-0.85**	-0.78**	-0.82**
	(0.02)	(0.02)	(0.01)	(0.04)	(0.03)
d_gasfield	-1.10***	-1.11***	-1.12***	-1.24***	-1.24***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
d_ukfield	-1.01***	-1.35***		-1.32**	
	(0.00)	(0.00)		(0.03)	
d_elect	-1.21***	-1.22***	-1.22***	-1.39***	-1.39***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
lnpcarb_new		0.08	-0.22***	0.10	-0.20***
		(0.41)	(0.00)	(0.46)	(0.00)
Constant	-7.23	-6.66	-10.59	68.87***	65.29***
	(0.63)	(0.66)	(0.48)	(0.00)	(0.00)
No. of observations	1,365	1,365	1,365	1,365	1,365
No. of observation unites	143	143	143	143	143

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

C.2 Original model regressions with Alt. 2.

Table C. 7. Comparing the Original model with different estimators (Alt. 2)

Variables	**RE**	**FE**	**MLE**	**AR (1) RE**	**AR (1) FE**
prod_share	-4.20***	-4.62***	-4.21***	-4.20***	-4.62***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
prod_share^2	4.72*	4.93*	4.72*	4.72*	4.93*
	(0.10)	(0.09)	(0.07)	(0.08)	(0.07)
prod_share^3	-2.31	-2.26	-2.30	-2.31	-2.26
	(0.20)	(0.21)	(0.18)	(0.18)	(0.20)
gasres_share	-1.31**		-1.31**	-1.31**	
	(0.02)		(0.04)	(0.04)	
gasprod_share	-0.26	-0.22	-0.26	-0.26	-0.22
	(0.24)	(0.43)	(0.34)	(0.34)	(0.45)
gasflare_share	0.00	0.00	0.00	0.00	0.00
	(0.21)	(0.29)	(0.16)	(0.16)	(0.38)
lnres_size	-0.14**		-0.09	-0.09	
	(0.04)		(0.46)	(0.45)	
lnw_depth	0.48**		0.48*	0.48*	
	(0.01)		(0.09)	(0.08)	
w_prod	0.00	0.01***	0.00	0.00	0.01
	(0.15)	(0.00)	(0.75)	(0.76)	(0.45)
w_inject	5.15***	4.23**	5.13***	5.15***	4.23***
	(0.00)	(0.04)	(0.00)	(0.00)	(0.01)
lnoil_p	0.07	0.15	0.07	0.07	0.15
	(0.65)	(0.38)	(0.65)	(0.66)	(0.39)
lngas_p	-0.16	-0.26	-0.16	-0.16	-0.26
	(0.42)	(0.25)	(0.37)	(0.38)	(0.21)
lncarb_p	0.02	0.03	0.02	0.02	0.03
	(0.73)	(0.63)	(0.61)	(0.62)	(0.48)
time	0.03*	0.02	0.03***	0.03***	0.02**
	(0.08)	(0.20)	(0.01)	(0.01)	(0.03)
start_year	-0.01		-0.01	-0.01	
	(0.43)		(0.44)	(0.43)	
d_confield	-0.78		-0.78	-0.78	
	(0.11)		(0.16)	(0.16)	
d_gasfield	-1.96***		-1.96***	-1.96***	
	(0.00)		(0.00)	(0.00)	
d_ukfield	-1.32***		-1.32***	-1.32***	
	(0.00)		(0.00)	(0.00)	
d_elect	-1.43**		-1.43	-1.43	
	(0.03)		(0.12)	(0.12)	
Constant	27.03	4.51***	26.75	27.03	4.51***
	(0.35)	(0.00)	(0.35)	(0.35)	(0.00)
No. of observations	1,462	1,462	1,462	1,462	1,462
No. of observation unites	147	147	147	147	147

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

C.3 Main model regressions with Alt. 1.

