Oil market in international and Norwegian perspectives

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Preface

I would like to express my gratitude to my supervisor, Olav Bjerkholt, for his invaluable and effective guidance. I also want to thank Knut, my husband, for his immense patience and love. All errors are mine.

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1 Introduction

Oil has been the leading source of energy since early in the twentieth century, due to its perceived benefits vis-à-vis other types of energy. These relate to accessibility, transportability, versatility and low costs, and as a consequence of all these, its established infrastructure right across the supply chain. The development of the industry has gone hand-in- hand with that of the global economy, to the benefit, principally, of what are now seen as the advanced consumer societies.

Price of oil is following a pricepath which was first analyzed by Hotelling and later a lot of extensions were added to it. The real price development shows casual outcomes and considerable deviation from the theoretical price. In this thesis I will summarize the most important theory elements, give some outlines on historical development of oil market, formation of price system, economical fundamentals of oil market and oil extraction on Norwegian continental shelf. At the end I will compare volume for Norwegian oil production over time and price level for the same years and will make evaluation how “successful” or “unsuccessful” Norway has been in relation to the price development and how the price development has been in relation to the expectation when the exploration just started.

The current oil situation may be succinctly described as follows. On the demand side growth in the period beginning in the mid-1970s until 2004 has been lacklustre. Thus oil consumption increased from 55990 million barrels per day (mb/d) in 1974 to 80,76 mb/ in 2006[1], at an average annual compound rate of 1,19 percent. In the same period world primary energy consumption grew from 6,07 billion tonnes of oil equivalent (toe) in 1974 to 10,2 billion toe in 2006, that is at an average annual compound rate of 1,8 percent. The growth rate differential implies that the share of oil in the energy slate has been declining during this period. The change was from an oil share of about 45 percent in 1974 to 36 percent in 2006. The shift in shares was largely due to the substitution of fuel oil by coal, gas, nuclear and hydro in power generation and steam-raising in industry; and of middle distillates by natural gas in other applications. Oil retained however its dominance in the transport sector, the area where technological developments are most critical to its future.

The determinants of oil demand are income (the rate of economic growth), price, the technology of oil using vehicles and appliances, changes in consumers’ tastes which are partly correlated to income, government energy policies and the availability of competitive

[1] Source: BP Statistical Review of World Energy

substitutes for uses where substitution is technically feasible. Demand for oil is the highest in OECD (Organization of Economic Cooperation and Development) countries both in absolute terms and per capita. However, the growth in oil demand has been relatively low in OECD countries and much higher in the developing world, particularly in the new industrialized countries of Asia.

On the supply side, the changes in the OPEC (Organization of The Petroleum Exporting Countries) share of global oil production went through a cycle in the period 1974-2004. Significant increases in non-OPEC production at a time when world demand was either stagnant or growing very slightly were accommodated by an equivalent reduction in OPEC's output. The reason is that non-OPEC producers are volume maximizers while OPEC, having assumed the role of defending an administered price (between 1973 and 1985), became the residual oil supplier to the world. Thus OPEC's production share which stood at about 52 percent in 1974 was as low as 30,7 percent in 1986, but then recovered to 41 percent in 2006.

Important changes also occurred in the regional structure of non-OPEC production in the past 30 years. The second half of the 1970s saw the arrival of new producers, the most significant being the UK and Norway in North Sea, Mexico and Alaska. Oil production in the USSR increased until the early 1980s reaching a peak of 12,520 mb/d in 1983. A huge decline set in after the brake-up of Soviet Union, with oil production of the FSU falling to 7,035 mb/d in 1996.

2 The oil market

2.1 Historical perspective of the oil market

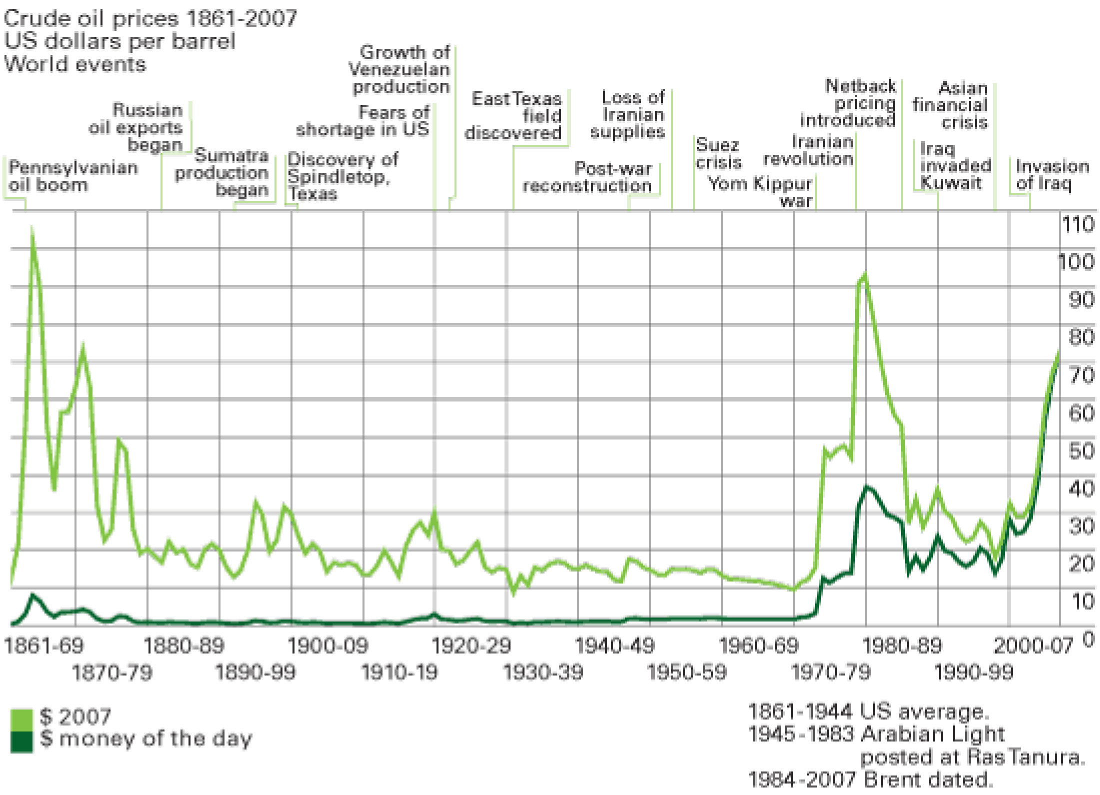
The use of oil as a source of energy is a recent phenomenon. The beginning of the oil industry is usually dated to 1859 when in Pennsylvania an oil well was struck instead of brine (Jones, 1988), but oil seepages have been known and taken advantage of for much of human history and in as various parts of the world as China, the Roman Empire, and Brazil in precolonial times (Van Meurs, 1981).

The oil industry and the uses of oil developed first and foremost in the United States, and it was one of the main engines of the rapid industrialization and growth of the American economy in the late nineteenth and early twentieth century. Oil quickly became important enough to shape world political events. Intense rivalry developed between the Germans and the British in the late nineteenth century in their diplomatic approaches toward Turkey, but Turkey then held sway over the Middle East, parts of which appeared to be promising for oil exploitation. After World War I and the disintegration of the Turkish empire Iraq and Kuwait, soon to emerge as important oil producers, came under British influence. The Shah of Iran was put in power by the British and American governments because of interruptions in oil supplies from Iran under the government of Mossadeq in the early 1950s. The Iraqi invasion of Kuwait in 1990 was rolled back, mainly through the efforts of the United States, undoubtedly because of the threat it represented to the supplies of oil from the Middle East (Hannesson, 1998).

The price of oil has shown a peculiar behaviour over time. Figure 2.1 shows how the price of oil has developed since the early beginnings of the industry, in nominal and real terms. Real prices are computed by dividing the nominal price in a given month by the ratio of the Consumer Price Index (CPI) in that month to the CPI in some "base" period. All real prices are expressed in "current" dollars and any current month price may be compared directly with any past or projected real prices. The 1950s and 1960s were a period of relatively stable and declining real price of oil. The early 1970s, particularly 1973-74, mark a watershed. Since then the oil price has been subject to three major shifts; it rose dramatically in 1973-75 and again in 1979-81, and fell steeply in 1986. Since 2005 and during 2008 prices reached record-breaking levels in nominal and real terms

There are a few peculiarities that are important for understanding the movements in the price of oil. First, the oil industry is dominated by a few large companies. This was particularly true in the past when the oil companies cooperated in setting their prices. Second, because oil is a storable commodity, the oil market is highly influenced by expectations about future prices and changes in inventories (Hannesson, 1998).

Figure 2.1 The price of Crude Oil 1861-2007



Source: U.S. Energy Information Administration

The steady decline in the oil price that persisted for much of the first quarter of a century after the end of World War II took place despite a steadily rising demand for oil. That the price of oil fell was due to two factors. First, sufficient oil was discovered to replace the increasing quantities that were used up. Second, the new reserves that were found were to an increasing degree controlled by “independent” oil companies, independent, that is, of the international giants that controlled the great reserves in Saudi Arabia and elsewhere and cooperated in exploiting them.

2.2 Formation of the price system

Since the beginning of the oil era in the Middle East until the early 1970s, Organization of Petroleum Exporting Countries (OPEC) did not participate in production or pricing of crude oil but simply received a stream of income through royalties and income taxes. OPEC consisted of thirteen countries, including Iran, seven Arab countries, plus Ecuador, Indonesia, Nigeria, Angola and Venezuela. OPEC had been formed on 14 September, 1960 at the Baghdad conference. It was made to protest pressure by major oil companies (mostly owned by US, British, and Dutch nationals) to reduce oil prices and payments to producers. At first it had operated as an informal bargaining unit for the sale of oil by Third World nations.

The oil pricing regime associated with the concession system that prevailed in the Third World until the mid 1970s was centred on the concept of “posted price”. The posted price served only as a fiscal parameter which was used to calculate the royalty and income tax per barrel of crude oil going to the host governments (Mabro, 1984). Spot prices, transfer prices and long-term contract prices could not play such a fiscal role.

Until the late 1950s, the international oil industry outside the USA, Canada, the USSR and China has been characterized by the dominant position of the large multinational oil companies (known as the Seven Sisters or the majors) which had majority control of reserves, extraction and production, transportation and marketing.The Seven Sisters consisted of three companies formed by the breakup by the US Government of Standard Oil, along with four other major oil companies. With their dominance of oil production, refinement and distribution, they were able to take advantage of the rapidly increasing demand for oil and turn immense profits. They controlled the rate of supply of crude oil through joint ownership of companies that operated in different countries. The Seven Sisters were comfortable with the system of posted prices because it maintained their oligopolistic position, and until the late 1960s the OPEC was too weak to change the existing pricing regime. It was only when the Arab states began to gain control over oil prices and production, mainly through the formation of OPEC, beginning in 1960 and really gaining power by the 1970s, that the Seven Sisters' influence declined (Mabro, 2006).

