Norwegian University of Life Sciences
School of Economics and Business

CO_2-emissions from Norwegian oil and gas extraction

Ekaterina Gavenas, Knut Einar Rosendahl and Terje Skjerpen

Working Papers No. 7 / 2015

ISSN: 2464-1561

CO_2-emissions from Norwegian oil and gas extraction

Ekaterina Gavenas[a], Knut Einar Rosendahl[b] and Terje Skjerpen[c]

[a] School of Economics and Business, Norwegian University of Life Sciences, Ås, Norway. E-mail: ekaterina.gavenas@gmail.com

[b] School of Economics and Business, Norwegian University of Life Sciences, Ås, Norway. E-mail: knut.einar.rosendahl@nmbu.no. Corresponding author

[c] Research Department, Statistics Norway, Oslo, Norway. E-mail: terje.skjerpen@ssb.no

Abstract:

Emissions from oil and gas extraction matter for the lifecycle emissions of fossil fuels, and account for significant shares of domestic emissions in many fossil fuel exporting countries. In this study we investigate empirically the driving forces behind CO_2-emission intensities of Norwegian oil and gas extraction, using detailed field-specific data that cover all Norwegian oil and gas activity. We find that emissions per unit extraction increase significantly as a field's extraction declines. Moreover, emission intensities increase significantly with a field's share of oil in total oil and gas reserves. We also find some indication that oil and CO_2-prices may have influenced emission intensities on the Norwegian continental shelf.

Keywords: CO_2-emissions; Oil and gas extraction; Panel data estimation

JEL: C23, L71, Q54

1. Introduction

Although most of the greenhouse gas (GHG) emissions from fossil fuel use occur downstream when the fuel is combusted, emissions related to the extraction of fossil fuels also matter for the lifecycle emissions of fossil fuels. Moreover, in large oil and gas producing countries, these emissions may constitute large shares of domestic emissions. Both in Canada and Russia oil and gas production and transmission account for more than 20% of domestic GHG emissions.[1] In Norway the share of GHG emissions coming from the oil and gas activity on the Norwegian continental shelf constituted 27% in 2013.[2] Despite a falling trend in overall production of oil and gas in Norway over the last decade, GHG emissions from this activity has not been falling. Hence, there is significant concern in Norway about these emissions.[3]

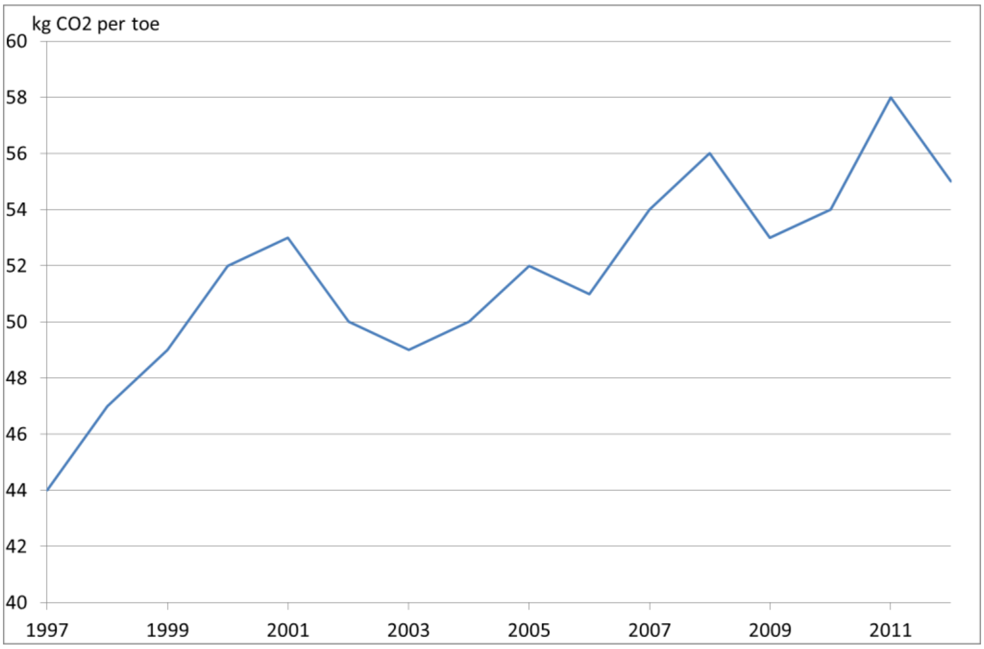
At the same time, the emission intensity for Norwegian oil and gas extraction is significantly below the world average. Whereas the world average is around 130 kg CO_2 per ton oil equivalent (toe) (OGP, 2014), the Norwegian average in 2012 was 55 kg CO_2 (see Figure 1).[4] One reason for the relatively low emission intensity is the Norwegian CO_2-tax, which was introduced in 1991 (Norwegian Ministry of climate and environment, 2014). The current CO_2-tax level for oil and gas production is 1 NOK per Sm3 gas, which translates into about 50 Euro per ton CO_2. This comes in addition to the EU ETS (EU Emission Trading System) regulation, meaning that the oil and gas industry in Norway pays both CO_2-tax and EU ETS price. The CO_2-tax is likely to have caused the separation and underground storage of the CO_2 content in the gas extracted at the Sleipner field since 1996 (and at the Snøhvit field since 2008).

In this paper we investigate the driving forces behind CO_2-emission intensities on the Norwegian continental shelf. We employ a unique dataset with annual field data for CO_2-emissions from 1997 to 2012, covering all Norwegian oil and gas fields. These data are combined with annual field data for production of oil and gas (and water), and field data on original reserves, reservoir and ocean depths, and whether the field has access to electricity from the grid ("electrified fields"). We test for the effects of these field characteristics as well as the effects of CO_2-prices, oil prices and time. In particular, we are interested in whether there are significant differences between oil and gas fields,

[1] See e.g. https://ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=F60DB708-1 for Canada, and McKinsey&Company (2009) for Russia.
[2] http://ssb.no/natur-og-miljo/statistikker/klimagassn
[3] See e.g. http://www.newsinenglish.no/2015/02/05/norway-passes-the-buck-again/ and http://www.economist.com/node/12970769
[4] In addition comes other GHG emissions such as methane – these constitute around 15% of total GHG emissions globally (from oil and gas extraction) but only 5% in Norway. This is partly due to strict restrictions on flaring in Norway.

or more precisely, whether the share of oil in a field's reserves or production is of significance for a field's emission intensity. Moreover, we want to examine how emission intensities develop in the decline phase of the field.