Table C. 8. Main model: comparing different estimators

Variable name	RE model	FE model	MLE model	RE AR(1) model	FE AR(1) model
prod_share	-4.95***	-5.20***	-4.97***	-4.91***	-5.36***
	(0.92/0.00)	(0.98/0.00)	(0.61/0.00)	(0.69/0.00)	(0.078/0.00)
prod_share^2	4.93***	5.07**	4.94***	5.43***	6.39***
	(1.89/0.01)	(1.97/0.01)	(1.40/0.00)	(1.55/0.00)	(1.70/0.00)
prod_share^3	-2.02*	-2.01*	-2.02**	-2.58***	-3.09***
	(1.13/0.07)	(1.17/0.09)	(0.91/0.03)	(0.99/0.01)	(1.08/0.00)
gasres_share	-1.70***		-1.74***	-1.73***	0.00
	(0.26/0.00)		(0.22/0.00)	(0.20/0.00)	(0.00/.)
w_inject	4.20***	3.81**	4.17***	3.95***	4.06***
	(1.45/0.00)	(1.51/0.01)	(0.80/0.00)	(0.79/0.00)	(0.80/0.00)
lnw_depth	0.42***		0.42***	0.42***	0.00
	(0.16/0.01)		(0.14/0.00)	(0.13/0.00)	(0.00/.)
lnres_size	-0.14**		-0.11*	-0.11*	0.00
	(0.07/0.04)		(0.07/0.10)	(0.06/0.07)	(0.00/.)
lnoil_p	0.10	0.13	0.11	0.02	-0.15*
	(0.11/0.33)	(0.11/0.26)	(0.08/0.21)	(0.08/0.79)	(0.09/0.09)
lngas_p	-0.03	-0.09	-0.04	0.06	0.36***
	(0.13/0.79)	(0.14/0.53)	(0.10/0.70)	(0.09/0.50)	(0.09/0.00)
lncarb_p	-0.03	-0.02	-0.02	-0.03*	-0.05***
	(0.02/0.25)	(0.02/0.29)	(0.02/0.20)	(0.02/0.05)	(0.02/0.01)
d_ukfield	-1.12***		-1.08***	-1.03***	0.00
	(0.16/0.00)		(0.20/0.00)	(0.18/0.00)	(0.00/.)
Constant	4.07***	4.75***	-6.69	-5.26	3.62***
	(0.86/0.00)	(0.41/0.00)	(16.38/0.68)	(15.42/0.73)	(0.16/0.00)
No. of observations	1,365	1,365	1,365	1,365	1,222
No. of observation unites	143	143	143	143	133
R^2	0.454	0.051		0.458	0.069
Sigma_u	0.824	1.411	0.850	0.758	1.304
Sigma_e	0.522	0.522	0.521	0.506	0.476
Rho	0.713	0.880	0.727	0.444	0.444

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 9. Comparing main model with/without production share, water production and water injection

Variables	Models with RE estimator							
prod_share	-4.91***	-4.99***	-4.91***	-4.99***				
	(0.00)	(0.00)	(0.00)	(0.00)				
$prod\_share^2$	4.88***	4.96***	4.86**	4.94**				
	(0.01)	(0.01)	(0.01)	(0.01)				
$prod\_share^3$	-2.00*	-2.03*	-1.99*	-2.02*				
	(0.08)	(0.08)	(0.08)	(0.08)				
gasres_share	-1.71***	-1.74***	-1.70***	-1.74***	-2.05***	-2.10***	-2.04***	-2.09***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
lnres_size	-0.14**	-0.14**	-0.14**	-0.14**	-0.09	-0.09	-0.09	-0.09
	(0.04)	(0.03)	(0.04)	(0.04)	(0.12)	(0.12)	(0.13)	(0.12)
lnw_depth	0.45***	0.44***	0.46***	0.45***	0.26	0.24	0.26	0.25
	(0.00)	(0.00)	(0.00)	(0.00)	(0.12)	(0.14)	(0.11)	(0.13)
w_prod	0.00	0.00**			0.00	0.00		
	(0.11)	(0.03)			(0.18)	(0.14)		
w_inject	4.19***		4.20***		5.14***		5.14***	
	(0.00)		(0.00)		(0.00)		(0.00)	
lnoil_p	0.11	0.11	0.11	0.11	0.42***	0.42***	0.41***	0.42***
	(0.33)	(0.32)	(0.33)	(0.33)	(0.00)	(0.00)	(0.00)	(0.00)
lngas_p	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03
	(0.79)	(0.81)	(0.80)	(0.82)	(0.78)	(0.79)	(0.79)	(0.80)
lncarb_p	-0.03	-0.02	-0.03	-0.02	-0.04*	-0.04	-0.04*	-0.04
	(0.25)	(0.32)	(0.25)	(0.32)	(0.09)	(0.13)	(0.09)	(0.13)
d_ukfield	-1.15***	-1.13***	-1.14***	-1.12***	-0.83***	-0.79***	-0.82***	-0.78***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Constant	4.12***	4.19***	4.07***	4.14***	2.54***	2.61***	2.50***	2.57***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)
No. of observations	1,365	1,366	1,365	1,366	1,365	1,366	1,365	1,366
No. of observation unites	143	143	143	143	143	143	143	143

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses

Table C. 10. Main model: Comparing RE models for UKCS and NCS with/without production share, water production and water injection

