Exploration economics in a regulated and mature petroleum province

by

Klaus Mohn and Petter Osmundsen

15 December 2005

Abstract

Reserve replacement remains a key challenge for the international oil and gas companies. As the market-oriented provinces in USA and United Kingdom are rapidly maturing, exploration activity is shifted towards the resource-rich, but regulated oil and gas provinces outside the OECD. Regulated oil and gas provinces remain underexplored also in econometric terms, as data from USA and United Kingdom dominates previous empirical research on exploration economics. In this paper, we specify and estimate an econometric model of exploration and appraisal drilling for the highly regulated Norwegian Continental Shelf over the period 1966 to 2004. Our explanatory variables include actual and expected oil price, unit cost, a simple tax variable, accumulated discoveries and open exploration acreage. The estimated error-correction models account explicitly for sluggishness and short-term adjustments in exploration drilling. We establish a structural relation between exploration behaviour and expected oil prices, based on adaptive price expectations. In the short term, our model also suggests a temporary influence on exploration-drilling from cash-flow effects and licensing rounds for new exploration acreage.

1 The authors would like to thank Frank Asche, Eric Mathiesen, Knut Einar Rosendahl, Erik Søndenå and Terje Sørenes for valuable comments and discussions. The usual disclaimer applies.
2 Both authors from the University of Stavanger (Department for Industrial Economics), 4036 Stavanger, Norway. Corresponding author: klaus.mohn@uis.no, web-site: http://www5.his.no/kompetansekatalog/visCV.aspx?ID=08332&sprak=ENGELSK
1. Introduction

The current high oil price environment makes investment behaviour and supply side dynamics in the oil and gas industry more interesting than ever. Several commentators and analysts link the current high oil prices to the lack of investments in the oil sector, as oil and gas exploration throughout the world has failed to respond to increasing oil prices over the last years (Osmundsen et al. (2005a, b)). At the same time, oil and gas reserves in market-oriented economies like USA, Canada and United Kingdom are faced with depletion. Oil and gas investments are therefore gradually redirected towards resource-rich regions of the world (e.g. Russia, Latin America, and the OPEC countries), where the degree of regulation and government intervention is far higher than Western oil and gas companies have been used to.

Since the mid 1960s, the Norwegian government has played an active role in the development of the offshore oil and resources, and laid the foundations for the development of a Norwegian oil and offshore industry. The strategy for resource management and industrial development has been characterised by gradualism. The impact of external market forces has been traditionally been subdued by a carefully developed regulatory system which is followed up through well-developed institutions and governance systems. Several resource-rich countries outside the show interest for the Norwegian Model for resource-management and industrial development. Today, both Norwegian authorities and companies see the domestic experience as a lever to develop alliances and business projects with governments and National Oil Companies in resource-rich parts of the world. Our study of exploration behaviour should be of interest to the governments in regulated oil and gas provinces worldwide, but also to companies who aim at developing new business in the expanding resource-rich regions outside the OECD area.

Figure 1. Oil production and net export by country

<table>
<thead>
<tr>
<th>Oil production 2004 by country (mmboepd)</th>
<th>Net oil export by country (2004) (mmboepd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Russia 9.2</td>
<td>Saudi Arabia 7.0</td>
</tr>
<tr>
<td>Saudi Arabia 9.0</td>
<td>Russia 6.5</td>
</tr>
<tr>
<td>USA 7.6</td>
<td>Norway 2.9</td>
</tr>
<tr>
<td>Iran 4.0</td>
<td>Iran 2.5</td>
</tr>
<tr>
<td>Mexico 3.8</td>
<td>Venezuela 2.1</td>
</tr>
<tr>
<td>China 3.5</td>
<td>Nigeria 2.0</td>
</tr>
<tr>
<td>Norway 3.2</td>
<td>UAE 2.0</td>
</tr>
<tr>
<td>Canada 2.6</td>
<td>Kuwait 2.0</td>
</tr>
<tr>
<td>Venezuela 2.6</td>
<td>Mexico 1.8</td>
</tr>
<tr>
<td>UAE 2.4</td>
<td>Iraq 1.5</td>
</tr>
</tbody>
</table>

Source: Petroleum Economics Ltd.
Oil and gas exploration has been subject to economic research for decades, but the attention has largely been concentrated on the US oil and gas industry, with some studies also for the United Kingdom. We present insights on the relation between oil and gas exploration activities and economic variables in the highly regulated industrial environment in Norway\(^3\), the third largest net oil exporter in the world. Based on detailed database information from the Norwegian Petroleum Directorate, a unique data set has been developed to cover the full history of three separate regions of the Norwegian Continental Shelf (NCS). This narrow panel data set cover 39 years of exploration history, and has not been subject to econometric studies before.

Microeconomic theory of producer behaviour forms the point of departure for our modelling approach. Based on a theoretical model of oil and gas production, we apply duality principles to derive exploration efforts as a part of the input/output system. Our empirical model is based on the translog profit function approach. We derive a drilling function whereby drilling efforts are explained by oil prices, unit costs, tax pressure, accumulated discoveries and open exploration acreage. Econometric relations for the drilling of exploration wells and appraisal wells are estimated in a dynamic framework that allows for sluggishness and short-term dynamics, as well as persistent long-term relations between drilling efforts and the explanatory variables. We also provide specific projections to illustrate how exploration activity is affected by changes in oil prices, unit costs and regulatory measures like taxes and licensed exploration acreage.

The paper is organized as follows. Section 2 provides an overview of the Norwegian Continental Shelf. A brief survey of previous related research is offered in Section 3, before a simple theory of exploration based on producer behaviour and duality principles is outlined in Section 4. The empirical specification is derived in Section 5 and our data set is presented in Section 6. Econometric results are presented and discussed in Sections 7 and 8, respectively, before some concluding remarks are offered in Section 9.

2. The Norwegian Continental Shelf

The Norwegian Continental Shelf (NCS) is a relatively young oil and gas province. Its petroleum potential was ignited among geologists by the discovery of the Groningen gas field in the Netherlands in 1959. The first discovery on the NCS was made in 1969, and the Ekofisk field was put on stream two years later. A number of discoveries were made in subsequent years, and these laid the foundations for the evolution of a new and important industry in Norway, and a supplying region for US and European oil and gas markets. Today, 48 NCS fields contribute to the total Norwegian oil and gas production. In 2004, total petroleum production came in at 3.2 bn scm, with a natural gas share of 30 per cent. According to the Norwegian Petroleum Directorate (NPD), total oil production will remain remain relatively

\(^3\) For an overview of the regulatory regime in the Norwegian oil and gas industry, see Glomsrød and Osmundsen (2005).
constant until 2007, and is then expected to enter a phase of gradual decline. On the other hand, gas production is seen to increase another five years from today – to plateau levels of around 120 bn Sm³ per year. For a thorough industry and policy overview of the NCS, see Ministry of Petroleum and Energy (2005).

Figure 2. Remaining NCS reserves by company (M sm³ o.e.)

