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Optimal Oil Exploration under Climate Treaties

Abstract:
In this paper we focus on how an international climate treaty will influence the exploration of oil in Non-OPEC countries. We present a numerical intertemporal global equilibrium model for the fossil fuel markets. The international oil market is modelled with a cartel (OPEC) and a competitive fringe on the supply side, following a Nash-Cournot approach. An initial resource base for oil is given in the Non-OPEC region. However, the resource base changes over time due to depletion, exploration and discovery. When studying the effects of different climate treaties on oil exploration, two contrasting incentives apply. If an international carbon tax is introduced, the producer price of oil will drop compared to the reference case. This gives an incentive to reduce oil production and exploration. However, the oil price may increase less rapidly over time, which gives an incentive to expedite production, and exploration. In fact, in the case of a rising carbon tax we find the last incentive to be the strongest, which means that an international climate treaty may increase oil exploration in Non-OPEC countries for the coming decades.

Keywords: International Climate Treaties, Exhaustible Resources, Optimal Oil Exploration

JEL classification: H23, Q30, Q40.

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1. Introduction

A climate treaty like the Kyoto Protocol, that regulates the emissions of carbon dioxide (CO_2), may have important impacts on the oil market. Combustion of fossil fuels is the main source for anthropogenic CO_2 emissions, and such a treaty will influence the magnitude and composition of fossil fuel consumption, and therefore also production pattern and exploration activity.

The impacts of carbon restrictions on the oil market have been studied in, e.g., Whalley and Wigle (1991), Wirl (1994,1995), Tahvonen (1996) and Berg et al. (1997a). However, none of these studies have explicitly modelled oil exploration; available oil reserves are handled exogenously. Berg et al. (1997b) concluded that the reserve base of Non-OPEC may be the most important parameter influencing OPEC's cartelisation gains, indicating that oil exploration may be an important determinant of the whole market structure. Hence, it should be vital to include exploration activity in the analyses of a climate treaty.

One of the few papers that explicitly analyses the effects of environmental regulations on oil exploration is Jin and Grigalunas (1993). They examine the impacts on firms in the oil and gas industry by incorporating the environmental compliance costs into the exploration and production stages. By studying a competitive market, they conclude that the total investment in exploration and oil production generally will decrease as a result of rising compliance costs. However, they find that with expectations of increasing compliance costs in both exploration and production, the optimal exploration may start at a higher level than without environmental regulations.

Exploration activity related to non-renewable resources has been examined either as a problem of constrained intertemporal maximisation or as a problem of stochastic optimisation under uncertainty (see, e.g., Pindyck, 1978; Gilbert, 1979; Arrow and Chang, 1982; Devarajan and Fisher, 1982; Livernois and Uhler, 1987; Swierzbinski and Mendelsohn, 1989; and Cairns and Quyen, 1998).[1] The seminal paper of Pindyck (1978) introduced exploration into a model of optimal extraction of non-renewable resources, and became a standard for modelling oil exploration in the years to come. Pindyck recognised that producers are not «endowed» with reserves, but instead must develop them through the process of exploration. The resource base is treated as the basis for production, and exploration activity as the means of increasing or maintaining reserves. Resource producers must

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[1] An important part of the literature on oil exploration are econometric studies. For a survey on econometric models on oil exploration, see, e.g., Rodriguez Padilla (1992).

simultaneously determine their optimal rates of exploration activity and production. A pivotal assumption in Pindyck's analysis is that production costs rise as reserves decline. Hence, the optimal reserve level balances revenues with exploration costs, production cost, and the «user cost» of depletion.

Solow and Wan (1976) show that in the absence of new discoveries, an aggregate extraction cost function can be defined and indexed by either the level of reserves or the amount of cumulative extraction. However, when new discoveries occur, the proper specification of the aggregate extraction cost function depends on the exploration technology and is in general different from that which is appropriate in the no-discovery case. Thus, according to Swierzbinski and Mendelsohn (1989) the common practice of including an aggregate extraction cost function from the no-discovery case in a model with exploration results in a misspecification as long as the quality of the resource is not homogeneous. This is the procedure in Pindyck (1978), where the unit extraction costs of new discoveries are set equal to the minimum unit costs of existing reserves at the time of discovery. This will artificially encourage early exploration to find cheap oil.

In our study we analyse the effects of an international climate treaty on the exploration activity outside OPEC. We study the effects of both constant and rising carbon taxes, globally and regionally. An extended version of the PETRO model (see Berg et al., 1997a,b) is used. This is a numerical intertemporal global equilibrium model for the fossil fuel markets, where producers take into account that the fuels are nonrenewable. Opposed to the original version of the model, exploration in Non-OPEC is explicitly modelled based on Swierzbinski and Mendelsohn (1989). Uncertainty is not considered as we assume a deterministic relationship between exploration effort and new discoveries. We consider Non-OPEC countries as price takers, so that their production activity and, therefore, their exploration activity depends on the price path of oil which is consistent with Hotelling's theory of exhaustible resources (Hotelling, 1931).

In this paper we find that a climate treaty implemented by an international CO_2 tax will reduce the producer price of oil giving an incentive to reduce the oil production and exploration activity. However, the price of oil is increasing at a lower rate after the introduction of a carbon tax. This gives the competitive producers an incentive to move production nearer in time, as the discounted value of future production is reduced more than the value of current production. As this incentive shows to be the strongest in the most plausible tax scenario, i.e., with a rising carbon tax over time, Non-OPEC countries will actually increase oil exploration somewhat for the coming decades. This counterintuitive result shows the importance of taking an intertemporal approach in studies of fossil fuel markets.

The paper is organised as follows. In Section 2, the model is outlined, while data are given in Section 3. The simulation results are presented in Section 4. We provide some sensitivity analyses in Section 5 to test the robustness of the results. In the final section, the paper concludes.

2. The model

The PETRO-model was first introduced in Berg et al. (1997a,b). In the new version of the model presented in this paper, oil exploration activity in Non-OPEC countries has been included. Further, the cost structure for Non-OPEC producers has been changed to fit in with the distinction between identified and unidentified resources.

The model describes the international markets for fossil fuels in an intertemporal way, considering that the fuels are nonrenewable resources. All prices and quantities at each point of time are determined simultaneously in the model. Consumers determine their demand according to current income and prices of the fuels, whereas producers determine their supply and exploration activity according to the market conditions in all periods assuming perfect foresight.

We specify three fossil fuels ($j = O,G,K$) in the model; oil (O), natural gas (G) and coal (K). Consumers are situated in three regions ($i = 1,2,3$), OECD-Europe (1), Rest-OECD (2) and Non-OECD (3). Moreover, we define two groups of producers in the world oil market ($k = C,F$), namely OPEC which acts as a cartel (C), and a competitive fringe (F). There are three regional natural gas markets with perfect competition, and the coal market is assumed to be a competitive world market.

All variables are functions of time. However, we will suppress the time notation in the following. The functional forms are assumed to be constant over time.

2.1. The demand side

The consumer price of a specific fuel in a specific region, Q_j^i, is the sum of the producer price, P_j^i, fixed unit costs due to transportation, distribution and refining, z_j^i, existing fuel taxes (subsidies are considered as negative taxes), v_j^i, and, eventually, a carbon tax. Thus before a climate agreement is imposed, we have

$$(1)\qquad \begin{aligned} Q_O^i &= P_O + z_O^i + v_O^i \\ Q_K^i &= P_K + z_K^i + v_K^i \\ Q_G^i &= P_G^i + z_G^i + v_G^i \end{aligned}$$

The demand of each fuel, X_j^i, is represented by a log-linear demand function, and is a decreasing function of the consumer price of that fuel and an increasing function of the consumer prices of the two other fossil fuels. Finally, the demand functions change over time to reflect economic growth. Moreover, we assume that there exists a single carbon-free backstop technology (e.g., solar, wind or biomass) which serves as a perfect substitute for fossil fuels. The technology is available in copious supply at a fixed consumer price, $\overline{P}$, at each point of time in all regions. Over time, however, the unit cost of the backstop technology is reduced by a constant rate μ to reflect technological change. With κ as the initial backstop price, we have:

$$(2)\qquad \overline{P} = \kappa e^{-\mu t}$$

Analytically, the demand structure is specified as follows. Let $\hat{X}_j^i$ be defined by

$$(3)\qquad \ln \hat{X}_j^i = \ln \omega_j^i + a_j^i \ln Q_O^i + b_j^i \ln Q_K^i + c_j^i \ln Q_G^i + d_j^i \ln Y^i$$

where ω_j^i is a constant coefficient, $a_j^i, b_j^i, c_j^i, d_j^i$ are price and income elasticities, and Y^i is the gross national income. Then the demand for fuel type *j* in region *i* is given by

$$(4)\qquad X_j^i = \left\{ \begin{array}{ll} \hat{X}_j^i, & Q_j^i < \overline{P} \\ 0, & Q_j^i > \overline{P} \\ \in [0, \hat{X}_j^i], & Q_j^i = \overline{P} \end{array} \right\}$$

Consider the oil market, and let x_O^k denote the production of oil by producer *k*. Then the restriction of market clearing in the world oil market can be written

$$(5) \qquad x_O^C + x_O^F = \sum_{i=1}^{3} X_O^i$$

From (1)-(5), we can describe the producer price of oil as a unique function of the other variables:

$$(6) \qquad P_O = P_O\left(x_O^C + x_O^F, z_O^1 + v_O^1, z_O^2 + v_O^2, z_O^3 + v_O^3, Q_K^1, Q_K^2, Q_K^3, Q_G^1, Q_G^2, Q_G^3, \overline{P}, Y^1, Y^2, Y^3\right)$$

In a similar way, we can describe the producer prices of natural gas and coal.