Figure 1. Development of average CO_2-emissions per unit of oil and gas in Norway from 1997 to 2012. Kg CO_2 per toe



Source: Own calculations based on data from the Norwegian Environment Agency

To our knowledge, similar studies have not been undertaken before, neither for Norway nor other countries, probably because of the uniqueness of the Norwegian emissions data associated with oil and gas production. There exist some related studies, though. The International Association of Oil and Gas Producers publishes every year regional GHG and CO_2 emission intensities for different regions of the world, based on reported data from its member companies (OGP, 2014). Rahman et al. (2014) quantify the GHG emissions from crude recovery of five selected North American crudes, using information about energy use and process fuel shares. They find very large differences in emission intensities between the different crudes, ranging between 3.94 and 23.85 g CO_2 per MJ.[5] Brandt and Unnasch (2010) calculate energy efficiency and GHG emissions of thermal enhanced oil recovery, both for generic cases and for 19 California-specific projects. Bergerson et al. (2012) quantify life cycle emissions associated with two different extraction processes for Canadian oil sand. Oil sand production is far more energy intensive than conventional oil production, leading to

[5] This corresponds to 165 and 1000 kg CO_2 per toe. Most of the crudes were in the lower range though – only one was above 240 kg CO_2 per toe.

high GHG emission intensities (cf. Charpentier et al., 2009). Betancourt-Torcat et al. (2012) model the effects of mitigation strategies to reduce GHG emissions from Canadian oil sands operations.

In the next section we discuss some relevant background information about Norwegian oil and gas extraction and corresponding emissions, and discuss some possible hypotheses for why emission intensities from Norwegian oil and gas extraction have increased over the last decade. Then we present our data sources and empirical approach in Section 3, while the empirical results are displayed and discussed in Section 4. Some robustness and alternative estimations are presented in Section 5, before we conclude in the last section.

2. Background

Oil and gas production in Norway takes place offshore, mostly in the North Sea but there are also several fields in the Norwegian Sea and one field in the Barents Sea. Norwegian oil production started up in 1971, and peaked in 2001 at around 200 million Sm3.[6] Since then, oil production has been approximately halved, cf. Figure 2. The first unit of Norwegian gas was extracted in 1977. Gas production in Norway was rather moderate until mid-1990's. Then it increased steadily until it peaked in 2012 at almost 120 billion Sm3 (or 120 million Sm3 toe). As shown in Figure 2, in the 16-years period we consider, total petroleum production has been rather constant, but there has been a gradual change from mostly oil production to about equal shares of oil and gas.

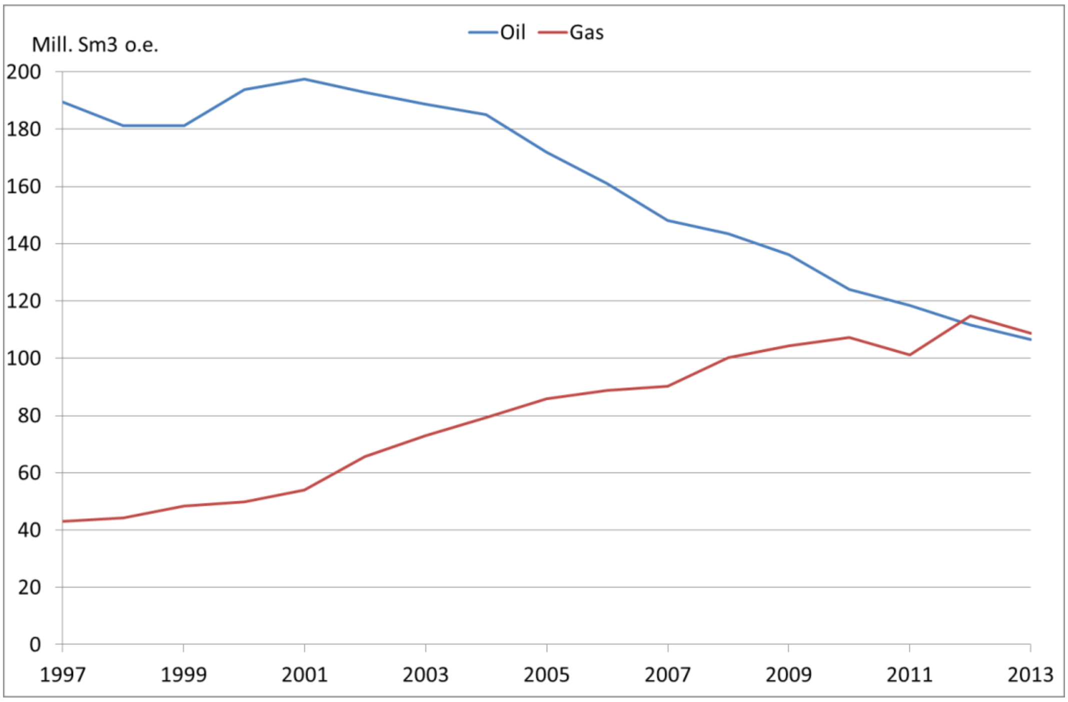
Oil and gas extraction is an energy intensive activity. Most of the GHG emissions from Norwegian petroleum production comes from the use of gas turbines that generate electricity. These are located at the platforms offshore, and are much less efficient than modern large-scale gas power plants (Econ Pöyry, 2011). In 2012, they accounted for 62% of total GHG emissions from Norwegian oil and gas production. The use of diesel accounted for 9% of emissions, flaring and venting for 9%, while the rest (14%) comes from gas turbines onshore that are only partly related to specific fields.[7]

During the period 1997-2012, the emission intensity of Norwegian oil and gas extraction increased by more than 20%, see Figure 1. There are several possible hypotheses to explain this development. By comparing with Figure 2, one hypothesis could be the change from mostly oil to both oil and gas production, i.e., that gas production is more emission intensive than oil production. As we show below, this is not the case according to our estimations – in fact we find quite the opposite result.

[6] By oil we mean crude, NGL and condensates.

[7] Flaring is the controlled burning of natural gas produced in association with oil in the course of routine oil and gas production operations. Venting is the controlled release of unburned gases directly into the atmosphere (OGP, 2000). Data source for Norwegian GHG emissions: http://ssb.no/natur-og-miljo/statistikker/klimagassn

