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Are high oil prices profitable for OPEC in the long run?

Abstract:

High oil prices are favourable for OPEC in the short run, but may undermine its future revenues. We search for the optimal oil price level for the producer group, using a partial equilibrium model for the oil market. The model explicitly accounts for reserves, development and production in 4 field categories across 13 regions. Oil companies may invest in new field development or alternatively in improved oil recovery in the decline phase of fields in production. Non-OPEC production is profit-driven, whereas OPEC meets the residual call on OPEC oil at a pre-specified oil price, while maintaining a surplus capacity. According to our results, sustained high oil prices stimulate Non-OPEC production, but its remaining reserves gradually diminish despite new discoveries. Oil demand is only slightly affected by higher prices. Thus, OPEC is able to keep and eventually increase its current market share beyond 2010 even with oil prices around \$30 per barrel (2000-\$). In fact, an oil price around \$40 seems to be profitable for OPEC, even if long-term revenues are not discounted. Sensitivity analyses show that even with many factors working jointly in OPEC's disfavour, the optimal oil price seems to be at least \$25. Thus, for OPEC there is a trade-off between high prices and high market share in the short to medium term, but not in the long term. For OECD countries, on the other hand, there is a clear trade-off between low oil prices and low import dependence.

Keywords: Oil market, oil price, market power, equilibrium model

JEL classification: L13, Q31, Q41

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Introduction

OPEC's strategy in the oil market is not easy to comprehend, and it has certainly changed over the years since the cartel's first significant manoeuvre in 1973. As from March 2000 to February 2005 OPEC's declared strategy was to adjust production in order to achieve crude oil prices between \$22 and \$28 per barrel of OPEC oil. This price band was of course not an ultimate goal, but only a quasi-goal that OPEC found appropriate in the prevailing market situation. When the oil market tightened significantly in 2004, oil prices reached \$38 on a yearly average, and in February 2005 OPEC suspended its price band. A new and higher price target will eventually be declared.¹

It is therefore interesting to ask what is the optimal oil price level for OPEC, both in the short and long term. For instance, is it in OPEC's interest to choose a price target similar to the prices seen in 2004? In the beginning of the 1980s OPEC followed a high-price strategy, with nominal crude oil prices around \$30 per barrel. This strategy brought about large increases in supply from Non-OPEC producers and a decline in worldwide consumption of oil. Thus, OPEC's production and market share fell dramatically, and in particular Saudi Arabia was hurt when their production fell by two third from 1980 to 1985. As a consequence the price strategy was abandoned in 1986, and the oil price was halved. During the 1990s OPEC seemed to be comfortable with oil prices below \$20 (the Dubai nominal price varied between \$12 and \$21 on a yearly average).

Few expect a similar course of development over the next years, in the case of a moderate increase in OPEC's price target. One reason is that Non-OPEC supply potential is not as bright as it was 20 years ago. Another reason is that the real oil prices in the early 1980s were much higher than the recently abandoned price target, and even higher than the prices observed in 2004. Moreover, oil demand seems to be less price responsive now than in the first decade after OPEC I in 1973 (see e.g. Liu, 2004). Yet, a permanently high oil price will to some extent stimulate supply outside OPEC and slow down the growth in oil demand, and OPEC's market share may not evolve as the cartel members expect. Several OPEC members have now announced plans to expand their production capacity over the next several years. With increased spare production capacity it may be harder for OPEC to reach consensus among its members. On the other hand, core OPEC countries are in need of revenue to cover public expenditure driven by high population growth, and may consider high oil prices in the short run as more important than a high income at a later stage. For OPEC as a whole, real per capita

¹ According to PIW (2004) a nominal OPEC basket price of around \$34 per barrel in late 2004 is in the middle of the old \$22-\$28 band, after adjustment for inflation and currency fluctuations, particularly the decline of the dollar.

oil export revenues in 2004 were less than one-third of the per capita revenues in 1980, but still 36 per cent higher than the revenues in 2003 (EIA, 2005).

In this paper we focus on two important features of the oil market, i.e. market power and the access to oil resources. In the 1970s two different modelling traditions emerged, describing the oil market as more or less dominated by OPEC. One is an intertemporal modelling of the supply side, where the oil producers maximise the present value of their oil wealth based on future expectations (see, e.g., Salant, 1976 and Pindyck, 1978 and lately Berg *et al.*, 1997 and 2002). The producers focus on the lifetime of the resource, taking into consideration that oil is exhaustible, as in the Hotelling tradition. Although this modelling approach is based on rational producers, the assumptions of perfect foresight and complete property rights are very critical.

Another class of oil models is recursively dynamic, i.e. the model is solved in sequential periods and equilibrium within each period depends only on past and contemporaneous variables (see, e.g., Gately *et al.*, 1977, and Burniaux *et al.*, 1992). These models have a shorter time perspective than the intertemporal models and have an adaptive expectations approach. Further, these models often let OPEC follow "rules of thumb" rather than optimising behaviour, like where the price rule is based on a connection between OPEC's capacity utilisation and the oil price. As capacity in general is exogenous, assumption about the development of this variable is central for the model results. The exhaustibility constraint is only indirectly taken into consideration through adjustments in the cost-functions, e.g. that costs increase with declining reserves.

In this study we employ a numerical model, which belongs to the recursive tradition. We examine if OPEC can combine high oil prices with a high market share, and search for the optimal oil price level for the producer group in the long run. In the model OPEC sets the oil price², and supply the market in order to fill the gap between Non-OPEC production and world oil demand. Similar recursive modeling approach has been employed lately by EIA (2004) and IEA (2004a). However, we implement a wide range of fixed oil prices, as opposed to the latter studies that only apply 2-3 oil price scenarios. The model incorporates both short- and long-run effects of changing oil prices in various regions on both the demand and supply side. An important contribution of our paper is the detailed modelling of the supply side. We separate between oil producers' investment and production decisions in 4 field categories in 13 different regions, based on profit maximisation and detailed information about the access to fields worldwide. Although the producers are not carrying out a dynamic optimisation in the

² Böckem (2004) finds that a price-leader model best describes OPEC and the oil market.

Hotelling tradition, the model incorporates some elements that partly mimic the shadow cost of the oil resources. The model is described more fully in Section 2 below.

The model simulations focus how different oil price scenarios affect world demand, investment and production in OPEC and Non-OPEC over the next 25 years. We study how OPEC's net income will develop in the various scenarios, and what the producer group's optimal strategy is, given various trade-offs between future and current income. We also study the development of OECD's import share, to examine how this region's dependency on oil deliveries from other regions will depend on the oil price level.

Our main claim is that the optimal price level for OPEC is significantly higher than the recently abandoned price target, even if OPEC takes on a long-term perspective and values future revenues on equal terms as revenues today. A thorough sensitivity analysis seems to confirm this. We test the effects of alternative levels of new discoveries, more or less price responsive demand, oil price responsive GDP growth, different discount rates for oil companies outside OPEC, and changed restrictions on their use of cash flow. Our results seem to be at odds with EIA (2004) and IEA (2004a), which predict substantial increase in OPEC production and a moderate oil price level over the next two centuries. Gately (2004) updates the results in Gately (2001) and finds, however, that OPEC has no incentives to increase its output as rapidly as these reports project, because a slower increase in OPEC output would increase their profit even more.

A relevant question is, however, if OPEC acts as a dominant producer, i.e., a cartel that optimises its joint petroleum wealth. Recent econometric analyses reject this hypothesis (see, e.g., Alhajji and Huettner, 2000, and Hansen and Lindholt, 2004), and there are several reasons for this. For instance, the producer group consists of different countries with different ambitions and intentions. Some countries are concerned about near term revenues and immediate budget needs, whereas others are more concerned about the longer perspective. Moreover, for a single country there is a clear temptation to produce more than its given quota. Still, in our paper the general focus is on OPEC as a homogeneous group.

The next section describes the numerical oil market model, which is called FRISBEE. In Section 3 we present simulations of different scenarios towards 2030, in Section 4 the sensitivity analyses are discussed, and in Section 5 we sum up.

Model description

The FRISBEE³ model is a recursively dynamic partial equilibrium model of the global oil market. The world is divided into 13 regions in the model (see Table 1). In each region oil companies produce oil, which they sell on the global market. Three different end-users in each region consume oil products, which they buy at regional prices linked to the international market. We assume that the global oil market clears in each period, i.e., total supply from all regions equals total demand in all regions, and all trade between regions goes through a common pool. The time periods in the model are one year, and the base year is 2000. Prices are thus stated in 2000-\$, and exchange rates are held constant over time. A formal and detailed description of the model is given in Appendix B.

Table 1. Regions in the FRISBEE-model

<i>Industrialised regions</i>	<i>Regions in transition</i>	<i>Developing regions</i>
Canada (CAN)	Caspian region (CAR)	Africa (AFR)
OECD Pacific (OEP)	Eastern Europe (EEU)	China (CHI)
USA	Russia/Ukraine/Belarus (RUB)	Latin America (LAM)
Western Europe (WEU)		OPEC core (OPC)
		Rest-Asia (RAS)
		Rest-OPEC (OPR)

Production of oil

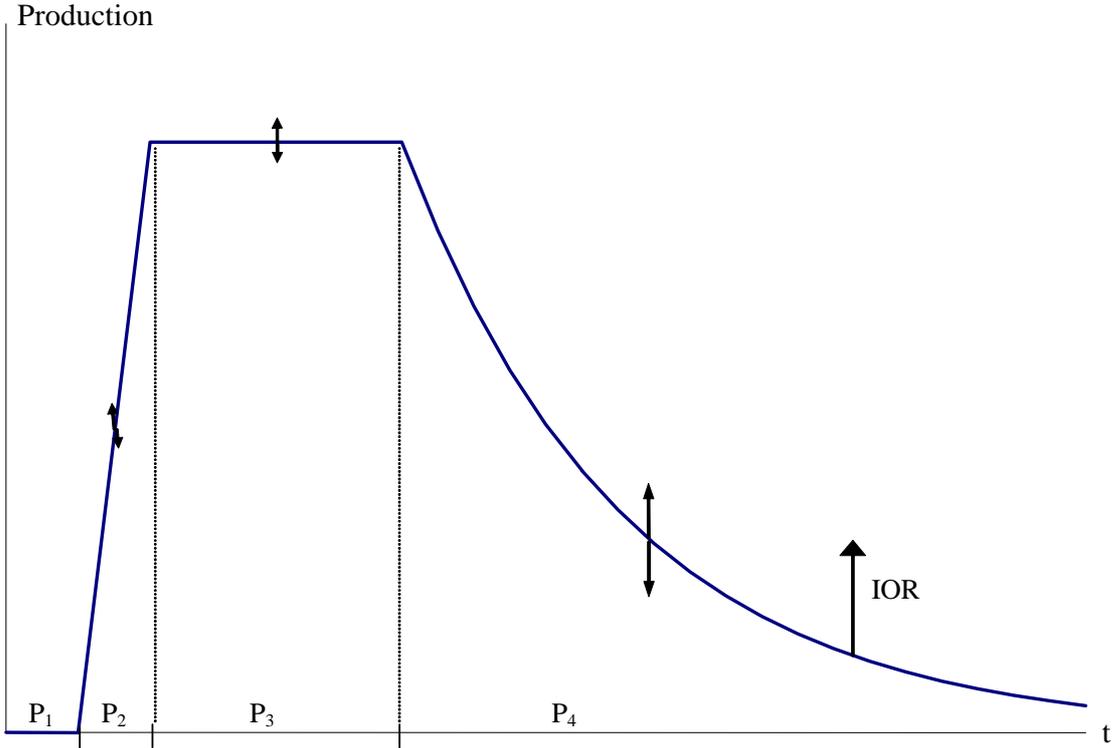
In each of the 13 regions the model distinguishes between 4 field categories based on field size and geology (see Table A1 in Appendix A). Within each of the resulting 52 operational areas, there are developed and undeveloped reserves. A field reserve is classified as developed when the decision to invest in the field is taken. New discoveries add to the stock of undeveloped reserves at the end of each year.

Both production and investment decisions are explicitly modeled. For each region and field category we apply a pre-specified production profile, see Figure 1. This profile is taken for granted in the investment decisions, but can to some degree be altered during the lifetime of the field (see below). The profile is divided into four phases: The first phase (P_1) is the *investment phase*, i.e., the time lag between the investment decision and start of production. The second phase is the *pre-peak phase* (P_2), i.e., when production builds up towards the peak level. The two first phases are quite short, varying

³ FRISBEE: Framework of International Strategic Behaviour in Energy and Environment.

between 2 and 6 years in total across regions. The third phase is the *peak phase* (P_3), when capacity is at a constant and pre-specified level. This phase lasts between 5 and 10 years. The fourth and final phase is the *decline phase* (P_4), when capacity declines at a constant rate per year until production is too low to be profitable. Thus, all developed reserves are divided into region, field category and vintage (phase). The initial allocation is based on input from an extensive database of global petroleum reserves in the year 2000.

Figure 1. Production profile for oil fields in the FRISBEE model



At the end of each year private and state oil companies may decide to invest in developing new fields, or in improved oil recovery (IOR) from existing fields. This is described in more detail below.