Regulated gradualism has been a guiding principle for the development of the Norwegian oil and gas sector. Exploration and production activities were restricted to the North Sea for nearly 20 years, before a piecemeal northward expansion was initiated. Exploration started in the Norwegian Sea and in the Barents Sea in 1980, after nearly 200 exploration wells had been drilled in the North Sea. The key regulatory instrument for exploration and production is the production license, which gives the exclusive right for exploration and production of oil and gas within a specified area, usually referred to as a block. Production licences on the NCS are awarded through discretionary licensing rounds, and licensees retain ownership for the produced petroleum. A specific number of blocks are announced by government, and the companies prepare applications based on published criteria. Based on submitted applications, the Ministry of Petroleum and Energy (MPE) decide on a partnership structure for each license, and an operator is appointed to take responsibility for the day-to-day activities under the terms of the license. Typically, a production license is awarded for an initial exploration period that can last up to 10 years. However, specified obligation regarding surveying and/or exploration drilling must be met during the license period. At completion of this kind of obligations, licensees generally retain up to half the area covered by the licence for a specified period, in general 30 years.

Source: Norwegian Petroleum Directorate (NPD).

4 Applicants may apply individually or in groups. For details, see the brochure for the recent 19th licensing round: http://odin.dep.no/filarkiv/259455/TFO_05_Eng.pdf).
After three decades of production, NPD estimates indicate that some 70 per cent of the expected total oil and gas resources remain in the ground, nearly 40 per cent of total resources are yet to be matured to proven reserves and 25 per cent of total resources remain undiscovered. To sustain production levels in the longer term, available exploration acreage, drilling activity and discovery rates will be important success factors. The parts of the NCS that the Parliament has opened up for petroleum activities are the bulk of the North Sea, Norwegian Sea and southern Barents Sea (cf. map in Appendix 1). According to NPD’s estimates (Norwegian Petroleum Directorate (2005)), undiscovered oil and gas resources are split approximately equally between these three regions\(^5\). However, the degree of maturity varies significantly across the three regions, implying that the exploration challenges and strategies cover a broad spectre.

The first exploration well was struck in the North Sea in 1966, but it took 30 wells and three years before the breakthrough was made with the discovery of the Ekofisk field late in 1969. Since then, another 1,200 exploration and appraisal wells have been drilled, of which some 850 are classified as exploration wells. With more than 600 exploration wells, the North Sea represents approx. ¾ of the total historical exploration activity on the NCS. 160 exploration wells have been drilled in the Norwegian Sea, whereas only 63 exploration wells have been drilled in the under-explored Barents Sea.

Mature areas like the North Sea are characterized by well-established exploration models, minor technical challenges and installed neighbouring infrastructure. Therefore, expected discovery rates are often relatively high for such areas. But average discovery size is usually also limited. On the other hand, frontier areas are distinguished by poorer understanding of the geology, technological challenges and no installed infrastructure. Thus, exploration risk is higher (lower success rates), but so are the expected rewards (higher average discovery size). Average annual discovery rates have hovered between 30 and 40 per cent for the NCS, and they have been trending upward since the early 1970s (NPD (2005)). On the other hand, average discovery size has trended downward, from an average around 40 M Sm\(^3\) o.e. before 1985 to an annual average between 5 and 10 M Sm\(^3\) o.e. over the last 5 years. Whereas the early “elephant” discoveries were largely oil fields\(^6\), discoveries of natural gas have become gradually more important over the last 20 years.

Since 2001, we have seen a downward trend in exploration activity on the NCS, and the number of major discoveries has also fallen quite sharply. Possible explanations are discussed by Kvaal et al. (2005). Industry structure, policy design, financial market pressure and changes in company behaviour (Osmundsen et al. (2005)) are some of the factors presented as explanatory variables.

#### 3. Previous research

\(^5\) However, the distribution of discovered resources is dominated by the North Sea (3.4 M Sm\(^3\) o.e.), whereas the importance of the Norwegian Sea (1.6 M Sm\(^3\) o.e.) and the Barents Sea (0.2 M Sm\(^3\) o.e.) is far less prominent in terms of the medium term development and production potential.

\(^6\) The discovery of the Troll field in 1983 was a notable exception, with its unprecedented resource estimate of 1.3 bn Sm\(^3\) natural gas.
The combination of geological and economic variables in empirical models of exploration dates back some 40 years. By many, Fisher (1964) is claimed to have opened this field of research with his seminal econometric studies of US oil and gas exploration. Fisher estimated equations for the drilling rate, success rate and the discovery rate for different US Petroleum Administration Defence Districts (PADD) over the period 1946-1955. Explanatory variables included oil prices, seismic crews and proxy variables for drilling costs.

Based on extended versions of the same data set, updates and extensions of the Fisher framework was presented in a range of papers for the US oil and gas industry over the following 15 years. Gradual improvements were due to improved data availability, more sophisticated modelling and additional explanatory variables. Erickson and Spann (1971) expanded the set of explanatory variables and detected a connection between technological ability and success rates. The early estimated models did not produce very robust results. Concentrating on gas exploration, Pindyck (1974) estimated a similar model on a broader data set, with quite different results from those of Fisher (1964) and Erickson and Spann (1971). These early Fischer models had a simple structure that largely could be justified based on economic fundamental principles. However, the theoretical foundation was gradually improved, as dynamics and uncertainty were introduced explicitly in the producer’s optimisation problem.

Pindyck (1978) was the first to open for the aspects of intertemporal maximisation, as he introduced the interest rate in his drilling equation. Kolb (1979) concentrated on oil-prone districts in a slightly more disaggregated approach, without much improvement in the econometric model diagnostics.

Three different perspectives have been applied to study the economics of exploration. The most common is based on aggregate data, for regions, countries or groups of countries. All the above articles fall into this category. An alternative approach is to see exploration behaviour from the company’s perspective, and base the econometric models on micro data (e.g. Ghouri (1991)). The third alternative is to consider individual oil and gas fields as the principal economic unit, focusing specifically on the life-cycle dynamics and vintage issues of oil and gas production (e.g. Iledare (1995)).

A requirement for theory-based econometric research on the oil and gas industry is that the data set is generated in an industrial environment mainly guided by commercial principles. Further, the quality of the data will usually increase, the longer the history of the actual activity. This explains why most of the work that has been done on the application of economic theory to observed exploration behaviour, is done in USA. A survey of empirical exploration models for the US oil and gas industry is offered by Dahl & Duggan (1998).

Into the 1990s, some studies also emerged for the exploration and production of oil and natural gas on the United Kingdom Continental Shelf (e.g. Pesaran (1990), Favero & Pesaran (1994)). These models typically departed from an integrated,
dynamic optimisation problem, and produced plausible, estimated equations for exploration, development and production. However, they fail to produce robust estimates in support of intertemporal maximisation.

Later studies, especially for the US oil and gas industry, have relaxed the assumption of intertemporal behaviour, and several have returned to the period-by-period optimisation approach (e.g. Iledare & Pulsipher (1999), Farzin (2001)). This behavioural assumption is also applied by Børnes et al. (2004). Still, their econometric specification of oilrig activity for a panel of non-OPEC countries is indeed dynamic. Our model will follow a similar line of thought.

The geological approach to exploration and production modelling emphasizes the importance of physical factors like cumulative production and technological conditions, whereas economic factors are typically not accounted for. The key reference to this approach is Hubbert (1962), where it is argued that cumulative production evolves according to a logistic growth model. A standard result of this literature is that the success rate from exploration will depend on the maturity of the petroleum province in question.

Since the mid 1970s (Bouhabib (1975)), accumulated measures of reserves, drilling efforts and discoveries have typically been included in the econometric exploration models. The role of these variables has been to account for the dampening depletion effects on exploration success and consequent reserve additions. Moroney & Berg (1999) illustrate that model diagnostics and forecasting performance of simple Hubbert models improve when economic and policy variables are included.