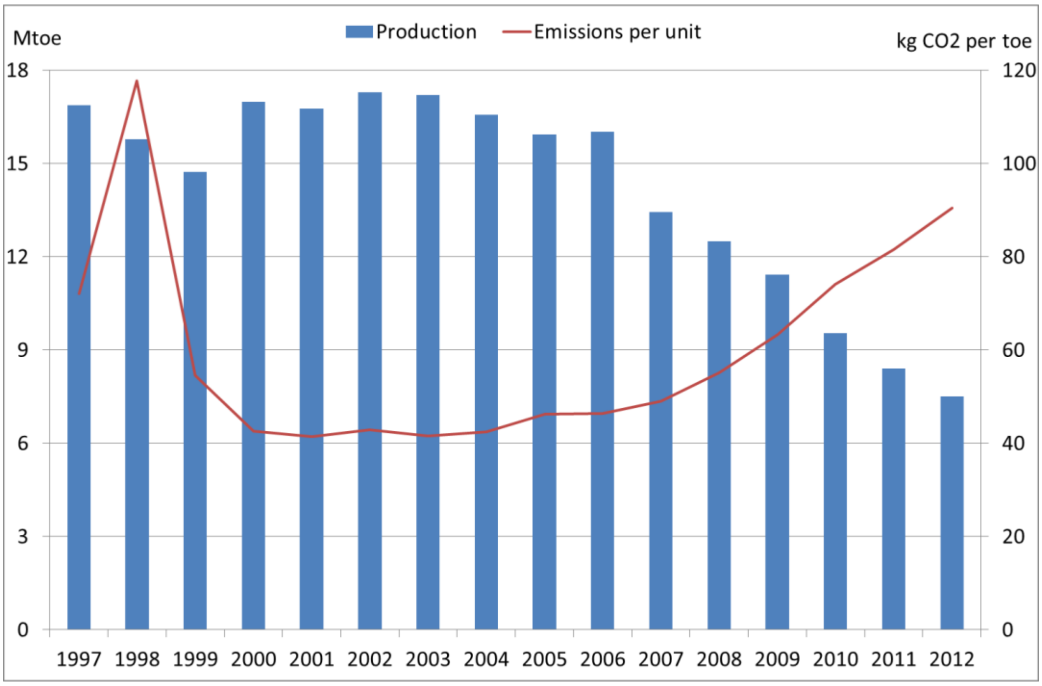
Figure 2. Development of Norwegian oil and gas production in the period 1997-2013. Million standard cubic meter (Sm3) oil equivalents



Source: Statistics Norway (http://www.ssb.no/energi-og-industri/statistikker/ogprodre/kvartal)

A second hypothesis could be that many of the fields on the Norwegian continental shelf are currently in the decline phase. This hypothesis is more consistent with our results below – indeed we find a strong effect on emission intensity when a field's extraction declines. As an illustration of this Figure 3 shows the development of the Ekofisk field, which is one of the major oil and gas fields in Norway. It was the first field on the Norwegian continental shelf and is expected to continue producing until around 2050 (NPD, 2013). Whereas the emission intensity was around 40 kg CO_2 per toe while production was around its peak level, it has increased to 90 kg in 2012 when production was slightly below 50% of its peak level. At Ekofisk, as well as other major oil fields like Statfjord and Gullfaks, production is currently dominated by water. For instance, at Ekofisk twice as much water was produced as oil in 2012 (measured in volume units). As we will see below, the amount of water produced has a significant effect on the emission intensity of a field.

Figure 3. Total production of oil and gas (Mtoe), and emissions per unit (kg CO_2 per toe), at the Ekofisk field in the period 1997-2012



Source: Own calculations based on data from the Norwegian Environment Agency and Statistics Norway

A third hypothesis could be related to the fact that the CO_2-price facing Norwegian oil and gas producers in fact declined by more than 50% from late 1990's to 2012 (in real terms). This is partly because the nominal CO_2-tax was reduced by more than 20% from 1999 to 2000, and partly due to lower than expected CO_2-prices in the EU ETS in 2009-2012. Hence, the incentives to cut emissions were reduced during our estimation period. At the same time, the oil price tripled (in real terms) in this period, giving companies more incentives to develop more expensive and often more energy demanding fields, and to delay termination of producing fields, e.g. by investing in improved oil recovery projects which often implies higher emissions per unit extracted due to more energy demanding activities. The North Sea is a rather mature oil and gas province now, and there has indeed been a gradual shift from large and easily accessible fields towards smaller and more marginal fields during the last 15-20 years. To what extent this shift would have happened without the mentioned price changes is difficult to say, and we return to this issue below.

Figure 4. Emission intensity for individual fields in the period 1997-2012, combined with the start year of production at the field[a]

Source: Own calculations based on data from the Norwegian Environment Agency and Statistics Norway

[a] Red squares indicate fields with production terminated before 2012

It is also important to add that technological improvements could mitigate the so-called depletion effect, e.g. if operations become more energy-efficient over time (see Lindholt (2013) for an analysis of this issue based on oil extraction costs worldwide). Figure 4 shows the emission intensity of individual fields over the period 1997-2012, combined with the start year of production. We notice very large differences across fields.[8] However, since none of the fields both started and terminated production during this period, we do not have the full life cycle emissions of any of the fields. Thus, the figure will probably overestimate life cycle emissions of older fields that had reached the decline phase in 1997, and underestimate emissions of newer fields that were still around peak level in 2012. Hence, the figure should be interpreted with caution. Nevertheless, the figure does not seem to indicate that newer fields have higher emission intensities than older fields.

[8] A few fields have close to zero emissions. These fields use electricity from the grid, and hence have very small direct emissions. We come back to this issue in the empirical model. Indirect emissions from electricity input are not accounted for in the statistics, and thus not in our study either.

3. Data and empirical approach

In order to test empirically the driving forces behind emission intensities of Norwegian oil and gas extraction, we use a dataset of annual CO_2-emissions at individual fields in Norway.[9] The dataset has been made available to us from the Norwegian Environment Agency. In order to calculate emissions per unit extraction, we combine the emission data with data for annual production of oil (crude, NGL, condensates) and gas at the field level.[10]

The datasets cover all oil and gas production in Norway. However, as several oil and gas fields are located in the same area, they are often connected as extraction at smaller satellite fields are managed from a larger field nearby. Hence, in the emission dataset several fields are aggregated. Whereas there are 74 individual fields with separate production data, for 33 of these we do not have separate emission data. Emissions from these fields are instead included in the emission data for the remaining 41 fields, which constituted 86% of total oil and gas production during this 16-years period. In the Appendix we list how each of the 74 fields are allocated to the 41 main fields that constitute the observational units in our dataset. When calculating emission intensity for a field in a given year, we use the sum over all the connected fields of both emissions and production. For other field-specific variables such as reserve size, share of gas in original reserves, reservoir depth and production level as percentage of peak production level, we only use data for the main field, however. As a robustness check, we do a separate estimation for the 25 fields that do not have any connected fields.