When new fields are developed, the stock of undeveloped reserves is reduced. We assume that new discoveries are made each year in every region and field category. The volumes of new discoveries are assumed to be a linear function of the average oil price over the last 6 years, and to fall exponentially over time at a constant oil price. This discovery function is calibrated for each region so that if the oil price stays at \$40 per barrel, total accumulated discoveries over the time horizon (i.e., until 2030) equal USGS's (2000) mean estimate of potential new discoveries over a 30 years period.

The model includes supply of conventional oil (crude oil and NGL), unconventional oil from Canada (tar sand) and Venezuela (extra heavy oil).

Production in Non-OPEC

The oil production capacity in a region is by and large fixed at each point of time, as expressed in the pre-specified production profile that is determined by investments in earlier years. However, production is not totally fixed, but can be above or below the pre-specified production profile if that is profitable. A short-term marginal cost function decides whether a deviation from the pre-specified profile is optimal. For Non-OPEC regions we assume that oil supply is determined by equalising the producer price of oil with the sum of marginal operating cost and gross sales taxes in each field category and vintage. The producer price of oil in a region is mainly determined by the global crude oil price and transport costs, but may also differ due to crude oil quality. We assume that the initial differences in producer prices across regions are unchanged over time.

In the pre-peak and peak phase we assume that marginal operating costs are fairly constant (and low) except when production is very close to capacity.⁴ As shown by the arrows in phase P2 and P3 in Figure 1, there is a slight possibility to adjust production in these two periods. In the decline phase, however, marginal operating costs increase more rapidly as production rises. This reflects that some of the declining fields are approaching the end of their lifetime, and extraction is falling for a given operational input. That is, costs per unit production get higher, and the oil price level will to a larger degree affect the optimal production level. Thus, as indicated by the arrows in phase P4 in Figure 1, production is more flexible in the decline phase. Marginal operating costs are based on detailed information about unit costs in different types of fields in the most important oil producing countries.⁵

Production in OPEC

As mentioned earlier, OPEC seems to focus on specific price targets. In the model we therefore assume that OPEC chooses a fixed price target (in constant 2000\$), and sticks to this over the next 30 years. This may seem to be at odds with history, but it will nevertheless give a good insight into the important trade-offs that OPEC faces over the next couple of decades. In addition, OPEC's declared strategy the last years actually has been a price target. The fixed price assumption implies that demand

⁴ In the model capacity is defined as the point where marginal costs pass \$100 per barrel. Initially we assume that marginal operating costs reach \$30 per barrel at 99 per cent capacity utilisation in the pre-peak and peak phase, see Appendix B.

⁵ The lowest unit operating costs in each region/field category vary between \$ 0.8 and 5.4 per barrel for conventional oil production outside OPEC (unconventional oil is twice as expensive as the most expensive conventional oil). In high-cost regions (e.g. US onshore) production will naturally react more to oil prices.

and Non-OPEC supply are determined independently of each other, and that OPEC supply is solely determined by the residual demand (or call on OPEC oil). OPEC must therefore continually possess enough capacity so as to support the chosen price (see OPEC's investment decisions below).

Investment decisions in Non-OPEC

The basic incentive for oil companies is to invest in provinces and field types with the highest expected return. To sort out the most profitable among projects, net present value (NPV) is calculated for investments in each of the 44 Non-OPEC provinces/field types over the entire project lifetime. The discount rate is set to 10 per cent, and linear capital allowances are made over 6 years (depreciation over 6 years seem to be a reasonable average period over different fiscal regimes). For this purpose, we have to rely on assumptions concerning future oil price. Expected future oil price is set equal to average oil price during the previous 6 years. Price expectations are thus continuously updated along the simulated scenarios.

The oil companies only invest in projects with an internal rate of return (IRR) of at least 10 per cent. To set the level of IRR for model simulations at an aggregate level is clearly somewhat arbitrary. The supermajors are frequently assumed to invest when expected rate of return reaches 15 per cent or higher. Before the 2004 surge in the oil price, such levels of profit were questioned. A discussion about oil companies' accounting methods and real rate of return is given in Antill and Arnott (2002). Their study of 5 supermajors concludes with a real rate of return of 9.5 per cent on average over the years 1997-2001 as compared with the 12 per cent based on company accounts. We use 10 per cent as an average for all Non-OPEC companies (state or private, big or small).

The assumption that investments first target the most profitable reserves opens up for geographical spread of oil extraction. Gradually reserves that are more costly to extract enter as candidates for investment, and the cost of oil production will rise as the reserves are depleted. On the other hand, new discoveries and technological change reduce the costs of developing new fields.

Besides investing in new fields, oil producers have the option to invest in improved oil recovery (IOR) from fields in the decline phase, see Figure 1. IOR investments can be made at any step along the declining production path, and are considered as an alternative to new field investments. They generate additional reserves and open up for increased current and future output by lifting the tale of the production profile of a given field (see Figure1). The costs of IOR investments increase as the recovery rate becomes higher.

To sum up there are three ways to increase the scale of production. First, the oil companies have the opportunity to raise production above the foreseen production profile at additional costs in all phases with ongoing production. Second, they may invest in new fields with specific production profiles over several years time horizon. Finally, there is the option to invest in IOR, which mobilises new reserves and lifts the production profile in the decline phase accordingly. In the absence of constraints on investments, all three options will be used to the extent that the marginal rates of return are equal. If there are effective constraints on investments, the short-term solution at increased costs is the only way to increase the activity and the output. FRISBEE operates with constraints on the scale of investments to modify the dynamic effect in periods with high profits. Total expenditure on capital is limited to 50 per cent of total cash flow (before subtracting exploration costs) in the oil industry⁶. The cash flow constraint is generally not binding in the reference scenario, and different levels of constraints are tested in the sensitivity analyses (see Figure 12).

When choosing among the various ways to enhance production, the discount rate makes a difference. An increase in discount rate will favour immediate production increase more than IOR investments, and IOR investments more than investments in new field development.

Further, the relation between current and expected oil price has an impact. If the current oil price is extraordinarily high compared with price levels in the previous years (i.e. the basis for price expectations) the high current oil price will count little in price expectations and thus only modestly affect the incentive for long-term engagement in new fields. This kind of historic price development would favour short-term production increase rather than investments in additional resource development.

Risk is a factor that has affected previous investment strategies and will continue to do so in the future. Risk can be political, fiscal or related to exploration and production as such. FRISBEE incorporates an exogenous risk premium to account for variations in risk assessment in different provinces and field types. The risk premium is expressed in terms of additional USD per barrel that is required to make the investment project as attractive as a risk neutral project.

There are other factors besides risk that may influence the basic investment allocation mechanism. When companies are already operating in a region, there may be economies of scale. Economies of

⁶ According to OGJ (2001) the oil industry has historically reinvested a remarkably consistent 60 per cent of cash flow (includes expenditures on exploration).

scale are present for technical reasons, as costs of pipes and tanks increase with the surface area, whereas output increases with the volume. Also there are fixed information costs associated with entry into a province. The overall level of petroleum activity in the area may further contribute to positive externalities as markets for inputs and services from supportive industries nurture more competitive behaviour. All these elements may imply that it is somewhat profitable for companies to hold on to provinces where there already is exploration and production activity, rather than plunging into new ones.

Another factor that may influence the investment decision is the non-renewability aspect. That is, fields that are not developed this year can be developed another year instead, which may be more profitable if the current investment rate is already high and pushing up the costs. This feature is most relevant for areas with few undeveloped resources.⁷ Thus, the less resources left in the ground, the more investments in new fields are restrained.

FRISBEE incorporates several of these factors in the investment cost function, postulating that

- at every stage of development in an area there are some reserves that are cheaper to develop than at the standard unit costs
- a large current production modifies the rising trend in field development costs (technical, institutional learning, "materiality")
- a large regional activity level modifies the rising trend in development costs (infrastructure, competitive subcontractors)
- few undeveloped reserves increase the costs of investing in new fields above the factual costs

These factors make it more attractive to stay on in an area rather than enter new locations with a lower degree of reserve development, as long as the mature area still has much undeveloped fields left. A more detailed description of the investment modeling is given in Appendix B.

Investment decisions in OPEC

OPEC is seen as a residual producer filling the supply gap that is necessary to keep the oil price at the preferred level. In this model version of FRISBEE, the operational rule for OPEC is to invest enough in new fields or IOR to maintain a current capacity surplus of about 10 per cent, in order to demonstrate the ability to increase production and control the price level. The distribution of

⁷ For instance, in a simulation model of the oil market with intertemporal behaviour, Berg *et al.* (1997) find that the initial scarcity rent for Non-OPEC (with a low R/P-rate) is \$9.2 per barrel, but only \$1.7 for OPEC (with a high R/P-rate). Thus, the non-renewability aspect is clearly more important for regions with little reserves left.

investments between OPEC Core and OPEC Rest, and between investments in new fields and IOR, is exogenous.

Demand for oil

We distinguish between three end-users of oil products, i.e., industry, households (including services) and power producers. Industries and households consume both transport oil and stationary oil (including processing), whereas power producers consume fuel oil. All oil products are bought at a regional product price, which is determined by the global crude oil price, transport costs and refinery costs. The end-user price of the different oil products must also cover distributional costs and taxes, and will generally differ across end-users. End-user prices and regional product prices are generally taken from IEA, but other sources and some guesstimates have been used to fill the gaps. Transport-related costs, refinery costs and taxes are held constant (in 2000\$) over the time horizon. Stock changes are exogenous and are phased out over time.

Demand for oil in industries and households are log-linear functions of population, income per capita, prices of other energy products and an autonomous energy efficiency improvement (AEEI), as well as demand in the previous year. This means that we distinguish between short- and long-run effects of price and income changes via an adjustment parameter. Between 30 and 55 per cent of the long-run effect is obtained after one year (varies between oil products and end-users), whereas the long-run price elasticity varies between -0.1 and -0.6 (weighted average is -0.37 for households and -0.19 for industries). The price elasticities and adjustment parameters are mainly taken from Liu (2004). Prices of gas and coal are exogenous in the model, and are held constant over the time horizon.⁸

Growth rates of GDP and population are exogenous in the model, and mainly taken from EIA (2004). Average annual GDP growth rates in OECD (excluding Eastern Europe) in 2005-2030 vary between 2.0 and 3.0 per cent, in Former Soviet Union and Eastern Europe between 3.6 and 4.1 per cent, and in the rest of Non-OECD between 3.4 and 5.6 per cent. Income elasticities are calibrated so that total oil demand at unchanged oil price is consistent with the corresponding EIA (2003) projections for 2025, and vary between 0.1 and 1.1 in the long run (weighted average is around 0.6 for both households and industries). Transport oil is generally about twice as income elastic as stationary oil. AEEI is set equal to 0.25 per cent per year in OECD and 0.5 per cent outside OECD. Earlier studies have usually applied

⁸ With significantly higher oil price, gas prices and possibly coal prices may also increase, and counteract some of the demand response simulated by the model with constant coal and gas prices. This draws in the direction of higher optimal oil price for OPEC.

somewhat higher levels of AEEI, but this has been criticised by Kaufmann (2004). In the sensitivity analyses below we examine the effects of different price elasticities and the effect of a relation between oil price and GDP growth rate.

Demand for fuel oil from power producers is simply set fixed and constant over time. EIA (2003) expects an annual increase of 0.9 per cent in global input of oil in power production, so our assumption may underestimate the growth in total oil demand unless a high oil price level suppresses the demand for fuel oil. Anyway, as input of oil in power production only constitutes 8 per cent of global oil demand in the base year, this simplification will not alter our conclusions significantly.

The oil market towards 2030 with different OPEC price targets

In this section we will examine how OPEC's choice of price target may affect the oil market towards 2030. This time horizon makes it easy to compare with other studies. The last couple of decades have seen a large variation in the oil price level, and in 2005 the price is high compared to the price levels observed over the last 20 years. It is of interest to examine to what degree this may boost Non-OPEC supply and hamper the growth in oil demand, and search for the optimal price level for OPEC. Both supply and demand are rather inflexible in the short run, but may respond to oil prices in the intermediate and long run as more fields are developed (cf. Ringlund *et al.*, 2004) and old equipment and machinery are replaced.

By simulating the FRISBEE-model we investigate how different oil prices affect oil demand in different regions and sectors, development of new oil fields and improved oil recovery (IOR) in different Non-OPEC regions, and eventually OPEC's market share and net income. To place the outcome for OPEC in a dynamic context we will also compute the total discounted revenue based on different discount rates as a background to the myopic decisions simulated by FRISBEE. We are also interested in the import share of OECD regions, which also may face a trade-off between low oil prices and low import dependence.