2.2. Oil production

The supply side of the international oil market consists of a cartel (corresponding to OPEC) and a competitive fringe.[2] While the fringe always considers the oil price path as given, the cartel regards the price as a function of its supply. Hence, the marginal revenue for the fringe is equal to the price, whereas for the cartel, marginal revenue is in general less than the price. We choose the Nash-Cournot model of a dominant firm to calculate the open loop solution of the game, where both the fringe producers and the cartel take the supply of all other producers as given when deciding their own production profile.[3]

Instead of considering the resources as strictly exhaustible, we assume that the unit extraction costs of both the cartel and the fringe are increasing functions of cumulative production which approach infinity as cumulative production approaches infinity. Hence, with a finite backstop price the economic reserves are finite (see, e.g., Heal, 1976). However, the competitive fringe has an opportunity to influence its extraction costs by finding oil of better quality (meaning lower extraction costs) than the previously identified remaining resources. This is done by exploration activity. Exploration costs also approach infinity as cumulative exploration approaches infinity, so this is a model of economic exhaustion (zero long-term scarcity rent) rather than physical exhaustion. Although there currently is

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[2] There exists two versions of the original model, differing only with respect to the treatment of the global oil market; one consisting of a cartel and a fringe, and one describing a hypothetical competitive market. In this study we only apply the former version.

[3] The term Nash-Cournot-model of a dominant firm was used by Salant (1976). It can be shown that this Nash-equilibrium is time consistent but not subgame perfect, see, e.g., Hoel (1992).

some exploration activity in OPEC countries, too, such as Venezuela, Indonesia and Nigeria, compared to Non-OPEC countries, OPEC as a whole has vast resources that are easily accessible. Thus, oil exploration in OPEC countries does not have noticeable impact on the supply from the cartel, at least in the nearest future.

2.2.1. The optimisation problem for OPEC

Let C_j^k be the unit cost of production of fuel *j* for producer *k*. To describe the cost structure of OPEC we have chosen the following exponential function

(7) $$C_O^C = \alpha e^{\eta_O^C A_O^C - \tau^C t}$$

where α is the initial unit cost, A_j^k is cumulative production and η_j^C is a constant depletion parameter determining how fast unit costs increase as the reserves are depleted. One of the main reasons behind the low oil prices the last decade is probably technological change. We therefore assume that unit costs are reduced by a constant rate, τ^k, each year (*t* is time), independent of production. This means that over time unit costs may be reduced or increased, depending on the production rate.

OPEC seeks to maximise the present value of the net revenue flow, i.e., the oil wealth. It is facing a downward sloping demand schedule at each point of time, and takes the extraction path of the fringe as given. The control variable in the optimisation problem is the extraction path and the state variable is accumulated production. Let *r* be the discount rate, and $P_O(x_O^C;\cdot)$ is the producer price given in (6). With an infinite planning horizon, the optimisation problem is as follows:

(8) $$\max_{x_O^C} \int_0^\infty \left[P_O(x_O^C;\cdot) - C_O^C \right] x_O^C \cdot e^{-rt} dt$$

s.t.

(9) $$\dot{A}_O^C = x_O^C$$

(10) $$x_O^C \geq 0$$

(11) $$C_O^C = \alpha e^{\eta_O^C A_O^C - \tau^C t}$$

The current value Hamiltonian, H^C, is given by

(12) $$H^C = \left[P_O\left(x_O^C;\cdot\right) - C_O^C\left(A_O^C, t\right)\right]x_O^C + \lambda^C x_O^C$$

where $\lambda^k(t)$ (≤ 0) is the shadow cost associated with cumulative extraction up to time t. The scarcity rent for the cartel is defined as $\pi_O^C = -\lambda^C$, and reflects that extracting one more unit today increases costs tomorrow.

The necessary conditions for an optimal solution are given by the Pontryagin's maximum principle. From this principle we get the time path of the shadow cost

(13) $$\dot{\lambda}^C - r\lambda^C = -\frac{\partial H^C}{\partial A_O^C} = \frac{\partial C_O^C}{\partial A_O^C} x_O^C \quad ,$$

which can be rewritten using the definition of the scarcity rent:

(14) $$\dot{\pi}_O^C = r\pi_O^C - \frac{\partial C_O^C}{\partial A_O^C} x_O^C$$

x_O^C maximises the Hamiltonian for all $x_O^C \geq 0$ which for an interior solution requires

(15) $$\frac{\partial H^C}{\partial \mathrm{x}_\mathrm{O}^\mathrm{C}} = P_O - C_O^C + \frac{\partial P_O}{\partial x_O^C} x_O^C + \lambda^C = 0$$

This gives the producer price of oil when OPEC produces

(16) $$P_O = C_O^C + \pi_O^C - \frac{\partial P_O}{\partial x_O^C} x_O^C$$

where $-\frac{\partial P_O}{\partial x_O^C} x_O^C$ is the cartel rent. The marginal revenue of OPEC, MR^C, is defined as

(17) $$MR^C = P_O + \frac{\partial P_O}{\partial x_O^C} x_O^C = C_O^C + \pi_O^C$$

Differentiating (17) and using (11) and (14) we find the time path of the marginal revenue

(18) $$\dot{MR}^C \equiv r\pi_O^C - \tau^C C_O^C$$

In equilibrium, then, as long as the cartel produces, the change in the marginal revenue over time must equal its scarcity rent times the discount rate, minus its unit cost times the technological rate of change. The first part reflects the standard Hotelling rule, while the second part reflects that the marginal revenue does not have to increase that fast in optimum as the costs are falling due to technological change.

In each demand region there is a maximum producer price for each fossil fuel, which is defined as the backstop price minus regional costs due to transportation, distribution and refining of the fuel, and regional fuel and carbon taxes. The cartel will stop producing at time $T_O^C \in (0, \infty)$ when the unit cost reaches the maximum producer price. Let $\overline{A}_O^C$ be the aggregate production of OPEC over the entire time horizon. The transversality condition is then

(19) $$\max_i(\overline{P}_{T_O^C} - z_O^i - v_O^i) = C_O^C\left(\overline{A}_O^C, T_O^C\right)$$

2.2.2. The optimisation problem for Non-OPEC

The competitive fringe has an opportunity to influence its extraction costs by finding oil of better quality than the resources already discovered. This is done by exploration activity. Thus, we introduce a separation of resources into identified resources and new discoveries. The specification of the Non-OPEC optimisation problem is based on Swierzbinski and Mendelsohn (1989).

The undiscovered oil is located in several deposits within different oil fields in the Non-OPEC region. New deposits are discovered via random search in different oil fields. Let *D* be the aggregated discovery, including resources that are not economically recoverable today, and let *w* be the new discoveries at a specific point of time. Thus

(20) $$\dot{D} = w$$

where $D(0) = D_0 > 0$ denotes the aggregated discoveries until the starting point of our analysis. At each point of time, there is a constant exploration unit cost for each unit discovered within each field, G, which is known to the fringe prior to any exploration. Thus, we assume a deterministic relationship between exploration effort and new discoveries. However, the unit costs increase over time as more oil is discovered (cf. the constant depletion parameter γ in equation (21)), reflecting that the most accessible fields are searched first. Further, let δ be the rate of technological progress in exploration costs, and β the initial unit exploration cost. Then, we can specify the following exploration unit cost function for Non-OPEC countries:

(21) $$G = \beta e^{\gamma(D-D_0)-\delta t}$$

By paying the exploration unit cost, the fringe will discover a unit of oil and learn the quality of it, i.e., its unit extraction cost. Only units that have been identified may be extracted. The quality of oil within a deposit can be described by a deposit-cost profile, $F(c,t)$, which at each point of time determines the fraction of oil within a deposit with a unit extraction cost less than c. We specify the deposit-cost profile as follows:

(22) $$F(c,t) = 1 - e^{-\frac{1}{\varphi}\left(ce^{\tau^F t} - C^{\min}\right)}$$

where C^{min} is the lowest possible unit extraction cost at time $t = 0$. We see that $F \to 1$ as $c \to \infty$. φ is a constant coefficient describing the cost distribution within the deposit, while τ^F is a parameter reflecting the technological progress in oil extraction outside OPEC. Hence, $C_t^{\min} = C^{\min} e^{-\tau^F t}$ denotes the lowest possible unit cost at time t, i.e., $F(C_t^{\min}, t) = 0$, which decreases over time. We assume that the deposit-cost profile is identical in every deposit and in all fields in the Non-OPEC region, and that this profile also applies to the previously identified resources, D_0.[4]

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[4] Thus, we assume that there is no systematic aggregate relation between the costs of *identifying* and *extracting* various deposits. Moreover, “this is a formalization of the assumption that new deposits are discovered by a random search within each field, where the probability of encountering units with particular extraction costs is equal to the relative abundance of such units within the field” (Swierzbinski and Mendelsohn, 1989).

Let $C_O^F(t)$ denote the unit cost of extraction from previously identified resources. Swierzbinski and Mendelsohn (1989) show in the case without technological change that C_O^F is non-decreasing along any cost-minimizing path. First, this means that from previously identified resources the cheapest units are extracted first. Secondly, all resources within a newly discovered deposit with unit costs below C_O^F are extracted immediately. In the case with technological change, C_O^F will no longer necessarily be non-decreasing. However, based on the proposition above, we can show that with equal technological rate of change in exploration and extraction, $\widetilde{C}_O^F(t) = C_O^F(t)e^{-\tau t}$ will be non-decreasing.[5] The same is true as long as production from previously identified resources is positive, even if the rates of technological change differ. Then the two implications stated above still hold. Hence, assuming one of these conditions holds true, we see that the cumulative extraction (*A*) at a specific point of time (including extraction before the starting point of our analysis) is equal to the fraction of the accumulated discoveries (*D*) with extraction costs less than C_O^F, i.e.,

$$(23) \qquad A_O^F = F(C_O^F, t)D$$

Thus, we get

$$(24) \qquad F(C_O^F, t) = \frac{A_O^F}{D}$$

Equating (22) and (24) gives after some calculation, the unit extraction cost for the fringe from previously identified resources, i.e., the resources available at the starting point of the analysis:

$$(25) \qquad C_O^F = \left[C^{\min} - \varphi \ln\left(\frac{D - A_O^F}{D}\right)\right]e^{-\tau^F t}$$

However, as indicated above, the fringe will also extract from newly discovered resources, and this extraction rate will equal $w(t)F(C_O^F, t)$, i.e., the share of the resources with extraction costs lower than C_O^F. Let $f(c,t) = \partial F(c,t)/\partial c$. By using this and employing (22), the total costs of extracting from newly discovered deposits are given by

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[5] The proof is straightforward, and is available on request to the authors.