Over the last 15 years, general depletion mechanisms have been supplemented with theories for infant-industry accumulated scale economies, stemming from learning-by-doing effects in exploration activities (see for example Quyen (1991)). Before any wells are drilled at all, the knowledge of the exploration area is sparse, based only on seismic research and geological studies. As soon as drilling is initiated, a flood of information becomes available to the explorer. The value of this additional information is wide-ranging, as it may serve as decision support not only for the prospect in question, but also for neighbouring prospects – and possibly for the whole area in question. Few efforts have been made to incorporate this kind of industrial dynamics in empirical models. One exception is Hendricks & Porter (1996), who apply game theory to study the impact of information externalities on drilling behaviour in the Gulf of Mexico. Rehrl & Friedrich (2005) also account for both learning and depletion effects in an applied logistic growth framework for long-term analysis of oil production and price formation.

7 To test for the validity of this assumption, interest rate variables were included in the preliminary estimation of our model. However, we were unable to establish plausible and robust estimates of their coefficients.
4. A simple model of exploration

The key differentiating factor of the production technology among oil and gas companies is the reserve concept. The stock of oil and gas reserves represents a crucial input in this production process. But oil and gas reserves are not readily available in well-functioning input markets, like the case is for most other traditional inputs. Rather, oil and gas companies have to invest in very risky exploration activities, to support and grow the base of oil and gas reserves, and to sustain subsequent production activity over the longer term. A simple sketch of the production structure in a representative oil and gas company is provided in Figure 3.

The technology of the oil and gas industry can be captured by a standard production function, whereby traditional inputs like capital, labour and energy are combined with reserves in the production of oil and gas. Abstracting from acquisitions, there are two primary sources of organic reserve growth. First, the companies may engage in exploration drilling. Traditionally, this activity has offered great rewards for the successful companies, but the associated risks are also high. Second, the companies may invest capital and efforts to increase the recoverable reserves in producing fields. Techniques for active reservoir management have come far, and include carefully planned drilling of new production wells, various injection techniques and other measures to increase recovery and maximise the economic value of reservoirs in production and their associated infrastructure. The risks associated with this type of investments are generally lower than for exploration activities, but so are also the expected rewards.

Figure 3. Stylized production structure in an oil and gas company

Our theoretical point of departure is a description of the technology structure associated with the development of oil and gas reserves. As illustrated in Figure 3, oil and gas reserves may be seen as input in the final production process. At the same time, reserves are the result of a production process of its own, and both the efficiency of this process and the stock of oil and gas reserves contributes significantly to the value of the firm. This raises the question of how reserves should be treated in a description of production technology.
According to Dahl & Duggan (1998), the majority of previous studies use a primal specification of the producer’s optimisation problem, whereby traditional inputs \((x_t)\) are combined with reserves \((r_t)\) in a production function for oil and natural gas \((q_t = f(x_t, r_t))\). We combine this approach with duality principles of microeconomic producer behaviour, and derive the production of oil and gas reserves from a restricted profit function. Oil and gas producers maximise profits of from products subject to output prices, input prices and technology constraints given by their production function. The restricted profit function of reserve-generation is therefore given by:

\[
\pi = \pi(v_t, w_t, z_t) = \max_{r_t} \quad v_t r_t - w_t x_t \quad s.t. \quad f(x_t) \geq r_t,
\]

where \(v_t\) is the marginal value of new oil and gas reserves, \(w_t\) represents traditional input prices and \(z_t\) is a vector of state variables to incorporate technology and policy conditions. Candidates for the \(z_t\) vector include licensed exploration acreage, tax variables, accumulated discovered oil and gas reserves, seismic activity and technology trends. Traditional inputs like capital, labour and energy are represented by \(x_t\), whereas the \(r_t\) represents the output from the exploration process. Hotelling’s lemma now permits the derivation the optimal unit reserve requirement in production directly from the profit function in Equation (1):

\[
r_t^* (v_t, w_t, z_t) = \frac{\partial \pi(v_t, w_t, z_t)}{\partial v_t},
\]

where an asterisk is added to \(r_t^*\) to distinguish the optimal reserve requirement from the observed level. Positive changes to marginal value of new reserves are expected to stimulate reserve additions – and drilling efforts. The marginal impact of changes to the state variables \((z_t)\) will depend on the specific nature of these variables.

Our model looks away from intertemporal optimisation, and implicitly assumes that producers maximise their profit in a period-by-period framework. The strongest argument for this simplification is that intertemporal maximisation is not supported by previous attempts to explain the dynamics of oil and gas exploration, especially not in Europe (see for example Pesaran (1990)). Farzin (2001) provides a more thorough discussion of this assumption of period-by-period maximisation among oil and gas companies\(^5\). But our theory will have to face up to data from the real world. Equation (2) neglects any short-term dynamics. The presence of price expectations and/or adjustment lags in the impact of the explanatory variables may cause exploration activity to differ from the desired level defined by Equation (2).

We recognize that the data-generating process may well be characterised by sluggishness and dynamics, even if it is not the result of an intertemporal optimisation problem. The availability of reserves may be disturbed by incomplete access to secondary exploration inputs (e.g. exploration acreage, drilling rigs and personnel), lead-times in the exploration technology, uncertainty about future prices,
as well as regulatory restrictions. We assume that any deviation from the optimal reserve requirement is adjusted by a constant fraction each year:

\[
\frac{r_t}{r_{t-1}} = \left( \frac{r_t^*}{r_{t-1}} \right)^\gamma
\]

where an asterisk is appended to separate the optimal reserve requirement \((r_t^*)\) from the observed level \((r_t)\). \(0 < \gamma < 1\) specifies the speed of adjustment. The following logarithmic form will have its parallel in our empirical specification:

\[
\ln r_t - \ln r_{t-1} = \gamma (\ln r_{t-1} - \ln r_{t-1})
\]

Estimated results from previous studies of exploration behaviour have generally been in favour of the adaptive-expectations hypothesis for oil prices (e.g. Farzin (2001)), and our approach therefore assumes a partial adjustment process also for oil price expectations:

\[
\frac{p_t^e}{p_{t-1}^e} = \left( \frac{p_{t-1}^e}{p_{t-1}^e} \right)^\phi
\]

where \(p_t\) is the spot price of crude oil, and \(p_t^e\) is its expectation. The speed of adjustment is regulated by the adjustment parameter \(0 < \phi < 1\). Taking logarithms, and solving for \(p_{t-1}\) yields:

\[
\ln p_t^e - \ln p_{t-1}^e = \phi (\ln p_{t-1}^e - \ln p_{t-1}^e)
\]

\[
\Rightarrow p_t^e = \phi p_{t-1}^e - (1-\phi) p_{t-1}^e
\]

Iterating substitutions for lagged price expectations \((p_t^e)\) now implies that price expectations for period \(t\) can be written as a weighted sum of historical prices:

\[
p_t^e = \phi \sum_{i=1}^T (1-\phi)^{t-i-1} p_{t-i}
\]

where the weights decline asymptotically as we move further into the past. The length of memory in expectations formation is determined by the adjustment parameter \(\phi\). All the information that shapes price expectations for period \(t\) is thus embedded in the history of observed prices. Our empirical specification will support both partial adjustment in exploration efforts, and adaptive expectations for the oil price. Further, it will allow exploration drilling to be influenced not only by price expectations, but also by fluctuations in actual oil prices.
5. Empirical specification