To begin with, we discuss how the market may evolve with three quite different oil prices, which in each case is kept constant over time in real terms (the price we consider corresponds to the OPEC basket price, which is slightly below the average world market price). These are \$20, \$40 and \$60 per barrel (2000-\$).⁹ Later on we consider how OPEC's income and market share may vary over time

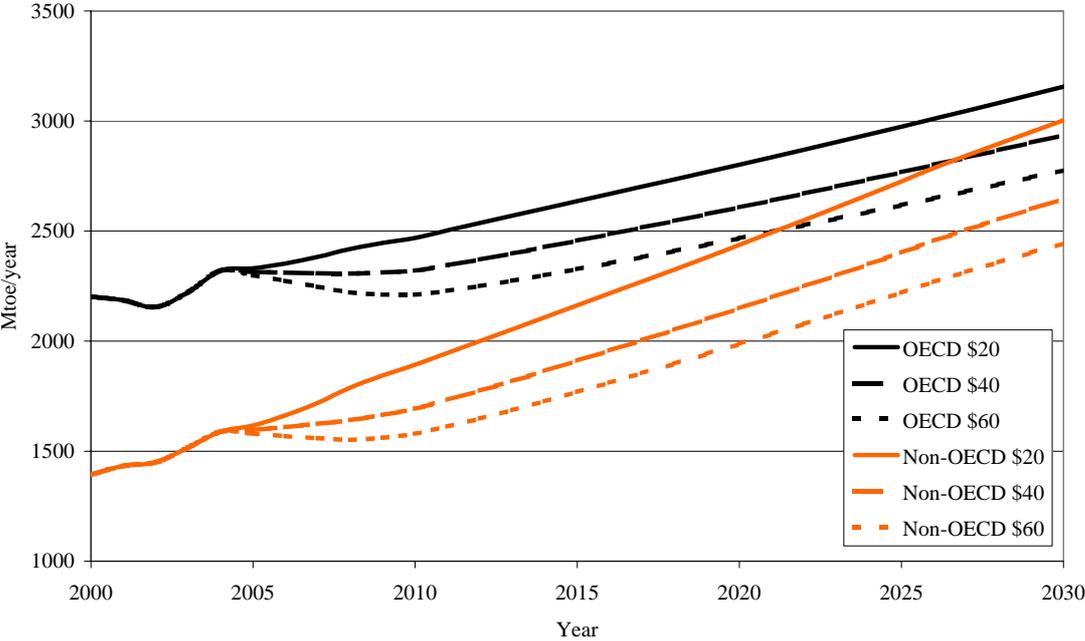
⁹ We assume that the price gradually moves from the historical levels in 2000-2004, reaching the target within 4 years.

under a range of oil prices, and search for OPEC’s optimal oil price level. In Section 4 we depict how sensitive modeling results are to altered assumptions.

The development of the oil market – three different price regimes

The projected demand of oil until 2030 is shown in Figure 2, distinguishing between OECD and Non-OECD.¹⁰ We see that demand grows significantly outside OECD, even at \$60 per barrel. The highest growth is seen in China, where consumption of oil doubles rises by 150 per cent over the 30 years in the \$40-scenario. OECD countries also increase their oil consumption, particularly the US where population continues to grow at almost 1 per cent per year. In the \$40-scenario oil demand in Western Europe grows by only 10 per cent over this 30 years period. OECD’s share of global oil consumption falls from 61 to around 53 per cent in 2030 in all price scenarios, whereas global demand grows by 50-80 per cent in this period. If we compare our demand projections with other studies with similar price assumptions (\$20-\$40), we notice that our projections follow relatively close to the scenarios in IEA (2004a), but are somewhat lower than those reported by EIA (2004).

Figure 2. Demand projection towards 2030 in OECD and Non-OECD



¹⁰ The demand equations in 2000-2004 have been slightly adjusted in order to meet historic levels with respect to global supply and demand, as the ordinary model relations do not fully capture the demand growth observed in 2004 in combination with very high price levels. We believe this could be due to structural changes in China, particularly in the transport sector, not captured by the model. Moreover, the weakening of the dollar since 2000 is not taken into account in the model, which means that the real oil price increase for most regions has been smaller than what the model assumes. This deviation will not alter our conclusions about the medium-term oil market.

The significant growth in oil consumption, even at a permanently high oil price, partly reflects that oil demand is assumed to be fairly price inelastic, even in the long run. This is to some degree in conflict with traditional modelling of energy demand (see e.g. Berg *et al.*, 2002), but is consistent with most recent empirical studies (see e.g. Hunt and Ninomiya, 2003). There are few substitution possibilities for oil products – a large proportion is used for transport purposes (almost 50 per cent in 2030), and demand for oil for stationary purposes (e.g. heating and industrial feedstock) is also rather inflexible. Another important reason is that end-user prices of oil products, at least in most OECD countries, are much higher than crude prices. For instance, when the crude oil price increases from \$20 to \$40, the end-user price of transport oil in Western Europe increases by only 12 per cent.

Figure 2 further reflects that population and GDP per capita growth are the main factors behind higher oil demand. In the sensitivity section below we examine the effect of letting GDP growth being a linear function of the oil price level, rather than exogenous. With endogenous GDP growth there will be larger discrepancy between the different oil price scenarios.

Figure 3 shows the development of OPEC and Non-OPEC supply of oil until 2030. In the low-price scenario Non-OPEC's supply peaks before 2010, whereas in the high-price scenario a 60 per cent higher peak level is reached 15 years later. A higher price increases the profitability of undeveloped fields and stimulates more IOR-efforts at fields in the depletion phase. Higher prices also lead to more discoveries, which subsequently can be developed and extracted. Finally, the cash flow from producing fields is increased, easing the cash flow constraint on investments. Non-OPEC's production profile in the \$40-scenario is quite similar to the high price scenario (\$35) in IEA (2004a), with a peak between 2015 and 2025. IEA projects a slightly higher Non-OPEC output in 2025. EIA (2004) is far more optimistic on behalf of Non-OPEC supply, and predicts steadily rising production in this region up to the end of their projection period in 2025. According to Horn (2004) this is very optimistic and would require substantial technical progress in crude oil exploration and production. On the other extreme, some geologists even argue that world crude oil production, including that of OPEC, will soon peak or has already reached a peak (see, e.g., Campbell and Laherrere, 1998).

In Figure 4 we see how investments in new field developments outside OPEC evolve in the three scenarios, as well as the corresponding IOR-investments. The figure shows that investments are very sensitive to the price level, and in particular investments in new fields. For instance, around 2015 there are 3-4 times more reserves (including IOR) being developed in the \$60- than in the \$20-scenario. We also see that both kinds of investments (especially in new fields) fall significantly over time after

2015. This reflects that the access to new fields and new prospects diminishes, despite a continuous stream of new discoveries. Nevertheless, the amounts of investments are far from insignificant at the end of our time horizon, and we notice that investments in new fields are less divergent across the scenarios in 2030 than in 2015. This reflects that the remaining undeveloped fields are cheaper in the \$20-scenario than in the \$60-scenario, in which much more reserves have already been developed.

Figure 5 shows how total investments (in mtoe/year) in new field development and IOR in Non-OPEC compares to the production level. This is an indication of whether Non-OPEC will face an increase or decrease in its current production, as a ratio above 1 means that the extracted reserves are more than replaced by added (developed) reserves. We see that the ratio is more than halved from 2005 to 2013 in the \$20-scenario, which explains the significant contraction in Non-OPEC supply after 2010. We also see that the ratio in 2030 is around 0.7 in all scenarios. Again, this reflects that the remaining undeveloped fields are cheaper in the low price scenario than in high price scenario, and that Non-OPEC production is significantly higher in the latter scenario (cf. Figure 3).

Figure 6 shows the total remaining reserves (i.e., developed and undeveloped) in Non-OPEC over the 30 years period. We see that the reserves are slightly falling in the \$20 and \$40 scenario, but not in the \$60 scenario. The falling trend is in line with the most recent 10 years period 1995-2004 (if we dismiss the sudden showing up of unconventional tar sand in Canada, cf. OGJ, 2004). Initially, a high price means that more IOR investments are undertaken, increasing the reserves of fields in the decline phase. Moreover, more exploration activity is taking place. Thus, remaining reserves are increasing or declining more slowly than with a low price. However, as the high price leads to more investments in new fields and subsequently more extraction, the high price eventually brings down the remaining reserves more rapidly than a low price. According to the figure, these counteracting forces result in remaining reserves being quite equal in the different price scenarios in 2030. However, whereas two third of these reserves are *undeveloped* in the \$20-scenario, in the \$60-scenario 85 per cent is *developed*.

Figure 3. Projection of OPEC and Non-OPEC supply towards 2030

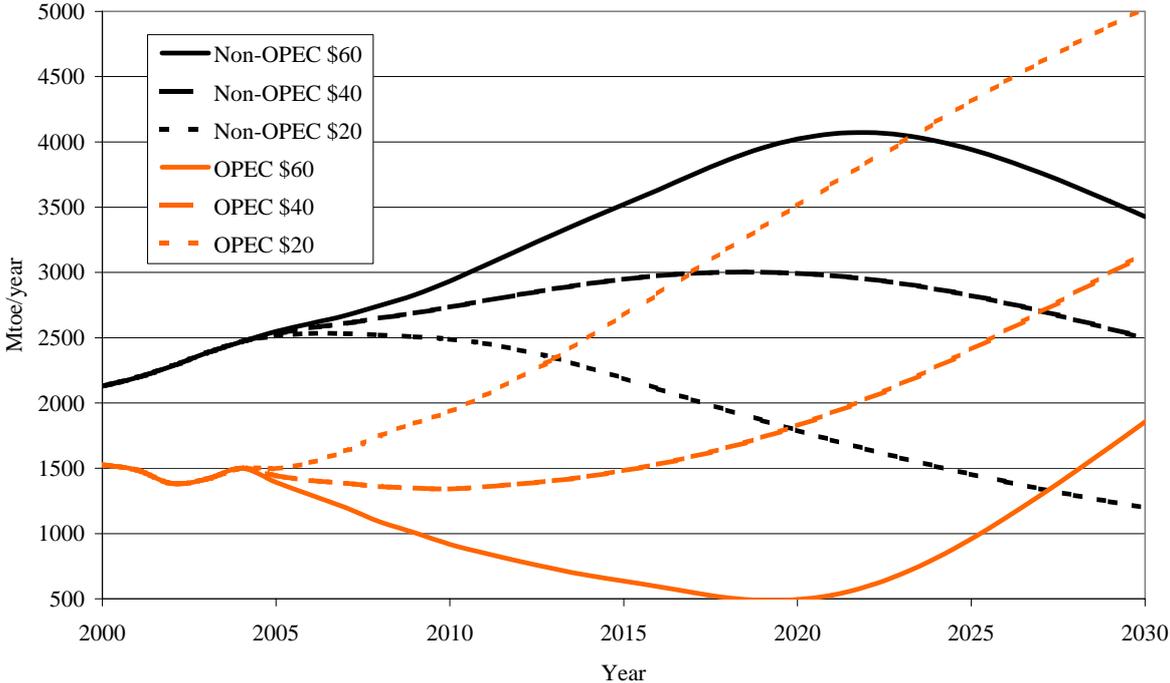


Figure 4. Investments in new fields and IOR in Non-OPEC towards 2030

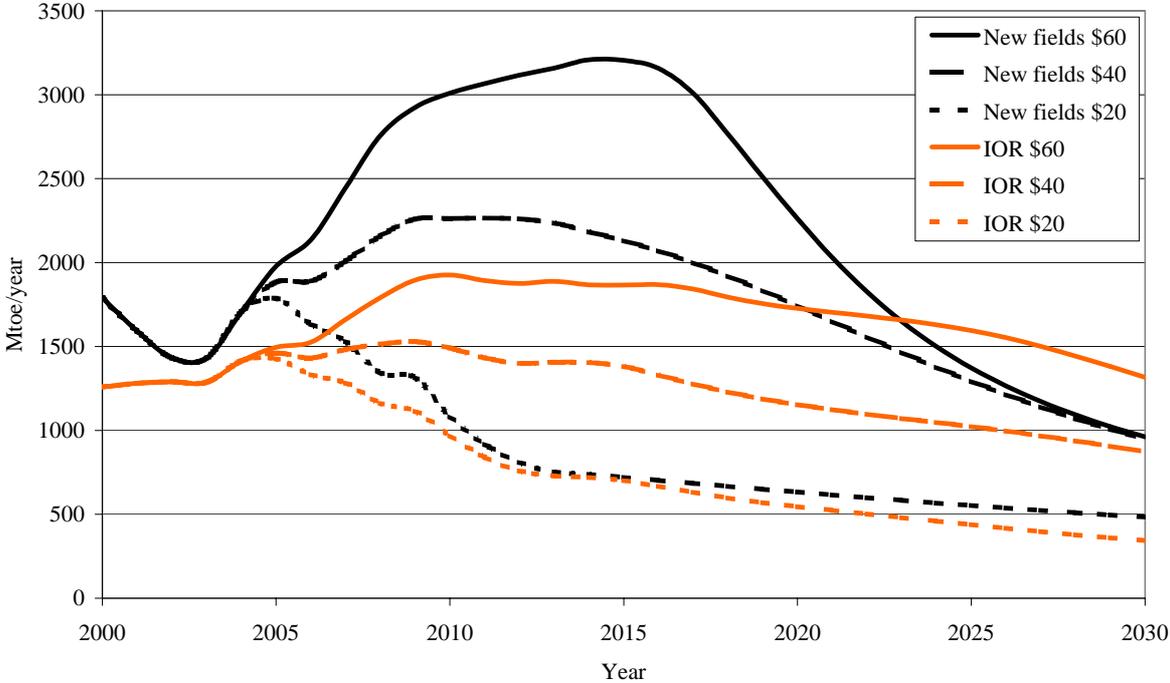


Figure 5. Investments in new fields and IOR in Non-OPEC as a ratio of total Non-OPEC supply towards 2030