(26) $$w\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc = w\left[(C_t^{\min} + \varphi e^{-\tau^F t}) - e^{-\frac{1}{\varphi}(C_O^F e^{\tau^F t} - C^{\min})}(C_O^F + \varphi e^{-\tau^F t})\right]$$

As $wF(C_O^F,t)$ is the extraction rate from newly discovered deposits, the unit extraction cost from newly discovered deposits is:

(27) $$\frac{1}{F(C_O^F,t)}\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc$$

The total oil production in Non-OPEC at a specific point of time is then the sum of the extraction from newly discovered deposits, $wF(C_O^F,t)$, and extraction from old resources, *q*.

(28) $x_O^F = wF(C_O^F,t) + q$

The fringe maximises its resource wealth taking the producer price as given. The optimisation problem with an infinite time horizon is then described by equation (29). As above, all variables are functions of time.

(29) $$\max_{q,w}\int_0^\infty \left\{ P_O \cdot (w \cdot F\left(C_O^F,t\right) + q) - w\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc - q \cdot C_O^F - w \cdot G \right\} e^{-rt}dt$$

subject to

(30) $$\dot{A}_O^F = wF + q$$

(31) $$\dot{D} = w$$

given $q \geq 0$, $w \geq 0$, and the functional forms in (21), (24), (25), and (26).

Let λ^F and μ^F be the shadow values corresponding to A_O^F and *D*. Then the current value Hamiltonian, H^F, of this maximisation problem is:

(32) $$H^F = P_O \cdot (wF(C_O^F,t)+q) - w\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc - q \cdot C_O^F - w \cdot G + \lambda^F (wF(C_O^F,t)+q) + \mu^F w$$

Hence, the necessary conditions for an optimum are

(33) $$\frac{\partial H^F}{\partial q} = P_O - C_O^F + \lambda^F \le 0 \qquad (= 0 \text{ for } q > 0)$$

(34) $$\frac{\partial H^F}{\partial w} = P_O F(C_O^F,t) - \int_{C_t^{\min}}^{C_O^F} cf(c,t)dc - G + \lambda^F F(C_O^F,t) + \mu^F \le 0 \qquad (=0 \text{ for } w > 0)$$

(35) $$\dot{\lambda}^F - r\lambda^F = -\frac{\partial H^F}{\partial A_O^F} = q\frac{\partial C_O^F}{\partial A_O^F} - wf(C_O^F,t)\frac{\partial C_O^F}{\partial A_O^F} \cdot \frac{\partial H^F}{\partial q}$$

(36) $$\dot{\mu}^F - r\mu^F = -\frac{\partial H^F}{\partial D} = q\frac{\partial C_O^F}{\partial D} + w\frac{\partial G}{\partial D} - wf(C_O^F,t)\frac{\partial C_O^F}{\partial D} \cdot \frac{\partial H^F}{\partial q}$$

From (33) we then see that for $q > 0$

(37) $$P_O = C_O^F - \lambda^F$$

Thus, as long as the fringe produces from old resources, the price must equal the unit cost plus the scarcity rent due to extraction from old resources, $-\lambda^F$.

To find the time path of the price for $q > 0$, we differentiate (37), and use (30), (31), (35) and the differentiation of equation (24) with respect to *A* and *D*, respectively. Thus we find:

(38) $$\dot{P}_O = rP_O - \left(r + \tau^F\right)C_O^F = r(P_O - C_O^F) - \tau^F C_O^F$$

Hence, as long as the fringe produces from old resources, the price follows a Hotelling path adjusted for technological change.

From (34) we see that for *w > 0*

$$(39) \qquad P_O = \frac{1}{F(C_O^F,t)}\left(\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc + G\right) - \lambda^F - \frac{1}{F(C_O^F,t)}\mu^F$$

By differentiating (39), and using (30), (31), (35), (36) and the characteristics of the extraction cost function, we find the development in price for *w>0*:

$$(40) \qquad \begin{aligned} \dot{P}_O &= r\left[P_O - \frac{1}{F(C_O^F,t)}\left(\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc + G\right)\right] - \frac{1}{F(C_O^F,t)}\delta G - \frac{f(C_O^F,t)}{F(C_O^F,t)}\tau^F (C_O^F)^2 \\ &+ \frac{f(C_O^F,t)}{F(C_O^F,t)(1-F(C_O^F,t))}\tau^F (C_t^{\min})^2 + \frac{1}{F(C_O^F,t)}\int_{C_t^{\min}}^{C_O^F} c\frac{\partial f(c,t)}{\partial t}dc \end{aligned}$$

Without technological change (i.e., $\delta = \tau^F = 0$), we see that all terms except the ones within the square brackets, are zero. Moreover, the second term in the square brackets is the unit costs of identifying and extracting a unit from new deposits. Thus, with positive exploration activity, the price follows a Hotelling path adjusted for technological growth. The first (negative) term after the square brackets denotes the effect of technological progress within exploration activity. This gives incentives to delay exploration, which clearly reduces the price increase. The other terms sum up the total cost effect of technological progress within extraction on a certain fraction *F* of a new discovery. Hence, this sum is by definition also negative as long as the technological progress is positive. This gives incentives to delay exploration as the extraction costs of unidentified resources will be lower in the future. Thus, both technological factors have a dampening effect on the price increase.

The condition for simultaneous production from old and new deposits, i.e., *q > 0* and *w > 0*, is found by equating (38) and (40):

$$(41) \qquad \begin{aligned} C_O^F\left(1+\frac{\tau^F}{r}\right) &= \frac{1}{F}\left[\int_{C_t^{\min}}^{C_O^F} cf(c,t)dc + G\left(1+\frac{\delta}{r}\right)\right. \\ &\left. + \frac{\tau}{r}\left(f(C_O^F,t)(C_O^F)^2 - \frac{f(C_O^F,t)}{1-F(C_O^F,t)}(C_t^{\min})^2 - \frac{1}{\tau}\int_{C_t^{\min}}^{C_O^F} c\frac{\partial f(c,t)}{\partial t}dc\right)\right] \end{aligned}$$

Thus, the cost of extracting a unit from previously identified resources adjusted for technological change, must equal the cost of identifying and extracting a unit from a new deposit adjusted for technological change in both exploration and extraction.

The transversality condition for the fringe, where $T_O^F \in \left(0, \infty\right)$ is the last period of production and $\overline{A}_O^F$ and $\overline{D}$ are aggregate production and discovery over the entire time horizon, is

(42) $$\max_i(\overline{P}_{T_O^F} - z_O^i - v_O^i) = C_O^F\left(\overline{A}_O^F, \overline{D}, T_O^F\right)$$

2.3. Gas production

Since the oil market is the main focus of our analyses, the gas and coal markets are modelled in a more simplified way. Of course, the connections between the markets through the demand side are important, as consumer prices of gas and coal are parts of the demand function for oil. However, with relatively low substitution elasticities between oil and the two other fossil fuels, more simplified modules should be sufficient for the gas and coal markets.

Because of large transportation costs, natural gas is mainly traded in regional markets. In the model we have somewhat arbitrarily divided the world into the three following regions. OECD-Europe is considered as a single region, whereas the rest of the OECD is taken together (i.e., despite separate markets, the Pacific area is technically included in the North-American market). The third region is Non-OECD, where the former Soviet Union is a dominating market. We further simplify and model competitive gas markets. However, gas producers dynamically optimise, and extraction costs for gas are modelled in the same way as for OPEC. The costs differ between the regions. For more information on the optimisation problems in the gas markets, see Appendix 1.

2.4. Coal production

The coal market is considered as an international competitive market. Since coal resources in the world are huge compared to oil and gas, we simply assume that the producer price of coal is fixed at each point of time. However, the price is reduced over time due to technological change. For more information on the optimisation problem in the coal market, see Appendix 1.

3. Non-OPEC data

The data applied for the demand structure and the supply from OPEC and producers of gas and coal were discussed in Berg et al. (1997a). These are given in Appendix 2, and we will give a short description of the sources we have used below. Then we focus on data for Non-OPEC producers.

Price elasticities have been taken from Golombek and Bråten (1994), whereas income elasticities were derived based on considerations around the “Autonomous Energy Efficiency Index” (AEEI) (see Matsouka et al. (1995)). Estimates of existing taxes were taken from ECON (1995), IEA (1995a) and Gupta and Mahler (1995). Costs of refining, transportation etc. have been found in ECON (1990) and Golombek et al. (1995). The demand functions were calibrated to agree with price and consumption figures in 1994.

Initial unit costs for OPEC are based on Ismail (1994), whereas corresponding cost estimates for gas and coal are based on Golombek et al. (1995), IEA (1995a,b) and ECON (1990). Unit costs for OPEC and for gas producers are assumed to grow exponentially with respect to accumulated production. The functions are calibrated so that the unit costs equal \$20 per barrel of oil equivalents (boe) when the proved reserves stated in BP (1995) are produced. At the same time unit costs decline due to a fixed rate of technological change (this also applies to coal). The initial backstop price of \$108 per boe is taken from Manne et al. (1995). We assume a slightly more rapid technological progress (still exogenous) for the backstop technology than for the fossil fuels. A market rate of 7 per cent is used as a discount rate in all markets.

According to EIA (1997a) world-wide finding costs by 24 major energy companies registered in the US (i.e., FRS (Financial Reporting System) companies) in the period 1994-96 were \$4.33 per barrel of oil equivalent. EIA define finding costs as exploration and development expenditures, divided by reserve additions. However, in our analyses development expenditures are included in the extraction costs. Moreover, EIA’s reserve additions does not include currently unprofitable discoveries. Thus, we would suppose that the value of the initial unit exploration cost in our model, β, would be lower than the above figure. On the other hand, EIA’s estimate includes both oil and gas exploration, and data reported by Fagan (1997) for the US indicate that finding costs for oil only may be about one third higher. The Norwegian Oil Directorate (1997) reports that unit exploration costs for oil *and gas* in Norway are about \$1.5 per barrel of oil equivalent discovered. As finding costs in OECD-Europe are close to the average (EIA, 1997a), we choose to use the figure for Norway, adjusted upwards by one-third. That is, the *initial* (1995) *unit exploration cost,* β, is set equal to \$2 per barrel of oil discovered. This estimate also compares well with a list by Petrocompanies (1998) of finding costs (here excluding development costs) in various oil companies.