We consider the following empirical model for the emission intensity, *em_int*, where *i* and *t* denote respectively field and year and log denotes the log-transformation:

$$\begin{aligned}\log\left(em\_int_{it}\right) &= \beta_0 + \beta_{1a}\, prod\_share_{it} + \beta_{1b}\left(prod\_share_{it}\right)^2 + \beta_{1c}\left(prod\_share_{it}\right)^3 + \beta_2\, gasres\_share_i \\ &+ \beta_3\, gasprod\_share_{it} + \beta_4 \log\left(res\_size_i\right) + \beta_5 \log\left(res\_depth_i\right) + \beta_6 \log\left(w\_depth_i\right) + \beta_7 water_{it} \\ &+ \beta_8 \log\left(carb\_p_t\right) + \beta_9 \log\left(oil\_p_t\right) + \beta_{10} D\_elect_i + \beta_{11} start\_year_i + \beta_{12} time_t + c_i + u_{it}\end{aligned}$$

The right-hand side variables are respectively annual production in percent of the field's historic peak production (*prod_share*), the share of gas in the field's original reserves (*gasres_share*), the share of gas in the field's running production minus the share of gas in original reserves (*gasprod_share*), original reserve size (*res_size*), reservoir depth (*res_depth*), ocean depth

[9] Hence, other GHG emissions like methane (CH_4) are not included in the dataset. As mentioned in footnote 4, these accounted for only 5% of total GHG emissions.

[10] This dataset is available from Statistics Norway. We have excluded 12 observations relating to fields' first year of production, if production that year constituted less than 20% of peak production. The reason is that emission intensities could be influenced by drilling or other activities during the start-up year but before start of production.

(w_depth), water produced as a share of peak oil and gas production (*water*), CO_2-price (*carb_p*), oil price (*oil_p*),[11] dummy for electrified fields (*D_elect*),[12] first year of extraction (*start_year*) and time trend (*time*). β_j (j=0,1a,...,11) are unknown parameters, c_i are unobservable field-specific effects, while u_{it} are genuine error terms. We assume that both c_i and u_{it} are normally distributed with zero expectation and with variances σ_c^2 and σ_u^2, respectively.[13] An overview of the variables is presented in Table 1, together with mean values, standard deviations and min./max. values. The table also displays summary statistics for two additional variables that we come back to later.

Some of the data sources have been stated above. In addition, field data for reserve size, reservoir depth and ocean depth have been taken from the Norwegian Petroleum Directorate (NPD, 2013). Field data on production of water is received from Statistics Norway. Data for the crude oil price Brent Blend are taken from the EIA (www.eia.gov) and translated from nominal USD prices into NOK_{2012} prices using annual exchange rates from the Central Bank of Norway and a producer price index for manufacturing from Statistics Norway.[14] The same procedure has been applied to CO_2-prices.

We notice from the model that there are three variables that vary over both field and time, i.e., *prod_share*, *gasprod_share* and *water*. Six of the variables are field-specific but time invariant, while three of the variables vary over time only. With so many relevant variables, some of which are somewhat (positively or negatively) correlated, we have tested a number of model variants that retain only a subset of the variables in Table 1. The main model, with results presented in Table 2, has been chosen mainly based on the p-values of the parameter estimates of the variables, but we have also kept some variables that we find particularly interesting.

On the other hand, two of the variables are omitted a priori from the main model. First, we do not include the variable *D_elect* since we omit the four electrified fields from the dataset in this case. The reason is that the left-hand side variable approaches minus infinity when the emission intensity goes towards zero (one of the fields had zero emissions in five years). Thus, instead we perform a separate estimation where we include these fields but set a lower bound on their emission intensity equal to 1 kg CO_2 per toe (i.e., 1% of the mean value, cf. Table 1). Second, we omit the variable

---

[11] An additional explanatory variable could be the Norwegian export price of natural gas. However, European gas prices have traditionally followed the oil price with a few months lag. Thus, it seems better to only include the price of oil in the estimations.
[12] There are four electrified fields. These are Troll I, Ormen Lange, Snøhvit and Gjøa. The three former fields are large fields producing gas only, whereas Gjøa produces both oil and gas. After a recent upgrading of Valhall, this field has also access to grid electricity now but not during our estimation period.
[13] All empirical results are based on maximum likelihood estimation.
[14] http://www.norges-bank.no/en/Statistics/exchange_rates/currency/USD/ and http://www.ssb.no/en/ppi/.

water in the main model, as the volume of water produced at a field typically increases as the volume of oil production drops, and we are particularly interested in how the emission intensity is changed when production declines from its peak level (i.e., *prod_share*). Thus, instead we perform a separate estimation where we consider the effects of *water*. At the end we discuss the results of some alternative model variants, too.

Table 1. Summary statistics for the data set with 452 observations. Electrified fields excluded

Variable name	Description	Unit	Mean	St.dev.	Min	Max
em_int	Emission intensity	Kg CO_2 per toe	90.5	68.2	7.51	675
prod_share	Production level. Share of peak annual production for the field	Percent	0.49	0.31	0.03	1
gasres_share	Share of gas in the field's original reserves	Percent	0.21	0.24	0	1.00
gasprod_share	Share of gas in the field's production, minus $gasres\_share_i$	Percent	-0.03	0.11	-0.53	0.32
res_size	Size of original reserves	Mill. Sm^3 oe	188	195	7.18	763
res_depth	Reservoir depth	Meter	2668	760	1360	4850
w_depth	Ocean depth	Meter	171	104	66	380
Water	Produced water (Sm^3) as a fraction of peak annual oil and gas production (Sm^3 oe)	Percent	0.35	0.42	0	1.61
carb_p	Total CO_2-price	NOK_{2012} per ton CO_2	431	94	265	654
oil_p	Crude oil price Brent Blend	NOK_{2012} per barrel	427	155	150	650
start_year	Start-up year	Year	1991	8.9	1971	2008
Time	Time trend	Year	8.99	4.54	1	16
Accp	Accumulated production as a share of original reserves	Percent	0.61	0.26	0.02	1.01
D_Statoil	Dummy variable for fields operated by Statoil	0 or 1	0.62	0.48	0	1

The dataset is an unbalanced panel, as several of the fields do not produce throughout our time period. 16 of the 41 fields started up after 1997, 5 terminated production before 2012, while 20 produced the entire time period. In the estimations we have tried models with fixed effects and models with random effects. A fixed effect model has less strict requirements, but does not allow estimation of the effect of time invariant variables that are of special interest to us. Thus, both model types have its advantages and disadvantages. As the Hausman test shows no significant difference between the two model types, and the estimated parameter values of the most important two-dimensional variable *prod_share* are very similar, we choose to focus on the random effects model.

4. Empirical results

Table 2 shows the results obtained when estimating the main model. The first variable in the table is *prod_share*, i.e., a field's production level as a share of its historic peak production. When we include only the linear term of this variable, its parameter estimate is highly significant (p-value below 0.01) with a negative sign – hence, emission intensities increase significantly as extraction from a field declines. To get a more precise picture of how it affects emissions per unit, we have included also the second and third order terms of this variable in the main model. Figure 5 shows how emissions per unit change as production declines from its peak level, according to the estimation results in Table 2. When comparing with the development at the Ekofisk field in Figure 3, we see a similar pattern. Figure 5 suggests that the emission intensity increases quite substantially as production declines, and rises particularly rapidly when production is more than halved. Moreover, *total* CO_2-emissions at the field fall only slightly as production falls. Based on the estimation results in Table 2, total emissions are on average reduced by 30% when the field produces 75% below its peak level.