We need a specification of the profit function in Equation (1) that can be estimated by econometric methods, also taking account of the statistical errors in the data-generating process. A flexible and tractable alternative is the translog function, originally introduced for the dual cost function by Christensen et al. (1971), and applied in a wide range of empirical studies of production technology over the last 30 years. For econometric specifications, the number of parameters will easily grow very large with this type of flexible functional form. However, exploration is undertaken to develop reserves, which represent the most crucial input to production of oil and natural gas. It is therefore reasonable to expect that substitution possibilities between reserve development and traditional inputs are limited. For our case, the translog profit function may therefore be specified as:

\[
\ln \pi (\cdot) = \alpha_0 + \alpha_e \ln v_t^e + \frac{1}{2} \alpha_v (\ln v_t^e)^2 + \sum_{j=1}^{n} \left[ \alpha_i + \alpha_{vz,ij} \ln v_t^e + \sum_{i=1}^{m} \alpha_{z,ij} \ln z_{it} \right] \ln z_{jkt}
\]

where \( v_t^e \) is the expectation for the marginal value of new resources. Subscript \( k \) is introduced to signal variation in state and policy variables \( (z_{ikt}) \) across the three regions of our data set. Partial differentiation with respect to \( v_t^e \) now yields the following expression for the supply of reserves:

\[
\frac{\partial \ln \pi(\cdot)}{\partial \ln v_t^e} = r_{it}(v_t^e, z_{ik}) = \alpha_v + \alpha_{vz} \ln v_t^e + \sum_{j=1}^{n} \alpha_{vz,ij} \ln z_{jkt}
\]

The relevant characteristics of the supply of new reserves are now described by Equation (10). \( \alpha_{vk} \) is a region-specific constant term, \( \alpha_v \) represents the own-price elasticity and \( \alpha_{vz,ij} \) gives a measure of the sensitivity to changes in the state variables.

Reserves are depleted through annual production. To sustain production in the long term, oil and gas companies have to strive continuously to replace their annual extraction by new reserves. Additions through exploration \( (e_i) \) and extension of reserves in producing fields \( (i_t) \) will contribute to the growth of reserves. For oil reserve levels to be maintained over time, reserve requirements for production \( (r_t) \) will have to be balanced by efforts to replace reserves. Over the life-time of an oil and gas province, the accumulated sum of reserves will therefore be given by:

\[
\sum_{t=0}^{T} r_t = \sum_{t=0}^{T} e_t + \sum_{t=0}^{T} i_t
\]

---

8 For a discussion on choice of aggregator function, see Fisher et al. (2001).
9 We allowed for general wage and interest rate variables in our introductory estimation. However, based on statistical evaluation, none of these variables justify a position in the empirical model.
The focus of our analysis is the contribution to reserve growth from exploration activities. Reserve additions from exploration ($e_t$) may be seen as a combined result of actual drilling activity ($d_t$), the success ratio ($s_t$) and average discovery size ($m_t$):

$$ e_t = d_t \cdot s_t \cdot m_t $$

Equation (12) states that reserve-additions from exploration in period $t$ is the product of drilling efforts ($d_t$) and drilling efficiency ($s_t \cdot m_t$). The main focus of our study is on drilling efforts, and in the following exposition we will therefore concentrate on the $d_t$ variable of Equation (12).

As indicated by the partial adjustment mechanism for exploration activity and the adaptive expectations hypothesis for prices, there is reason to believe that the data-generating process is dynamic by nature. This has to be taken into account in our econometric specification. In econometric terms, both the dependent and the independent variables in Equation (10) are likely to be non-stationary. If these variables have a trend, their linear combination may well also have a trend, and the error term $u_t$ will fail to meet the requirements of standard estimation methods. In that case, direct estimation of the parameters will produce inefficient coefficient estimates, and the validity of statistical inference is therefore problematic. Further, direct estimation of the structural relation will fail to describe the dynamics of the data-generating process properly. However, if the variables of Equation (10) are integrated of degree 1 ($I(1)$), their difference will be stationary ($I(0)$): $x_t \sim I(1) \Rightarrow \Delta x_t \sim I(0)$.

A key result from the literature on error-correction models and co-integration is that a linear combination of non-stationary variables will produce a stationary error-term. If such a combination is represented by Equation (10), we say that the variables are co-integrated, and their set of coefficients defines the co-integrating vector. In this case, we may estimate the dynamics of the process in an error-correction specification of drilling activity:

$$ \Delta \ln d_{kt} = a_{0k} + a_1 \Delta \ln d_{k,t-1} + a_2 \Delta \ln v_r^n + \sum_{i=3}^{n+2} a_i \Delta \ln z_{ikt} $$

$$ + \lambda \ln d_{k,t-1} + b_1 \ln v_{r,t-1} + \sum_{i=2}^{n+1} b_i \ln z_{ikt-1} + u_{kt} $$

where $a_i$ and $b_i$ are the coefficients to be estimated, and $u_{kt}$ is an error-term with the usual white noise characteristics. Equation (13) states the change in the dependent variable as a function of lagged changes in independent variables and the lagged deviation from the underlying structural equilibrium, as defined by Equation (10). The error-term will now be stationary and well-behaved, provided that a co-integrating vector is indeed identified by Equation (10).

10 A pioneering reference to the literature on cointegration and error-correction is Engle & Granger (1987). A later survey is represented by Watson (1994).
The short-term dynamics of the model is now described by the set of \(a\)-coefficients. These coefficients may be interpreted as instantaneous and temporary effects on the dependent variables from changes in the explanatory variables. The cointegrating vector is now described by the coefficients of the level variables of Equation (13). \(\lambda\) represents the speed of adjustment, or the error-correction coefficient. The explicit relation between the \(b_j\) coefficients in Equation (13) and the underlying structural relationship in Equation (10) are given by (Bårdsen (1989)):

\[
\alpha_{eq} = -\frac{b_1}{\lambda}, \quad \alpha_{ev} = -\frac{b_2}{\lambda}, \quad \alpha_{vz,j} = -\frac{b_j}{\lambda}, \quad i = 2, \ldots n+1
\]

Ordinary least squares estimation may now be applied directly on Equation (13) to obtain unbiased and efficient estimates for both short-term dynamics and the long-term underlying structure of our model. However, the number of parameters to be estimated is quite large, and direct estimation on Equation (13) therefore requires a sufficiently large data set. An alternative for estimation on smaller data samples is the 2-step procedure, described by Engle & Granger (1987). In the first step, Equation (10) is estimated by OLS to determine the structural relation. The estimated residuals (\(ecm_{rt}\)) from this estimation will now correspond to section of level variables in Equation (15). In a second step, we may therefore estimate the short-term dynamics of the model based a modified version of the error-correction model:

\[
\Delta \ln k_{it} = a_{0t} + a_1 \Delta \ln d_{k_{t-1}} + a_2 \Delta \ln v' + \sum_{i=3}^{n+2} a_i \Delta \ln z_{it} + \lambda \left[ecm_{k_{t-1}}\right] + u_{it}
\]

Short-term dynamic effects may now be derived directly from the estimated version of Equation (15), whereas the structural equilibrium is given by Equation (10).

6. Data set and variables

Our data set is retrieved from the data bases of the Norwegian Petroleum Directorate, who has collected and processed information and statistics on Norwegian oil and gas activities since the early 1970s. We have time series for all variables over the period 1966-2004, split between the three major offshore regions on the Norwegian Continental Shelf\(^1\). The upper bound for the number of observations in our panel is 39x3 = 117. However, observations are missing for some of the regions in some of the years. For example, the Norwegian Sea and the Barents Sea were not opened for exploration drilling before 1980. Key variables of the data set are illustrated in Figure 4.