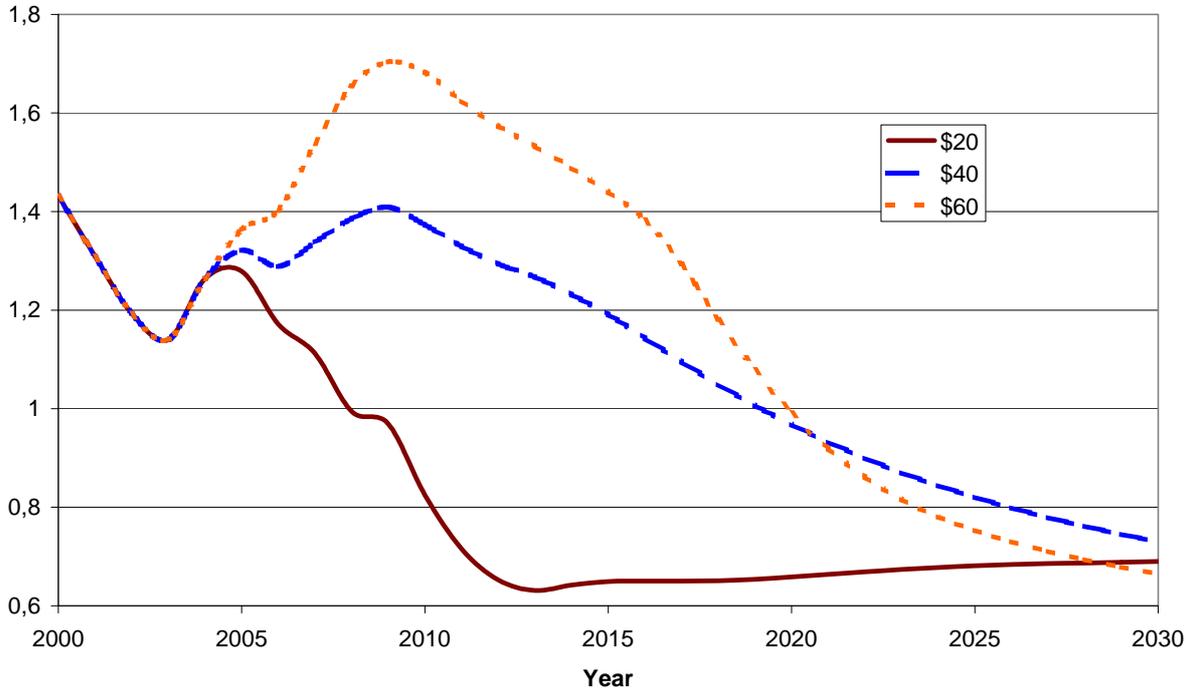


Figure 6. Remaining reserves (developed and undeveloped) in Non-OPEC towards 2030

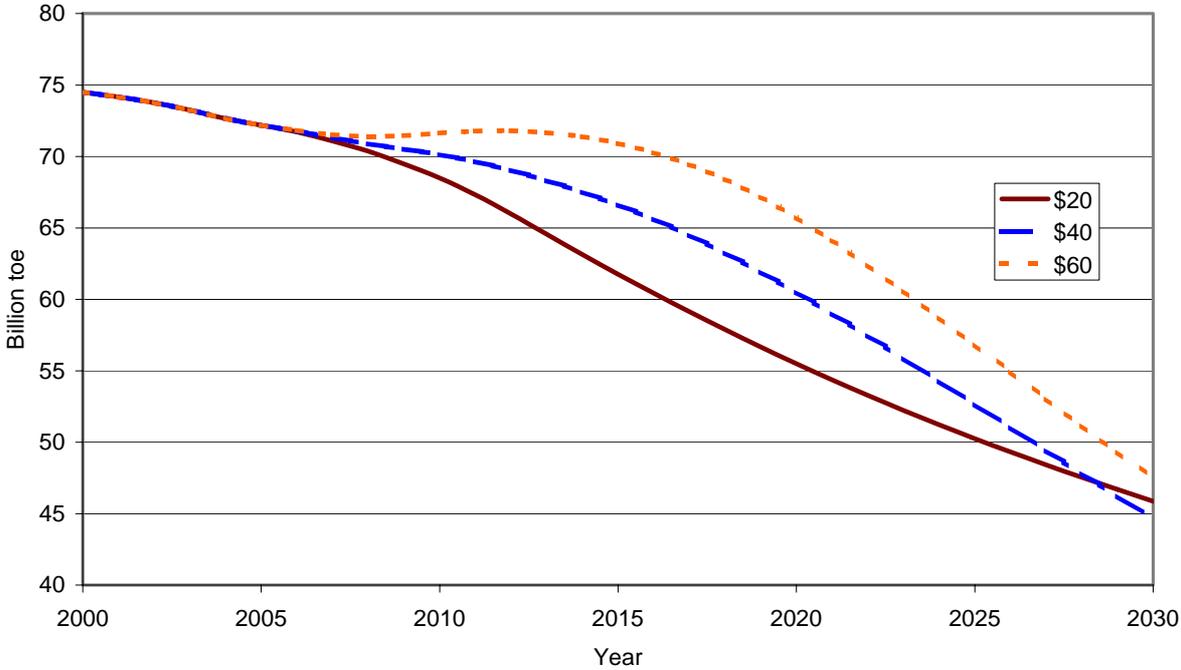
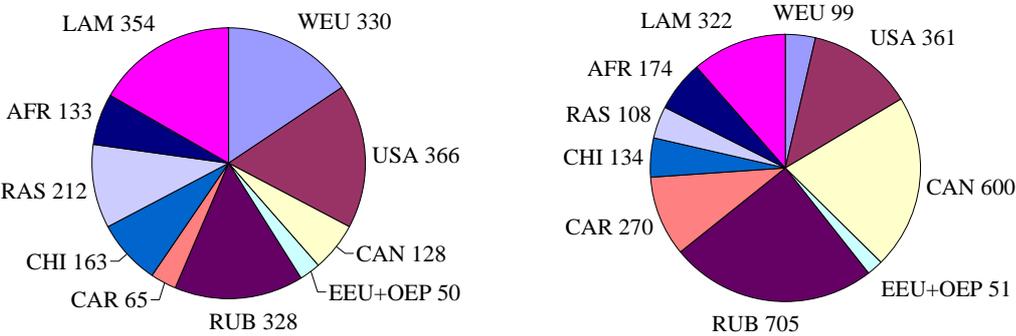


Figure 7. Distribution of Non-OPEC supply in 2000 and 2025 in \$40-scenario. Mtoe per year*



*The abbreviations used in the figure are explained in Table 1.

Within Non-OPEC there are large variations in reserves and supply development, as illustrated in Figure 7, which shows the distribution of Non-OPEC supply in 2000 and 2025 in the \$40-scenario. We choose 2025 to make possible a comparison with IEA (2004a) and EIA (2004). As seen from Figure 3, total Non-OPEC supply is about 30 per cent higher in 2025 than in 2000. Oil supply from Russia and the Caspian region grows significantly until around 2020 and 2030 respectively, but then starts to fall. In 2025 joint supply from the former Soviet Union (FSU) is 2.5 times higher than in 2000. This reflects that both regions have large amounts of oil reserves, as well as large potential for new discoveries and IOR-investments. Moreover, in 2000 the Caspian region was quite undeveloped, producing only about 0.5 per cent of the estimated total reserves available over the next 30 years (cf. USGS, 2000).

Oil production in the OECD region as a whole increases by 25 per cent over the 25 years period, but there are large variations across OECD countries. In Western Europe production has declined by 70 per cent. The US is able to slightly increase its production level until 2015, but then production falls steadily. According to the USGS there are large amounts of undiscovered oil in the US, as well as great potential for reserve growth from depleting fields (the importance of IOR is tested in the sensitivity section below). In Canada there is a substantial increase in production of unconventional oil in this price scenario.

The remaining Non-OPEC regions, i.e., outside OECD and FSU, all increase their supply over the first decade, but then production gradually falls. From Figure 7 we see that only Africa has a higher production level in 2025 than in 2000, reflecting that parts of this region, having large reserves, was quite undeveloped in 2000.

With regard to the production level in 2025, our model predicts around 30 per cent lower supply in Western Europe and Africa than IEA (2004a), even if IEA uses an oil price around \$25 per barrel. Compared to EIA (2004), with similar oil price path as IEA, our supply projections in 2025 are much lower in Africa, Latin America and Western Europe. On the other hand, IEA and EIA predict much slower growth in unconventional oil production in Canada compared to our \$40-scenario. This reflects that supply of unconventional oil is much more price sensitive than conventional oil supply.

OPEC's choice of price target

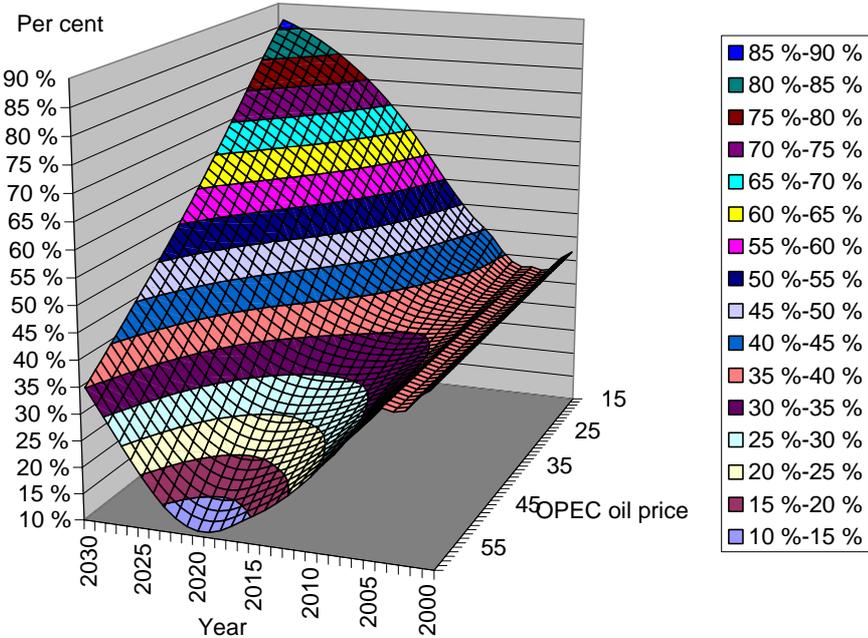
OPEC's production and market shares are very different in the three scenarios, cf. Figure 3. In the \$20-scenario production almost doubles during the first ten years after 2005, whereas in the \$60-scenario OPEC supply is more than halved in this period. The main explanation is the significant variation in Non-OPEC production across the scenarios, which in 2015 accounts for two third of the deviation in OPEC's supply between the \$20- and \$60-scenario. The remaining difference is of course due to different expansion of oil demand. The dramatic increase in OPEC production in the \$20-scenario requires very large investments in new capacity, which may seem rather unrealistic and thus reduces the likelihood of this scenario.

Figure 3 clearly shows that higher prices go along with lower OPEC production, and it is interesting to ask what is the optimal oil price level for OPEC? Before trying to answer that question, let us first examine its market share. Figure 8 shows how OPEC's market share varies with the oil price over time. We have run the model for constant real (2000-\$) oil prices between \$15 and \$60 per barrel. The figure indicates that it is difficult for OPEC to maintain its current market share over the first decade without choosing a low oil price. Around 2020 we see that the market share is particularly sensitive to the oil price level (varies between 11 and 73 per cent), as both consumption and Non-OPEC production has had time to adjust. Thus, it is evident that there is a clear trade-off for OPEC between high prices and high market share, at least in the medium term.

On the other hand, OPEC's market share will eventually rise above 50 per cent also with sustained high oil prices (before 2030 at oil prices below \$45), see Figure 8. After 2020 Non-OPEC loses market share in all price scenarios. Even in the \$40-scenario total OPEC investments (new fields plus IOR) surpass those in Non-OPEC before 2020. The reason is simply that even if high oil prices stimulate private oil companies and Non-OPEC producers in general, there are not enough oil resources outside OPEC to match the persistent increase in world oil consumption. Consequently, whereas in 2000

undeveloped reserves outside OPEC amount to 12 times global oil consumption, in 2025 the factor has dropped to only 3 in the \$40-scenario.