Variables	Models with RE estimator					
	UKCS			NCS		
prod_share	-4.50***	-4.60***		-5.07***	-4.98***	
	(0.00)	(0.00)		(0.00)	(0.00)	
prod_share^2	4.30	4.40		5.21*	5.33**	
	(0.20)	(0.19)		(0.05)	(0.03)	
prod_share^3	-2.09	-2.14		-2.06	-2.21	
	(0.33)	(0.32)		(0.17)	(0.12)	
gasres_share	-1.62***	-1.68***	-1.92***	-1.13***	-1.03***	-0.53
	(0.00)	(0.00)	(0.00)	(0.00)	(0.01)	(0.16)
lnres_size	-0.20**	-0.20**	-0.09	-0.04	-0.03	-0.09
	(0.02)	(0.02)	(0.17)	(0.66)	(0.71)	(0.33)
lnw_depth	0.65***	0.63***	0.54***	-0.02	-0.02	-0.45
	(0.00)	(0.00)	(0.01)	(0.93)	(0.92)	(0.05)
w_inject	4.06***		4.75***		19.51***	26.88***
	(0.00)		(0.00)		(0.01)	(0.00)
	(0.00)	(0.00)	(0.01)	(0.93)	(0.92)	(0.05)
lnoil_p	0.09	0.09	0.21	0.07	0.10	0.34***
	(0.56)	(0.56)	(0.14)	(0.48)	(0.35)	(0.01)
lngas_p	-0.02	-0.02	-0.07	0.06	0.00	0.02
	(0.93)	(0.92)	(0.66)	(0.62)	(0.98)	(0.88)
lncarb_p	-0.02	-0.02	-0.03	-0.07	-0.07	-0.00
	(0.28)	(0.36)	(0.14)	(0.47)	(0.43)	(0.97)
w_prod			0.00			0.42***
			(0.58)			(0.00)
Constant	2.21**	2.44**	1.52	5.48***	5.59***	4.86***
	(0.03)	(0.02)	(0.19)	(0.00)	(0.00)	(0.00)
No. of observations	797	797	797	569	568	568
No. of observation unites	100	100	100	43	43	43

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 11. Main model: Comparing models with lagged prices (RE estimates)

Variable name	Models with lagged prices					
	UKCS and NCS together	**UKCS**	**NCS**	**UKCS and NCS together**	**UKCS**	**NCS**
prod_share	-5.21***	-4.61***	-5.29***			
	(0.00)	(0.00)	(0.00)			
$prod\_share^2$	5.70***	4.48	6.27**			
	(0.00)	(0.19)	(0.02)			
$prod\_share^3$	-2.54**	-2.18	-2.86*			
	(0.02)	(0.32)	(0.06)			
gasres_share	-1.64***	-1.55***	-0.97***	-1.97***	-1.79***	-0.70*
	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.06)
lnres_size	-0.13**	-0.20**	-0.03	-0.07	-0.08	-0.05
	(0.04)	(0.02)	(0.70)	(0.25)	(0.26)	(0.61)
lnw_depth	0.44***	0.66***	-0.03	0.22	0.55***	-0.44*
	(0.00)	(0.00)	(0.90)	(0.17)	(0.01)	(0.06)
w_inject	4.74***	4.58***	19.03***	5.07***	4.76***	29.77***
	(0.00)	(0.00)	(0.01)	(0.01)	(0.00)	(0.00)
d_ukfield	-1.07***			-0.84***		
	(0.00)			(0.00)		
lagged_lngas_price	-0.14	-0.06	-0.13	-0.41***	-0.46*	-0.17
	(0.26)	(0.72)	(0.13)	(0.01)	(0.08)	(0.18)
lagged_lncarb_price	0.03	0.03	-0.01	0.03	0.04	0.01
	(0.13)	(0.18)	(0.91)	(0.12)	(0.11)	(0.97)
lagged_lnoil_price	0.16	0.06	0.18*	0.76***	0.95***	0.53***
	(0.18)	(0.81)	(0.07)	(0.00)	(0.00)	(0.00)
Constant	4.27***	2.43**	5.92***	2.92***	-0.01	5.42***
	(0.00)	(0.04)	(0.00)	(0.00)	(0.99)	(0.00)
No. of observations	1,241	698	543	1,241	698	543
No. of observation unites	138	95	43	138	95	43

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 12. Main model: Comparing models with smoothed prices (RE estimates)