Around 1970 there were signs that the era of slowly falling real oil prices was coming to an end. The price rose in the early 1970s. Even if more oil was found than was being used up, these discoveries were distributed in a lopsided fashion. Most of these discoveries and the ones that were easiest to exploit were located in the Middle East. The countries in Western Europe imported most of their oil from the Middle East and United States was becoming dependent on imports from this source (Parra, 2004). Consequently, disruption in supply from the Middle East could be expected to have a major impact on the world oil market. OPEC was becoming aware of this and was adopting a more aggressive stance in its negotiations with the international oil companies about posted prices, on which the tax payments to the governments of the oil-producing countries were based.

The war between Israel and Egypt in October 1973 precipitated dramatic increase in oil prices. On 16 October 1973, the six Gulf Members of OPEC announced an immediate increase in the posted price of the Arabian Light crude from $3,65 to $5,119. The Arab countries imposed an oil embargo on the United States and the Netherlands, in order to put pressure on Western governments because of their support of Israel. The oil embargo was over quickly, but what had become evident was the power the oil-exporting countries wielded over the price of oil. In December 1973, OPEC raised the posted price of the Arabian Light to $11.651. This jump in price was unprecedented. The year 1973 represented a dramatic shift in this balance of power towards OPEC. For the first time in its history, OPEC assumed a unilateral role in setting posted prices (Terzian, 1985).

The oil industry witnessed a major transformation in the early 1970s when some OPEC governments stopped granting new concessions and started to claim equity participation in the existing concessions. Equity participation gave OPEC governments a share of the oil produced which they had to sell to third-party buyers. This led to the introduction of new pricing concepts to deal with this new reality (Mabro, 1984). As owners of crude oil, governments had to set a price for third-party buyers. Here entered the concept of official selling price (OSP) or government selling price (GSP). The complex oil price regime of the early 1970s centred on three different concept of oil prices (posted, OSP, and buyback prices) was highly inefficient.

Equity participation and nationalization of oil resources affected the structure of the oil industry and led to the emergence of a market for crude oil. As a result of these developments, multinational oil companies lost large reserves of crude oil and they found themselves net short and dependent on OPEC supplies. This encouraged the development of an oil market outside the inter-multinational oil companies' trade and pushed companies to diversify their sources of oil supply by gaining access and developing reserves outside OPEC. This process began well before the 1970s. In 1969, oil was found in the Norwegian sector and in 1970 a major find (the Ekofisk field) was confirmed. In the UK sector in 1970, BP drilled the exploratory well that found the Forties field. One year later, Shell-Esso discovered the Brent field (Parra, 2004).

During the years 1975-78, OPEC countries consolidated their control over production, prices and investment.

In the 1979 the second oil crisis occurred in the wake of the Iranian Revolution. The new regime resumed oil exports, it was inconsistent and at a lower volume, forcing prices to go up. Saudi Arabia and other OPEC nations increased production to offset the decline, and the overall loss in production was about 4 percent. 2

In 1980, following the Iraqi invasion of Iran, oil production in Iran nearly stopped, and Iraq's oil production was severely cut as well. After 1980, oil prices began a six-year decline that culminated with a 46 percent price drop in 1986. This was due to reduced demand and over-production. Significant amounts of oil began to reach the international market from outside OPEC. Between 1975 and 1985 non-OPEC countries managed to increase their share of world total oil production from 48% in 1973 to 71% in 1985 (EIA, 2007). Most of increase in oil came from Mexico, the North Sea, and Soviet Union (Parra, 2004).

The OPEC-administrated oil pricing regime lasted until 1985. The demand for OPEC oil declined from a yearly average of 16 mb/d in 1985 with Saudi Arabia's production falling from a yearly average of 9,9 mb/d in 1980 to around a yearly average of 3,4 mb/d in 1985.3 With this continued decline in demand for its oil, OPEC saw its own market share in the world's oil production fall from 52% in 1973 to less than 30% in 1985.

Saudi Arabia adopted the netback pricing system in 1986 in order to restore both the $26 price level and the country's market share (Mabro, 1986). The netback pricing system provided oil companies with a guaranteed refining margin even if oil priced were to collapse. The price formula was equal to the ex-post product realization minus refining and transportation costs. The netback pricing system resulted in the 1986 price collapse, from $26 a barrel in 1985 to less than $10 a barrel in mid-1986.

After the collapse of the OPEC-administrated system and the short experiment with netback pricing, oil-exporting countries adopted market-related pricing. First adopted by the Mexican national oil company PEMEX in 1986, market-related pricing received acceptance among many oil-exporting countries and by 1988 it became and still is the main method for

[2] "Oil Squeeze", Time magazine (1979-02-05).

[3] Source of data is EIA

pricing crude oil in international trade. Its structure is based on formula pricing were the reference price is derived from the market rather than being the administered OPEC marker price. This led to the development of a complex structure of oil markets which consist of spot, physical forward, futures, options and other derivative markets. Such a complex structure emerged in the North Sea around Brent. In the early 1980s, the Brent market only consisted of the spot market and the informal forward physical market (the 15-day market). By the late 1980s, the Brent market had become quite complex including also a futures contract traded on the International Petroleum Exchange (IPE), options, swaps and other trading instruments (Mabro, 2006). In North America, other complex layers of trading instruments emerged around the West Texas Intermediate (WTI).

2.3 Formula pricing in the current oil pricing regime

The emergence and expansion of the market for crude oil allowed the development of market-referencing pricing off spot crude markers such as spot WTI, dated Brent and Dubai. Formula pricing which constitutes the basis of the current “market-related” oil pricing regime is a relatively recent development in the oil market. First adopted by the Mexican national oil company PEMEX in 1986, formula pricing received wide acceptance among many oil-exporting countries and by 1988 it became and still is main method for pricing crude oil in international trade (Mabro, 2006).

Long-term contracts constitute the main method for arranging physical delivery of oil in this system. These contracts are negotiated directly between the parties and they specify among other things, the volumes of crude oil to be delivered, the actions to be taken in case of default, the tolerance level and the method used in calculating crude oil prices. The formula used in pricing oil is straightforward. The price of a certain variety of crude oil is set as a differential to a certain marker or reference price. Specifically for crude oil variety X, the formula pricing is:

$$PX = PR + D,$$

Where PX is the price of crude X, PR is the reference or marker price and D is the value of the price differential.

The differential, also called the coefficient of adjustment, determined independently by each of the oil-producing countries, is usually set in the month preceding the loading month, and adjusted monthly or quarterly (Parra, 2004). Theoretically, the differential is supposed to reflect differences in the quality of crude. The differential between the different varieties of crude oil is not constant over time and changes continuously according to relative demand and the relative supplies of the various crudes which in turn depend on the relative prices of petroleum products. Oil-exporting countries that announce their differentials first are at a competitive disadvantage of being undercut by their closest competitors. This can induce them to delay the announcement of the differential or in the case of multiple transactions compensate the buyers with adjusting downwards the differential in the next rounds.

There is also a time lag problem. When there is a lag between the date at which a cargo is bought and the date of arrival at its destination, there is a price risk. Oil-exporting countries usually share this risk with their buyers through the pricing formula. Agreements are sometimes made for the date of pricing to occur around the delivery date. The price used is the market price quotes averaged over 10 days around the delivery date. For oil sold to the Far East, the pricing is the average of the reference price over the calendar month in which loading took place (James, 2003).

The next important element of formula pricing is identification of the reference or benchmark crude. Brent, WTI and Dubai-Oman are the main crude oil benchmarks of the current oil pricing regime. Nearly all oil traded outside America and the Far East is priced using Brent as a benchmark. Brent Blend is a combination of crude oil from different oil fields located in the North Sea. WTI is the main benchmark used for pricing oil imports into the USA. Although more crude oil is priced off Brent, the standard WTI futures contract is the most widely traded commodity futures contract in the world. West Texas Intermediate (WTI) crude oil is of very high quality. Dubai-Oman is used as a benchmark for Gulf crudes (Saudi Arabia, Iran, Iraq, the UAE, Qatar and Kuwait) sold in the Asia-Pacific market (Mabro, 2006). Initially, Dubai became the main price marker for the region by default as it was one of the few Gulf crudes available for sale on the spot market.

With a large fraction of traded crude oil being priced off Brent, Brent price takes a privileged position within the current oil pricing regime. In the early 1980s the volume of production in the Brent market was quite large and ensured enough physical liquidity. But similar bases of physical liquidity could be found in other regions of the world, especially in OPEC which constituted the largest physical market for crude oil to question the choice of Brent price as a marker. Thus, the volume of production though important is not the determining factor for the choice of a marker.

Because the international benchmarks are differentiated by the type of crude oil and its location, they fetch different prices. WTI is lighter and sweeter than Brent and as a result of these gravity and sulphur differences WTI typically trades at a dollar or two dollars premium to Brent. The price differential between the international benchmarks, also known as spreads, however are not fixed and can widen or narrow in response to factors other than differences in the intrinsic properties of the crude (Mabro, 2006). Movements in oil price differentials can result from non-parallel movements of either of the underlying benchmark prices or both. The nonparallel movements are possible because each type of crude oil can be influenced by local conditions, the set of traders in the market, their perceptions of the oil crude market. This may lead sometimes to wide spreads between the benchmarks.

2.4 Market developments and marketing strategies for crude oil

The oil derivative markets have developed around two complementary axes: hedging oil prices exposures of large companies, and the financing operations of the oil industry. Both of these have generated rapid growth for the over-the-counter (OTC) energy derivatives industry. For the last ten years, the OTC market has also fuelled much of the growth in liquidity in the exchanges, especially for back-month trading (Kaminski, 2004).

The physical crude market is the foundation of the oil market. Prices of crude are generally quoted free on board (fob) at their loading port. Most physical crude oil is priced as a differential to an actively traded future or forward marked (Kaminski, 2004). Instead of buyer and seller agreeing an absolute price for the cargo of crude oil, they agree floating price, which is generally an average of several days around the bill of lading date (when the ship loads the oil). Most oil traded in Europe and many West African crudes, for example, are priced against Brent while almost all crude exported to the US, or traded within it, is priced against Nymex futures (Kaminski, 2004). In the short-term, the crude oil market is the trendsetter for the other energy markets; it is highly sensitive to OPEC rhetoric, to the general economic environment and to political events or uncertainties.

It is the composition and structure of the underlying physical Brent market that accounts for much of its importance. The upstream tax regulations in the UK give integrated companies producing oil an incentive to trade arm’s length in order to establish an independent and market-related price. As a result, there is always a large amount of oil available to the market, thus guaranteeing the market’s liquidity. Since the blend can be traded to within a few days of physical delivery, the Brent market fills an essential gap in the term structure of the world oil market by providing a price reference over a period of one to two months ahead (Kaminski, 2004). Finally, because North Sea crudes are generally light and sweet, they are attractive to any refiner if the price is right.