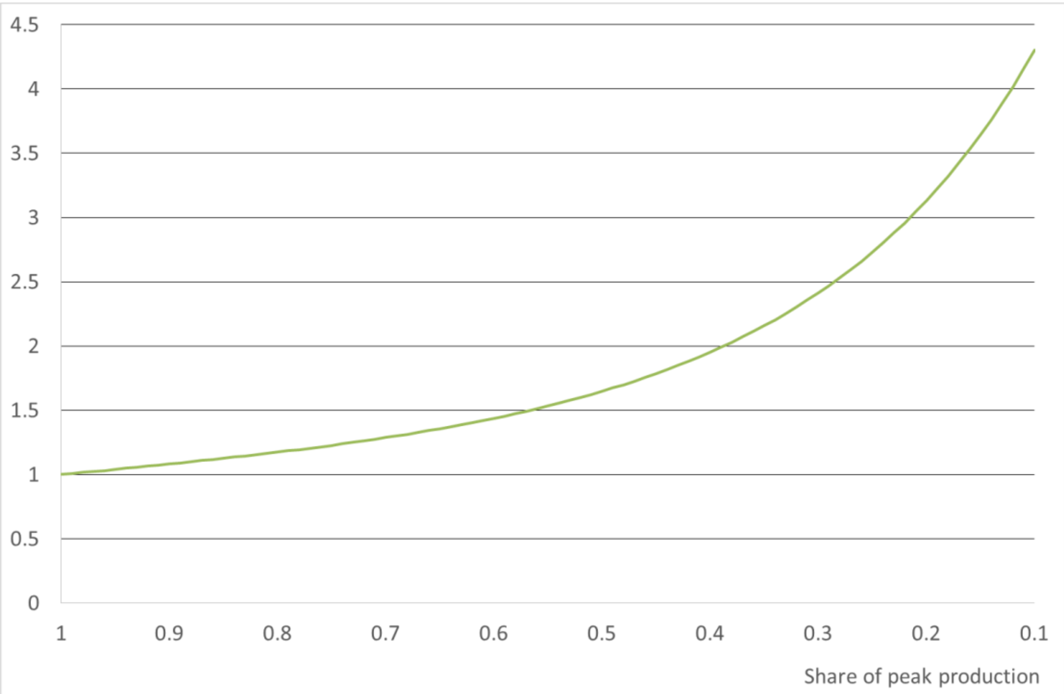
One important reason for the increased emission intensity as production decreases, at least for oil fields, is that lower extraction is typically linked with increased production of water. Thus, total liquid production may be quite unchanged, while energy use per output of oil (and gas) increases. We return to this issue below when we bring water production into the estimation. Another explanation for the increased emission intensity is that the natural pressure in the reservoir gradually drops as the oil and gas are extracted. Hence, with e.g. unchanged energy use, production will eventually decrease, and emissions per unit extraction go up. In some cases, the operator may instead increase the energy use in order to keep up the production level. Then the relationship between production level and emission intensity will be different than if energy use is kept unchanged. The emissions data do not suggest that increasing the energy use is a typical strategy, however. Nevertheless, we test an alternative model specification below where accumulated production is included as a potential explanatory variable.

Table 2. Estimation results. Main model with random effects

Variable	Estimated parameter value	t-value
prod_share	-4.18***	-6.52
(*prod_share*)^2	3.63***	2.81
(*prod_share*)^3	-1.30*	-1.66
gasres_share	-0.77***	-2.71
gasprod_share	-0.42**	-2.49
log (*carb_p*)	-0.13	-1.21
log (*oil_p*)	0.089	1.55
constant	5.85	6.28
σ_c^2	0.189	
σ_u^2	0.073	
log-likelihood value	-112.408	
No. of obs.	452	
No. of obs. units	37	

* Significant at 10% level ($p < 0.10$). ** Significant at 5% level ($p < 0.05$). *** Significant at 1% level ($p < 0.01$)

Figure 5. Illustration of the relationship between production level (as a share of peak production) and emission intensity



Source: Estimation results in Table 2

.

The significant, negative parameter estimate of *gasres_share* suggests that emissions per unit increase with the share of oil in the field's original reserves. Given the estimated parameter value in Table 2, a field with only oil has twice as high emission intensity as a field with only gas. Note that this result is obtained without including the four electrified fields, which are predominantly gas fields (cf. footnote 12). Thus, it is fair to say that on the Norwegian continental shelf, gas fields have significantly lower emissions than oil fields. The variable *gasprod_share*, which denotes the share of gas in the running extraction minus the share of gas in original reserves, has the same sign as *gasres_share*, suggesting that extracting oil from the reservoir is more emission-intensive than extracting gas. One could ask whether this is simply because the gas is extracted before the oil. However, since we control for production as a share of peak production, such an effect should be captured by that variable. Moreover, there is no clear pattern as to which of the two fossil fuels is extracted first – this varies between the fields.

One possible explanation for the higher emission intensity for oil fields may be that oil generates more revenues than gas, as oil prices typically are higher than gas prices (BP, 2014). Moreover, gas extraction involves more additional costs and investments related to processing and infrastructure. Thus, it seems more likely that a high-cost oil field will be developed than a high-cost gas field, and higher costs are often associated with higher energy use.

Another explanation could be that Norwegian gas fields are on average bigger than oil fields in terms of reserves. According to NHO/OLF (2009), smaller fields have historically had higher emission intensities than larger fields on the Norwegian continental shelf. However, when we control for reserve size in our estimations, it does not enter significantly and it does not affect the estimated parameter (or significance level) of *gasres_share* notably (we return to the reserve size below).

The two last variables in Table 2 are the prices of CO_2 and oil (both log transformed). We notice that both prices enter with the expected sign, but the parameter estimates are not significant. However, the estimate of the oil price is almost significant at 10% level with a p-value of 0.12, while the p-value of the estimate of the CO_2-price is 0.23. Hence, both of these prices may have had some effects on the emission intensities. The CO_2-price was halved (in real terms) during the estimation period, reducing the incentives to install more energy-efficient turbines and increasing the incentives to continue extracting even if emissions per unit increase significantly. On the other hand, the oil price tripled in real terms, increasing the incentives to develop marginal fields and to extend extraction even if energy use (and other costs) per unit increases. If we make use of the estimated parameters, and the price changes from 1997 to 2012, the estimation results indicate that both the CO_2-price decline and the oil price increase may have led to about 10% increases each in the emission intensities in this period. However, these rough calculations are of course very uncertain and should therefore be interpreted with caution.