According to EIA (1997b) a low and high estimate of undiscovered oil in Non-OPEC is 197 and 685 billion barrels, respectively. This is based on an assessment prepared by the US Geological Survey (USGS). However, EIA points out that the USGS is assuming constant technology and economics, and that the potential may be much higher if technology continues to advance or/and if real oil prices increase over time. Thus, somewhat arbitrarily, we choose to calibrate the *depletion parameter* γ in the exploration cost function so that the unit exploration cost reaches \$20 per barrel when the average of the low and high estimate above has been discovered (ignoring technological change for the moment). Then, using 10 billion boe as metrics, we arrive at $\gamma = 0.052$. With an annual discovery of e.g. 10 billion boe (which is close to actual discoveries per year in Non-OPEC - see Petroconsultants (1996)), this will of course imply a cost increase of 5.2 per cent per year (still ignoring technological change). As this parameter is highly uncertain, we present sensitivity analyses of this as well as other parameters at the end of the paper.

There has been a remarkable *technological change in exploration* outside OPEC the last decade. For the United States, Fagan (1997) concludes that “an accelerating rate of technical change reduced average finding cost 15 per cent (onshore) and 18 per cent (offshore) per year by 1994”. The technological advances have particularly taken place after the dramatic drop in oil prices in 1986, and it is doubtful that this will continue for a prolonged period. Thus, taking a somewhat conservative view, we set the annual rate of technological change in exploration costs equal to 2 per cent initially, declining gradually to 1 per cent over a 30 year period.

To calibrate the *deposit-cost profile* (see equations (22) and (24)) we must first of all determine the current values of D and A, i.e., accumulated discoveries and production up to the year 1995. From EIA (1997b), Table 13, we find an estimate of accumulated production in Non-OPEC at the end of 1992. Adding the production in 1993 and 1994, we arrive at $A_{1995} = 446$ billion barrels. Furthermore, D_{1995} is the sum of A_{1995} and remaining identified resources outside OPEC at the end of 1994. From Table 13 in EIA (1997b) we find that remaining “identified reserves” in Non-OPEC were 397 billion barrels at the end of 1992. This includes “proved, probable, and possible reserves”. To also include the more uncertain “potential additional reserves” (which are not economically recoverable today), we add 10% based on information from the UK (Petroleum Economist, 1998). Moreover, to adjust to the end of 1994, we use the percentage change of Non-OPEC reserves identified by Petroconsultants (1996). Finally, adding A_{1995} we arrive at D_{1995} = 872 billion barrels, which subsequently implies that F_{1995} = 0.51.

To further identify the deposit-cost profile, we use an estimate of unit costs in oil production outside OPEC of $10.9 per barrel (calculated from Ismail, 1994). We assume that C_O^F takes on this value in 1995, so that $F(10.9,1995)=0.51$. Moreover, according to Adams (1991),[6] up to 70 per cent of oil resources outside OPEC could be developed at less than $20 per barrel. When combining this fraction with the figure calculated above on remaining resources, we arrive at 299 billion barrels, which is almost halfway between the stated Non-OPEC reserves in BP (1995) and Petroconsultants (1996), respectively. Both BP and Petroconsultants define (proved) reserves as remaining resources which can be recovered under existing economic and operating/technical conditions, so this assumption seems valid. Thus, we have another point on the deposit-cost profile, and are able to determine the values of C^{min} ($5.5 per barrel) and φ (7.6).

We have generally assumed the rate of *technological change in oil and gas production* to be 1 per cent per year. Initially, however, as oil producers outside OPEC have had impressive technological improvements lately (see, e.g., Ismail, 1994), we assume a rate of 2 per cent in Non-OPEC. This rate is gradually reduced to 1 per cent after 30 years.[7] In figure a we illustrate the shape of the deposit-cost profile in 1995 and 2010. The current value of C_O^F and $F(C_O^F,1995)$ is marked with an $\times$.

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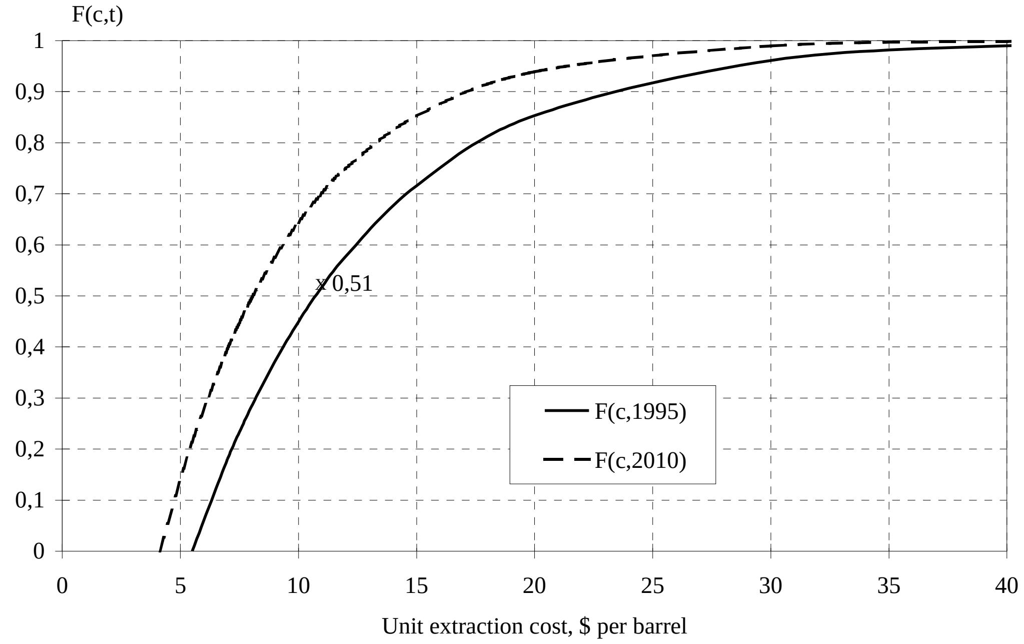
[6] Quoted by MacKenzie (1996).

[7] Then we ensure that the conditions discussed in front of equation (23) are fulfilled.

Figure A. The calibrated deposit-cost profile of Non-OPEC oil fields in 1995 and 2010.



Results are presented in a *Reference scenario* where there are no carbon taxes, and in three tax scenarios where carbon taxes are introduced. In the *OECD carbon tax scenario I* a carbon tax of $10 per boe is introduced in the OECD regions from 2000, and outside OECD as well from 2030. This may be one possible tax scenario based on the Kyoto Protocol agreed upon in December 1997, which put restrictions on CO_2 emissions in OECD countries (in addition to Russia, Ukraine and Eastern European countries) in 2010. As a comparison, in the *Global carbon tax scenario* the same carbon tax is introduced in all regions from 2000 onwards. However, there are reasons to believe that restrictions on CO_2 will be gradually tougher. Hence, a more plausible tax scenario may be the one we call the *OECD carbon tax scenario II*. Here a carbon tax of $5 per boe is introduced in the OECD regions in the first period, increasing to $10 in the second period, and finally $20 from 2020 onwards. From 2030 the $20 tax is levied outside OECD, too.

Simulations were carried out for the time period 1995-2135 with ten year periods, using the GAMS/MINOS system (see Brooke et al., 1992). Thus the results in each period are the average over the ten years, e.g., the results for the year 2000 are the average over the period 1995-2005.

4. Simulation results

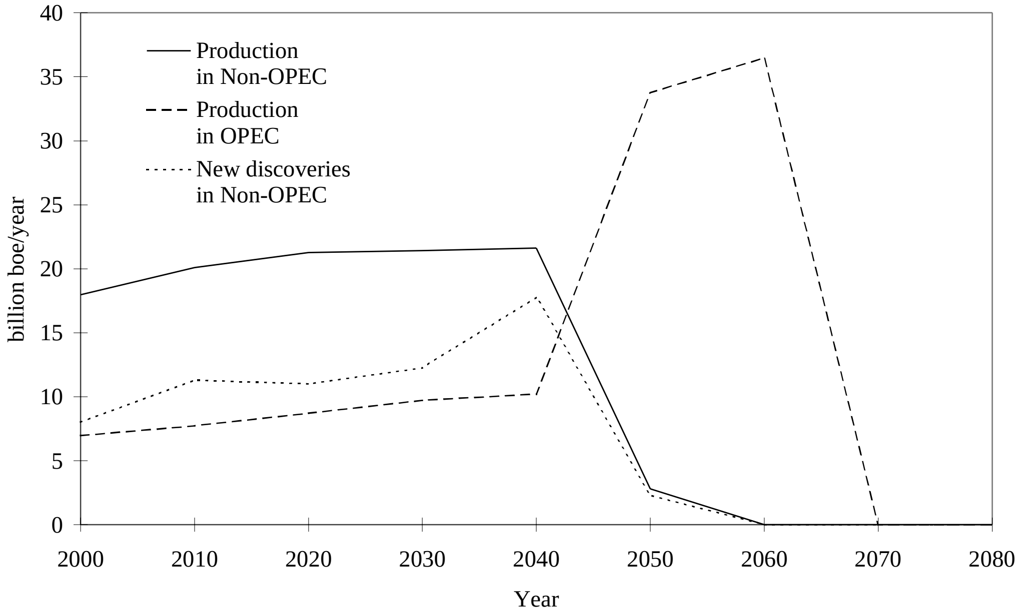
4.1. The Reference scenario

In 2000 the total oil production in the world is calculated to 24.9 billion barrels of oil (boe) per year (i.e., 68 mbd - million barrels per day). OPEC produces about 7.0 billion boe (19 mbd), see figure b. Thus the OPEC's share of the total production is 28 per cent which is less than the real 1994 share of 41 per cent. This may indicate that OPEC acts as a more effective cartel in the model than in reality, *or* that they are in a more leading position in the real market than in our Nash-Cournot model, e.g., like a Stackelberg leader. In the latter case OPEC must give credible signals to the market that the cartel will produce more than what is seemingly profitable in the short run in order to prevent developments of new oil fields in Non-OPEC. We will come back to this problem later on in the discussion of the results.

The annual Non-OPEC production in 2000 is 18.0 billion boe (49 mbd). It increases slightly until 2040, where it reaches the top production of 21.6 billion boe. The last period of production in Non-OPEC is 2050. OPEC has a steady increase in its production as long as Non-OPEC is in the market. However, when Non-OPEC stops producing, OPEC takes over the whole market. The last period of production in OPEC is 2060 - then the price of the backstop is so low that further oil production is not economically viable.