The importance of the physical oil market in the North Sea has encouraged the development of active and liquid paper markets. WTI, on the other hand, is the leading benchmark for the US domestic crude market and the physical underlying of the deepest commodity futures market in the world. Unlike the North Sea, virtually every barrel of US domestic crude, with the exception of Alaskan North Slope (ANS), is traded, priced and transported by pipeline rather than on waterborne tankers and barges (Kaminski, 2004).

The main instruments of the crude oil market are futures, forwards or swaps based on WTI and Brent indices. Cargoes of Brent blend crude oil are traded on an active forward market, so that one cargo may change hands many times before it is finally collected from Sullom Voe, its loading terminal (Kaminski, 2004).

A forward contract requires the seller to give the buyer 15 day’s notice of physical lifting dates. Once a cargo has been nominated, it is known as a “dated cargo”, and specific loading dates are attached to it. Many types of physical crude oil are priced against dated Brent (Kaminski, 2004). Flat price risks are hedged using IPE Brent contracts and the differential between dated Brent and the first future contract are traded through “contracts for differences” (CFDs). CFDs normally refer to calendar weeks; this means that the unwinding of these swaps takes place using Platt’s quotations for the relevant Monday to Friday period.

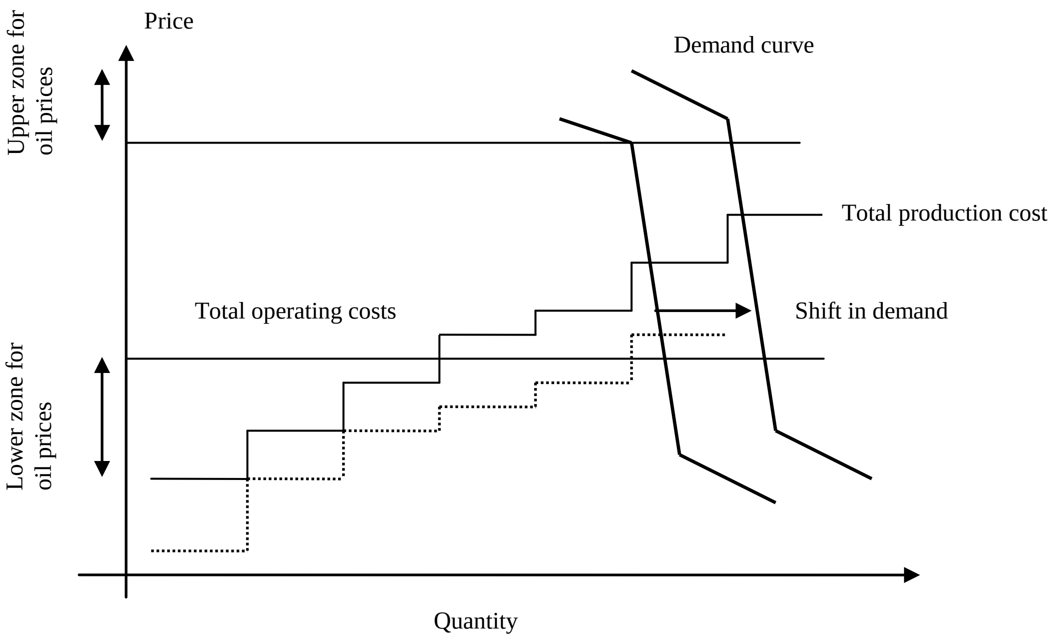
Crude oil is also the index of choice for most arbitrageurs and investment funds, since it is by far the most liquid of all energy markets. The demand generated by investment strategists for derivative funds has been growing at an impressive pace in terms of variety and volume. Short-term oil and natural gas futures prices are heavily affected by the trading decisions of large financial entities, including Wall Street investment banks and hedge funds. Investment transactions, which can be either private placements or public offerings such as warrants, allow financiers to assume trading positions that are indexed to oil without the bother and risk of directly managing a commodities desk. Because of their liquidity, and hence the relatively low-cost dynamic hedging they allow, futures markets for crude oil have seen the creation of many financial structured products of increasing complexity: range swaps, index-amortising swaps, corridors, etc. (Kaminski, 2004). This activity, however, requires the development of specific distribution channels that offer access to institutional, retail and private clients. The driving force behind any offering of structured product is investor demand, which is itself triggered by specific market configurations and proprietary views.

The market in long-term price management for financing purposes is dominated by natural gas and crude oil. The OTC market contracts with maturities of as long as 10 years, but specific risks are attached to such transaction. Positions may have to be “rolled over” on the longest available terms. Physical considerations have to be taken into account as well. For example, the production of both Brent and WTI is expected to decline over the years, and therefore they may become less effective as representative markers; in particular, lower production rates might make price easier to manipulate (James, 2003). The Brent and Ninian fields have already been mixed, with a limited loss of quality, to form Brent Blend. However, some traders (and even Saudi Arabia) are pushing for the replacement of Brent by Forties which has a large ownership structure involving 40 companies and whose production has been rising sharply as new fields such as Scott and Nelson have been brought into the blend. In the case of WTI, there is still no real alternative crude (Pegado, 1989). Companies with very long-term derivatives indexed on WTI and Brent may have to negotiate on fallback indices, and quality differentials, or make use of early termination clauses.

2.5 The economic fundamentals of the crude oil markets

The short-term equilibrium of the oil market (production and consumption capacities are considered to be fixed) can be inferred from Figure 2.2 below.

Figure 2.2. Supply/demand picture of the oil market



Source: Kaminski, 2004

The supply curve is the histogram of total production costs for the existing oil fields and displays economic rents due to the relative ease of extraction of crude oil and the proximity to refining centers. The basic marginal cost of Middle East oil production is approximately US$2/bbl, compared to US$11/bbl in Canada and the North Sea, and US$14/bbl in Siberia (Kaminski, 2004). Neither supply nor demand are particularly responsive to changes in price in the short run. In some of its uses, such as transportation, oil still has no effective substitute. Moreover, since oil demand usually magnifies economic growth, the vertical curve on Figure 2.2 is liable to move violently to the left or to the right over the course of few months time.

In purely competitive market, when production or transportation capacities are close to saturation and demand soars, oil prices would need to reach a fairly high level before return forces became effective. At the onset, a price hike is self-realising as it triggers a cautionary demand for stocks, which in turn enhances the original imbalance. Return forces include substitution to coal or natural gas in power stations, a marginal increase in production for wells with flexibility in supply volumes or public measures for energy conservation (Hannesson, 1998). Price hikes are a strong incentive to invest in new production facilities and so cannot be sustained indefinitely. Because of the time required to put new fields on stream, they usually result in an over-capacity in E&P sector one to two years later.

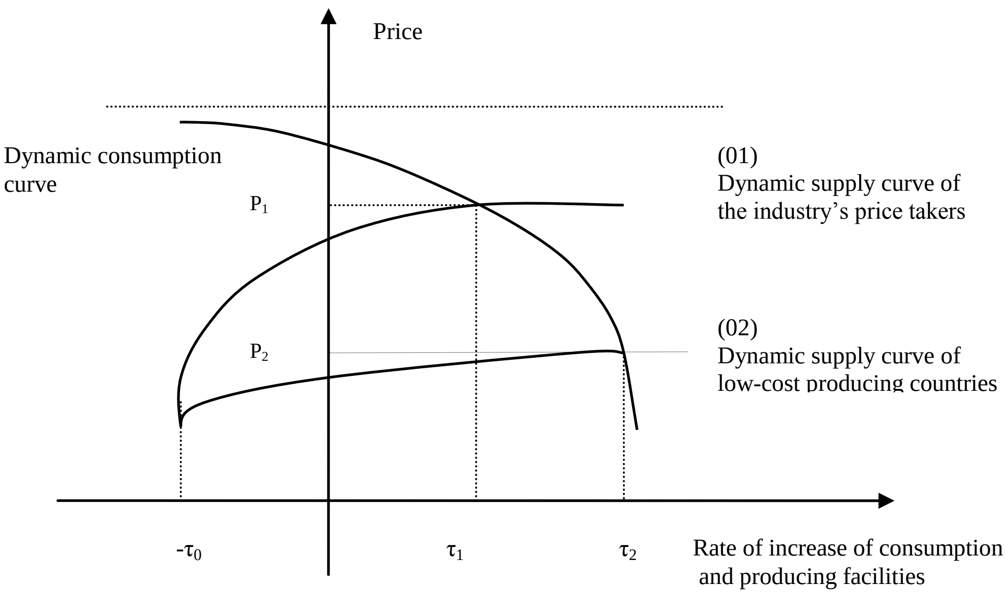
Inversely, when production exceeds consumption, stocks usually build up and the situation may degenerate into a price war if, in the absence of agreement between producing countries, any one of them tries to expand its market share at the expense of the others (Mabro, 2006). Since the oil industry is capital-intensive, if the market were completely free, reductions in output should happen only when prices fall below the operating costs of marginal units. When this level is reached, exploration programmes are scaled down, wells are ultimately shut in and the demand side benefits from substitution in favour of oil.

In a competitive market, prices should fluctuate wildly between an upper and lower zone whose limits are determined by purely economic constraints.

However, this is not quite the case. The Middle East contains two third of the world's proven reserves and it produces approximately a third of total consumption. Most importantly, production is significantly cheaper and more flexible in this region than almost anywhere else in the world. This allows the main producers (Saudi Arabia, Iran UAE, Iraq, Kuwait, etc) to operate "swing capacities" that can be closed well before prices drop below the variable costs of marginal units, and reactivated when demand suddenly peaks (Kaminski, 2004). Since such a strategy has a cost (stopping facilities when they could still be operated at a profit), there must be a collective reward for its implementation. This reward is the extra profits gained by low-cost producing countries when they maintain the oil price above "a purely competitive level" , at which level owners of the best oil fields would enjoy only small rents as compared to owners of good oil fields (Kaminski, 2004).

However, OPEC is no longer able to prop up oil prices indefinitely. Due to advances in geology and drilling techniques, the cost of finding and developing new reserves outside the Middle East has been significantly reduced over the past 20 years. As a result price takers in the industry (international oil companies and minor to medium-size producing countries) have lowered the minimum level at which it is economically sensible for them to develop new reserves. The resulting situation is summarised in Figure 2.3.

Figure 2.3 A dynamic view of the supply/demand equilibrium in OPEC and non-OPEC countries.



Source: Kaminski, 2004

The "dynamic consumption curve" relates the rate increase of worldwide consumption to the long-term oil price: it shifts to the right when economic growth increases; it is bounded upward by the price of substitutes and thus becomes flatter when alternative technologies find their way to the market. The "dynamic supply curve" (02) gives the rate of increase of oil output at a given market price if low-cost producing countries decide to satisfy consumption increments entirely on their own, without any agreement between them. The "dynamic supply curve" (01) is identical to (02), except that it assumes that new developments are carried out only by means of price takers' reserves.