If we include a time trend in the estimation, the two prices enter much less significantly (the sign of the estimates is the same). The parameter estimate of the time trend is also insignificant then, but becomes highly significant (with a positive sign) if we exclude the two prices. As explained before, a positive time trend could be due to the depletion effect, i.e., that there is a gradual shift from easily accessible fields to more costly fields. However, if we replace the time trend with *start_year*, i.e., the field's first year of production, this variable does not enter significantly whereas the two prices have very similar effects as in the main model (both with respect to estimated parameter values and t-values). The likely reason for the differing estimation results when a time trend is included is that the time trend is quite correlated (positively/negatively) with the two prices, and the prices are also negatively correlated with each other, cf. Table 5. Thus, whereas all these three variables point to an increase in the emission intensity during the estimation period, it is somewhat difficult to pin down the exact effect of each of them.

Although the empirical evidence of a CO_2-price effect is somewhat weak, the relatively low emission intensities related to oil and gas production in Norway suggest that the CO_2-price has been important in a longer perspective. In general it is difficult to estimate long-term effects of the CO_2-price, such as installing more energy-efficient turbines or CO_2-storage. The CO_2-tax was introduced as early as 1991. Hence, an estimation study based on data also before 1991 could possibly have shown more significant effects of the CO_2-price, but such data are not readily available.

As emission intensities to some degree are influenced by investment decisions, lagged oil and CO_2-prices could by as relevant explanatory variables as current prices. Hence, we have performed several estimations with different variants of lagged prices. The signs of the estimated parameter values are consistently positive for the oil price and negative for the CO2-price, but the significance levels vary from below 5% (for both prices, but not simultaneously) to insignificant levels. Hence, we maintain the main model in Table 2, which gives a fairly good representation of the estimated effects of the two prices.

We have of course run a number of estimations in addition to the one we have presented in this section, and which we have referred to as our main (or preferred) model. In the next section we will comment and present some of them.

5. Robustness and alternative estimation models

In the empirical model put forward at the beginning of section 3, we included 12 separate variables, whereas in the main model we only retained 5 of these. The results of including all variables in the empirical model except *water* and *D_elect* (which we return to below) are shown in Table 6 in the Appendix. We notice that the results for the variables *prod_share*, *gasres_share* and *gasprod_share* are very similar to the main model results, both with respect to estimated parameter values and their significance levels. The two price variables enter with the same sign as before, but the parameter estimates are far from significant as the time trend is also included (cf. the discussion above). We see from the table that there is no effect of reserve size in this estimation, which is somewhat surprising and contrary to what NHO/OLF (2009) has suggested. The estimate of reservoir depth has the expected sign, i.e., emissions per unit increase with higher depths, but it is not significant. There are substantial differences in reservoir depths across Norwegian oil and gas fields (see Table 1), and given the size of the estimate we cannot rule out that reservoir depth *may* have a noticeable effect on emissions. The estimate of ocean depth has the opposite sign of the reservoir depth estimate, but is even less significant. As already mentioned, the start year of production for a field has no effect at all according to this estimation – this is also the case if we exclude the time trend from the model.

As mentioned before, oil fields in the decline phase will typically produce water alongside the oil, and this is likely to increase emissions per unit oil (and gas) extracted. Thus, in a separate estimation we have added *water* to the empirical model. The estimation results are shown in Table 3. We see that water production has a significant, positive effect on the emission intensity. The size of the estimated parameter value indicates that if an oil field produces as much water as its peak oil production (both measured in Sm3), emissions per unit of oil increase by around 15%. We see that the estimation results for the other variables are only slightly changed (the combined effect of the *prod_share* terms are slightly stronger than in the main model – this can be seen by drawing a figure similar to Figure 5).

When including the fields that use electricity from the grid, the dummy *D_elect* for these fields becomes highly significant with a negative parameter estimate, cf. Table 3. This is of course as expected – the average emission intensity for these observations is less than 5 kg CO_2 per toe, compared to 90 kg CO_2 per toe for the remaining observations. Again we notice that the estimation results for the other variables are only slightly changed – the qualitative results are mostly the same. The main difference is that the oil price now enters significantly at the 10% significance level.

As a robustness check, we have estimated the main model for the fields that do not have any connected fields, cf. Table 4 in the Appendix. This shrinks the number of fields from 41 to 25, and the number of observations is almost halved. The estimation results are shown in Table 3. By drawing a figure similar to Figure 5, we find that the joint effect of the three *prod_share* terms are somewhat stronger than with the full sample. We see from Table 3 that this is also the case for the share of gas in original reserves – the estimated parameter of *gasres_share* is twice as high and the t-value has increased as well. On the other hand, the three other variables do not enter significantly, and the sign of the estimate of the CO_2-price has changed.

Table 3. Estimation results. Alternative models with random effects.

Variable	Estimated parameter value	t-value[a]	Estimated parameter value	t-value[a]	Estimated parameter value	t-value[a]
prod_share	-4.429***	-6.895	-4.334***	-6.894	-6.80***	-8.88
$(prod\_share)^2$	4.305***	3.295	3.943***	3.139	7.40***	4.84
$(prod\_share)^3$	-1.725**	-2.177	-1.464*	-1.939	-3.10***	-3.39
gasres_share	-0.672**	-2.359	-0.985***	-3.008	-1.52***	-3.22
gasprod_share	-0.388**	-2.317	-0.435***	-2.627	-0.17	-0.92
log (*carb_p*)	-0.127	-1.171	-0.128	-1.234	0.043	0.35
log (*oil_p*)	0.046	0.771	0.097*	1.766	0.038	0.55
water	0.160***	2.718				
D_elect			-2.276***	-6.612		
constant	6.016	6.497	5.847	6.562	5.76	5.40
σ_c^2	0.185		0.266		0.334	
σ_u^2	0.072		0.071		0.051	
log-likelihood value	-108.742		-121.753		-27.787	
No. of obs.	452		480		241	
No. of obs. units	37		41		25	

* Significant at 10% level ($p < 0.10$). ** Significant at 5% level ($p < 0.05$). *** Significant at 1% level ($p < 0.01$)

An interesting question could be whether there are significant differences in emission intensities between fields operated by the state-dominated company Statoil and other companies. Statoil operates 23 of the 41 main fields, cf. Table 4 in the Appendix. Although Statoil is a commercial company, it could be the case that it is more concerned about its GHG emissions than other oil and gas companies, e.g., due to the Norwegian state dominance. Statoil was fully owned by the

Norwegian state until 2001, when it was partly privatized and listed on the Oslo Stock Exchange and the New York Stock Exchange. Since then the state's share has varied somewhat, but since 2009 the share has been 67%. When including a dummy for Statoil-operated fields into the main model, we do not find any significant effect, however. Moreover, the sign of the estimated parameter is the opposite of what we could expect. The results are displayed in Table 6 in the Appendix.