Panel 1 and 2 in Figure 4 illustrate NCS drilling activity, with a maximum plateau level between 1980 and 1995. Exploration drilling on the NCS has been on a downward trend over the last 10 years, in spite of the recent increase in oil prices.

\(^1\) The North Sea, The Norwegian Sea and The Barents Sea, cf. map in Appendix 1.
Figure 4. Key variables of the data set

Exploration and appraisal wells

"True Wildcats" by region

Open exploration acreage

Petroleum resource growth

Sources: Oil price from EcoWin, tax payments from the Norwegian Ministry of Finance. All other numbers are from the Norwegian Petroleum Directorate.
Our data for drilling activity stem from NPD’s data base system, which provides detailed individual characteristics on 3840 wells over the period 1966-2004. 30 per cent (1201) of these wells relate to exploration. Further, exploration-related wells are split between exploration (844) and appraisal wells (367).

We regress the sum of exploration and appraisal wells, as well as the two specific subgroups, against the explanatory variables. We also include a variable for “true wildcat” wells, as NPD’s definition of exploration wells is a bit wide to resemble the international concept of wildcat wells. Our wildcat variable is defined as initial exploration wells in blocks where no resources previously have been discovered. Thus, there can only be one “true wildcat” in each of the licensed exploration block on the NCS. With this definition, the number of “true wildcat” wells totals 245. Historical drilling activity is illustrated in the first three charts of Figure 4.

Our point of departure for the marginal value of discovered resources \( v_t^e \) is the oil price \( p_t \). However, observed market volatility, economic theory and previous research suggest that the oil and gas companies base their exploration and investment decisions on some sort of forward-looking expectations for the oil price, rather than the actual, observed average spot price. As described above, we apply the adaptive expectations hypothesis for oil prices, and calculate expectations \( P_t^e \) from Equation (8). Both actual and expected prices were tried out in the estimated models, with interesting results for short-term and long-term effects. The oil price chart in Figure 4 illustrates actual and expected oil prices, with an adjustment parameter \( \phi \) of 0.65. This estimate for \( \phi \) is calibrated from previous relevant literature (e.g. Dahl & Duggan (1998) and Farzin (2001)).

The marginal value of discovered resources will also depend on the cost of development and production, and on the general tax pressure on the industry. Our proxy for unit cost of production is a series for total production costs (including transport and tariffs for natural gas) from the NPD. Following Iledare (1995), we divide this cost series by total production, and then compute the unit production cost \( c_t \) as a ratio of the expected oil price. A similar approach is applied to capture the general tax pressure. Total tax payment per unit of production \( t_t \) is calculated as share of the oil price. Data prohibits the application of adaptive expectations for unit cost and tax. These variables are therefore computed as historical averages over the last five years. This gives us a proxy for how much of the expected net value that is consumed by production cost and tax, and our variable for the marginal cost of discovered resources is now given by:

\[
(16) \quad v_t^e = p_t^e \cdot (1 - c_t) \cdot (1 - t_t)
\]

12 Dated brent blend, USD/bbl. Based on tests for both NOK and USD denomination, our econometric results favoured the oil price measured in USD.
13 We have tested the properties of our models for a range of values for the price adjustment parameter \( \phi \). The properties of the coefficient estimate (and the model diagnostics) are quite robust to varying values of \( \phi \) below 0.5, but deteriorates significantly as \( \phi \) is increased above 0.7.
In our econometric models, we include both the expected marginal value of resource additions \((v_t^e)\), as well as the actual oil price \((p_t)\), as cash-flow effects on exploration may be captured by the latter.

Oil and gas production started on the Ekofisk field in 1971, and increased by an annual average of 16 per cent up to the turn of the century. Over the last three years total production has stabilized around 260 M sm\(^3\) per year (4.5 mmboepd), as illustrated by chart 4 in Figure 4. The large, legacy oil fields of the North Sea are gradually going into decline, and this decline is only partly offset by new fields in the Norwegian Sea. Consequently, total oil production peaked at around 200 M sm\(^3\) (3.4 mmboepd) in 2001. Natural gas has become more and more important, and is now a crucial contributor to continued total production growth on the NCS.

The two bottom panels of Figure 4 illustrate how exploration acreage \((acrt)\) have been regulated by The Norwegian Government. 42,000 km\(^2\) were awarded in the 1\(^{st}\) licensing round in 1965, ahead of the opening of the Norwegian Continental Shelf. Returns to Government reduced the accumulated open exploration acreage towards the mid 1970s, before new licensing rounds added new frontier acreage in the Norwegian Sea and in the Barents Sea from 1980. Licensing policies have been adjusted over the last few years, to spur exploration activity, and large areas were awarded in mature areas and frontier areas both in 2003 and 2004. Still, exploration activity remains stagnant. This remains a puzzle for Norwegian authorities, and to some extent also for us.

7. Estimation and testing

As described in Section 5, our econometric model consists of two parts. First, we establish the long-term structural relation between drilling efforts and the explanatory variables. Second, we estimate the short-term dynamics in the data in an error-correction model. This approach allows a separation between temporary and persistent (structural) effects, as well as an explicit representation for the adjustment process towards the structural equilibrium. All estimations are performed with ordinary least squares, and regional dummy variables \((D_1, D_2)\) are included in our structural relations to allow for variation in the intercepts across the three regions (DVLS). Our estimation strategy follows a general-to-specific approach, starting out with a full-blown model, including all explanatory variables. We have tested for a variety of lag specifications, and have largely retained the variables and lags that could justify a position in the model based on estimated coefficient qualities and more general model diagnostics. From this approach we establish 4 preferred models for the structural relation in Equation (10), and include the estimated residuals from these models in a dynamic error-correction specification.

Before we present the estimates for the structural and dynamic models, we include a note of caution with respect to co-integration. Our hypothesis is that the structural equilibrium of our exploration model can be described as a cointegrating vector, and we would like to specify a dynamic representation of the relationship as an error-
correction model. A critical requirement in this respect is that our structural equilibrium is indeed characterized by co-integration. Strictly speaking, our data set is a panel – consisting of three time series over 39 years. A consensus is yet to be reached on how to test for co-integration in panel data. Several tests have been developed, but a challenge of our data set is that the series of estimated residuals will contain gaps due to the imbalance of our panel\textsuperscript{14}. We have therefore tested the stationarity properties of all our explanatory variables separately for each of the three regions, applying both Dickey-Fuller and Phillips-Perron procedures and test ratios\textsuperscript{15}. Detailed results from these tests are presented in Appendix 3, including results also for the aggregate series for the total NCS. The hypothesis of non-stationarity in the estimated residuals is rejected in 14 out of 15 cases – and on a 99 per cent level in 7 out of 15 cases. These results suggest that we have the necessary support for our specification of error-correction models for NCS exploration efforts.