This defines an economic range of prices where low-cost producing countries can attempt to stabilize the market price of oil by varying the development rate of their own reserves (Hannesson, 1998). The floor of this range would be reached only if low-cost participants were acting on a purely competitive basis; below this level, an oil shock would be inevitable. On the contrary, if they tried to impose a market price above the ceiling of the range, new developments in the oil industry would only take place in the price takers' reserves and OPEC's market share would steadily decrease. Various studies have estimated these boundaries at US$5/bbl and US$25/bbl respectively.

From an economic standpoint, there is thus an "equilibrium range" wherein political factors can durably exert their influence on oil prices. By political factors, means factors that have no immediate monetary translation, stability in the Middle East, security of supply of importing countries, pace of development of the Gulf States (Mabro, 2006). These secondary factors can themselves contribute to narrow the variation range of oil price. Before 1998, it had long been widely accepted that a "political floor" at US$15/bbl was good compromise between the oil producing countries' willingness to increase there revenues and the importing countries' reluctance to aggravate their exposure to political disruption of their source of supply.

2.6 Relationship between oil and gas prices

For many years, fuel switching between natural gas and residual fuel oil kept natural gas prices closely aligned with those for crude oil. More recently, however, the number of U.S. facilities able to switch between natural gas and residual fuel oil has declined, and over the past five years, U.S. natural gas prices have been on an upward trend with crude oil prices but with considerable independent movement (Brown, 2008).

For many years, natural gas and refined petroleum products were seen as close substitutes in U.S. industry and electric power generation. Industry and electric power generators switched back and forth between natural gas and residual fuel oil, using whichever energy source was less expensive. Consequently, U.S. natural gas price movements generally tracked those of crude oil. As shown by Yücel and Guo (*Energy Journal*, 1994), crude oil prices were shaped by world oil market conditions, and U.S. natural gas prices adjusted to oil prices. Over the past 10 years, however, the number of facilities able to switch quickly between natural gas and refined petroleum products has declined (Brown, 2008). And, although U.S. natural gas prices have taken a general upward trend with crude oil prices over the past five years, they also have shown considerable independent movement. Natural gas prices rose above what was seen as their historical relationship with crude oil prices in 2000, 2002, 2003 and late 2005. In the early 2005 and the first half of 2006, natural gas prices seemed to fall well below this historical relationship (Brown, 2008). In apparent confirmation of these observations, Bachmeir and Griffin (2006) find only a weak relationship between oil and U.S. natural gas prices. In contrast, a more recent study by Villar and Joutz (2006) finds oil and natural gas prices to be cointegrated with a trend.

In a slightly different vein, Hartley, Medlock and Rosthal (2007) find that substitution between residual fuel oil and natural gas is particularly strong in the US North American Electric Reliability Council (NERC) regions where there is sufficient fuel-switching capability.

Given the historical importance of substitution between natural gas and petroleum products, the energy industry has long time used rules of thumb to relate natural gas prices to those for crude oil. Two simple rules of thumb use constant ratios between natural gas and crude oil prices. One seems to fit historical data, and one roughly reflects the difference in energy content between the commonly sold units of oil and natural gas. A third rule tries to relate parity in pricing of natural gas and residual fuel oil at the burner tip to prices for natural gas and crude oil at major trading hubs (Brown, 2008).

One simple rule of thumb is the 10-to-1 rule under which the natural gas price is one-tenth the price of crude oil price. A price of $20 per barrel for West Texas Intermediate crude oil (WTI) would mean a natural gas price of $2 per million Btu at Henry Hub, and a $50 price would mean $5 natural gas (Brown, 2008).

Another simple rule reflects the energy content of a barrel of oil. Because a barrel of WTI contains 5.825 million Btu, some analysts have used a 6-to-1 rule, in which the price of a million Btu of natural gas ought to be roughly one-sixth the crude oil price. Under this rule of thumb, a WTI price of $20 per barrel would mean a natural gas price of $3.33 per million Btu at Henry Hub, and $50 oil would mean $8.33 natural gas (Brown, 2008).

A few analysts have interpreted the apparent transition from the 10-to-1 rule to the 6-to-1 rule as indicative of improving market conditions for natural gas. In fact, the apparent transition in pricing may reflect a more complex relationship between natural gas and oil prices. Burner-tip parity is a more complex rule that takes in account competition between petroleum products and natural gas occurs where they are used—at the burner tip. Barron and Brown (1986) provide guidance for operationalizing burner-tip parity rules. For competition with residual fuel oil, the burner-tip parity rule takes into account the energy content of a barrel of residual fuel oil, the long-run relationship between prices for residual fuel oil and West Texas Intermediate crude oil (WTI), and the higher costs of transporting natural gas from Henry Hub to market (Brown, 2008).

A barrel of residual fuel oil has an energy content of 6.287 million Btu, and historically residual fuel oil is priced at 85 percent of WTI, which suggests a price of $0.1511 x P_{WTI}$ for a million Btu of residual fuel oil. Barron and Brown report natural gas transportation differentials in a range of $0.10-1.10 per million Btu from the wellhead to power plants and industrial users, but our examination of recent residual fuel oil prices and the Henry Hub price of natural gas prices shows an average transportation differential of about $0.5 (Brown, 2008). Combining these elements, we obtain a pricing rule of thumb based on burner-tip parity as follows:

$$P_{HH,t} = -.5 + .1511 \times P_{WTI,t}$$

(1)

where P_{HH} is the Henry Hub price of natural gas in dollars per million Btu and P_{WTI} is the price of West Texas Intermediate crude oil (WTI) in dollars per barrel. With this relationship, a $50 per barrel price for WTI would mean a natural gas price of $7.06 per million Btu at Henry Hub. For these prices, a 150 percent increase in the oil price would mean a 180 percent increase in the natural gas price (Brown, 2008).

3 Models of the oil market

3.1 The relevance of exhaustibility

There is a finite amount of oil available on earth; how important is this scarcity in explaining the recent history of the market?

A good exhaustible if greater consumption today implies less consumption tomorrow. The consequences of this intertemporal link were first studied formally by Hotelling (1931). Considering a competitive economy with perfect foresight and perfect capital markets, he showed that, in equilibrium, the difference between the price of an exhaustible good and its marginal cost of extraction is strictly positive and rises at the rate of interest. Even under perfect competition the price of an exhaustible resource would be different from its marginal cost of production (Crémer, 1996).

Thus, even an exhaustible good that is costless to extract would command a positive price, which is the reward to the resource owners for having held to their stocks up to the present date. This difference between price and marginal cost is known as the "scarcity rent". The sum of the marginal cost of production and the scarcity rent is known as the "user cost" (Crémer, 1996).

Oil price increases have been attributed to scarcity and to monopoly depending on the analyst's point of view. OPEC used exhaustibility as justification for the first price increase in 1973, in order to mollify the outcries against the resulting huge shift in the worldwide distribution of income. The Shah of Iran proclaimed oil too precious a resource to burn, and other OPEC spokesmen wished the world would thank them for reminding it of the rapid rate of depletion in petroleum reserves (Ortiz, 1982).

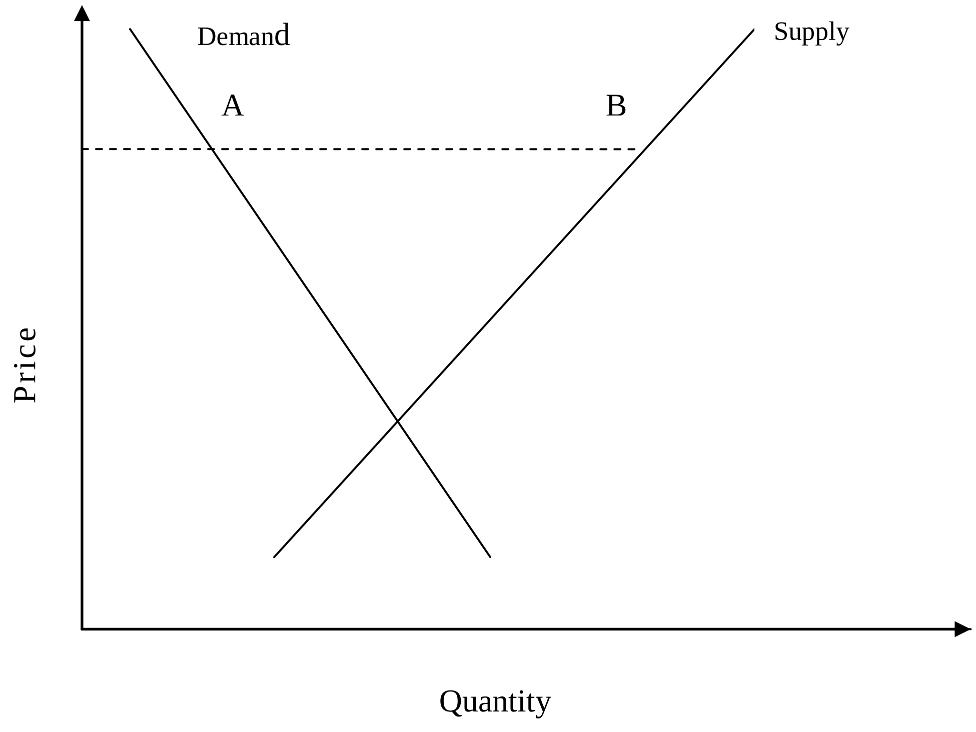
3.2 Models of monopoly behavior

It is convenient to distinguish two basic variants of monopoly behavior: cartel and dominant firm theories. The cartel version is by far the most widely used to describe OPEC but, as it became increasingly clear, interactions within OPEC did not correspond to the classic cartel theory, the dominant firm version recently gained in acceptance (Crémer, 1996).

3.2.1 The cartel model: theory

Cartels are groups of producers who cooperate to reduce the quantity supplied of a commodity and thereby raise the price. As a consequence, price exceeds marginal cost, cartel members are kept to the left of their competitive supply curves and have incentives to increase sales through price discount. The cartel's task to absorb the excess supply at the high price (AB in Figure 3.1**)**

Figure 3.1 Cartel model



Source: Crémer, 1996

Pindyck (1978) contrasts a model in which OPEC behaves as a monopoly to one in which it behaves competitively. Pindyck modifies the standard monopoly model to take account of the slow rate at which consumers adjust to a rapid increase in price. For example, in the long run, consumers may buy smaller cars and put more insulation in their homes, allowing them to reduce their demand for oil; in the short run, they are not able to make such adjustments (that is, long-run demand elasticities are greater than short-run elasticities) (Carlton, 2006). In Pindyck's monopoly model, OPEC's profit-maximizing strategy was to charge a high price initially (taking advantage of the slow rate of adjustment of net demand to higher prices), then to lower price through the 1970s, and then to raise it as the oil reserves were depleted (Carlton, 2006).