As briefly mentioned above, an alternative explanatory variable for the emission intensity could be accumulated production at the field level (as a fraction of original reserves). As the field's resources are extracted, it may gradually become more energy demanding to extract the remaining resources. In the main model this is indirectly incorporated through the variable *prod_share*, as it is a clear correlation between accumulated production and the level of production at the field level, especially in the decline phase (see e.g. Figure 3 for the Ekofisk field). When including this variable in addition to the ones in Table 2, the estimated parameter value has the expected (positive) sign, but it is far from significant. This is probably due to the high correlation between this variable and *prod_share* (the empirical correlation is -0.69). The latter variable still enters very significantly, and the results for this and the other variables are not much changed compared to the main model. If we exclude *prod_share*, however, accumulated production becomes highly significant with a positive parameter value, see Table 6. We see from the table that the empirical results for the other variables change quite a lot. The share of gas in original reserves is no longer significant, while the parameter estimate of the share of gas in production is more significant than in the main model (and the estimated parameter value is larger). Finally, the carbon price and the oil price enter highly significantly at respectively the 1% and almost the 1% level, with much larger estimated parameter values than before. However, given the robustness of the *prod_share* variable in all the estimations undertaken, we do not consider this model variant as good as the main model. That is, the production level, as a fraction of peak production, seems to be a better explanatory variable for the emission intensity than accumulated production.

6. Conclusions

CO_2-emissions per unit oil and gas production in Norway vary substantially across fields and over time. In this paper we have investigated empirically the driving forces behind the emission intensities of Norwegian oil and gas extraction, using detailed field-specific data for the period 1997-2012.

Our first conclusion is that emissions per unit extraction increase significantly as a field's extraction declines. This is not really surprising, but it is interesting to note how fast emission intensities rise in the decline phase according to the estimations. A number of robustness tests suggest that the quantitative illustration in Figure 5 provides a good indication of how emissions per unit increase as a field's production decreases from its peak level. According to the estimation results, a field producing 20% of peak level has about three times higher emission intensity than in the peak phase.

Our second conclusion is that a field's emission intensities increase significantly with the share of oil in the field's original oil and gas reserves. This result is obtained even though we have excluded the electrified fields, which are mostly gas fields, from the estimations. We also find that the emission intensities increase with the share of oil in the field's running production (after controlling for the share of oil in original reserves). Thus, extracting oil is associated with higher emissions per unit than extracting gas on the Norwegian continental shelf. This conclusion is obviously strengthened when we take into account the very low emission intensities from the electrified fields.

We also find some indication that oil and CO_2-prices may have influenced emission intensities on the Norwegian continental shelf. The real oil price tripled during our estimation period, while the real CO_2-price was approximately halved. A higher oil price gives more incentives to also extract less accessible fields, which often require more energy use, while a lower CO_2-price gives less incentives to reduce emissions. Both these prices influence the emission intensity with the expected sign according to the estimation results, but they do not enter significantly (the oil price is almost significant at 10% level in our main model). Thus, these results should be interpreted with particular caution. As both oil and CO_2-prices probably have stronger impacts in the longer term (i.e., more than one year), it is generally difficult to uncover the effects on emission intensities of these price changes.

From a policy perspective, our results may give some insights into how CO_2-emissions from Norwegian oil and gas production could be reduced. A cost-effective way to reduce emissions would be to increase the CO_2-price. This has in fact already been done after 2012 – the Norwegian CO_2-tax was increased substantially in 2014. A more direct regulation could involve requirement of field termination when production falls below a certain threshold. This could however risk foregoing substantial profits. Alternatively, the government could be more restrictive when giving permissions to improved oil recovery projects, as these projects typically imply higher emission intensities than the average extraction of oil and gas on the Norwegian continental shelf. The same goes for the development of marginal oil fields that often require much energy use per extracted unit. Finally, requiring electrification of more fields will obviously reduce emissions from oil and gas production. All these direct regulatory approaches are likely to be less cost-effective than CO_2-prices, however.

An interesting extension of this study could be to make projections of CO_2-emissions from Norwegian oil and gas production based on the estimated parameters and projections of oil and gas production at the field level (and oil and CO_2-prices). Despite uncertainties, such a projection could give a reasonable indication of the future development of CO_2-emissions for a major sector and emission source in Norway. Another interesting extension could be to consider data also prior to 1997. Although emissions data are not readily available, some field-specific data on energy use exist and could be used to calculate proxy data for emissions. Finally, in our estimation we have only considered CO_2-emissions, which currently account for 95% of total GHG-emissions from Norwegian oil and gas extraction. It could be interesting to consider other GHG-emissions as well, particularly methane emissions.

References

Bergerson, J.A., O. Kofoworola, A.D. Charpentier, S. Sleep and H.L. MacLean (2012): Life Cycle Greenhouse Gas Emissions of Current Oil Sands Technologies: Surface Mining and In Situ Applications, Environmental Science Technology 46(14), 7865-7874.

Betancourt-Torcat, A., A. Elkamel and L. Ricardez-Sandoval (2012): A modeling study of the effect of carbon dioxide mitigation strategies, natural gas prices and steam consumption on the Canadian Oil Sands operations, Energy 45, 1018-1033.

BP (2014): Statistical review of world energy 2014. http://www.bp.com/content/dam/bp/pdf/Energy-economics/statistical-review-2014/BP-statistical-review-of-world-energy-2014-full-report.pdf

Brandt, A.R. and S. Unnasch (2010): Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery, Energy Fuels 24, 4581–4589.

Charpentier, A.D. J.A. Bergerson and H.L. MacLean (2009): Understanding the Canadian oil sands industry's greenhouse gas emissions, Environmental Research Letters 4 (11pp).

Econ Pöyry (2011): CO_2-emissions effect of electrification, Econ Report no. R-2011-041. http://www.statoil.com/no/EnvironmentSociety/Environment/impactassessments/JSutredninger/Downloads/Poyry_%20Emissions%20Effect%20of%20Electrification,%202011.pdf

Fæhn, T., C. Hagem, L. Lindholt, S. Mæland and K.E. Rosendahl (2013): Climate policies in a fossil fuel producing country. Demand versus supply side policies, Discussion Paper No. 747, Statistics Norway, and CREE Working Paper 11/2013.

Lindholt, L. (2013): The tug-of-war between resource depletion and technological change in the global oil industry 1981 – 2009, Discussion Paper No. 732, Statistics Norway.