### Table 1. Estimated structural relations for NCS exploration efforts

<table>
<thead>
<tr>
<th></th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
<th>Model 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dependent variable: $\ln d_t$ (E&amp;A)</td>
<td>All wells</td>
<td>Appraisal wells</td>
<td>Exploration wells</td>
<td>True wildcats</td>
</tr>
<tr>
<td>Intercept</td>
<td>-0.170</td>
<td>-1.384</td>
<td>0.588</td>
<td>1.269</td>
</tr>
<tr>
<td></td>
<td>(1.512)</td>
<td>(0.655)</td>
<td>(1.725)</td>
<td>(2.370)</td>
</tr>
<tr>
<td>$D_1$</td>
<td>-0.948</td>
<td>-0.830</td>
<td>-0.964</td>
<td>-0.398</td>
</tr>
<tr>
<td></td>
<td>(0.135)</td>
<td>(0.177)</td>
<td>(0.153)</td>
<td>(0.210)</td>
</tr>
<tr>
<td>$D_2$</td>
<td>-1.621</td>
<td>-0.937</td>
<td>-1.532</td>
<td>-0.705</td>
</tr>
<tr>
<td></td>
<td>(0.217)</td>
<td>(0.476)</td>
<td>(0.247)</td>
<td>(0.330)</td>
</tr>
<tr>
<td>$\ln v_t^e$</td>
<td>0.244</td>
<td>0.184</td>
<td>0.242</td>
<td>0.016</td>
</tr>
<tr>
<td></td>
<td>(0.152)</td>
<td>(0.158)</td>
<td>(0.173)</td>
<td>(0.233)</td>
</tr>
<tr>
<td>$\ln p_t$</td>
<td>0.259</td>
<td>0.249</td>
<td>0.212</td>
<td>0.041</td>
</tr>
<tr>
<td></td>
<td>(0.147)</td>
<td>(0.194)</td>
<td>(0.167)</td>
<td>(0.241)</td>
</tr>
<tr>
<td>$\ln res_{t-1}$</td>
<td>0.009</td>
<td>0.230</td>
<td>-0.055</td>
<td>-0.311</td>
</tr>
<tr>
<td></td>
<td>(0.059)</td>
<td>(0.081)</td>
<td>(0.068)</td>
<td>(0.094)</td>
</tr>
<tr>
<td>$\ln acr_{t-1}$</td>
<td>0.155</td>
<td>..</td>
<td>0.107</td>
<td>0.213</td>
</tr>
<tr>
<td></td>
<td>(0.130)</td>
<td></td>
<td>(0.148)</td>
<td>(0.203)</td>
</tr>
</tbody>
</table>

**Model diagnostics**

- $R^2$: 0.78, 0.60, 0.66, 0.23
- Obs. (#): 74, 57, 74, 63

\textsuperscript{a) Standard errors in brackets}

\textsuperscript{14} Since 1966, regular drilling has taken place only in the North Sea. Exploration wells have been drilled every year in the Norwegian Sea since the opening of the area in 1980, but there have been both voluntary and required interludes in exploration activities in the Barents Sea (cf. Chart 2 in Figure 2).

Estimated structural equilibrium models are presented in Table 2. Standard errors are also reported, but statements relating to inference have been skipped, as the estimated standard errors are likely to have a bias. The structural elasticity of exploration activity with respect to expected oil prices is stable for Models 1, 2 and 3. The estimated models suggest long-term elasticities with respect to the marginal value of new resources (v\textsubscript{t}e) in the range of 0.27-0.34. This compares well to the results of Ringlund et al. (2004), although their model is based on monthly data for a shorter time period (1995-2002). The stock effect from accumulated oil and gas resources is unstable, and its magnitude and sign vary across the well categories.

According to R\textsuperscript{2}, Models 1, 2 and 3 account for 60 to 78 per cent of the variation in the data set, whereas the estimated Model 4 is quite powerless in statistical terms. We fail to establish a convincing structural relation for the drilling of “true wildcat” wells. Model 4 shows weak performance in important areas. The coefficient estimates are unstable and R\textsuperscript{2} is only 23 per cent.

Table 3. Error-correction models for NCS exploration efforts

<table>
<thead>
<tr>
<th></th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
<th>Model 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Depvar:</strong> Δ ln dt, (E&amp;A)</td>
<td>All wells</td>
<td>Appraisal wells</td>
<td>Exploration wells</td>
<td>True wildcats</td>
</tr>
<tr>
<td><strong>Estimated coefficients</strong> a)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intercept</td>
<td>-0.022</td>
<td>0.006</td>
<td>-0.044</td>
<td>-0.027</td>
</tr>
<tr>
<td></td>
<td>(0.600)</td>
<td>(0.912)</td>
<td>(0.324)</td>
<td>(0.680)</td>
</tr>
<tr>
<td>Δ ln dt\textsubscript{-1}</td>
<td>-0.411***</td>
<td>-0.428***</td>
<td>-0.446***</td>
<td>-0.482***</td>
</tr>
<tr>
<td></td>
<td>(0.000)</td>
<td>(0.000)</td>
<td>(0.000)</td>
<td>(0.000)</td>
</tr>
<tr>
<td>Δ ln v\textsubscript{t}e</td>
<td>0.081</td>
<td>0.048</td>
<td>-0.001</td>
<td>-0.463</td>
</tr>
<tr>
<td></td>
<td>(0.744)</td>
<td>(0.876)</td>
<td>(0.996)</td>
<td>(0.197)</td>
</tr>
<tr>
<td>Δ ln pt\textsubscript{-1}</td>
<td>0.330**</td>
<td>0.440**</td>
<td>0.279*</td>
<td>0.092</td>
</tr>
<tr>
<td></td>
<td>(0.037)</td>
<td>(0.030)</td>
<td>(0.098)</td>
<td>(0.683)</td>
</tr>
<tr>
<td>Δ ln rest\textsubscript{-1}</td>
<td>0.037</td>
<td>0.329**</td>
<td>-0.043</td>
<td>-0.271**</td>
</tr>
<tr>
<td></td>
<td>(0.733)</td>
<td>(0.020)</td>
<td>(0.710)</td>
<td>(0.049)</td>
</tr>
<tr>
<td>Δ ln acr\textsubscript{t\textsubscript{-1}}</td>
<td>0.361**</td>
<td>-0.748** b)</td>
<td>0.422***</td>
<td>0.628***</td>
</tr>
<tr>
<td></td>
<td>(0.013)</td>
<td>(0.012)</td>
<td>(0.006)</td>
<td>(0.002)</td>
</tr>
<tr>
<td>Δ ln ecm\textsubscript{t\textsubscript{-1}} (λ)</td>
<td>-0.779***</td>
<td>-0.893***</td>
<td>-0.884***</td>
<td>-0.949***</td>
</tr>
<tr>
<td></td>
<td>(0.000)</td>
<td>(0.000)</td>
<td>(0.000)</td>
<td>(0.000)</td>
</tr>
<tr>
<td><strong>Model diagnostics</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R\textsuperscript{2}</td>
<td>0.60</td>
<td>0.75</td>
<td>0.67</td>
<td>0.84</td>
</tr>
<tr>
<td>Joint significance</td>
<td>F(6, 61)</td>
<td>F(6, 40)</td>
<td>F(6, 61)</td>
<td>F(6, 39)</td>
</tr>
<tr>
<td>Obs. (#)</td>
<td>68</td>
<td>47</td>
<td>68</td>
<td>46</td>
</tr>
</tbody>
</table>

a) p-values in brackets.

b) Change in open exploration acreage lagged twice for appraisal well model (Δ ln acr\textsubscript{t\textsubscript{-2}})

***) Significant at 99 per cent confidence level.
**) Significant at 95 per cent confidence level.
*) Significant at 90 per cent confidence level.
In the next step, estimated residuals from the models of Table 2 are included as explanatory variables in a dynamic error-correction specification of the models (cf. Equation (14)). Estimated error-correction models are presented in Table 2\textsuperscript{16}. The significance of estimated parameters varies, but test statistics for joint significance suggest that the general power of the models is satisfactory. $R^2$ is in general higher than for the structural relations, and ranges from 0.66 to 0.85. Model 4 shows the highest explanatory power, but again, the price variable performs rather poorly in the explanation of wildcat drilling dynamics.