Pindyck finds that to be successful a cartel must:

- Determine a price and a production level for the group as whole. If the cartel does not include all the suppliers, this determination requires some calculation of the “residual demand” left after subtracting from the market demand the supply of the producers that are not part of the cartel, the so-called “competitive fringe” (Crémer, 1996).
- Allocate output between members. If OPEC were run as a unified profit maximizing entity, it would produce mainly from the lower cost reserves in Saudi Arabia and Kuwait and some form of redistribution of the profits to the other members would be necessary. In turn, those who would produce later would promise to pay part of their future profits to the early producers. Because such transfers are difficult to enforce, in any period all countries must generate their share of profits from the sales of their own products (Crémer, 1996).
- Detect and punish cheaters.

Description of OPEC as a cartel came naturally to mind in 1973, when it decided to set price of oil unilaterally without negotiation with the international oil companies.

3.2.2 Dominant firm: theory

In this family of models, all firms except one, the dominant firm, behave competitively. This firm computes its own demand curve, DDF, by subtracting the supply of the competitive fringe, SCF, from the market demand, DF, and then finds the maximum profit point, P1, on this derived demand curve (Figure 3.2).

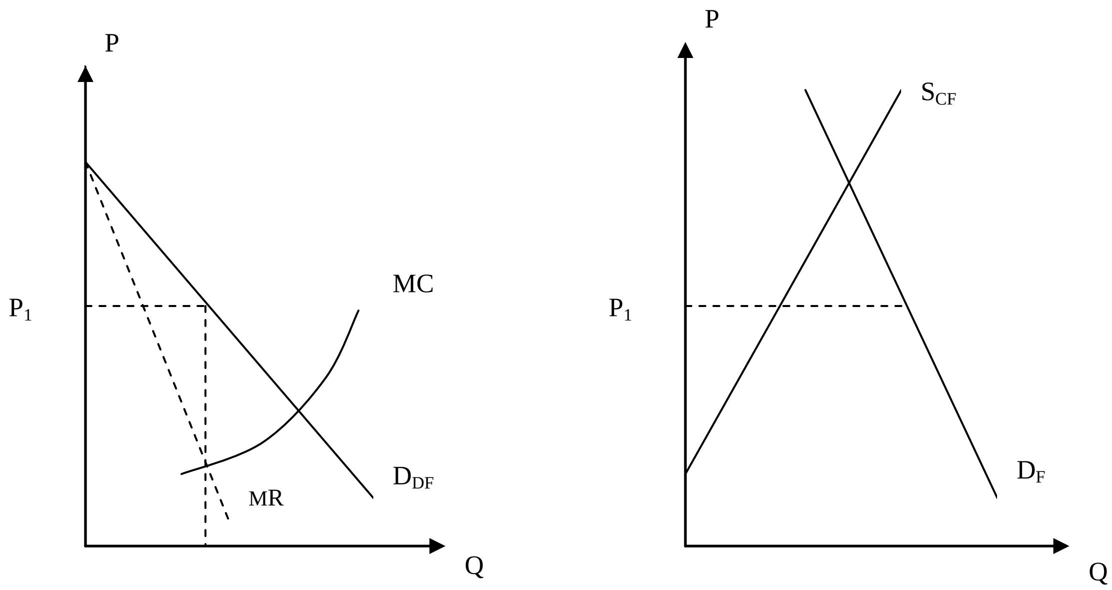


Figure 3.2 Dominant firm model. Source: Crémer, 1996

This is the Stackelberg equilibrium. In contrast to the cartel theory, in this version of monopolistic behavior all complications related to cooperative behavior are bypassed. The dominant firm faces a more elastic demand curve than a cartel that would include it, and would therefore choose a lower price. If its market share is very small, will be reversion to the competitive solution.

Many people argue that Saudi Arabia acts as a dominant firm while many other OPEC countries are price takers. One problem with claiming that Saudi Arabia is a dominant firm is that its share of OPEC production rose from 23.98 percent in 1973 to 36.8 percent in 1980. Some of the increase in Saudi Arabia's share, however, may have been due to reduced output by warring OPEC nations (Carlton, 2006).

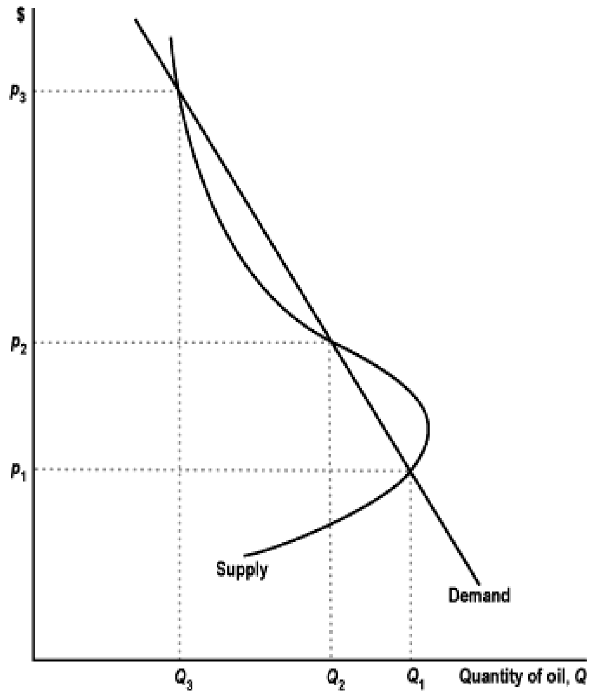
A more sophisticated model holds that Saudi Arabia and a few other OPEC nations collectively act like a dominant firm and restrict output. While several OPEC countries have had substantial excess capacity in various years, it is generally believed that non-OPEC producers have had little excess capacity since 1973 (Griffin and Teece 1982, 29). For example, Adelman (1982) contends that a cartel core within OPEC (Saudi Arabia, the United Arab Emirates [UAE], Kuwait, Qatar, and Libya) has acted as a profit-maximizing dominant firm, facing a competitive fringe composed of non-OPEC producers (Carlton, 2006). Saudi Arabia has not reduced its output to the short-run profit-maximizing level because it fears that high prices speed the development of viable oil substitutes or induce consumers to make investments that allow them to purchase less oil, increasing the elasticity of demand for OPEC oil in the future. Adelman argues that when oil prices are high, the cartel partially breaks down: Countries start to produce more and undersell each other (Carlton, 2006). The resulting fall in the price of oil induces Saudi Arabia (and, in some cases, other countries) to cut back production.

3.3 Models of competitive behavior

In the early 1980s several papers appeared arguing that OPEC was not a cartel because its members had no incentive to increase production at the high price. Benard (1980), Cremer and Salehi-Isfahani (1980), Scott (1981), and Teece (1982) all used the idea of absorptive capacity and imperfect capital markets to note that oil exporting countries had more revenues than they could spend (Crémer, 1996).
The first serious statement of this theory by economists was by Crémer and Salehi-Isfahani (1989). MacAvoy (1982) also argues that the long-run trend in oil prices can be explained by a competitive model. Using a target-revenue model, Crémer and Salehi-Isfahani contend that the supply curve for oil is backward bending.

Exporting countries try to achieve target revenue for internal investment purposes. Target revenue is set because the countries have limited capacity to absorb investment. For given oil price, fixing revenues determines output: there is no incentive to produce more oil (Carlton, 2006).

Figure 3.3 Competitive Theory About OPEC



Source: Crémer, 1996

Figure 3.3, which is based on Crémer and Salehi-Isfahani's diagram, shows a backward-bending supply curve with a demand curve that intersects it three times. In their explanation, the oil industry in early 1973 was at the low-price, competitive equilibrium (*p*1, *Q*1). In two steps (October 1973 and January 1974), the six Persian Gulf OPEC members agreed to raise prices, which caused a shift to the high-price equilibrium (*p*3, *Q*3) (Carlton, 2006). The equilibrium at (*p*2, *Q*2) is unstable. Were the quantity to fall slightly below *Q*2, the price would be above *p*2, but demand would be greater than supply. As a result, there would be upward pressure on the price, driving it towards *p*3. A similar argument holds that if the price fell below *p*2, it would continue to fall to *p*1. In contrast, the (*p*1, *Q*1) and (*p*3, *Q*3) equilibria are stable (Carlton, 2006).

3.4 Modeling production. Hotelling's model

In this section I will present the basic models of competition, monopoly and oligopoly that we can find in the literature. The theory for this chapter is taken from the lecture notes to Bjerkholt (2008) used in course ECON 4925.

A general result in Hotelling's study (Hotelling 1931) is that along the optimal path the marginal net price, which is identical to the resource rent, should increase at the rate of discount.

I will start with a simple model for free competition. Let S_0 denote the total resource stock in the economy and R_t the total extraction at time t. Let's assume that unit costs are constant and equal to $\bar{b}$ and that the market price, taken as given by each producer, is p_t . $U(R_t)$ is utility of the consumption of the resource at time t (in money terms).

The optimal extraction path for the society as a whole is found by maximizing

(3.4.1) $$\int_0^T [U(R_t) - \bar{b}R_t]e^{-rt}dt, \quad R_t \geq 0$$

with respect to *Rt*, over a possibly infinite time horizon *[0,T]* . Again, the maximization is constrained by the condition

(3.4.2) $$\int_0^T R_t dt = S_0$$

The Hamiltonian is

(3.4.3) $$H(t, S_t, R_t, \lambda_t) = [U(R_t) - \bar{b}R_t]e^{-rt} - \lambda_t R_t$$

The optimal extraction path must fulfill the following relation:

(3.4.4) $$[U'(R_t) - \bar{b}]e^{-rt} \leq \lambda_t \quad (= \lambda_t \text{ for } R_t > 0)$$

(3.4.5) $$\dot{\lambda} = -\frac{\partial H}{\partial S} = 0 \Rightarrow \lambda_t = \lambda\left(\text{constant}\right)$$

Using that in a market economy with free competition, $U'(R_t) = p_t$. The shadow price of the resource stock at time *t*, λ_t, is in the present case, with extraction costs not depending on the accumulated production, constant. We have $\partial H / \partial S = 0$.

(3.4.6) $$U'(R_t) - \bar{b} = \lambda e^{rt}$$

The Hotelling rule for prices of exhaustible resources $p = \bar{b} + \lambda e^{rt}$.

Thus, a main conclusion in Hotelling's study was that in equilibrium the resource rent (the net price), defined as the difference between the market price of the resource and marginal extraction costs, must increase at a rate equal to the rate of interest.

I will solve now social planning problem for the optimal depletion profile for *n* identical natural resource firms. Let’s assume that there are *n* identical natural resource firms. The socially optimal rate of depletion is conceived as the rate that maximizes the gross surplus (consumers’ surplus plus producers’ surplus) derived from the demand function given as *p(.)*. The amount depleted (per unit of time) from each firm at time *t* is R_t while the amount of unextracted resource in each firm at time *t* is S_t. The cost of extraction is given for each firm by the function *b(Rt, St)* with *bR’ > 0, bR’’ > 0* and *bS’ < 0*. The rate of discount is, *r*, the same for the social planning problem and in the competitive solution.