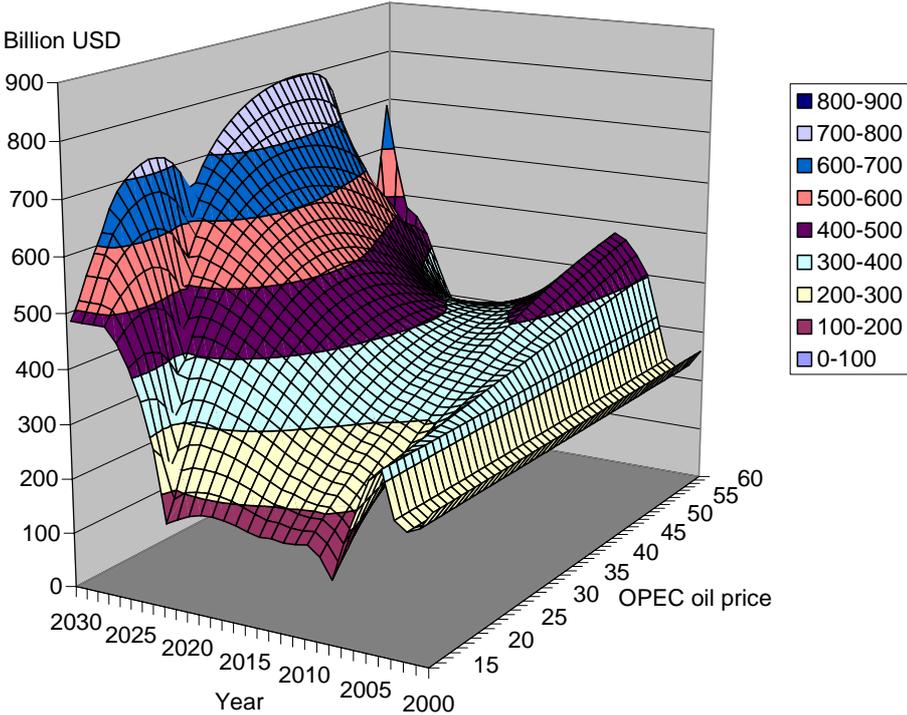
Figure 8. OPEC's market share in different years at different oil prices (2000-\$)



What do the different scenarios tell about the income of the producer group? In Figure 9 we show how OPEC's net cash flow from oil production (i.e., gross income minus operating costs and investments costs excl. taxes) varies with the oil price over time. As expected, inflexibilities in both oil consumption and Non-OPEC production makes it initially profitable for OPEC to choose a high oil price. Still, the maximum net cash flow in 2010 is achieved around \$55, as higher prices leads to a smaller market share for OPEC. From 2014 to 2027 the maximum net cash flow is achieved between \$35 and \$40 per barrel, at a higher and higher level (cf. the saddle shape in Figure 9). It is interesting to note that after 2020 the maximum net cash flow for OPEC is reached with an increasingly higher oil price, even though consumption and Non-OPEC supply have more time to adjust the longer into the future we consider. The explanation is similar to the discussion of market share above, i.e., after 2020 OPEC's market share is increasing over time for any oil price level. Thus, it is more profitable with a higher oil price level.

Note that with low oil prices OPEC eventually will have difficulties in finding enough undeveloped fields or IOR projects to satisfy the large capacity growth induced by the low oil price. Then investments in OPEC fall and net cash flow increases for some years until capacity is too low to supply the oil market's call on OPEC oil. Thus, low oil prices (below \$20 per barrel) are not sustainable towards the end of our time horizon in the model simulations.¹¹

Figure 9. OPEC's net cash flow in different years at different oil prices (2000-\$)



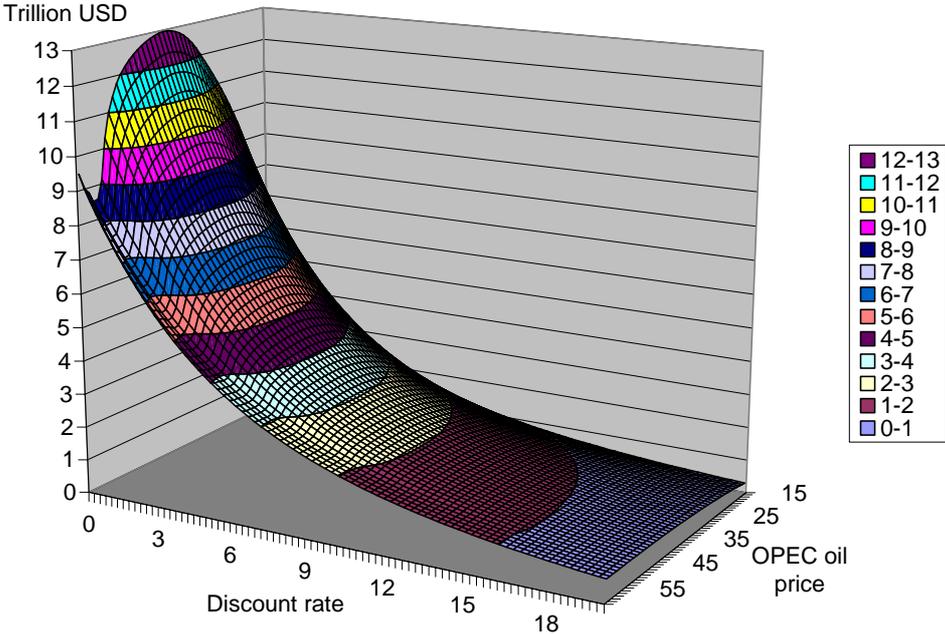
It is difficult to assess how OPEC weighs current versus future revenues. Several member countries with high population growth and less vigorous non-oil sectors are in urgent need of government revenue to support public expenditure. On the other hand, main OPEC countries have also been concerned with the long-term development of the oil market.

In order to shed some light on OPEC's trade-off between current and future income, we have computed the discounted income (net cash flow) over the time horizon (2005-2030) for the producer group, using different discount rates. The results are shown in Figure 10. We see that for discount rates around 5-10 per cent, OPEC's maximal discounted income is achieved at oil prices just above \$40 per

¹¹ This is indicated by a flat net cash flow in the left corner of the figure (e.g., after 2027 in the \$15-scenario).

barrel. In fact, even at a zero discount rate, the optimal oil price is as high as \$40.¹² At a discount rate of 20 per cent, reflecting a producer group with urgent needs for revenues, it is most profitable to choose an oil price above \$50, but the costs of choosing \$40 is only around 2 per cent. Thus, it seems that oil prices just above \$40 is optimal for OPEC according to our model simulations, as it treats the trade-off between high prices and high market share in the best way.¹³

Figure 10. OPEC's discounted income 2005-2030 with different discount rates and different oil prices (2000-\$)



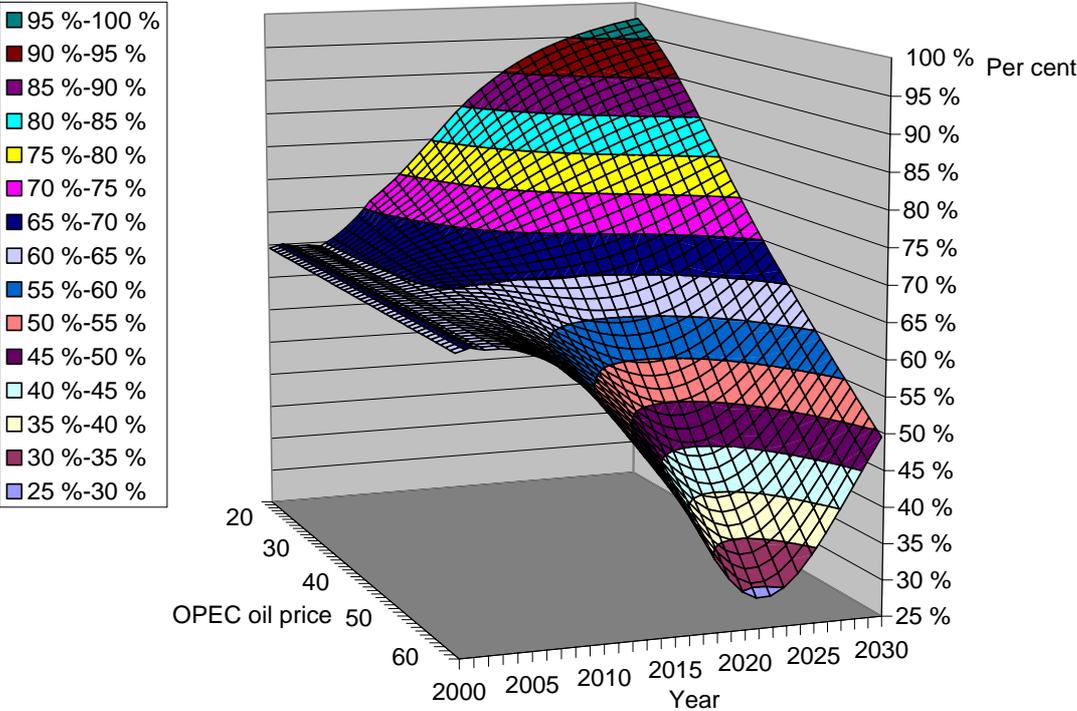
Trade-off between low prices and low import share

Although a low oil price level is beneficial for oil consumers, it will also bring about worries for the governments of OECD regions. The reason is that OECD faces a trade-off between low oil prices and low oil import dependence. Low prices stimulate oil consumption, and depress investments outside OPEC. Figure 11 shows how the import share in OECD as a whole varies with the oil price over time.

¹² Note that we do not consider revenues after 2028. However, the results indicate that these revenues will be highest at relatively high oil prices, i.e., above \$40 (cf. also Figure 9).
¹³ In the calculations of optimal oil price we have ignored that some of the oil production is consumed by citizens in OPEC countries, i.e., implicitly assuming that the OPEC governments are not concerned with the welfare of its own citizens. As many OPEC countries are subsidising domestic oil consumption, it may be more reasonable to subtract costs and revenues related to domestic sales. In this case the optimal oil price falls by \$2-\$5 per barrel (smallest reduction at low discount rates).

The variation naturally increases as time goes by, at least until 2020, as both consumption and Non-OPEC production get time to adjust to the price level. It is interesting to note that with an oil price of around \$35 per barrel, the import share seems rather constant over time at 65 per cent. At higher prices the import share decreases over time. After 2020, however, import dependence rises in all price scenarios, as even unconventional oil from Canada cannot keep up with the oil demand from OECD countries. The trade situation changes most dramatically for Europe, where the import share rises steadily in all price scenarios. For instance, in the \$40-scenario it increases from 57 per cent in 2000 to 84 per cent in 2020 and 95 per cent in 2030. In the same scenario the US import share rises from 62 to 69 and 79 per cent in 2020 and 2030 respectively, whereas in North America as a whole it declines from 53 to around 30 per cent in 2020, but then climbs to 44 per cent in 2030.

Figure 11. OECD's import share at different oil prices (2000-)



When it comes to other Non-OPEC regions, the former Soviet Union stays as a net exporter over the whole time horizon in every price scenario. For developing (Non-OPEC) countries in Asia (China + Rest-Asia) the import dependence evolves quite similar to Europe, except that their import share is slightly lower. Latin America switches from exporting to importing oil between 2015 and 2025,

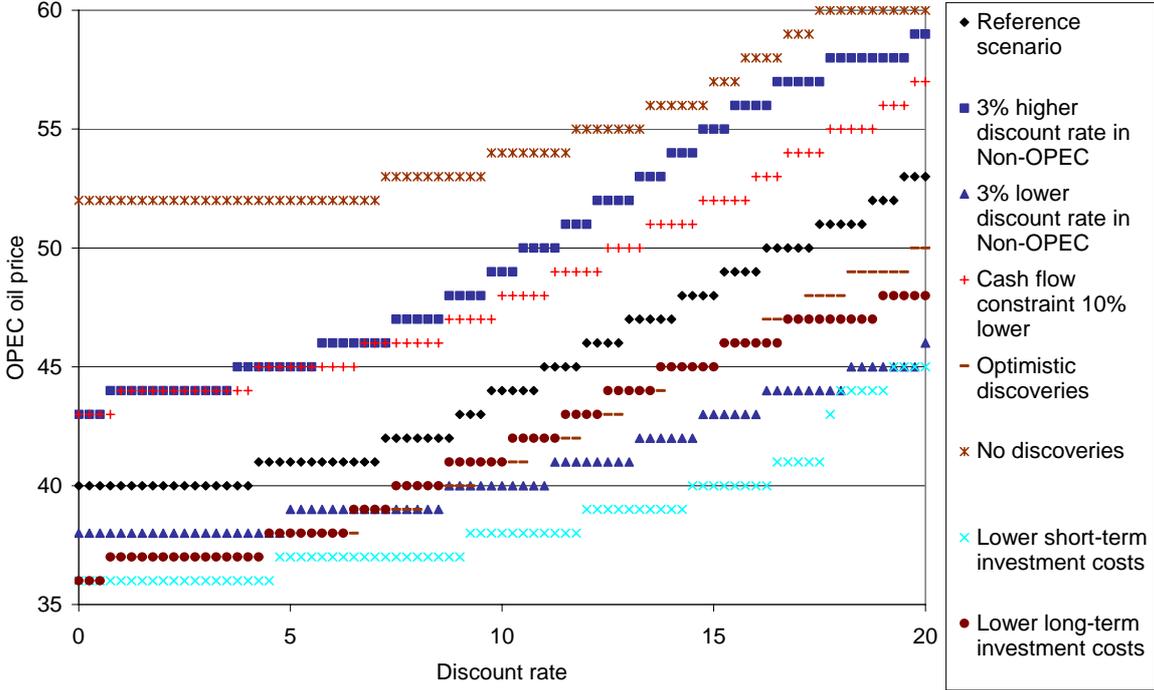
depending on the oil price level, whereas Africa stays as oil exporter until at least around 2020 (at low prices), and possibly over the whole time horizon (at high prices).¹⁴

Sensitivity analyses of OPEC’s optimal oil price

The results presented above are of course dependent on a number of assumptions that are more or less uncertain. Thus, a set of model runs have been carried out to see how sensitive the optimal OPEC oil price, defined as the price that maximises the net present value for a given discount rate, is to a variation in central model assumptions.