Observe that that the error-correction coefficient is highly significant for all models, lending additional support for our hypothesis of co-integration in NCS exploration efforts. The estimated error-correction coefficients also suggest a very rapid adjustment process, as they indicate that 70 to 99 per cent of last year’s deviation from the structural equilibrium is eliminated every year\textsuperscript{17}.

Figure 4. Estimated NCS drilling efforts (Model 1: E&A wells)

Figure 4 illustrates how the model captures the pattern in NCS drilling efforts. The structural model for the sum of exploration and appraisal wells forms a smoothing pattern through the more volatile pattern for the observed number of wells. The estimated error-correction model picks up some of the volatility around the structural

\textsuperscript{16}Stationarity tests for the explanatory variables of the error-correction models are presented in Appendix 2.

\textsuperscript{17}An error-correction coefficient above one suggests over-shooting effects in the short-term. For this case, an exogenous shock will produce an oscillating pattern in the convergence towards a new structural equilibrium.

8. Discussion of results

Figure 4 illustrates how the model captures the pattern in NCS drilling efforts. The structural model for the sum of exploration and appraisal wells forms a smoothing pattern through the more volatile pattern for the observed number of wells. The estimated error-correction model picks up some of the volatility around the structural
relation, but we admit that several of the peaks and troughs in exploration drilling remain unexplained.

Observe that our estimated model predicts an increase in exploration drilling since the late 1990s, based on observed values for the explanatory variables. This is sharply at odds with the realised development, as NCS exploration drilling has trended down over the last 5 years – to a record low level 15 exploration and appraisal wells in 2005. This stagnation in NCS exploration spending has developed in spite of increasing oil prices, reduced production costs and continuous and substantial offers of new exploration acreage through several licensing rounds. One explanation might be a shift in industry behaviour over the last few years. After the Asian economic crisis in 1998, temporary financial distress led to a strong focus on cost discipline and short-term profitability across the oil and gas industry. Companies have also been slow to update price expectations after 1998, suggesting that the low oil price environment of the late 1990s may have had persistent effects on exploration behaviour. We believe that this situation is temporary, and that exploration is set to rise as price expectations adjust to the current market situation and the focus among oil and gas companies shift back to long-term reserve-generation and production growth.

Some of our explanatory variables take on robust coefficients in the econometric models. But in general, their magnitude is modest. Our structural relations imply a long-term elasticity from oil prices between 0.4 and 0.5. According to Dahl & Duggan (1998), the average of estimated oil price elasticities of US exploration exceeds 1. This suggests that the exploration response to price changes is lower in a regulated, high-tax environment like the Norwegian than for USA and United Kingdom. Ringlund et al. (2004) estimate error-correction models for rig activity in six global regions. Their results also indicate that price elasticities of exploration vary inversely with the degree of regulation.

\[ d_t = D_t \cdot p_t, \quad \text{where} \quad D_t = \begin{cases} 1 & \text{if } \Delta p_t > 0 \\ 0 & \text{if } \Delta p_t < 0 \end{cases} \]

When introduced in our econometric models, the \( d_t \) variable took on negative coefficients both for the structural relation and for the error-correction models, but the t-values were just too low to justify a position in the preferred models.

This view is also supported by the latest (quarterly) oil and gas investment survey from Statistics Norway. According to the survey, oil and gas companies on the NCS plan for a 70 per cent increase in exploration spending from 2005 to 2006. This outlook is set to reduce the deviation from our structural relation considerably.
Empirical research suggests that cash-flow variables dominate capital-cost variables in the explanation of investment behaviour, (e.g. Caballero (1999), Stein (2003), Bertrand & Mullainathan (2005)). Oil and gas exploration is no exception. As pointed out by Reiss (1990), risky investments like exploration are usually funded by internal funds, thereby strengthening the link between cash flow and exploration spending. In our model, there are three variables that are linked to current cash-flows. Current oil price ($p_t$) is one of them. The two other are the unit cost ($c_t$) and unit tax variables ($t_t$), whose effect goes via the coefficient for the marginal value of new resources ($\nu_t^e$).

Figure 5 illustrate some marginal effects of shifts in the explanatory variables. Again, we apply Model 1 (exploration and appraisal wells) as a reference, and compute the effects of 5 different shifts on a 10-year horizon. The first scenario illustrates the effect of a 10 per cent permanent increase in the oil price. As expectations adapt only gradually, the response in terms of exploration efforts is also sluggish. It takes 5 years to accumulate 90 per cent of long-term effect of 5 per cent.

**Figure 5. Simulation of marginal effects on drilling efforts**

The second trajectory in Figure 5 illustrates the effect of an instantaneous and permanent increase in oil price expectations of 10 per cent. As illustrated, such a shift involves more than a permanent shift in oil prices, as we now assume that expectations adjust without any lag ($\phi = 0$). This may not seem very realistic, but is included to illustrate that both the two estimated price effects of our model ($p_t$ and $\nu_t^e$) now come into effect. The result is a quite sharp, temporary response in exploration drilling, with a maximum at 8.1 per cent in year 2 – before a gradual approach of the long-term effect of 5 per cent is introduced.
In a similar fashion, Figure 5 also illustrates two scenarios for shifts in the unit cost ($c_i$) and unit tax ($t_i$) ratios. In general, exploration drilling efforts are also not very sensitive to cost and tax changes, and our scenarios demonstrate that it takes large shifts to produce effects that are worth mentioning. Our two scenarios are based on a positive shift of 10 percentage points in the cost and tax shares, respectively. An approximate interpretation is a cost or tax increase that reduces the expected cash-flow by 10 per cent. The effect is a reduction in exploration drilling by 2.9 and 3.2 per cent, respectively. The sluggishness is caused not only by the error-correction mechanism, but also by our simplified adaptive expectations formation for these variables, whereby their 5-year lagging average is the relevant figure for our model. Our tax variable is a crude proxy for the general regulatory pressures on the industry, and one should be careful not to impose too clear-cut conclusions on the links between tax and exploration activity based on our models. An obvious deficiency of our approach is the neglect of finding and development costs. Another is that our tax indicator is an average measure, whereas the companies are more likely to base their decisions on considerations of marginal tax rates\(^{21}\). All the same, our models do suggest a link a link between tax payments and exploration activity.

The estimated structural relations establish a persistent effect between the extent of open exploration acreage ($ac_{rt-1}$) and exploration drilling. As illustrated in Figure 4, this effect is very small for the sum of exploration and appraisal wells. This is the case for all our structural relations, and the limited long-term impact of new exploration acreage is also clearly illustrated by the last scenario of Figure 5. However, there are temporary effects that provide interesting insights. Our error-correction models include somewhat more substantial license round effects. According to our results, an increase in exploration acreage of 10 per cent will increase the drilling of exploration wells by 3 per cent in the short-term, and 1.2 per cent in the longer term. This suggests that there are short-term stimulative effects on exploration activity, whenever the Government offers new, attractive and unexplored acreage. But the effect dwindles rapidly, as only the most attractive prospects are drilled immediately (see Hendricks & Porter (1996)).