(3.4.7) $$\max_{R_t} \int_0^T [\int_0^{nR_t} p(x)dx - nb(R_t, S_t)] e^{-rt} dt$$

$$n\dot{S}_t = -nR_t,\ S_0 = \bar{S},\ S_T = \underline{S},\ R_t \geq 0$$

The state variable in this problem is the amount of remaining resource nS_t, while the control variable is the rate of depletion nR_t. The current value Hamiltonian of this problem is – with shadow price μ_t - as follows:

(3.4.8) $$H^C(t, nS_t, nR_{t,}\mu_t) = \int_0^{nR_t} p(x)dx - nb(R_t, S_t) - \mu_t nR_t$$

Assume that S_t* and R_t* solves the problem. Then it follows from the maximum principle that R_t* maximizes the Hamiltonian, which implies that when continuity, differentiability and concavity of the Hamiltonian hold, we have

(3.4.9) $$\frac{\partial H^C}{\partial (nR_t)} = p(nR_t) - b'(R_t, S_t) - \mu_t = 0$$

The rate of change of the shadow price in current values is given by

(3.4.10) $$\dot{\mu}_t - r\mu_t = -\frac{\partial H_C}{\partial (nS_t)} = b'_S(R_t, S_t)$$

Now consider the profit maximizing problem of one of the *n* firms facing a given price path (in fact the price path resulting from the given demand curve and the depletion of the *n* firms). We thus have the problem:

$$(3.4.11) \qquad \max_{R_t} \int_0^T [p_t R_t - b(R_t, S_t)] e^{-rt} dt$$

$$\dot{S}_t = -R_t,\ S_0 = \bar{S},\ S_T = \underline{S},\ R_t \geq 0$$

The current value Hamiltonian of this problem is

$$(3.4.12) \qquad H^C(t, S_t, R_t, \kappa_t) = p_t R_t - b(R_t, S_t) - \kappa_t R_t$$

Assume that S_t* and R_t* solves the problem. Then it follows from the maximum principle that R_t* maximizes the Hamiltonian, i.e.

$$(3.4.13) \qquad \frac{\partial H^C}{\partial R_t} = p_t - b_R'(R_t, S_t) - \kappa_t = 0$$

Furthermore, the rate of change of the shadow price in current values is given by

$$(3.4.14) \qquad \dot{\kappa}_t - r\kappa_t = -\frac{\partial H^C}{\partial S_t} = b_S'(R_t, S_t)$$

As the price *pt* is assumed to be *p(nR_t*), i.e. n* identical firms producing the same amount, these conditions are exactly the same as in the social planning problem and in equilibrium κ_t is equal to μ_t.

Hotelling thus derived conditions for the existence of equilibrium in markets for depletable resources. Theory does not tell how equilibrium is brought about. Neither does the theory give guidelines for the market development in cases where prices and quantities for some reason have reached values outside the equilibrium path. Strictly, market equilibrium in the Hotelling model requires the existence of future markets. Individual resource owners must have perfect foresight as to the evolution of net price of the resource, $(p_t - \bar{b})$. Total extraction must also satisfy the end point conditions.

$$(3.4.15) \qquad \int_0^T R_t dt = S_0 \quad \text{and} \quad \left[p_0 - \bar{b}\right] e^{rT} = \left[p^{\max} - \bar{b}\right],$$

Where $p^{\max}$ is choke price, price when demand is equal zero.

Hotelling's model shows the extraction path. If the initial price is too high, there is too much conservation in early years and a part of the resource stock will be left in the ground at the time when the demand schedule reaches the choke price, $p_{\max}$. If, on the other hand, p_0 is too low, there is over-exploitation initially, and the resource stock will be depleted too early. There is also the possibility that in the latter case, the pressure against the resource stock, at a higher level of demand than along the optimal path, will induce the price of the resource to increase at a rate higher than what follows from the Hotelling's rule.

I am going to find how the resource market with one monopolist affects the optimal extraction how the Hotelling's rule will be derived.

Let's assume there is no extraction cost. Monopolist is assumed to be faced by a downward sloping demand function, $p = p(y)$. From this demand schedule the marginal revenue is derived as

(3.4.16) $$m = \frac{d\left[p(y)y\right]}{dy} = \gamma p \text{, where } \gamma = 1-(1/\varepsilon),$$

ε the elasticity of demand (in positive value).

The objective for the monopolist is the same as for the competitive firms, i.e. maximizing discounted profits over a horizon that is also to be determined. By using the same kind of argument as in the Hotelling Rule we derive easily guess intuitively that optimal extraction, requires that marginal revenue increases at a rate equal to r when the production is non-zero. Formally, the equilibrium condition for the simple monopolist case is

(3.4.17) $$\frac{\dot{m}_t}{m_t} = r$$

The equilibrium solution for a resource monopoly can be further illuminated by expressing (3.4.17) in the following way, still assuming zero unit cost:

(3.4.18) $$m(R) = p(R)\cdot\gamma \;\Rightarrow\; \frac{\dot{m}}{m} = \frac{\dot{p}}{p} + \frac{\dot{\gamma}}{\gamma} = r$$

Relation (3.4.18) expresses the crucial role of the elasticity of demand when discussing monopoly equilibrium. If ε is constant the monopoly case and competitive equilibrium case are identical, due to the dynamic nature of equilibrium concepts in the theory of exhaustible resources. Suppose the demand elasticity (in absolute value) increases as demand increases towards "saturation". Then optimal path will be

$$\frac{\dot{p}}{p} \prec r \tag{3.4.19}$$

This is because p increases along the optimal path, this implies that $\dot{\gamma} \succ 0$. The implication of monopoly behaviour is a higher price initially, and smaller production in an early part of the extraction period compared to a perfectly functioning competitive market. The fact that current extraction is restricted, forms the background for the statement that “the monopolist is the conservationist's best friend”.

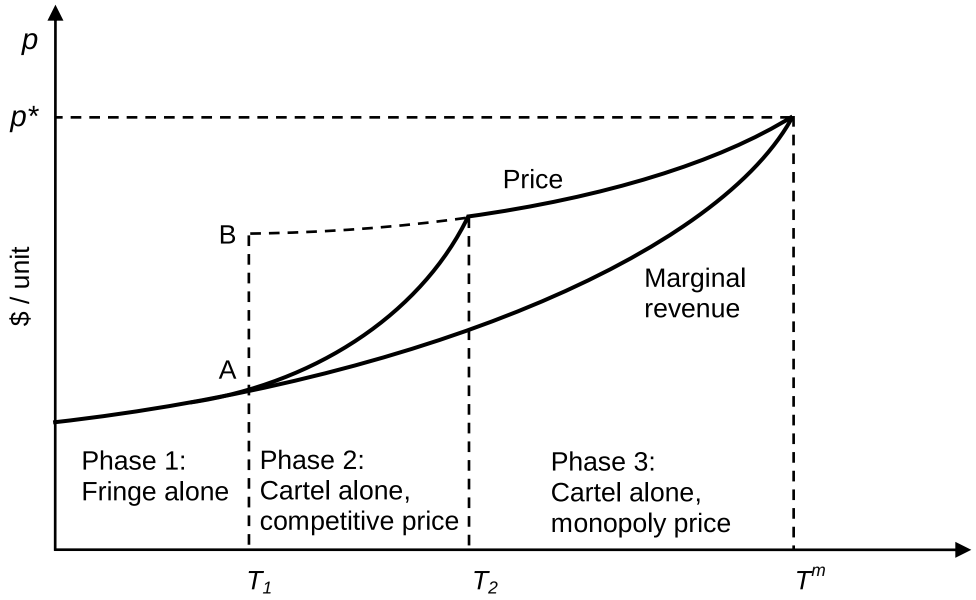
Now I will look at oligopolistic market with help of Hotelling’s theory. There are two groups of suppliers: a cartelized group and a competitive fringe. The latter consists of a number of identical producers. Each producer chooses quantity of output, taking market price as given. Market price is set up by dominant firm, who chooses the price to maximize own profit. The cartel's decisions, on the other hand, take into account both the demand reactions of the consumers and the behaviour of the competitive fringe. The cartel is assumed to behave strategically. In its price setting, it recognizes that the fringe reacts to the prices. Assuming perfect information, the cartel is accordingly able to calculate in detail how the fringe responds to any price profile that is announced.
Here are characteristics of the equilibrium solution.

The cartel adjusts its extraction so that its marginal revenue increases at the rate of discount. Suppose ε increases with p, this implies that the resource price increases at a rate less than r. On the other hand, fringe production requires equality between the rate of increase in the resource rent and the interest rate.

Only if unit costs of the fringe are significantly higher than the extraction costs of the cartel (sufficiently high to induce the cartel price path being steeper than the competitive price path) will the succession of production be turned around: the cartel takes control and supplies the market initially, while fringe production is held back for some time. While extracting, the marginal revenue of the cartel increases at the rate of interest.

It is shown in Ulph (1982) that the equilibrium solution involves three phases, see Figure 3.4. In the first period ($[0, T_1]$) the fringe supplies the market. At T_1 the resource stock of the fringe is emptied and the cartel takes over the market. For some time ($[T_1, T_2]$), however, the cartel follows a price and extraction policy that is a continuation of the competitive price path. Then, at time T_2 the cartel adopts the price behaviour that corresponds to its de facto monopoly situation in the market, with marginal revenue increasing at rate equal to r.

Figure 3.4 Extraction path for cartel-fringe solution



Source: Bjerkholt, 2008

4 Norway on the oil market

4.1 Market overview

Norway is currently the world’s third largest exporter of crude oil and the eighth largest oil producer. Norway is also the third largest exporter of natural gas, with significant long-term supply contracts to the European continent. The petroleum sector is Norway's single largest industry. In 2005, the petroleum sector accounted for 22.5% of Norway's GDP (annual GDP about USD 280 billion). Total investments in the Norwegian oil and gas industry in 2006 are projected at about USD 15.5 billion. The oil and gas industry in Norway is only offshore. There is no onshore production. The number of sub-sea, zero-surface projects is growing. Despite a large number of equipment suppliers in a very selective market, Norway continuously seeks new and proven technology for exploration and field developments in deep and remote northern waters.

Norway is the world’s third largest exporter of crude oil behind Saudi Arabia and Russia, but ahead of Iran. Production of crude oil currently averages about 3 million barrels per day. Norway exports 90% of its oil production, accounting for nearly 50% of overall Norwegian exports. Norway is also the third largest exporter of natural gas behind Russia and Canada, but ahead of Algeria. Norway is ranked as the world’s seventh largest gas producer. Norway has significant long-term supply contracts by pipelines to the European continent.

The petroleum sector has for the last three decades been a key driver for the Norwegian economy. It is the country’s single largest industry. It accounts for nearly three times the value generation of all other Norwegian industries.

First exploration well on the Norwegian continental shelf was drilled by Ocean Traveler for 40 years ago. Very few envisaged in 1966 that this was the start of Norwegian oil and gas fairytale. There are 65 fields which have been put into production, and 13 of these are now closed down. Seven onshore facilities have been built. New technology has been developed and adopted in order to satisfy increasingly stringent demands on environmentally sound and safe activities, and to meet the challenges that have arisen as the most easily accessible resources have been produced.