The reference scenario is seen amidst a set of alternatives in Figure 12 and 13, depicting optimal oil price for OPEC across a range of discount rates (from 0 to 20 per cent) used in net present value calculations of OPEC income. A myopic OPEC with urgent need for revenues is likely to identify itself with the right hand side of the figures.

Figure 12. Results of sensitivity analyses. Supply side assumptions



¹⁴ Note that OPEC-countries are not included in these regions, and for some of them the question of import dependence may be of limited relevance.

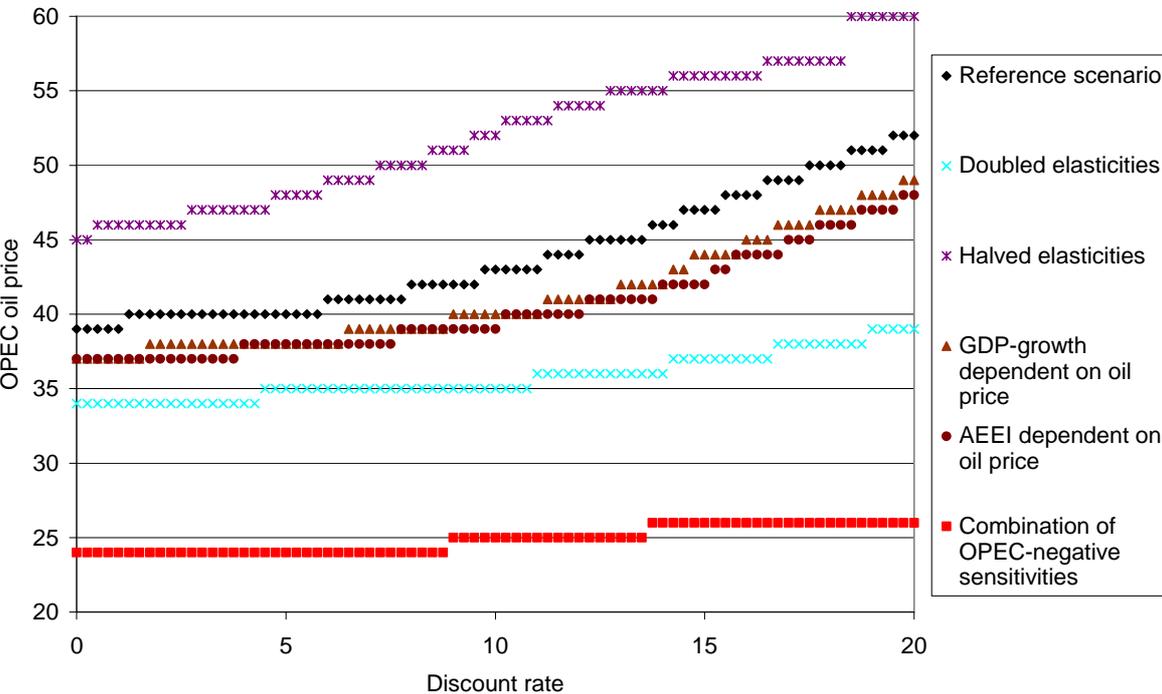
The discount rate (or required real rate of return) of Non-OPEC is set equal to 10 per cent in the reference scenario. A deviation from this rate of return to Non-OPEC oil investments has a big impact on the world market oil price. A 13 per cent discount rate in Non-OPEC cancels otherwise profitable projects, restricts supply and increase the optimal OPEC price by \$3-6 per barrel, cf. Figure 12. A 7 per cent Non-OPEC profit target will analogously bring the oil price down, although the oil price in this case responds more moderately in absolute terms (\$2) at low OPEC discount rates. However, at 20 per cent OPEC discount rate, a 7 per cent Non-OPEC rate of return provides the world with an oil price discount of \$7 compared with the reference scenario.

OPEC's optimal oil price is hardly affected if oil companies in Non-OPEC are less constrained as to the share of cash flow that they are allowed to reinvest. In the reference scenario they may invest up to 50 per cent of cash flow (before expenditure for exploration is subtracted). If this constraint is increased to 60 or 70 per cent of the cash flow, the optimal oil price is falling only by up to \$1 per barrel (not shown in the figure). This reflects that the 50 per cent constraint is hardly binding in the reference scenario. However, if Non-OPEC companies limit their investments to 40 per cent of cash flow, the optimal oil price increases by \$3-4 per barrel, i.e., much the same as with a higher discount rate in Non-OPEC.

We have also tested the effects of higher exploration activity in Non-OPEC, where the mean estimate of new discoveries in USGS (2000) has been replaced by the average of the mean and the 5 per cent estimate (i.e., 5 per cent probability of discovering at least this amount). In this case the optimal oil price is lowered by about \$3 per barrel. More discoveries dampen the resource constraints for Non-OPEC, but the reward is only appearing after a considerable time lag. Very high oil prices might be optimal for OPEC if there is no exploration at all. This assumption is of course unrealistic, but the results indicate the importance of new discoveries outside OPEC.

Assumptions regarding costs of developing new fields are quite uncertain, and we have tested the effects of doubling the rate of increase in unit costs when investments increase (both in the short- and the long-run). As seen in Figure 12, lower short-term investment costs reduces OPEC's optimal oil price by at least \$4, and much more at high discount rates. This reflects that lower short-term investment costs reduce OPEC's possibility to collect high immediate revenues from a high oil price. Lower long-term investment costs also suppress OPEC's optimal oil price, but only by \$2-5. Higher short- or long-term investment costs naturally have the opposite effect on the optimal oil price (not shown in the figure).

Figure 13. Results of sensitivity analyses. Demand side assumptions and combination of assumptions



In our simulations we have applied direct price elasticities between -0.6 and -0.1 (long run), as recent econometric evidence seems to suggest rather low elasticities. However, it might be possible that a sustained higher oil price level would make oil demand more price elastic, as in the 1970's. Thus, we have tested the effect of doubling all oil demand price elasticities. From Figure 13 we see that the effect is striking; the optimal OPEC oil price would drop to \$34 per barrel and only reach \$39 for a discount rate as high as 20 per cent, i.e., about \$15 below the optimal oil price in the reference scenario. If demand price elasticities are halved, the optimal oil price increases to a level of \$52-60 per barrel for OPEC discount rates above 10 per cent.

A high oil price is frequently seen as an obstacle to economic growth. According to IEA (2004b) world GDP would be at least 0.5 per cent lower in the year following a \$10 increase in the oil price. The effect would be smaller in OECD countries, and higher elsewhere, especially in Sub-Saharan African countries. However, the effect is assumed to diminish the following years. In the FRISBEE model GDP growth rates are exogenous in the reference scenarios. In one of the sensitivity scenarios we assume that the oil price lowers the annual GDP growth rate by 0.05 percentage points for every dollar increase in the oil price (with \$30 per barrel as the base level). Figure 13 shows that such a mechanism might significantly reduce the optimal OPEC price (by \$2-5).

A higher oil price may also bring about a more rapid improvement in energy efficiency. This would have more or less the same impact in the model as the price-responsive GDP mentioned above. If the AEEI parameter is increased by 0.33 percentage points for every \$10 increase in the oil price, we get almost the same effect on OPEC's optimal oil price as the price-responsive GDP, see Figure 13.

Figure 13 also shows the outcome of the combined effect of several assumptions that all go in the direction of a lower optimal oil price for OPEC. That is, demand price elasticities are doubled, there are feedback effects from oil prices to economic growth, Non-OPEC discount rate is 7 per cent, the cash flow constraint is 60 per cent, new discoveries are higher, and short- and long-term investment costs are lower. Although this setting is very pessimistic from OPEC's point of view, it is interesting to see that the optimal price for OPEC is still around \$25, i.e., in the middle of the recently abandoned price band.

Conclusions

In this paper we have examined if high oil prices are profitable for OPEC also in the long run, and searched for the optimal price level for the producer group. Our model simulations show that sustained high oil prices stimulate Non-OPEC production to a certain extent, but demand is only slightly affected. Thus, according to our modeling results, OPEC would benefit from choosing an oil price target just above \$40 (2000-\$) per barrel. In this case OPEC may be forced to reduce production and lose market share up to 2010, but after 2015 their market share will increase. Thus, for OPEC there is a trade-off between high oil prices and a high market share in the short to medium term, but not in the long run. If OPEC values current revenues much more than future income (i.e., with a discount rate of 20 per cent), it is optimal to choose an oil price of around \$50, but the income loss of choosing \$40 instead is only marginal.

High oil prices give the oil companies large cash flow and the option to invest profitably in new oil fields. Still, after 2020 Non-OPEC actually loses market share in all our price scenarios. In the \$40-scenario total OPEC investment in new fields and increased oil recovery surpass those in Non-OPEC before 2020. The reason is simply that even if high oil prices stimulate the investment of private oil companies and Non-OPEC in general, there are not enough oil resources outside OPEC to match the persistent increase in world oil consumption. With oil prices around \$20 per barrel, OPEC will have to increase its production dramatically, requiring enormous investments in new capacity. Thus, a low price scenario seems both unrealistic and undesirable for OPEC.

Our model simulations build upon assumptions concerning a given amount of undiscovered oil by region, the oil companies' inclination to invest, the demand price elasticities and a possible effect from higher oil prices on economic growth. These factors are obviously uncertain. Taking these uncertainties into consideration, our sensitivity analyses show that the most profitable oil price for OPEC generally is above \$35 per barrel. Even in a very unlikely situation with a combined effect from several factors unfavorable to OPEC, like doubling of demand price elasticities, a relatively strong effect from higher oil prices on the economic growth, and lower costs for Non-OPEC, the optimal price for OPEC is still around \$25. On the other hand, as the model does not take into account exchange rate changes, the weakening of the dollar since 2000 probably implies that we underestimate OPEC's optimal oil price.

For OECD countries, on the other hand, there is a clear trade-off between low oil prices and low import dependence. Low oil prices stimulate oil consumption and depress investments outside OPEC. With an oil price of around \$35 per barrel, the import share seems to be rather constant over time. At lower prices the import share increases over time and vice versa.

To sum up, relatively high oil prices seem to be in the interest of OPEC countries, other oil producers of course, and OECD countries concerned with energy security. The main losers are probably poor, oil importing countries, whose economies may be particularly hurt.

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List of regions and field categories

Table A1. List of regions and field categories in the FRISBEE model

	Field category			
	1	2	3	4
Africa (AFR)	Onshore All	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow All
Canada (CAN)	Onshore All	Unconventional All	Offshore < 400 Mboe	Offshore > 400 Mboe
Caspian region (CAR)	Onshore < 400 Mboe	Onshore > 400 Mboe	Offshore < 400 Mboe	Offshore > 400 Mboe
China (CHI)	Onshore < 100 Mboe	Onshore >100; < 1000 Mboe	Onshore > 1000 Mboe	Offshore All
Eastern Europe (EEU)	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore < 100 Mboe	Offshore > 100 Mboe
Latin America (LAM)	Onshore All	Offshore deep < 1000 Mboe	Offshore deep > 1000 Mboe	Offshore shallow All
OECD Pacific (OEP)	Onshore All	Offshore deep All	Offshore shallow < 100 Mboe	Offshore shallow > 100 Mboe
OPEC core (OPR)	Onshore < 400 Mboe	Onshore >400; < 1000 Mboe	Onshore > 1000 Mboe	Offshore All
Rest-Asia (RAS)	Onshore < 400 Mboe	Onshore > 400 Mboe	Offshore < 400 Mboe	Offshore > 400 Mboe
Rest-OPEC (OPR)	Onshore < 400 Mboe	Onshore > 400 Mboe	Offshore deep All	Offshore shallow All
Russia/Ukr./Bel. (RUB)	Onshore < 400 Mboe	Onshore > 400 Mboe	Arctic < 400 Mboe	Arctic > 400 Mboe
USA	Onshore All	Alaska All	Offshore deep All	Offshore shallow All
Western Europe (WEU)	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow + Onshore < 100 Mboe	Offshore shallow > 100 Mboe

A formal description of the FRISBEE model

FRISBEE is a recursively dynamic partial equilibrium model of the global oil market. The world is divided into 13 regions in the model (see Appendix A). In each region oil companies produce oil, selling it on the global market, and end-users consume oil, buying it from the same global market. That is, all trade between regions goes through a common pool. In the model the global oil market clears in each period, i.e., total supply from all regions equals total demand in all regions (adjusted for an exogenous level of storage). The time periods in the model are 1 year, and the base year is 2000. The world market price of oil is exogenous in the model (interpreted as an OPEC price target). This implies that world demand (D_t^O) and Non-OPEC supply ($S_t^{Non-OPEC}$) are independently determined, and that the global oil market is balanced when OPEC supply (S_t^{OPEC}) satisfies the following equation (i.e., call on OPEC):

$$S_t^{OPEC} = D_t^O - S_t^{Non-OPEC} + \Delta Storage_t$$

where $\Delta Storage_t$ is exogenously reduced to zero during the first decade.