McKinsey & Company (2009): Pathways to an energy and carbon efficient Russia, December 2009. http://www.mckinsey.com/~/media/mckinsey/dotcom/client_service/sustainability/cost%20curve%20pdfs/russian_cost_curve_summary_english.ashx

NHO/OLF (2009): Offshoreindustrien, TEMAHEFTE Oktober 2009 (in Norwegian). http://legacyweb.nho.no/getfile.php/global/konvertert/NHO/RootNY/filer_og_vedlegg1/Temahefte%20Offshoreindustrien.pdf

NPD (2013): Facts 2013. The Norwegian Petroleum Sector, Norwegian Petroleum Directorate and Norwegian Ministry of Petroleum and Energy.
http://www.npd.no/en/Publications/Facts/Facts-2013/

Norwegian Ministry of climate and environment (2014): Norway`s Sixth National Communication under the Framework Convention on Climate Change. Status report as of January 2014.
https://www.regjeringen.no/contentassets/efed292ce1d5456cb1eae2ffc8ebd72d/t-1543.pdf

OGP (2000): Flaring & venting in the oil & gas exploration & production industry. An overview of purpose, quantities, issues, practices and trends. Report No. 2.79/288. January 2000. International Association of Oil and Gas Producers.
http://www.ogp.org.uk/pubs/288.pdf

OGP (2014). Environment Performance Indicators – 2013 data. OGP Data Series: International Association of Oil and Gas Producers.
http://www.iogp.org/Reports/Type/2013e/id/776

Rahman, M.M., C. Canter and A. Kumar (2014): Greenhouse gas emissions from recovery of various North American conventional crudes, Energy 74, 607-617.

Appendix

Table 4. Overview of main fields and connected fields. Main fields operated by Statoil are marked with *

Main field name	Connected field name(s)	No. of obs.	Start year
Albuskjell		2	1979
Alvheim	Vilje, Volund	5	2008
Balder	Jotun	13	1999
Brage[a]		16	1993
Cod		2	1977
Draugen		16	1993
Edda		2	1979
Ekofisk		16	1971
Eldfisk	Embla	16	1979
Frigg		8	1977
Gjøa[b]	Vega	2	2010
Glitne[a]		12	2001
Grane[a]		9	2003
Gullfaks[a]	Gimle, Gullfaks Sør, Tordis, Visund Sør	16	1986
Gyda		16	1990
Heidrun[a]		16	1995
Heimdal[a]	Atla, Huldra, Skirne, Vale	14	1985
Kristin[a]	Tyrihans	7	2005
Kvitebjørn[a]		8	2004
Njord[a]		15	1997
Norne[a]	Alve, Marulk, Urd	15	1997
Ormen Lange[b]		5	2007
Oseberg[a]	Tune	16	1988
Oseberg Sør[a]		13	2000
Oseberg Øst[a]		14	1999
Ringhorne Øst		7	2006
Sleipner Vest+Øst[a]	Gungne, Sigyn	16	1993
Snorre[a]	Vigdis	16	1992
Snøhvit[ab]		5	2007
Statfjord[a]	Statfjord Nord, Statfjord Øst, Sygna	16	1979
Tor		16	1978
Troll I[ab]		16	1996
Troll II[a]	Fram	16	1995
Ula	Tambar, Olsevar	16	1986

Table 4 (continued)

Main field name	Connected field name(s)	No. of obs.	Start year
Valhall	Hod	16	1982
Varg		14	1998
Veslefrikk[a]		16	1989
Visund[a]		13	1999
Volve[a]		5	2008
Yme		5	1996
Åsgard[a]	Mikkel, Morvin, Yttergryta	13	1999

[a] Main field operated by Statoil

[b] Electrified fields

Table 5. Empirical correlation matrix based on 452 observations (electrified fields excluded)

	em_int	*prod_share*	*gasres_share*	*gasprod_share*	*res_size*	*res_depth*	*w_depth*
em_int	1						
prod_share	-0.599	1					
gasres_share	-0.011	-0.051	1				
gasprod_share	-0.056	-0.060	-0.106	1			
res_size	-0.196	0.178	0.007	0.177	1		
res_depth	0.067	-0.010	0.316	-0.138	0.030	1	
w_depth	-0.182	0.237	-0.031	-0.192	-0.009	-0.089	1
water	0.277	-0.192	-0.463	0.132	-0.058	-0.331	0.042
carb_p	-0.244	0.214	0.073	-0.122	0.039	-0.018	-0.060
oil_p	0.235	-0.229	-0.068	0.177	-0.044	0.031	0.056
start_year	-0.114	0.328	-0.163	-0.074	-0.496	-0.032	0.418
Time	0.252	-0.249	-0.067	0.194	-0.049	0.026	0.058
Accp	0.395	-0.688	0.051	0.371	0.102	-0.045	-0.336
D_Statoil	-0.014	0.107	0.112	0.030	0.132	-0.060	0.540

Table 5 (continued)

	water	*carb_p*	*oil_p*	*start_year*	*time*	*accp*	*D_Statoil*
Water	1						
carb_p	-0.321	1					
oil_p	0.306	-0.812	1				
start_year	0.162	-0.241	0.242	1			
Time	0.318	-0.889	0.913	0.251	1		
Accp	0.247	-0.270	0.290	-0.539	0.341	1	
D_Statoil	0.101	-0.090	0.087	0.399	0.093	-0.161	1

Table 6. Estimation results. Alternative model variants with random effects

Variable	Estimated parameter value	t-value	Estimated parameter value	t-value	Estimated parameter value	t-value
prod_share	-4.076***	-6.141	-4.238***	-6.587		
$(prod\_share)^2$	3.490***	2.655	3.723***	2.873		
$(prod\_share)^3$	-1.222	-1.546	-1.341*	-1.712		
gasres_share	-0.805**	-2.574	-0.784***	-2.764	-0.266	-0.827
gasprod_share	-0.466***	-2.676	-0.415**	-2.466	-1.214***	-5.174
log (*res_size*)	0.004	0.057				
log (*res_depth*)	0.146	0.535				
log (*w_depth*)	-0.030	-0.180				
log (*carb_p*)	-0.039	-0.291	-0.128	-1.168	-0.482***	-3.161
log (*oil_p*)	0.038	0.530	0.087	1.509	0.207**	2.555
start_year	0.001	0.135				
time	0.010	1.167				
water						
D_elect						
accp					0.769***	4.849
D_Statoil			0.134	0.899		
constant	1.666	0.081	5.777	6.181	5.514	4.275
σ_c^2	0.187		0.186		0.238	
σ_u^2	0.073		0.073		0.137	
log-likelihood value	-111.531		-112.007		-247.292	
No. of obs.	452		452		452	
No. of obs. units	37		37		37	

* Significant at 10% level ($p < 0.10$). ** Significant at 5% level ($p < 0.05$). *** Significant at 1% level ($p < 0.01$)