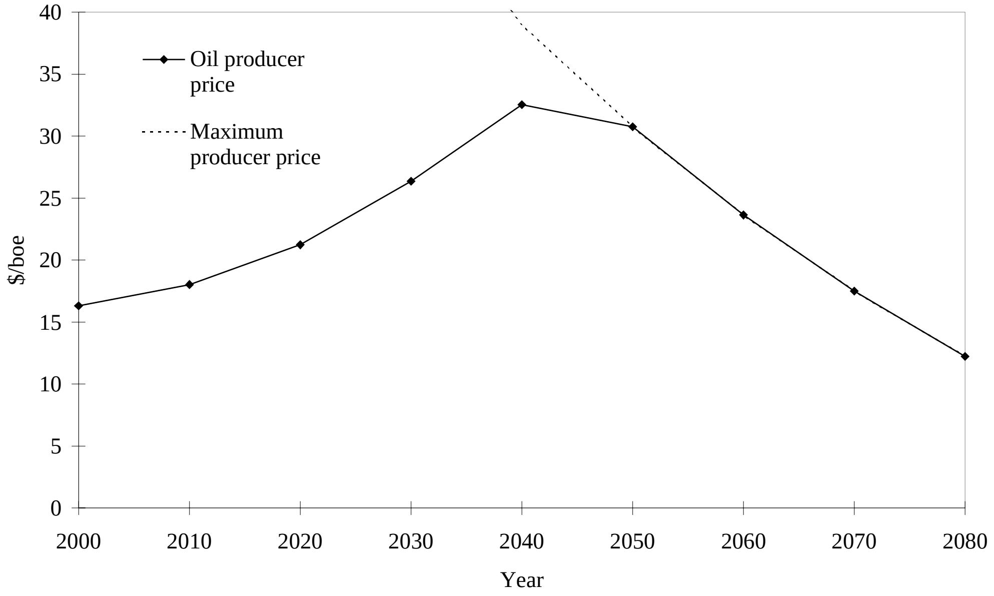
The oil exploration in Non-OPEC, or the new discoveries, start on an annual level of about 8.0 billion boe in 2000, see figure b. As a comparison, actual discoveries in Non-OPEC in the period 1991-1995 were in average 8.2 billion boe per year, as reported by Petroconsultants (1996). However, this figure only includes resources that are recoverable under current economic and technical conditions, and from figure a we see that for 1995 about 80 per cent of new discoveries in the model may be put in this category. In later periods from 2010 to 2040, exploration and new discoveries are quite high, i.e., on a level between 11 and 18 billion boe per year. One reason for the somewhat lower exploration in the first period may be that the initial resource base is high. Moreover, as the difference between extraction costs from old resources and new discoveries are increasing over time as the lowest-cost deposits are extracted first, this may call for intensified exploration effort in later periods. However, as the costs of making new discoveries increase, exploration activity eventually comes to an end in the middle of the next century. Non-OPEC has a simultaneous exploration and production from previously identified resources in all periods. In the first period around three quarter of the production come from resources discovered in earlier periods, and the rest from new discoveries. Then, for the next three decades, the distribution is fairly even. Finally, in 2040 and 2050 about 80 per cent of the production come from new discoveries. Total new discoveries in Non-OPEC over the time horizon is about 627 billion boe, which is not far from the high estimate of undiscovered oil in Non-OPEC stated by EIA (1997b) (see Section 3).

Figure B. Oil production and new discoveries, reference scenario



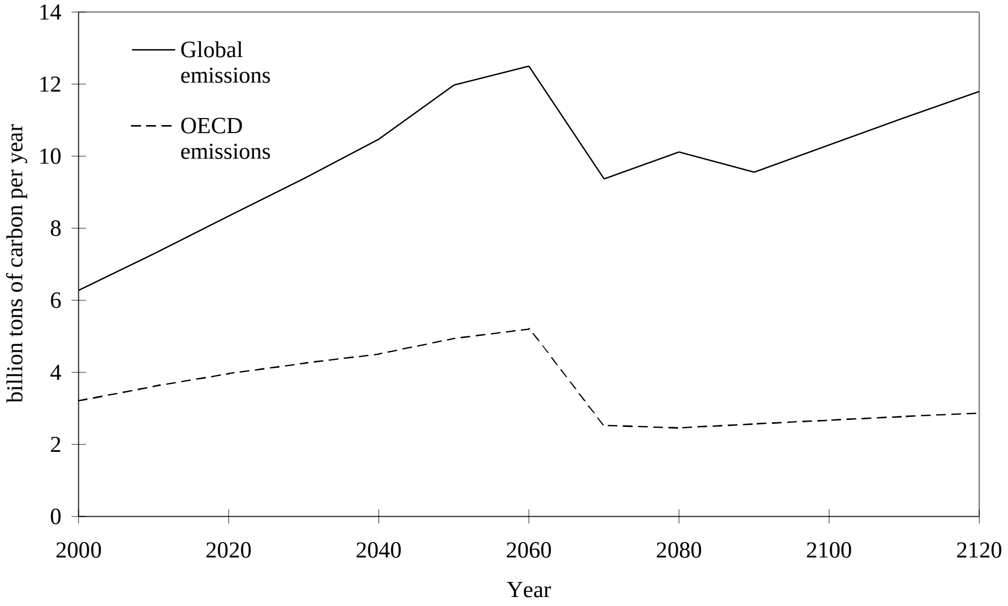
The oil price starts at $16.3 and increases to $32.5 in 2040, before it meets the maximum producer price of oil, see Figure 3. From 2050 onwards, the producer price follows the maximum producer price. Due to the simultaneous exploration and production from old resources in Non-OPEC from 2000 to 2050, the price path satisfies equations (38) and (40) simultaneously as long as the price is less than the maximum producer price.

Figure C. Oil producer price, reference scenario



Global CO_2 emissions due to combustion of fossil fuels increase from 6.3 billion tons of carbon in 2000 and reach the top of about 12.5 billion tons in 2060, see Figure 4. Then emissions drop as oil is substituted by the backstop in 2070. Due to increasing coal consumption, the emissions rise thereafter, with a small drop from 2080 to 2090 when the backstop replaces natural gas globally. Coal is consumed and produced over the entire time horizon.

Figure D. CO_2 emissions from fossil fuel combustion, reference scenario

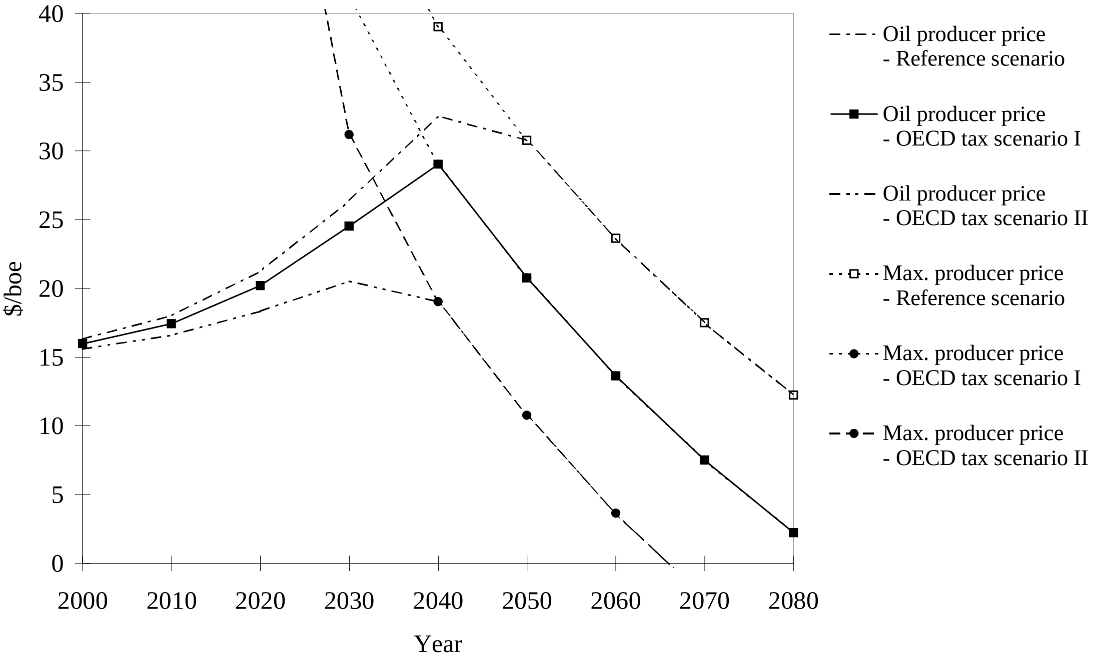


4.2. Effects of constant carbon taxes

4.2.1. The OECD carbon tax scenario I

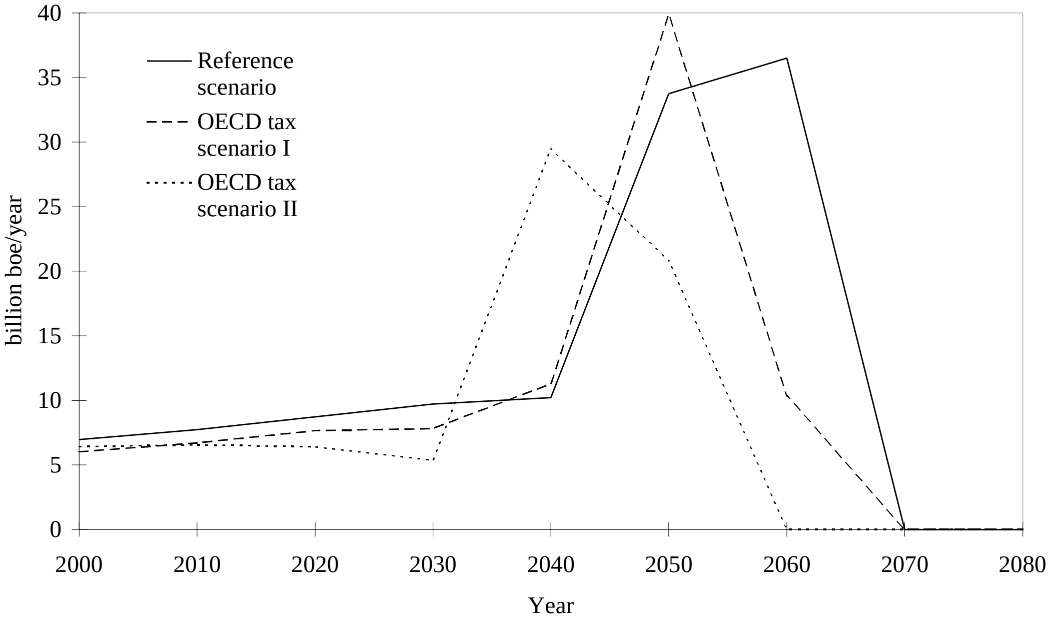
In the OECD carbon tax scenario I, a carbon tax of $10 per boe is levied on OECD countries from 2000 onwards, but also on countries outside OECD from 2030. As seen from figure e, the producer price of oil is reduced by only $0.3 in the first period, which means that the consumer price increases with $9.7. However, the slope of the price path is lower, and in 2040 the producer price is reduced by $3.5. From 2050 onwards, when both price paths follow the respective maximum producer price paths, the producer price is $10 less than in the Reference scenario. See also equation (38) to understand the impacts on the slope by a fall in the price.