Production of oil

Production profile and vintages

For fields in production the lifetime of the field is divided into 4 phases, as indicated in Figure 1. The figure shows the general shape of the production profile for all fields in the model. Although this profile is exogenous and taken for granted in the investment decisions, actual production can be altered during the lifetime of the field. Thus, we will introduce the term capacity to denote the production possibilities at different phases of production. Phase 1 is the time (t_1) from a development decision is made until development starts. At the end of phase 1 capital costs are incurred. Phase 2 is the time (t_2) from the development starts until the peak production capacity is reached. Phase 3 is the peak production phase, which lasts t_3 years. Phase 4 is the time (t_4) when production capacity declines from its peak level.

For each of the 13 FRISBEE regions (r) there are 4 field categories (k), which are constructed based on different characteristics such as geological conditions (e.g., offshore/onshore, deep water/shelf),

and field size, cf. Appendix A. The construction of the field categories varies across the regions. There are thus 52 combinations of regions and categories, and we will refer to these as field groups (j). Within each field group we do not distinguish between fields, only vintages. Thus, we rather speak about how much reserves are developed in specific years, without specifying the number of fields or size of each field.

We make the following assumptions regarding time and production or capacity level:

- For each field group the time span of phase 1-3 (t_1-t_3) is established based on existing data. Phase 4 is assumed to last as long as the field is profitable.
- The production capacity in phase 2 is assumed to be half the peak capacity.
- For each field group the peak production capacity is determined as an exogenous share η of recoverable reserves. This is also based on existing data.
- In phase 4 we assume there is an exponential decline in the production capacity level, with a constant decline rate α . Without changes in the recovery rate, this decline rate follows automatically from the exogenous levels of t_2 and t_3 , and the exogenous peak share mentioned above.
- We allow for increases in the recovery rate, which is assumed to take place in phase 4, i.e. as a reduction in the decline rate (or an indirect prolongation of the peak phase), see below.

In order to account for when fields (i.e. reserves) are switching from one phase to another, we introduce field vintages. Vintage 0 contains all fields in phase 4. These fields may be grouped together without specifying e.g. year of development. Furthermore, Vintage n consists of all fields that turn into phase 4 in n years. Thus, when a decision is made to develop a certain amount of reserves in a field group of a region, these reserves are placed in Vintage ($t_1+t_2+t_3$) of that field group. When the model runs from one year to the next, all fields in Vintage n ($n>0$) are moved to Vintage $n-1$. From the exogenous levels of $t_1 - t_3$, the production capacity level in each vintage can be determined from the reserve base.

It is straightforward to show from the assumptions above that we get the following expressions for the the relationship between remaining reserves in Vintage n (R_n) and its capacity (CAP_n):¹⁵

¹⁵ Note that this function applies to all field groups (j) at all time periods (t), but the indices j and t are not included in the expression. This omission also applies to later equations, unless the indices improve the understanding of the equation.

$$CAP_n = \begin{cases} \alpha R_0 & n = 0 \\ \frac{\alpha R_n}{(1 + \alpha n)} & 0 < n \leq t_3 \\ \frac{\alpha R_n}{(2 + \alpha(n - t_3) + 2\alpha t_3)} & t_3 < n \leq t_3 + t_2 \\ 0 & t_3 + t_2 < n \leq t_1 + t_2 + t_3 \end{cases}$$

When the model runs from year t to $t+1$, the reserve bases of the vintages are up-dated in the following way:

$$R_n = \begin{cases} R_0(1 - \alpha) + R_1 - CAP_1 + RRI + R_0(1 - REC_1)rec & n = 0 \\ R_{n+1} - CAP_{n+1} & 0 < n < t_1 + t_2 + t_3 \\ RI & n = t_1 + t_2 + t_3 \end{cases}$$

where RI and RRI denote respectively new reserve investments and recovery rate investments (IOR), which are both determined by producers at the end of each year (see "Investments and exploration in Non-OPEC" below). The latter term (for $n=0$) denotes exogenous improvements in recovery rates, which depend on the current recovery rate REC_1 (see below) and an exogenous parameter rec .¹⁶

Developed and undeveloped oil resources

Before we turn to the production and investment decisions, it is necessary to discuss how we treat the different developed and undeveloped resources in the model. For each field group we have three separate sets of resources. The first set consists of developed fields, the second consists of discovered, undeveloped fields, and the third set consists of undiscovered, but expected fields/resources. Each set is further divided into recoverable and unrecoverable resources. In addition, the first set also distinguishes between produced and remaining resources. Within each set there is an average recovery rate REC that denotes the share of total resources that are recoverable. For simplicity we assume that the recovery rate is equal for all fields in Sets 2 and 3, but that this rate may increase exogenously over time due to technological progress. The average recovery rate in set 1 may change due to the same reason, but also due to investments in increased recovery rate (IOR) and due to development of new fields from Set 2 (see below). Thus we have the following updating of REC in Sets 1, 2 and 3:

¹⁶ In our simulations this parameter has been set to 0, i.e., we have only considered endogenous IOR.

$$REC_{1,t+1} = \frac{AS_t + R_t + RI_t + RRI_t + R_{0,t}(1 - REC_{1,t}) \cdot rec}{RR_t + \frac{RI_t}{REC_{2,t}}}$$

$$REC_{2,t+1} = REC_{3,t+1} = REC_{2,t} e^{(1 - REC_{2,t}) \cdot rec}$$

where AS is accumulated supply, R is total remaining recoverable reserves in developed fields (i.e., the sum of all R_n), and RR is total resources in developed fields (incl. produced resources).

RR and AS is updated in the following way:¹⁷

$$RR_{t+1} = RR_t + \frac{RI_t}{REC_{2,t}} + \sum_n CAP_{n,t} - \sum_n S_{n,t}$$

$$AS_{t+1} = AS_t + \sum_n S_{n,t}$$

In Set 2 undeveloped reserves (UR) are updated in the following way:

$$UR_{t+1} = (UR_t - RI_t) e^{(1 - REC_{2,t}) \cdot rec} + DRR_t \cdot REC_{2,t+1}$$

where DRR is discovered resources last period (this is endogenous - see below). Accumulated discoveries ($ADRR$), including initial undeveloped reserves, are then given by:

$$ADRR_t = UR_0 + \sum_{i=1}^t DRR_i$$

Non-OPEC production

Within a year, production capacity is determined as explained above. The production level S is determined by this capacity, the operating costs, prices and taxes. The operating costs vary between field groups, but also between vintages. Let C_O^R denote the initial unit operating cost for a field, i.e., total operating costs divided by total reserves in the field, $C_O^{R,n}$ unit operating cost for a field in Vintage n . We assume that annual operating costs for a field are constant over time, and that the field's

¹⁷ If production is less than capacity, the difference is assumed to be shifted to the unrecoverable part of the resources (that is, before eventual IOR investments).

expected lifetime is T years. Unit costs in the peak-phase is then $C_O^{R,n}/(\eta T)$. For fields in the pre-peak and peak phase (i.e., P2 and P3 in Figure 1), we assume the following marginal cost function:¹⁸

$$c_O^n(S_n) = C_O^{R,n} + \phi_1 \left(\frac{S_n}{CAP_n} \right)^{\phi_2} \quad 0 < n \leq t_3 + t_2$$

where ϕ_1 and ϕ_2 are calibrated so that the marginal cost in the base year equals the base year oil price (i.e., around \$28) when 99 per cent of capacity is produced, and \$100 when full capacity is produced (adjusted by gross taxes in the region in both cases). This reflects that there are cost variances across fields, but that most of the fields in the peak phase will produce at approximately full capacity.

For fields in the decline phase (P4 in Figure 1), unit operating costs will increase as the field production declines. Assuming that the reserves in Vintage 0 are evenly distributed over the lifetime of the field, and that there are other cost differences across fields as well, we apply the following expression for marginal operating costs in this vintage:

$$c_O^0(S_0) = C_O^{R,0} + \phi_1 \left(\frac{S_0}{CAP_0} \right)^{\phi_3}$$

Note that this equation is similar to the equation for the peak phase, except for the exponential parameter. ϕ_3 is calibrated in a similar way as ϕ_2 above, but with a lower capacity utilisation at the baseyear price than in the peak phase (i.e., $\phi_3 < \phi_2$ - the level of ϕ_3 depends on the initial unit operating cost $C_O^{R,0}$).

We assumed above that the cheapest fields are developed first. Thus, the operating costs (C_O^R) vary across vintages. We introduce the following relationships that keep track on the operating costs in different vintages (the relationship applies between periods, and is of course region/category specific):

¹⁸ Although unit operating costs are higher in the pre-peak phase than in the peak phase, it is unreasonable to assume that production is stopped in this phase. Thus, with respect to the production decision in the model we treat the unit operating costs in phase 2 and 3 as identical.

$$C_O^{R,n} = \begin{cases} \frac{R_0(1-\alpha)C_O^{R,0} + (R_1 - CAP_1)C_O^{R,1}}{R_0(1-\alpha) + R_1 - CAP_1} e^{-\tau_p} & n = 0 \\ C_O^{R,n+1} e^{-\tau_p} & 0 < n < t_1 + t_2 + t_3 \\ C_{O,t}^R & n = t_1 + t_2 + t_3 \end{cases}$$

Here τ_p denotes the technological progress for fields in production, and $C_{O,t}^R$ denotes the unit operating costs of new fields, which change over time (see below).

Non-OPEC production is then given by the following equations:

$$c_O^{n,r}(S_{n,j}) = PP_r (1 - GT_r) \quad \text{if } S_{n,j} > 0$$

where PP is the producer price in the region, considered exogenously by Non-OPEC producers, and GT is the region's gross income tax. Total Non-OPEC production is then simply given by:

$$S^{Non-OPEC} = \sum_{n,j \in Non-OPEC} S_{n,j}$$

OPEC production

OPEC's total production is simply given by the residual demand at the fixed oil price level, i.e., total Non-OPEC production minus total demand. The distribution within regions and field categories in OPEC is simply assumed to be based on capacity (i.e., identical capacity utilisation across field categories).

Costs of undeveloped resources

One important element in the investment decision is the costs of new fields. We distinguish between capital costs and operating costs. We assume that all capital costs are incurred the year before production starts¹⁹, whereas operating costs are evenly distributed over the lifetime of the field. As the last phase of production may last forever unless it is shut down, we assume that investors in their calculations consider production until a certain lower level is reached. Let κ denote this minimum

¹⁹ In reality some costs are incurred before and some costs after production starts, but this simplifying assumption seems sensible.

production level relative to the peak level (α is still the decline rate). Then the expected lifetime of the field is (rounded up):

$$T = t_2 + t_3 - \frac{\ln \kappa}{\alpha}$$

In the baseyear the undeveloped, but discovered fields in Set 2 will typically have different extraction costs, even within a field category in a region. This could be due to e.g. different geology, location, size etc. Due to discounting of future costs it is profitable to extract the cheapest fields first, which means that the marginal total costs (capital + operating costs) rise with accumulated extraction.

Let C_o and C_c denote total (undiscounted) operating and capital costs for a new field, and C_o^R and C_c^R the corresponding (undiscounted) costs per reserve unit. We assume that unit costs are increasing as the undeveloped reserves are developed. Without new discoveries this means that unit costs are a decreasing function in the size of undeveloped reserves, UR . However, it is unreasonable to assume that new discoveries will have lower costs than all existing undeveloped fields. Thus, we rather assume that unit costs are a decreasing function of the ratio between undeveloped reserves and accumulated discoveries ($ADRR$):

$$C_{c,t,j}^R = C_{c,0,j}^R F_j(UR_j, ADRR_j, t)$$

$$C_{o,t,j}^R = C_{o,0,j}^R F_j(UR_j, ADRR_j, t)$$

$$F_j(UR_j, ADRR_j, t) = \left[1 - \gamma_j \ln \left(\frac{UR_j}{ADRR_j} \right) \right] e^{-\tau_j t}$$

where $C_{c,o}^R$ and $C_{o,o}^R$ denote the costs of the cheapest field in this field group in the baseyear.²⁰ As seen from the expression we also assume that technological progress may reduce the costs exogenously over time by the rate τ_j . Moreover, when UR approaches zero, unit costs approach infinity. The parameters γ_j (>0) are determined based on available cost data.

²⁰ Note that we implicitly assume that the field with lowest capital costs also has the lowest operating costs etc. This is of course a simplification, which however seems justified since we have four different field groups in each region.

We further assume that there are increasing marginal costs of investments within each time period. There are a number of reasons for this assumption. First, it reflects shortage on the availability of oilrigs, personnel etc. Second, the cost variation across fields in a region is probably larger in the short term than in the long term due to different fields being more or less prepared for development (e.g. due to informational and infrastructure considerations). Third, different oil companies may have acquired special competence in one or a few regions, and at the aggregate level this may lead to increasing marginal costs as each company may have a certain capacity for new projects.