Variable name	Smoothed prices					
	UKCS and NCS together	UKCS	NCS	UKCS and NCS together	UKCS	NCS
prod_share	-4.71***	-4.22***	-4.89***			
	(0.00)	(0.00)	(0.00)			
prod_share^2	4.41**	3.97	5.16**			
	(0.02)	(0.23)	(0.04)			
prod_share^3	-1.73	-1.96	-2.12			
	(0.13)	(0.37)	(0.13)			
gasres_share	-1.69***	-1.63***	-0.91**	-2.05***	-1.93***	-0.75*
	(0.00)	(0.00)	(0.02)	(0.00)	(0.00)	(0.05)
lnres_size	-0.13**	-0.19**	-0.04	-0.06	-0.08	-0.04
	(0.04)	(0.02)	(0.69)	(0.27)	(0.22)	(0.69)
lnw_depth	0.46***	0.64***	-0.04	0.25	0.53**	-0.40*
	(0.00)	(0.00)	(0.86)	(0.12)	(0.01)	(0.09)
w_inject	4.16***	4.03***	20.19***	5.04***	4.60***	35.78***
	(0.01)	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)
d_ukfield	-1.06***			-0.60**		
	(0.00)			(0.05)		
smlnoil	0.21	0.22	0.19	0.87***	1.21***	1.20**
	(0.10)	(0.57)	(0.66)	(0.00)	(0.00)	(0.02)
smlngas	-0.22	-0.12	-0.16	-0.46	-0.20	-0.97
	(0.10)	(0.28)	(0.76)	(0.16)	(0.24)	(0.14)
smlncarb	0.06	0.10	-0.44	0.18*	0.23**	-1.19***
	(0.46)	(0.27)	(0.25)	(0.07)	(0.02)	(0.00)
Constant	4.32***	1.87	7.81***	1.98	-2.90	11.68***
	(0.00)	(0.40)	(0.00)	(0.13)	(0.22)	(0.00)
No. of observations	1,363	797	566	1,363	797	566
No. of observation unites	142	100	42	142	100	42

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C. 13. Main model: Comparing Main model with models allowing for heterogeneous effects of CO_2-prices between UK and Norway (RE estimates)

Variable name	Main model	Models with heterogeneous CO_2-price effects			
prod_share	-4.91***	-4.92***	-4.85***		-4.85***
	(0.00)	(0.00)	(0.00)		(0.00)
$prod\_share^2$	4.86**	4.89***	4.73**		4.73**
	(0.01)	(0.01)	(0.01)		(0.01)
$prod\_share^3$	-1.99*	-2.00*	-1.90*		-1.90*
	(0.08)	(0.08)	(0.09)		(0.09)
gasres_share	-1.70***	-1.70***	-1.69***	-2.04***	-1.69***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
lnres_size	-0.14**	-0.14**	-0.13*	-0.09	-0.13*
	(0.04)	(0.04)	(0.05)	(0.13)	(0.05)
w_inject	4.20***	4.20***	4.19***	5.14***	4.19***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
lnw_depth	0.46***	0.46***	0.48***	0.26	0.48***
	(0.00)	(0.00)	(0.00)	(0.11)	(0.00)
lnoil_p	0.11	0.10	0.10	0.41***	0.10
	(0.33)	(0.33)	(0.37)	(0.00)	(0.37)
lngas_p	-0.03	-0.03	-0.02	-0.03	-0.02
	(0.80)	(0.80)	(0.87)	(0.79)	(0.87)
lncarb_p	-0.03	-0.08	0.22***	-0.00	0.22***
	(0.25)	(0.43)	(0.00)	(0.99)	(0.00)
lnpcarb_new		0.05	-0.25***	-0.04	-0.25***
		(0.59)	(0.00)	(0.77)	(0.00)
d_ukfield	-1.14***	-1.36***		-0.66	
	(0.00)	(0.00)		(0.27)	
Constant	4.07***	4.30***	2.80***	2.34**	2.80***
	(0.00)	(0.00)	(0.00)	(0.03)	(0.00)
No. of observations	1,365	1,365	1,365	1,365	1,365
No. of observation unites	143	143	143	143	143

Notes: * p<0.1; ** p<0.05; *** p<0.01; p-values in parentheses.