Figure E. Oil producer price, reference scenario and OECD tax scenarios



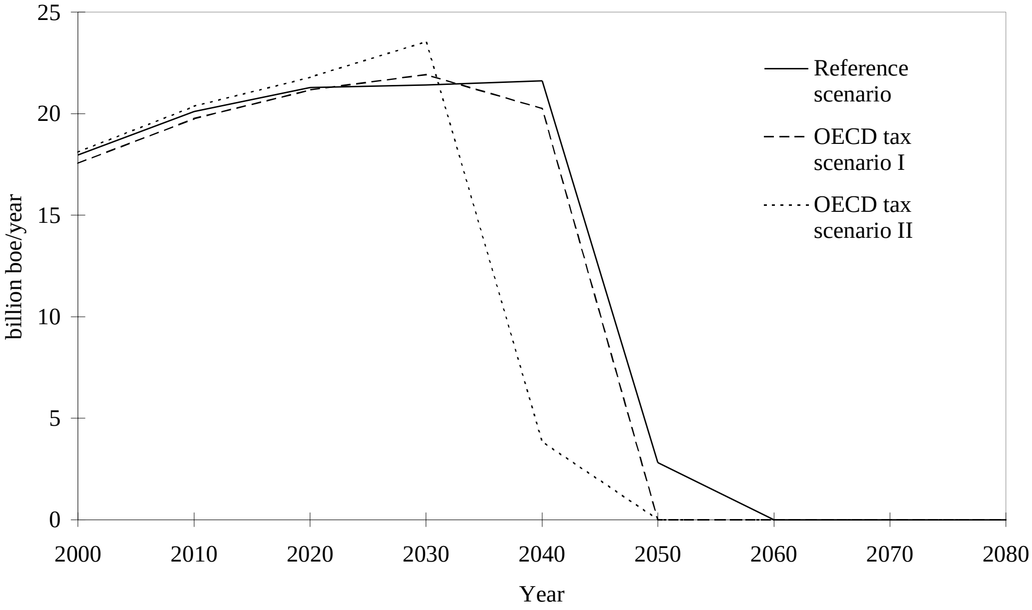
The reason for the small initial change in the oil price is the OPEC behaviour. As seen from figure f, OPEC reduces its production quite significantly in the year 2000, by about 14 per cent, as a response to this climate policy. The cartel knows (at least in the model) that reducing production gives a higher price. In a static model, the optimal response by a cartel is to reduce its production to retain its marginal revenue, i.e., the cartel rent. In a dynamic model, however, OPEC also takes into consideration the exhaustability aspect, introduced by the scarcity rent, and the oil rent now consists of the cartel rent and the scarcity rent. But the marginal extraction costs in OPEC are almost constant as long as Non-OPEC is in the market, which means that the scarcity rent is rather low, and OPEC behaviour is not much influenced by the dynamic aspects. Thus for OPEC it is optimal to reduce the production to retain its cartel rent and therefore its oil rent, see also Berg et al. (1997a).

Figure F. Oil production in OPEC, reference scenario and OECD tax scenarios



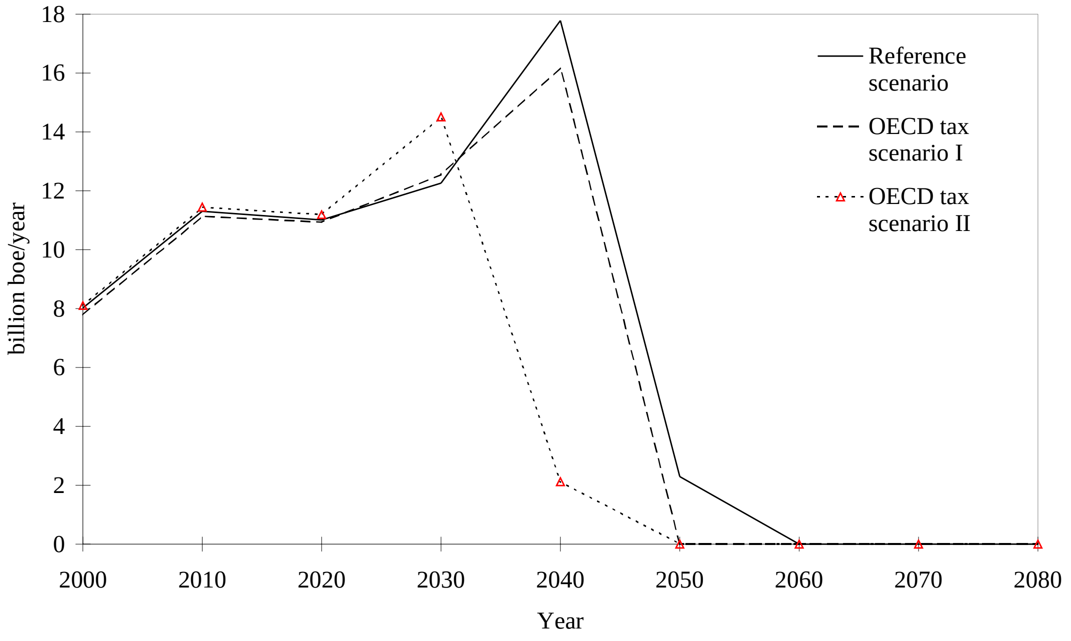
Non-OPEC is a competitive fringe, and views the oil price as given. A lower oil price level gives an incentive to reduce production. However, the slope of the price path also matters. An increasing price path gives an incentive to delay production. As the price increases less under the climate policy, this incentive is weakened, and Non-OPEC wants to move the production profile nearer in time, i.e., to increase production in earlier periods and to reduce production in later periods. From figure g we see that this last effect mainly occurs in the later periods of Non-OPEC production. In 2030 production increases by 2.4 per cent even though the price has fallen by $1.9 per boe. The reason is of course that the price fall in the next periods is much larger, which reduces Non-OPEC production significantly in these periods. Thus, in 2030 the incentive to accelerate production is stronger than the incentive to reduce production level due to lower prices. In the three first periods Non-OPEC production decreases somewhat, but never more than 2.3 per cent. Over the time horizon, the aggregated Non-OPEC production is reduced by about 4 per cent to 1,007 billion boe.

Figure G. Oil production in Non-OPEC, reference scenario and OECD tax scenarios



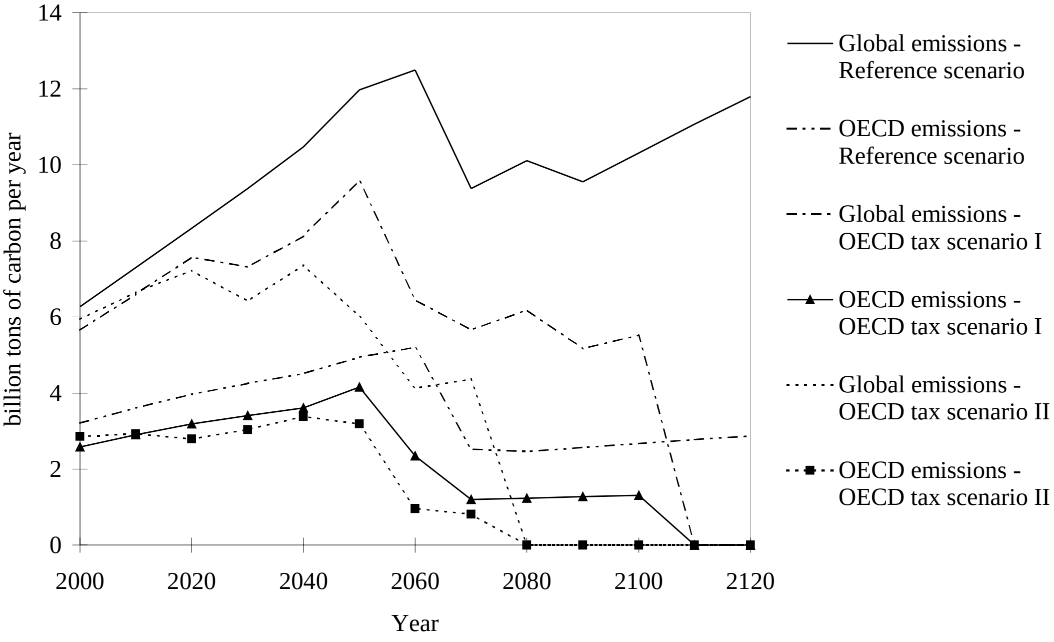
The impact of the carbon tax on exploration activity follows closely the impact on Non-OPEC production, see figure h. In the three first periods new discoveries decrease by up to 3 per cent. Then, in 2030 exploration activity increases somewhat, i.e. by 2.3 per cent, before it falls below the reference scenario in the next periods. Thus, in these later periods the oil exploration path has been moved nearer in time in a similar way as the production profile. Aggregated discoveries are reduced by 6.5 per cent - before 2040 the reduction is only 0.4 per cent. We therefore conclude that introducing a constant carbon tax in the OECD area has only negligible impacts on Non-OPEC production *and* exploration before the middle of the next century. This is mainly due to OPEC behaviour, but also to the dynamic aspects of non-renewable resources.