The trend has gone from building large steel and concrete platforms with processing plants, a permanent crew and many support functions, to developments based on sea-bed installations where the processing and control functions take place entirely from existing installations or on land. This has also brought enhanced safety for the personnel and the environment (NPD, The Resource Report 2007).

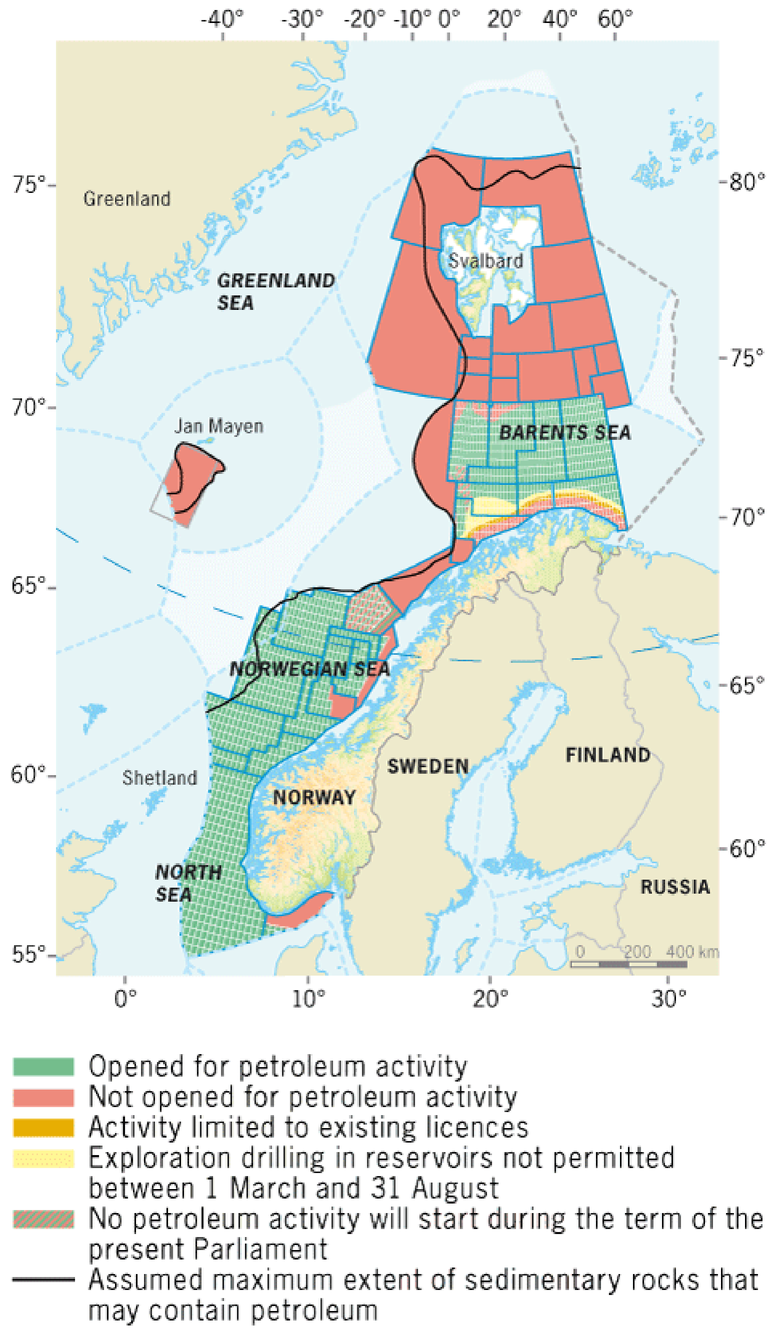
After 40 good and exciting years, it is the time to think about what the future may bring. Recent situation on the oil market can be characterized by high prices for oil and gas, a growing demand for Norwegian gas, increasing interest for exploration in the Barents Sea, record large response regarding allocations and many new companies wanting to get a foothold on the Norwegian continental shelf. At the same time, challenges, which face Norwegian oil industry, are declining oil production, rising costs, fewer and smaller discoveries.

4.2 Facts about production. Produced volumes

Significant volumes remain to be produced and found on the Norwegian continental shelf. Only a third of the total resources have so far been produced, and a quarter of them have still not been discovered. Oil and gas prices are high at the moment, giving the industry and society in general good incentives to produce at a maximum rate. Oil production reached its peak a couple of years ago, but gas production is still increasing (NPD, The Resource Report 2007). Large volumes of oil and gas also remain in fields that are in production. Based on current plans, the average recovery factor for oil is expected to be 46 per cent. Continuous research and development of technology are required to raise this further. The authorities expect the companies on the Norwegian continental shelf to make a determined effort to ensure the highest possible recovery (NPD, The Resource Report 2007).

The volume of the resources on the Norwegian continental shelf is uncertain. The Norwegian Petroleum Directorate (NPD) estimates that between 1.6 and 5.8 billion Sm3 o.e. of oil, gas, condensate and NGL remain to be found. Their mean value is 3.4 billion Sm3 o.e. It is also uncertain how much of these resources the industry will gain access to (NPD, The Resource Report 2007). The areas that are now open for exploration are shown in Figure 4.1. Large areas have still not been opened; these are shown in red.

Figure 4.1 Status of petroleum activity on the Norwegian continental shelf



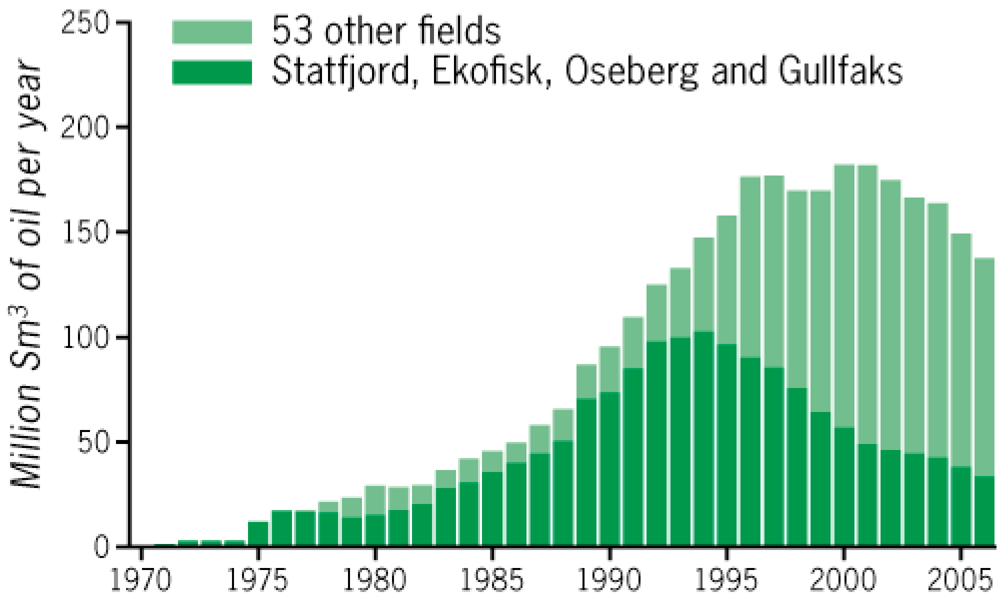
Source: Norwegian Petroleum Directorate

The largest areas that are still not opened are in the North. The development here will be important for how much acreage will be available for exploration. In addition to concern for the environment and the fisheries, the relationship with Russia will be crucial.

The total recoverable resources are calculated to be between 10.6 and 16.9 billion standard cubic metre oil equivalents (Sm3 o.e.), with a mean value (base estimate) of 13.1 billion Sm3 o.e. About a third (4.6 billion Sm3 o.e.) of the expected, recoverable petroleum resources have already been produced. More than three-quarters of the total production since the start in 1971 have been oil, condensate or NGL (Natural Gas Liquids). The sale of gas, which began in 1977, is steadily increasing and in 2006 it accounted for 35 per cent of the total production (NPD, The Resource Report 2007).

3.2 million Sm3 of oil have been produced from 57 fields. Production from nine of these fields has now ceased. The four large fields, Statfjord, Ekofisk, Oseberg and Gullfaks in the North Sea, account for half of the oil that is produced (NPD, The Resource Report 2007). Since 1994, these fields have stood for an increasingly smaller percentage of the total oil production (Figure 4.2).

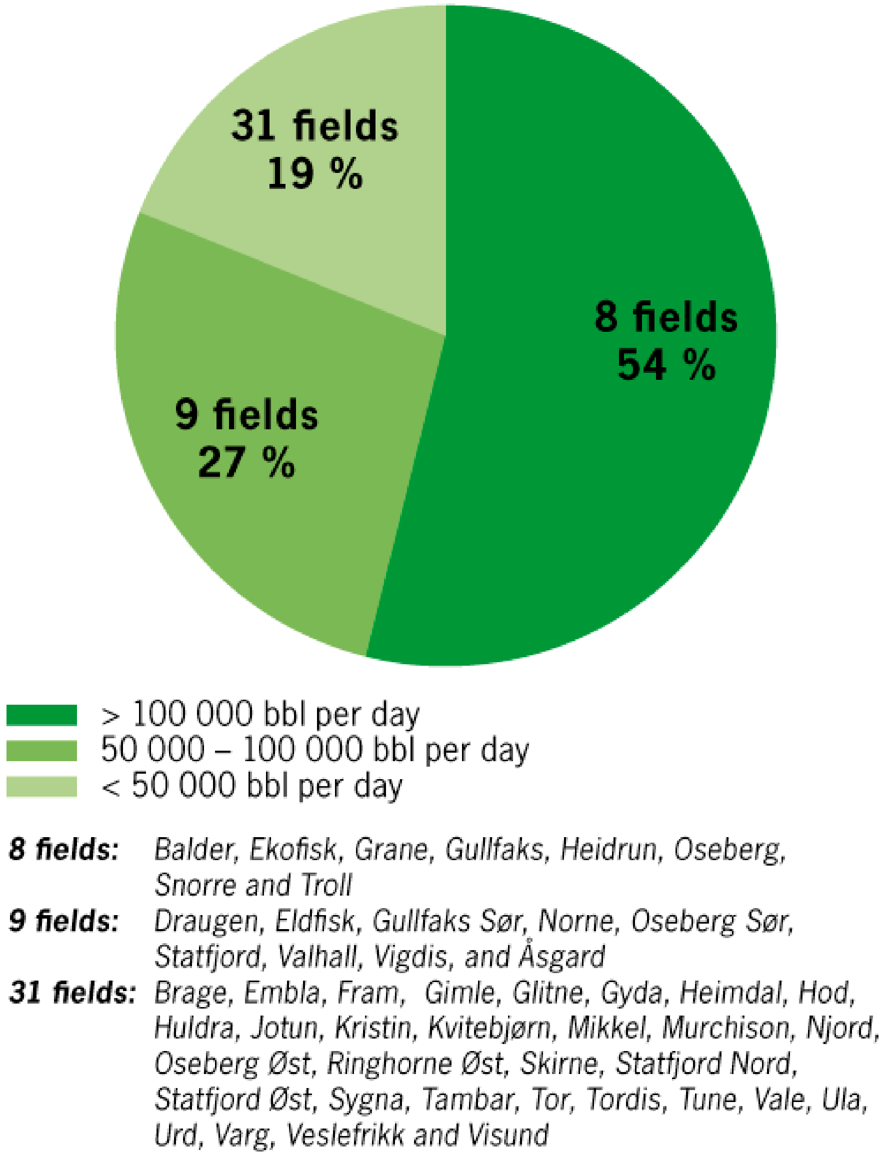
Figure 4.2. Oil production on various fields



Source: Norwegian Petroleum Directorate

Nine oil fields have begun production in the last five years. As of 31 December 2006, 48 fields were producing oil on the continental shelf. Eight of these produce more than 100 000 barrels per day and account for more than half of the oil production (Figure 4.3).