Table C.14. Main model: Without and with gas flaring

Variable name	Models with RE estimator					
	UKCS and NCS together	UKCS	NCS	UKCS and NCS together	UKCS	NCS
prod_share	-4.91***	-4.50***	-4.91***	-5.00***	-4.68***	-5.08***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
prod_share^2	4.86**	4.30	5.23**	5.07***	4.74	5.43**
	(0.01)	(0.20)	(0.04)	(0.01)	(0.15)	(0.04)
prod_share^3	-1.99*	-2.09	-2.17	-2.12*	-2.40	-2.21
	(0.08)	(0.33)	(0.12)	(0.06)	(0.26)	(0.12)
gasres_share	-1.70***	-1.62***	-0.99***	-1.69***	-1.60***	-0.95***
	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.01)
lnres_size	-0.14**	-0.20**	-0.03	-0.13**	-0.19**	-0.03
	(0.04)	(0.02)	(0.71)	(0.04)	(0.02)	(0.75)
lnw_depth	0.46***	0.65***	-0.01	0.45***	0.64***	-0.04
	(0.00)	(0.00)	(0.96)	(0.00)	(0.00)	(0.89)
w_inject	4.20***	4.06***	19.63***	4.16***	4.02***	18.96***
	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)
lnoil_p	0.11	0.09	0.10	0.10	0.08	0.09
	(0.33)	(0.56)	(0.34)	(0.34)	(0.59)	(0.37)
lngas_p	-0.03	-0.02	0.00	-0.03	-0.01	0.01
	(0.80)	(0.93)	(1.00)	(0.81)	(0.94)	(0.91)
lncarb_p	-0.03	-0.02	-0.08	-0.02	-0.02	-0.00
	(0.25)	(0.28)	(0.42)	(0.26)	(0.30)	(0.99)
d_ukfield	-1.14***			-1.15***		
	(0.00)			(0.00)		
gasflare_share				0.00	0.00	0.07**
				(0.28)	(0.28)	(0.01)
Constant	4.07***	2.21**	5.65***	4.09***	2.22**	5.37***
	(0.00)	(0.03)	(0.00)	(0.00)	(0.03)	(0.00)
No. of observations	1,365	797	568	1,365	797	568
No. of observation unites	143	100	43	143	100	43

Notes: * $p<0.1$; ** $p<0.05$; *** $p<0.01$; p-values in parentheses.

C.3 Main model regressions with Alt. 2.

Table C. 15. Comparing the Main model with different estimators (Alt. 2)

Variables	RE	FE	MLE	AR (1) RE	AR (1) FE
prod_share	-4.97***	-5.26***	-4.98***	-5.00***	-5.30***
	(1.19)	(1.25)	(1.13)	(1.24)	(1.44)
	0.00	0.00	0.00	0.00	0.00
prod_share^2	5.28**	5.54**	5.28**	5.95**	6.42**
	(2.63)	(2.68)	(2.61)	(2.86)	(3.20)
	0.04	0.04	0.04	0.04	0.05
prod_share^3	-2.41	-2.46	-2.41	-3.04*	-3.33
	(1.72)	(1.74)	(1.71)	(1.84)	(2.04)
	0.16	0.16	0.16	0.10	0.10
gasres_share	-2.98***		-2.98***	-2.98***	0.00
	(0.43)		(0.37)	(0.35)	(0.00)
	0.00		0.00	0.00	.
lnres_size	-0.06		-0.06	-0.06	0.00
	(0.11)		(0.10)	(0.09)	(0.00)
	0.57		0.55	0.55	.
lnw_depth	0.62***		0.62***	0.62***	0.00
	(0.24)		(0.23)	(0.22)	(0.00)
	0.01		0.01	0.00	.
w_inject	4.97***	4.29**	4.96***	5.23***	4.88***
	(1.74)	(2.04)	(1.55)	(1.59)	(1.68)
	0.00	0.04	0.00	0.00	0.00
lnoil_p	0.14	0.20	0.14	0.04	-0.17
	(0.17)	(0.18)	(0.16)	(0.16)	(0.17)
	0.40	0.26	0.38	0.80	0.33
lngas_p	-0.13	-0.22	-0.13	-0.05	0.15
	(0.20)	(0.21)	(0.19)	(0.18)	(0.19)
	0.52	0.31	0.49	0.79	0.43
lncarb_p	0.01	0.02	0.01	-0.00	0.02
	(0.05)	(0.05)	(0.04)	(0.03)	(0.03)
	0.86	0.75	0.80	0.94	0.53
d_ukfield	-1.34***		-1.34***	-1.29***	0.00
	(0.23)		(0.34)	(0.32)	(0.00)
	0.00		0.00	0.00	.
Constant	3.54***	4.52***	3.55***	3.52***	4.13***
	(1.27)	(0.50)	(1.32)	(1.24)	(0.44)
	0.01	0.00	0.01	0.00	0.00
No. of observations	1,462	1,462	1,462	1,462	1,315
No. of observation unites	147	147	147	147	143

Notes: * p<0.1; ** p<0.05; *** p<0.01; Robust standard errors & p-values in parentheses.

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