Figure H. New discoveries in Non-OPEC, reference scenario and OECD tax scenarios



A carbon tax of $10 per boe introduced in OECD countries will reduce global emissions by 10 per cent to 5.8 billion ton carbon in 2000, see figure i. This is around the actual level of fossil fuel-related carbon emissions in 1990. The emissions will, however, increase slightly over time and peak at 9.6 billion tons in 2050. Due to the carbon tax, coal is actually substituted by the backstop from 2110 onwards, which gives no carbon emissions. CO_2 emissions in the OECD area are reduced by 20 per cent in 2000 and 2010, and reach a level of 2.9 billion tons in 2010, which is about 5 per cent above the actual 1990 level. At first glimpse this reduction may seem too small compared to the agreed reduction in the Kyoto Protocol of 5.2 per cent compared to 1990. However, as explained above this overall commitment applies to countries outside the OECD, too, in which emissions are expected to decrease between 1990 and 2010, and it applies to an aggregate of 6 greenhouse gases (including CO_2).

Figure I. CO_2 emissions from fossil fuel combustion, reference scenario and OECD tax scenarios



4.2.2. The Global carbon tax scenario

When the carbon tax is introduced in all regions from the beginning, the price path of oil is more or less identical to the price path in the OECD carbon tax scenario I. Thus, Non-OPEC production and exploration is also almost identical. The reason for this is again the OPEC behaviour. As the Non-OECD region also meets climate restrictions, it has a lower demand for fossil fuels than in the OECD carbon tax scenario I. In the same manner as OPEC reduces its supply when the tax is levied in the OECD area only, it reduces its supply even more when the tax is levied globally so as to prevent the oil price from falling. Moreover, after 2030 the maximum producer price is equal in these two tax scenarios. Thus, the result is that the price paths in the two tax scenarios are almost identical.[8]

Global CO_2 emissions in 2000 have been reduced by 21 per cent to 4.9 billion tons of carbon. Thereafter, the emissions increase and follow the path of the OECD carbon tax scenario I from 2030 (when the carbon tax applies globally in both scenarios). As fossil fuel prices are almost identical to the OECD carbon tax scenario I, CO_2 emissions in the OECD regions are also almost equal in these two tax scenarios.

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[8] Since this scenario is almost identical to OECD carbon tax scenario I, it is not shown in the figures.

This scenario shows that the general impacts on exploration in Non-OPEC countries will be the same whether or not the carbon tax initially is introduced in all regions or only on OECD countries, as long as the tax is levied globally after some decades. This is mainly due to the OPEC behaviour.

4.3. Effects of rising carbon taxes

4.3.1. The OECD carbon tax scenario II

As stated above, the most plausible scenario is that we will see a rising carbon tax, first introduced in OECD countries. The reason is that the goal of stabilising emissions will be increasingly tougher to reach as the distance from the Business as Usual path gets larger. Moreover, several studies have concluded that the optimal time path of a carbon tax may be rising initially (e.g., Ulph and Ulph (1994) and Hoel and Kverndokk (1996)). In the OECD carbon tax scenario II we analyse the effect of one such scenario, where the carbon tax in OECD is $5 per boe in the first period, $10 in the second period (2010), and $20 thereafter (from 2020). In 2030 the carbon tax of $20 per boe is levied on all countries.

From figure e we see that the oil price has fallen even more than in the first OECD carbon tax scenario. Moreover, the oil price path increases less rapidly over time, and reaches its maximum level in 2030 just above $20 per boe. Note that the oil price in 2000 is actually lower in this case when the carbon tax is $5 per boe initially than when the carbon tax is constant and equal to $10 per boe. This is due to the intertemporal behaviour, and the fact that the price path is barely increasing over time. As explained above, the producers then have incentives to accelerate their production compared to the situation in the OECD carbon tax scenario I with more rapidly increase in the oil price, and so the initial price is suppressed.

This is confirmed in figure f which shows that OPEC does not reduce its production as much in the beginning as when the constant carbon tax is introduced. In 2020 and 2030, however, when the tax is $20 per boe, OPEC’s production is significantly reduced. Thus, the reduction in OPEC supply seems to be tight connected to the size of the tax in the specific period, as long as Non-OPEC produces. We also see that OPEC takes over the market one period earlier, but as the cartel also stops producing one period earlier, its aggregated production is reduced by 34 per cent compared to the reference scenario.

The Non-OPEC reaction to this carbon tax scenario is interesting. From figure g we see that production outside OPEC has increased in each of the first four periods. Then production drops to one sixth when the price reaches the maximum producer price. The reason is that the incentive to accelerate production due to an almost flat price path is stronger than the incentive to reduce production level due lower prices. Hence, Non-OPEC's response to this carbon tax scenario is actually an increase in production for the first 40 years to come.

In figure h we see that this conclusion also applies to exploration activity outside OPEC. To increase Non-OPEC production in early periods, more exploration seems to be optimal. Compared to the reference scenario, in 2030 the discovery rate is increased by 18 per cent, and at the end of the fourth period, aggregated discoveries in Non-OPEC are 6 per cent higher. However, over the entire time horizon, aggregated discoveries are reduced by 24 per cent as the life of Non-OPEC oil is shortened by one decade. Still, it is a startling result that for the first 40 years oil exploration outside OPEC is not being negatively affected by a climate agreement. In fact the contrary may occur.

Notice that carbon emissions in OECD are between 0 and 10 per cent above the actual 1990 level for the first forty years, and never exceed more than 25 per cent above this level, see figure i. Global emissions, too, do not exceed more than 25 per cent above its 1990 level. Hence, despite the counteractive effect in Non-OPEC activity, this tax scenario is not far from stabilising emissions in the long run. Whether the commitment put forward in the Kyoto Protocol is reached or not, is however unclear (see the end of Section 4.2).

5. Sensitivity analyses and discussion

As exploration in Non-OPEC countries is the main topic in this paper, we concentrate the sensitivity analysis around this activity. As pointed out in Section 3 there are several parameters that are quite uncertain.

The *deposit-cost profile* were calibrated under the assumption that 70 per cent of remaining resources could be extracted at a unit cost lower than \$20 per boe. If we rather assume that the share is 60 per cent, the deposit-cost profile gets more linearly, i.e., the value of φ gets higher ($\varphi = 9.9$) and the initial minimum cost decrease to \$3.8 per boe. In this reference case exploration is increased in the first period, as the difference between extraction cost from old resources and the best quality deposits in new discoveries has increased. However, this is compensated in later periods, so that aggregated discoveries are almost unchanged. If we instead make the deposit-cost profile more *non*-linear by assuming that 80 per cent of remaining resources can be extracted at a unit cost less than \$20 per boe (implying that φ drops to 5.7 and the minimum cost increases to \$6.9 per boe), the opposite effect occurs. In both cases, when we introduce constant or rising carbon taxes in OECD, the previous results on exploration are confirmed. In particular, a gradually increasing carbon tax increases exploration in Non-OPEC for the next 40 years.

The *exploration unit cost* is of course an important variable for determining the optimal exploration, and both the initial value, the depletion parameter γ and the technological change must be tested. Halving the *initial unit cost* to \$1 increases exploration in the two first periods by 50 per cent, but then the positive effect is consumed. With a constant carbon tax in OECD, exploration is almost unchanged in the four first periods, and increases by about 5 per cent in 2040. A rising carbon tax has also negligible effects on exploration in the beginning, but in 2030 new discoveries are 10 per cent higher (production is higher in all the four first periods). Thus, in this case the effect of a rising carbon tax is a bit different from the main scenarios, as the incentives to accelerate exploration weakens with a low exploration unit cost and high exploration. If the initial unit cost increases to \$5, exploration in the first period is not profitable, however, in later periods new discoveries range from 7-17 billion barrels per year. In this case exploration (and production) increases in the periods 2020-2030 with the constant carbon tax, and in the periods 2010-2030 with the rising carbon tax. In the last scenario aggregated discoveries before the period 2040 have increased by 6 per cent.

Exploration is very sensitive to the *depletion effect in exploration costs* (γ). First, we study the effect of reducing the parameter from 0.052 to 0.036, which means that (ignoring technological change) the unit exploration cost reaches \$10 per barrel (instead of \$20) when the average of the low and high estimate of undiscovered oil in Non-OPEC (EIA, 1997b) has been discovered (see Section 3). In this case exploration increases considerably in all periods in the reference scenario, and Non-OPEC keeps its high level of exploration and production for one more period. The effects on exploration by a constant or rising carbon tax in OECD are almost identical to the case with a low initial unit cost (see above). In the opposite case, we analyse the effect of increasing γ to 0.082, which means that the unit exploration cost reaches \$10 per barrel when the *low* estimate of undiscovered oil is discovered. Now exploration in Non-OPEC is suppressed in all periods in the reference scenario, and aggregated discoveries are reduced by one third. Here, too, the effects of carbon taxes on exploration are about the same as in the case with a *high* initial unit cost. Hence, with smaller potentials for new discoveries, the impact of a climate treaty seems to be an accelerating exploration activity in Non-OPEC.

In order to study the effect of technological progress, we increase the initial rates of *technological change in exploration and production* to 5 per cent per year. In this reference scenario the price *decreases* from 2000 to 2010, which is due to the cost reductions giving producers incentives to delay exploration and production. Still, due to the overall increase in exploration over the time horizon, initial exploration activity is almost at the same level as in the ordinary reference case, but in later periods new discoveries are 15-30 per cent higher. When a constant carbon tax is introduced, exploration decreases somewhat in all periods, except in 2040. A rising carbon tax leads to only marginal changes in exploration for the three first periods. Then, in 2030 new discoveries increase by 10 per cent. Thus, we get the same result as with either low initial unit cost or low depletion effect in exploration, which indicates that when exploration is cheap and the activity already high, the incentive to accelerate it under a climate treaty seems weakened, at least in the beginning.

Increasing the initial technological change in the *backstop technology* to 5 per cent per year (and gradually reducing it to the original rate of 1.5 per cent over 30 years), causes the oil price to increase from $15 in 2000 to only $15.4 in 2020, before it declines. This increases Non-OPEC exploration in the first two periods as they get an incentive to move production to an earlier stage. However, as the maximum producer price is reduced, Non-OPEC stops producing and exploring two periods earlier. Introducing a constant or rising carbon tax reduces exploration to some degree in all periods. With a rising carbon tax the reductions in the two first periods are, however, only 1-2 per cent. On the other hand, if we assume a constant rate of technological change of merely 1 per cent in the backstop technology, the oil price reaches its maximum level of $45 per boe in 2050, and Non-OPEC production continues for one more period. Before 2050, however, due to the continued rapid rise in the oil price, both exploration and production is in fact lower than in the main reference scenario. When a constant or rising carbon tax is levied on OECD countries, only marginal effects occur for the first thirty years. Yet in 2030 and 2040 new discoveries increase in both tax scenarios, and with a rising tax aggregated discoveries before 2050 is 7 per cent higher than without a carbon tax.