Based on the reasoning above we assume that the increase in marginal costs is related to the remaining undeveloped reserves in the region and field category, UR_j . The less undeveloped resources, the faster marginal cost rises. This partly reflects that the scarcity rent is higher the less undeveloped resources there are. Moreover, the current production level (S_j) will also have bearings on how fast marginal costs rise, as it is an indicator of the level of activity and infrastructure in the area. Both production in the particular field category and the total production in the region matter. Finally, we assume that a certain share of remaining fields is cheaper than the unit cost C_C^R , as some fields may utilise the infrastructure etc. of existing fields. Thus, we apply the following relationship for the total undiscounted capital costs (remember that RI is investments measured in oil reserves):

$$TC_C(RI_j) = C_C^R \cdot RI_j \left(0.5 + c_{C,UR} \frac{RI_j}{UR_j} + c_{C,S1} \frac{RI_j}{S_j} + c_{C,S2} \frac{RI_j}{S} \right)$$

where $c_{C,UR}$, $c_{C,S1}$ and $c_{C,S2}$ are parameters stating the importance of the three variables UR_j , S_j and S in the marginal cost function. In the simulations in this paper the parameters are set equal to $c_{C,UR}=4$, $c_{C,S1}=0.1$ and $c_{C,S2}=0.4$ in all regions and field categories. This means e.g. that marginal capital costs equal $2 \cdot C_C^R$ when RI_j is about 6 per cent of UR_j , 2.5 times S_j , and about 0.6 times S . These parameter values are partly based on comparing model results with the actual outcome in 2000-2004, as it is difficult to obtain objective information on this matter.

Costs of improved oil recovery (IOR)

Improved oil recovery (IOR) can only take place in phase 4 of the capacity profile in the model, i.e., in the decline phase. We assume that the marginal costs are increasing in the amount of IOR (RI_j), and decreasing in the amount of initial reserves in the decline phase. However, the costs are adjusted to take into account that fields with short decline phase have the same potential for IOR as fields with long decline phase. The reason for increasing marginal costs is the same as for new fields investments.

Moreover, in the long run the unit costs are assumed to be a convex function of the recovery rate (REC_1). We use the following function for total costs of IOR:

$$TC_{IOR}(RRI_j) = C_{IOR,j}^0 \cdot RRI_j \left(0.5 + IOR0_j \left(\frac{RRI_j}{\frac{\alpha_j}{\eta_j} R_{0,j} + 0.01} \right)^2 \right) \left(\frac{REC_{1,j}}{(1-REC_{1,j})} \right)^{IOREXP_j} \left(\frac{REC_{1,j}^0}{(1-REC_{1,j}^0)} \right) e^{-\tau_j t}$$

$IOR0$ and $IOREXP$ are parameters that determine how fast unit costs increase in the short and long term, respectively. The latter parameter is calibrated to roughly fit projections made by the EIA (2004) regarding potential for IOR in different countries until 2025. Note that we assume the same technological progress here as for undeveloped fields.

Investments and exploration in Non-OPEC

We are now ready to describe the investment decision in Non-OPEC. Oil companies maximise expected profits of new investments, where all regions and field categories outside OPEC are available. The maximisation may however be constrained by the availability of credit, e.g. related to cash flow. The companies may invest in new fields or in improved oil recovery (IOR).

Investments in new fields mean that the field resources are put into phase 1 of the capacity profile, as discussed in the beginning of this appendix. Capital costs are incurring between phase 1 and 2, operating costs are distributed over the lifetime of the field, and revenues occur when production takes place.

Improved oil recovery (IOR) can only take place in phase 4 in the model, i.e., in the decline phase. When IOR investment is undertaken, the recovery rate increases, and the reserves of Vintage 0 are increased. The costs occur immediately (we only consider capital costs and not extra operating costs), and the extra revenues occur during the remaining lifetime of the field.

The oil companies' expected profit is then given as:

$$\begin{aligned}
Max_{RI_j, RRI_j} \quad \Pi^e = & \sum_{j'(j)} \left[\left(\eta \cdot PP_j^E (1 - GT_j) - \frac{C_O^R}{T_j} \right) \cdot (1 - NT_j) \cdot h(r, t_2, t_3, T) \right. \\
& \left. - \frac{TC_C(RI_j)}{RI_j} \left(1 - \frac{1}{6} NT_j \cdot e^{-r} \frac{1 - e^{-6r}}{1 - e^{-r}} \right) - RISK_j \right] \cdot RI_j \\
& + \sum_{j'(j)} \left[\frac{PP_j^E (1 - GT_j) \alpha}{r + \alpha} (1 - NT_j) - \frac{TC_{IOR}(RRI_j)}{RRI_j} \left(1 - \frac{1}{6} NT_j \cdot e^{-r} \frac{1 - e^{-6r}}{1 - e^{-r}} \right) \right] \cdot RRI_j
\end{aligned}$$

where

$$h(r, t_2, t_3, T) = 0.5 \frac{1 - e^{-rt_2}}{1 - e^{-r}} + e^{-rt_2} \frac{1 - e^{-rt_3}}{1 - e^{-r}} + e^{-r(t_2+t_3)} \frac{1 - e^{-(r+\alpha)(T-t_2-t_3)}}{1 - e^{-(r+\alpha)}}$$

$j'(j)$ denotes the subgroup of field groups that the companies can invest in, i.e. all Non-OPEC fields. GT denotes the gross tax rate, whereas NT denotes the net tax rate. PP^E is expected (constant real) future oil price during the lifetime of the field (see below). $RISK$ is an exogenous variable that reflects other important non-cost factors such as political risk, contract terms etc. This is partly calibrated based on past investment behavior.

The expected future crude oil price in the region PP^E is simply assumed to be an average of the price over the last 6 years, in the following way:

$$PP_{j,t}^E = \frac{1}{6} \sum_{i=0}^5 PP_{j,t-i}$$

If the oil companies are (voluntarily or not) constrained by credit, e.g. by their cash flow, the following restriction will apply in their maximisation:

$$\sum_{j \in J} (TC_{C,j}(RI_j) + TC_{EOR,j}(RRI_j)) \leq CREDIT$$

Note that current operating costs and taxes are deducted on the right hand side of the inequality.

In order to take into account new findings due to exploration, we assume that new discoveries are a linear function of the expected oil price in the region (PP^e), and an exponentially declining function of time.

$$DRR_t = DRR_0 PP_j^e e^{-\delta t}$$

This means that for a given oil price, accumulated discoveries are limited and approaches $DRR_0 PP^e / \delta$ when time goes to infinity.

Investments and exploration in OPEC

Investments in OPEC are not based on profit maximisation, but on how much capacity is needed in order to supply the residual demand for the chosen, fixed oil price. Investments therefore depend on the actual production or capacity level in the past year, and the expected growth in OPEC production (based on recent history). We apply the following investment function for OPEC (new fields plus IOR in OPEC-Core and OPEC-rest):

$$RI_t^{OPEC} = v \left(\frac{S_t^{OPEC}}{S_{t-1}^{OPEC}} - 1 \right) R_t^{OPEC} + CAP_t^{OPEC}$$

The distribution between OPEC-core and OPEC-rest is based on remaining undeveloped reserves in the two regions (proportional distribution). The distribution between new fields and IOR investments is simply set to 60 per cent new fields and 40 per cent IOR (this is based on EIA's (2004) assumptions about IOR potential, new discoveries and remaining undeveloped reserves in the baseyear).

Exploration in OPEC is modeled in the same way as for Non-OPEC.

Demand for oil and other energy products

Demand for final energy goods in each region is divided into two sectors, households (incl. services) (H) and industry (I). Both sectors demand transport oil (TO) and stationary oil (SO), as well as gas (G), coal (C) and electricity (EL). Demands for the other energy goods are functions of real end-user

prices (PFE) and GDP (Y). In addition there is an autonomous energy efficiency improvement (AEEI), denoted χ .²¹

The model distinguishes between short-term and long-term effects. The immediate effect (i.e., first year) is reflected by the short-term elasticities, whereas the long-term effect (towards infinity) is reflected by the long-term elasticities. The transition from the short-term to the long-term effect is reflected by an adjustment parameter.

The long term demand functions for the final energy FE (TO , SO , G , C , EL) in sector $j \in (H, I)$ are given by the following relationships (which apply in all regions):

$$D_{j,t}^{FE} = A_j^{FE} \cdot (PFE_{j,t}^{TO})^{\alpha_j^{FE,TO}} \cdot (PFE_{j,t}^{SO})^{\alpha_j^{FE,SO}} \cdot (PFE_{j,t}^G)^{\alpha_j^{FE,G}} \cdot (PFE_{j,t}^C)^{\alpha_j^{FE,C}} \cdot (PFE_{j,t}^{EL})^{\alpha_j^{FE,EL}} \cdot (Y_{j,t})^{\beta_j^{FE}} \cdot (\chi_j^{FE})^t$$

Thus, the parameters in these equations denote the long-term elasticities. However, in order to take account of the short- and medium-term effects, too, the demand functions in the model are rather specified in the following (partial adjustment) way:

$$D_{j,t}^{FE} = A_j^{FE} \cdot (D_{j,t-1}^{FE})^{\gamma_j^{FE}} \cdot (PFE_{j,t}^{TO})^{a_j^{FE,TO}} \cdot (PFE_{j,t}^{SO})^{a_j^{FE,SO}} \cdot (PFE_{j,t}^G)^{a_j^{FE,G}} \cdot (PFE_{j,t}^C)^{a_j^{FE,C}} \cdot (PFE_{j,t}^{EL})^{a_j^{FE,EL}} \cdot (Y_{j,t})^{b_j^{FE}} \cdot (\tilde{\chi}_j^{FE})^t$$

Here the long-term elasticities have been replaced by the short-term elasticities (a 's and b), and the last period's demand is included (note that $0 < \gamma_j^{FE} < 1$). The long-term elasticities are given by

$$\alpha_j^{FE,i} = \frac{a_j^{FE,i}}{1 - \gamma_j^{FE}} \text{ and } \beta_j^{FE} = \frac{b_j^{FE}}{1 - \gamma_j^{FE}}, \text{ whereas } \tilde{\chi}_j^{FE} = (\chi_j^{FE})^{1 - \gamma_j^{FE}} \text{ gives a good approximation for the}$$

AEEI effect.

²¹ In the calibration, gasoline and aviation fuels are classified as Household's demand for transport oil, diesel and marine oil are classified as Industry's demand for transport oil, heating oil is classified as Household's demand for stationary oil, and residual fuel oil is classified as Industry's demand for stationary oil. Historic prices are deflated using a US GDP index.

The end-user prices in a region are the sum of (cif) product prices in the region (PF), distributional costs (DC), energy taxes (ET), and carbon taxes (tax level (CT) times carbon coefficient (CC)), all multiplied by the VAT rate:

$$PFE_j^{FE} = (PF_j^{FE} + DC_j^{FE} + ET_j^{FE} + CT_j^{FE} CC_j^{FE})(1 + VAT_j^{FE})$$

Both DC and ET are fixed parameters, which differ across the two sectors. PF is an endogenous variable for oil products, and varies between stationary (SO) and transport oil (TO). In our simulations non-oil prices have been held constant throughout the time horizon.

Electricity production also demand primary energy, and this demand is denoted DE . Regional demand for primary energy (D) may then be summed up in the following way, i.e. we assume that all transformation/refining is taking place within the demand region, and there is no physical loss in the transformation process:

$$D_{r,t}^O = \sum_j (D_{r,j,t}^{TO} + D_{r,j,t}^{SO}) + DE_{r,t}^{FO} \quad O = oil$$

$$D_{r,t}^E = \sum_j D_{r,j,t}^E + DE_{r,t}^E \quad E \neq O = oil$$

Global demand for fossil fuels (D) is then given by the following equation:

$$D_t^E = \sum_r (D_{r,t}^E)$$

Trade, transport and transformation of oil

Oil is traded in a global market at the world market price P .²² We use region-specific transport costs that reflect the marginal transport cost of respectively exporting (TCE) and importing (TCI) oil. That is, for each region we have:

$$P_t = PP_{r,t} + TCE_{r,t}$$

²² This is an average crude oil price, which is slightly higher than the average OPEC price, and slightly lower than the price of Brent Blend.

The oil product prices in each region is determined by the following relationships (applies for all regions):

$$PF_{r,j,t}^{FE(O)} = P_t + TCI_{r,t} + RC_{r,j,t}^{FE(O)}$$

$$PF_{r,t}^{FO} = P_t + TCI_{r,t} + RC_{r,t}^{FO}$$

where $FE(O)=\{TO,SO\}$ and FO is Fuel Oil used in power production. RC denotes the refinery costs, which differ across the oil products and sectors. The extra refinery costs for unconventional oil are put directly on the operating costs of producing this oil.

For oil exporting regions, we may have $0 \geq TCI \geq (-TCE)$, i.e., their cif. prices may be less than the world market price. For oil importing countries, we may have $0 \geq TCE \geq (-TCI)$, i.e., their producer price may be higher than the world market price.

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