State variables for industrial maturity are usually included in empirical studies of exploration behaviour and reserve additions (Dahl & Duggan (1998)). An important for the inclusion of the resource stock ($res_i$) and open exploration acreage ($ac_{r_i}$) in our analysis has been to capture the vintage dynamics of the Norwegian Continental Shelf. However, we have not been able to establish a dampening effect on exploration activity from the e.g. the stagnating production. Reserve growth will slow as an oil and gas province matures, and the exploration potential is exhausted. However, exploration effort is only one of the factors behind reserve growth. Other important factors are discovery rates and average discovery size (cf. Equation (12)), and these variables are clearly on a downward trend on the NCS.

\(^{21}\) However, the Norwegian tax system is close to being linear, implying that the difference between marginal and average tax rates is small. Moreover, the average tax rate is the most relevant tax parameter for country entry and exit decisions (see Olsen & Osmundsen (2002, 2003)).
According to the structural relationships in Table 1, the volume of accumulated discoveries (rest) have a positive impact on appraisal wells, a negligible impact on exploration wells, and a clearly negative impact on the drilling of “true wildcats”. To shed light on this pattern, observe that there is an implied sequential relation between our well categories. By definition, “true wildcat” wells have to be the first in their areas. NPDs definition of exploration wells imply that these come second, whereas appraisal wells will lag both “true wildcats” and other exploration wells. Blocks available for “true wildcats” will diminish quite rapidly as a province matures, and their relation to accumulated oil and gas resources is therefore likely to be negative, as in the structural relationship for Model 4 in Table 2. Exploration wells have similar characteristics, but this type of wells may also be drilled more continuously as resources grow, which is probably the reason why the structural connection between resource accumulation and the number of exploration wells is not clearly determined in our model. Finally, according to Model 2, the number of appraisal wells responds positively to an increase in the stock of oil and gas resources. Appraisal wells will necessarily show a lagging response to both “true wildcats” and exploration wells. In some cases, it may take years from a discovery is made and the appraisal well is drilled. Over time, a growing stock of oil and gas resources therefore tends to stimulate the drilling of appraisal wells.

9. Conclusion

During the last 40 years, exploration activities on the Norwegian Continental Shelf have produced enormous oil and gas resources, and laid the foundations for the Norwegian oil and gas industry. The Norwegian government has played an active role in the development of the offshore oil and resources since the mid 1960s. The regulatory approach has been guided by prudent gradualism, and market forces have not been allowed to dominate the industrial arena. Careful industrial, regulatory and macroeconomic management has proved successful. Huge revenues have been absorbed by the Norwegian economy without the classic challenges that we observe in many other countries that are rich in natural resources.

As the mature market-oriented oil and gas provinces of the world – in USA and UK – are gradually going into decline, international oil and gas companies now redirect their attention for resource-rich countries outside the OECD. During the last years, the Norwegian Model for petroleum and resource management has attracted interest in many of these countries. Both Norwegian authorities and Norwegian companies cooperate actively on regulatory framework conditions, exchange of competence, and industrial development opportunities. We therefore believe that our analysis is relevant for the type of business framework many oil and gas companies will meet in the years ahead.

22 The robustness of cross-category lags have been tried out in our empirical specifications, but with limited success. Contrary to a priori expectation, lagged exploration wells do not defend a position in the econometric model for appraisal wells.
Our models are estimated for a regulated market regime. Still, the results reveal some interesting and appealing insights with respect to exploration behaviour. We establish economic effects that are quite robust, but their magnitude is rather small compared to previous studies. As found by Ringlund et al. (2004), we argue that cross-country variation in exploration behaviour may well be due to variation in the degree of regulation. In the short term, our models also suggest that exploration-drilling is affected by cash-flow effects. Our results also illustrate how new licensing rounds stimulate exploration drilling in new attractive prospects. The resulting discoveries contribute to the growth in oil and gas resources, but drilling efforts will usually stabilize in anticipation of new licensing rounds. The estimated models are quite successful in accounting for dynamics and sluggishness in the exploration drilling behaviour, although the estimated error-correction models suggest a very rapid adjustment process.

This paper has addressed one component of resource growth. In addition to exploration efforts, resource growth will depend on exploration success and average discovery size. Modern investment theory provides interesting themes for further empirical research on discovery rates and its relation to economic variables. In a wider perspective, oil and gas companies balance their drilling efforts between exploration and production drilling. A topic for further research would also to study how production drilling has contributed to reserve growth on the NCS, and at best, to analyse total drilling efforts in a combined framework of investment behaviour.
Appendix 1. Opened and unopened regions on the NCS
### Appendix 2. Tests for stationarity in ECM variable

Dickey-Fuller (DF) and Phillips-Perron (PP) test ratios computed in Stata

<table>
<thead>
<tr>
<th>Dependent variables</th>
<th>Series 1</th>
<th>Series 2</th>
<th>Series 3</th>
<th>Series 4</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Explanatory variables</th>
<th>Series 1</th>
<th>Series 2</th>
<th>Series 3</th>
<th>Series 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Δ ln q&lt;sub&gt;rt&lt;/sub&gt;</td>
<td>DF: -6.670***</td>
<td>PP: -6.467***</td>
<td>DF: -5.959***</td>
<td>PP: -5.958***</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ ln v&lt;sub&gt;t&lt;/sub&gt;&lt;sup&gt;e&lt;/sup&gt;</td>
<td>DF: -4.530***</td>
<td>PP: -4.576**</td>
<td>DF: -5.959***</td>
<td>PP: -5.958***</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ ln p&lt;sub&gt;t&lt;/sub&gt;</td>
<td>DF: -5.026***</td>
<td>PP: -5.008***</td>
<td>DF: -5.690***</td>
<td>PP: -5.758***</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ ln res&lt;sub&gt;rt&lt;/sub&gt;</td>
<td>DF: -5.026***</td>
<td>PP: -5.008***</td>
<td>DF: -5.690***</td>
<td>PP: -5.758***</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ ln acr&lt;sub&gt;rt&lt;/sub&gt;</td>
<td>DF: -5.690***</td>
<td>PP: -5.758***</td>
<td>DF: -5.690***</td>
<td>PP: -5.758***</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Estimated residuals of structural relations</th>
<th>Series 1</th>
<th>Series 2</th>
<th>Series 3</th>
<th>Series 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>ecm&lt;sub&gt;rt&lt;/sub&gt; (eaw&lt;sub&gt;rt&lt;/sub&gt;)</td>
<td>DF: -3.653**</td>
<td>PP: -3.598**</td>
<td>DF: -3.649**</td>
<td>PP: -3.598**</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ecm&lt;sub&gt;rt&lt;/sub&gt; (aw&lt;sub&gt;rt&lt;/sub&gt;)</td>
<td>DF: -6.865***</td>
<td>PP: -7.099***</td>
<td>DF: -3.141**</td>
<td>PP: -3.067**</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ecm&lt;sub&gt;rt&lt;/sub&gt; (ew&lt;sub&gt;rt&lt;/sub&gt;)</td>
<td>DF: -5.467***</td>
<td>PP: -5.485***</td>
<td>DF: -6.110***</td>
<td>PP: -5.696***</td>
</tr>
</tbody>
</table>

***) Significant at 99 per cent confidence level.
***) Significant at 95 per cent confidence level.
*) Significant at 90 per cent confidence level.
a) No observations.
Literature


Norwegian Petroleum Directorate (2005), The petroleum resources on the NCS 2005, (http://www.npd.no/English/Frontpage.htm).