To summarise, these sensitivity analyses show that an accelerated Non-OPEC exploration is a fairly strong result in the case of a rising carbon tax. In four of the nine alternatives, exploration activity is increased for the first three or four decades, which confirms our main scenarios. In four of the other alternatives, which are characterised by either less expensive exploration or prospects of high oil prices in the future, new discoveries are almost unchanged in the beginning, but increase around 2030. In the last alternative the duration of oil production is so short that there is no room for either short- or long-term increases in exploration. Still, nor in this alternative is there any significant reduction in Non-OPEC exploration for the two first decades when a rising carbon tax is introduced.

Another question relates to whether the model structure is realistic or not. We pointed to above that OPEC’s market share is relatively low in our reference scenario compared to the actual level. The explanation could be that OPEC does not behave coherently enough in reality, or it could be that OPEC tries to squeeze other producers out of the market in a Stackelberg manner. In both cases, OPEC will probably not be that willing to reduce production when carbon taxes are introduced, as our model tells. Hence, producer prices will fall even more. It is difficult to state what will happen with Non-OPEC production and exploration in this case. However, an analysis of a competitive oil market in Berg et al. (1997a) indicates that even in such an extreme case Non-OPEC production (and thus probably exploration) may increase in some periods when constant carbon taxes are introduced.

A more fundamental critic against our model could be that oil producers do not act in a fully intertemporal way. This may be true, however, it is equally unlikely that resource owners do not consider whether it is profitable to extract their resources today or in the future. The aim of our analysis is to show that this characteristic of the oil market may have some counterintuitive effects in connection with climate treaties.

6. Conclusions

This paper studies how an international climate treaty influences oil exploration in Non-OPEC countries. The expected result may be that both exploration and production will fall as the demand for oil declines. This was partly confirmed by Jin and Grigalunas (1993), however, they found that the immediate exploration activity could in fact increase when environmental compliance costs were expected to increase over time. A tax on carbon emissions (or a tradable quota system) will influence the producer price of oil. The producer price will fall, but the price tends to rise more slowly over time. If Non-OPEC countries act as competitive producers, they will consider the price as given when deciding their production profile. A lower producer price gives an incentive to reduce production and, therefore, also exploration. However, when the price reduction is higher in the future than today, the incentive to delay production is reduced. Thus, Non-OPEC may move the production profile forwards which gives an incentive to accelerate exploration.

To study which effect is the strongest, we have run simulations on a numerical intertemporal global equilibrium model for the fossil fuel markets, where the international oil market consists of a cartel (OPEC) and a competitive fringe (Non-OPEC) on the supply side. When a constant carbon tax is introduced either globally or in OECD countries only (and later in the rest of the world), exploration is only slightly affected the first 40 years: In the three first decades there is a marginal reduction, whereas in the ten-years period 2030 there is a small increase. Then exploration falls to zero more quickly than in the reference scenario, so that aggregated discoveries will be lower under the climate treaty. The effect on the production profile is fairly equal. Hence, a constant carbon tax does not have a dampening effect on Non-OPEC exploration as, e.g., Jin and Grigalunas (1993) found with their competitive model. This is both due to OPEC's reaction, and to the dynamic effects which give incentives to accelerate exploration.

In the case with a rising carbon tax, first in OECD and then globally, exploration activity as well as production are *increased* for the first 40 years. Aggregated discoveries over this time interval are 6 per cent higher than in the reference scenario. Thus, as opposed to Jin and Grigalunas (1993), we find that the positive effect on exploration is not just a short-lived phenomenon. This result is fairly robust when it comes to other parameter choices, although in the case with persistently low exploration costs or alternative assumptions about the backstop technology, exploration activity is more or less unchanged initially by this tax. However, in all but one of the sensitivity analyses carried out, new discoveries eventually increase after some decades.

As this last tax scenario may be the most plausible one following the climate treaty signed in Kyoto in 1997, due to the behaviour of OPEC and the dynamic aspects of non-renewable resources, we conclude that oil exploration in Non-OPEC countries *may be intensified, or at least unchanged,* compared to a non-treaty scenario over the next few decades.

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Appendix 1

The optimisation problems in the natural gas markets

As in the oil market, the gas producers also maximise the present value of the net revenue flow. We consider three separate regional natural gas markets with perfect competition. There are similar restrictions and first order conditions for the optimisation problems for all markets *i*=1,2,3. Each producer faces the following optimisation problem:

(A1) $$\max_{x_G^i} \int_0^\infty \left[P_G^i - C_G^i \right] x_G^i \cdot e^{-rt} dt$$

s.t.

(A2) $$\dot{A}_G^i = x_G^i$$

(A3) $$x_G^i \geq 0$$

(A4) $$C_G^i = \sigma^i e^{\eta_G^i A_G^i - \gamma^i t}$$

The first order conditions give

(A5) $$P_G^i = C_G^i \left(A_G^i, \gamma^i, t \right) + \pi_G^i$$

(A6) $$\dot{P}_G^i = rP_G^i - \left(r + \gamma^i \right) C_G^i = r\pi_G^i - \gamma^i C_G^i$$

In a market equilibrium the producer price is

(A7) $$P_G^i = P_G^i \left(x_G^i, z_G^i + v_G^i, Q_O^i, Q_K^i, \overline{P}, Y^i \right)$$

The transversality conditions in the natural gas markets, where $T_G^i \in (0, \infty)$, are similarly

$$\overline{P}_{T_G^i} - z_G^i - v_G^i = C_G^i\left(\overline{A}_G^i, T_G^i\right) \tag{A8}$$

The optimisation problem in the coal market

We assume that there is one global coal market with perfect competition. Since the coal resources in the world are so huge compared to those of oil and gas, we ignore the dynamic aspect of the resource extraction and treat the optimisation problem in the coal market as a static problem, where the coal producers maximise the profit in every period. Each producer faces the following problem:

$$\max_{x_K} \int_0^\infty \left[P_K - C_K\right] x_K \cdot e^{-rt} dt \tag{A9}$$

s.t.

$$x_K \geq 0 \tag{A10}$$

$$C_K = \theta e^{-\psi t} \tag{A11}$$

The unit cost in coal production is assumed to be independent of accumulated production. The first order condition is simply,

$$P_K = C_K \tag{A12}$$

In a market equilibrium we get the following producer price of coal

$$P_K = P_K\left(x_K, z_K^1 + v_K^1, z_K^2 + v_K^2, z_K^3 + v_K^3, Q_O^1, Q_O^2, Q_O^3, Q_G^1, Q_G^2, Q_G^3, \overline{P}, Y^1, Y^2, Y^3\right) \tag{A13}$$

The transversality condition, where $T_K \in \left(0, \infty\right)$, is

$$\max_i(\overline{P}_{T_K} - z_K^i - v_K^i) = C_K(T_K) \tag{A14}$$

Appendix 2

Table A1. GDP growth rates, in per cent.

	1995 2004	2005 2014	2015 2024	2025 2034	2035 2044	2045 2054	2055 2064	2065 2074	2075 2084	2085 2094	2095 2104	2105 2114	2115 2124	2125 2134
OECD-Europe	2.2	1.9	1.6	1.4	1.3	1.2	1.1	1.05	1.0	0.95	0.9	0.85	0.8	0.75
Rest-OECD	2.8	2.5	2.2	1.9	1.6	1.4	1.2	1.1	1.0	0.95	0.9	0.85	0.8	0.75
Non-OECD	3.6	3.4	3.2	2.95	2.7	2.4	2.2	2.0	1.8	1.7	1.6	1.45	1.3	1.2

Table A2. Price and income elasticities

	OECD	Non-OECD
Direct price elasticities	-0.90	-0.75
Cross price elasticities	0.10	0.10
Income elasticities	0.50	0.60

Table A3. Existing taxes on fossil fuels in 1994, 1994$/boe

	OECD-Europe	Rest-OECD	Non-OECD
Tax on oil	34.02	12.21	3.52
Tax on gas	3.60	0.00	0.00
Tax on coal	0.74	0.00	0.00

Table A4. Constant parameter in demand function, ω, mtoe/year

	Oil	Natural gas	Coal
OECD-Europe	13,506	2,524	1,596
Rest-OECD	17,735	6,126	3,465
Non-OECD	8,390	4,011	4,598

Table A5. Parameters in the cost functions (Non-OPEC not included)

$C = C_0 e^{\eta A - \tau t}$	initial unit cost of prod., C_0, 1994$/boe	technological change, τ, per cent	depletion parameter, η^*
oil			
OPEC	3.32	1.0	0.023
natural gas			
OECD-Europe	7.00	1.0	0.122
Rest-OECD	5.45	1.0	0.088
Non-OECD	5.53	1.0	0.017
coal	8.80	0.5	--
backstop technology	108.20	1.5	--

[*] 10 billion barrels is used as metrics in the cost functions

Table A6. Cost data in oil production for Non-OPEC

	initial unit cost, β and C_{min}, 1994$/boe	depletion parameter, γ^* and φ	technological change δ and τ^F, per cent
exploration costs	2.0	0.052	2.0 → 1.0
extraction costs	5.5	7.6	2.0 → 1.0

[*] 10 billion barrels is used as metrics in the exploration cost function

Table A7. Accumulated production and remaining resources in Non-OPEC, billion barrels of oil

	accumulated production	remaining resources 1995
Non-OPEC	445.6	426.6

Table A8. Initial unit costs of transportation, distribution and refining, 1994$/boe

	OECD-Europe	Rest-OECD	Non-OECD
oil			
transportation	1.64	1.53	1.06
distribution	3.4	3.4	3.4
refining costs	2.28	2.53	2.16
total	7.32	7.46	6.62
natural gas			
transportation	5.1	3.16	2.1
distribution	6.8	6.8	6.8
storing and load balancing	2.0	2.0	2.0
total	13.9	11.96	10.9
coal			
transportation	3.79	1.43	0.57
distribution	3.4	3.4	3.4
total	7.19	4.83	3.97