Figure 4.3 Oil fields arranged according to the oil production rate in 2006



Source: Norwegian Petroleum Directorate (NPD)

Norway exports 2542000 bbl/day.[4]

[4] Oljemarkedet og Norge – www.regjeringen.no

4.3 Prices of crude oil. Changes in prices

Petroleum activities started in Norway for 40 years ago and the price of oil has varied in this period from less than 3 dollars a barrel to the level of 145 dollars a barrel. Norwegian continental shelf has significantly higher cost than corresponding ones in other oil-producing countries like Saudi Arabia and Iran. In order exploration and recovery of oil and gas on the Norwegian continental shelf to be of interest, the prices have to be sufficiently higher than cover the costs.

The present price of oil is at a historically high level (Figure 4.4). The companies have adjusted their price expectations upwards accordingly. According to the Cambridge Energy Research Association (CERA), the companies now use 40 dollars a barrel as the lower limit to test the robustness of the projects, whereas they recently applied 20 dollars (NPD, The Resource Report 2007).

Figure 4.4 Trend in the nominal price of Brent Blend oil

Source: BP Statistical Review of World Energy 2006

IEA presented reference scenario in World Energy Outlook 2006, it was based on a slightly rising oil price from 2012. An expected increase in the market share for a few oil-producing countries and rising production costs outside the OPEC nations are reflected in this price trend. It assumed by IEA that in general the gas price will follow the trend in the price of oil since natural gas largely follows the oil price due to the oil-price index in sales contracts and because of considerable competition between different sources of energy in the end-user markets for natural gas (NPD, The Resource Report 2007). When the price of oil rises, exploration activity usually increases. A high oil price also leads to more developments and the implementation of more measures for improved recovery. At the same time, high prices stimulate more technological development. On the other hand, lower prices will give a reduction in exploration, fewer developments and less effort put into improved recovery and development of technology. (NPD, The Resource Report 2007).

5 Analysis of the data from Norwegian oil market

To analyze how oil production related to oil prices I will compare first production volumes from years 1988 to 2008 and prices on Brend Blend for the same years. Data is taken from Statistics Norway and is represented in Table 5.1.

Table 5.1 Production volumes and prices on Brent Blend

Year	Oil production, 1000 Sm3	Yearly average Brent Blend price, USD/barrel
1988	64723	14,91
1989	85983	18,02
1990	94542	23,61
1991	108510	20,19
1992	123999	19,31
1993	131843	17,08
1994	146281	15,76
1995	156776	16,98
1996	175422	20,6
1997	175915	19,13
1998	168746	12,7
1999	168690	17,9
2000	181181	28,4
2001	180884	24,4
2002	173649	25,1
2003	165475	28,7
2004	162777	38,1
2005	148137	53,5
2006	136577	64,5
2007	128277	72,2
2008	122673	98,4

Figure 5.1 represents total production of oil for years 1988-2008 and Figure 5.2 represents Brent Blend spot price.

Figure 5.1 Total oil production for years 1988-2008,

1000 Sm3

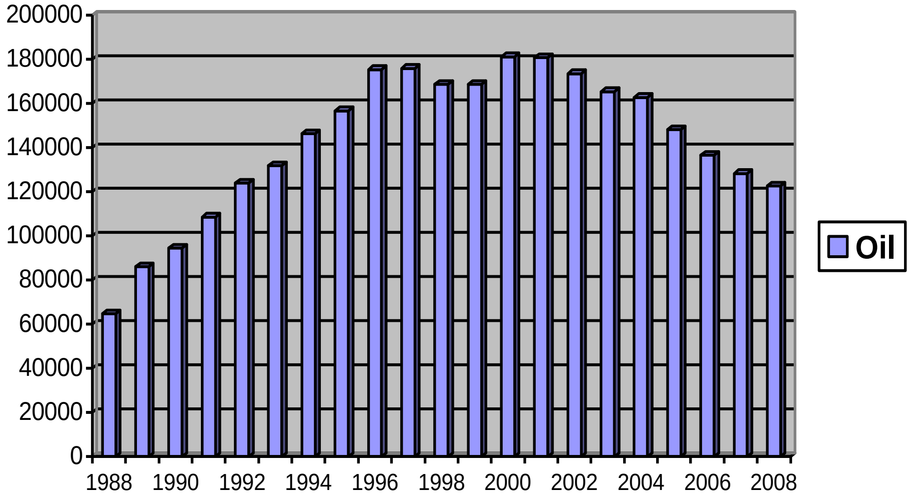


Figure 5.2 Brent Blend spot price

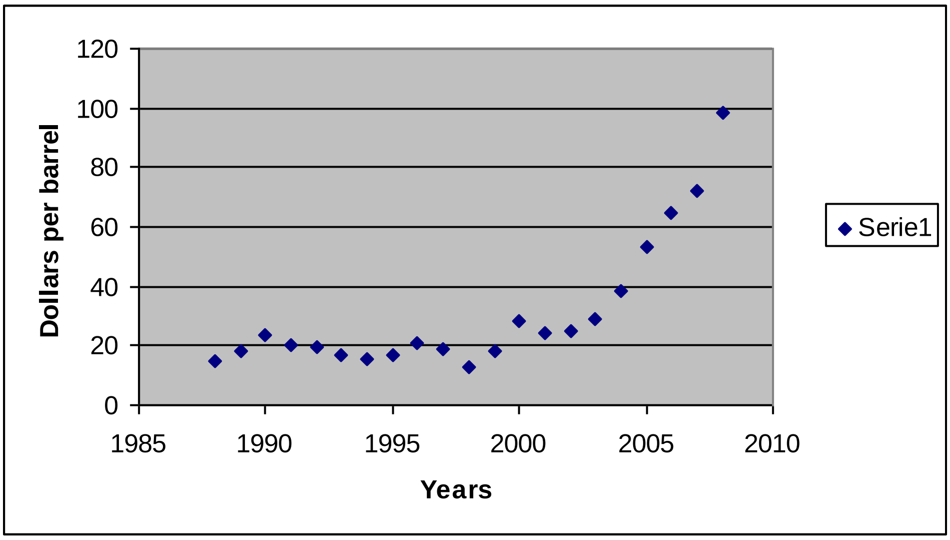
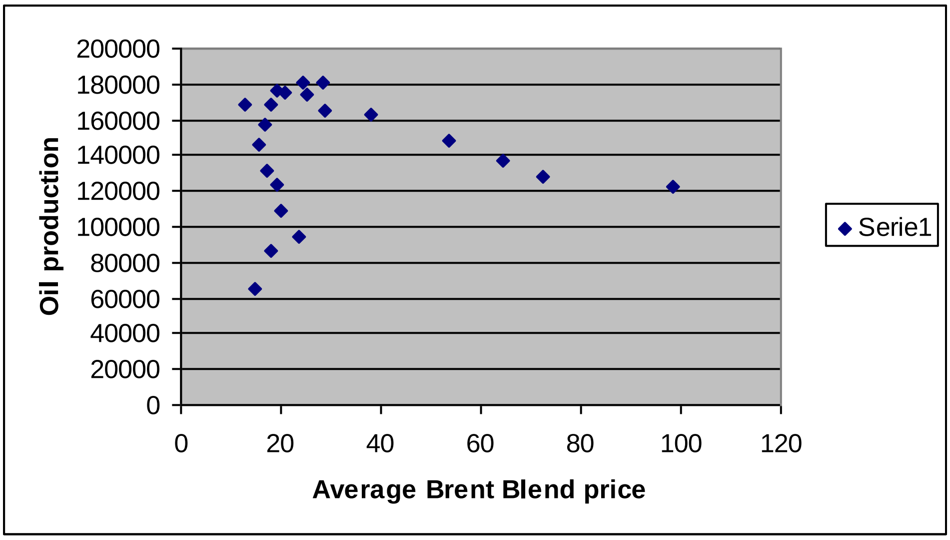


Figure 5.3 Oil production and average Brent Blend price



According to the figure 5.3 there is no strong connection between oil production and yearly average Brent Blend price, but for the last 6 years oil production and average Brent Blend price tend to move in opposite directions. It is confirmed by correlation coefficient which is equal to -0,07877979 in this case.

As we can see from Figure 5.1 peak of production falls on years 1996-2002. Highest production volume 181181000 Sm3 is extracted in 2000. The yearly average price for this year on Brent Blend was 28,4USD/barrel what is 62,3% higher than in 1999. Theory suggests that when the price of oil rises, exploration activity increases. But on the Figure 5.1 we can observe slightly decline in production despite increasing prices. The reaction on this increase is saying about difficulties to adjust production to oil prices. It would be reasonable to expect highest production at 4 last years, when the price of Brent Blend was climbing to 145USD/barrel in 2008. But for 2008 the volume of oil production amounts only 122673000 Sm^3 almost the same as in 1992 when the yearly average price on Brent Blend was 19,31USD/barrel. This shows how “unsuccessful” Norway has been in relation to the price development. High cost of building platforms is a characteristic of Norwegian continental shelf. Because of that it is little flexible to adjust production to oil prices.

There are different extraction costs, and for the case of pure competitive market it means that the oil reserves with the lowest extraction cost will be extracted first. In this case, according to the Hotelling’s theory, it will lower the initial gross price in the beginning of extraction, increase the rate at which the gross price increases (even though the net price increases at the same rate as before according to the Hotelling's rule), and shorten the time to complete exhaustion of the oil reserve. Norwegian oil production is characterized by high extraction cost so in the case of pure competitive market Norwegian reserves would be explored at last.

What was the price expectation on Norwegian oil market when the exploration just started? When the oil exploration in Norway started, in an article in the periodical Norges Industri in 1976, Kjell Stahl Johannesen, an oil expert, examined six cases. While this study is now out of date, it illustrates some of possible outcomes, using a variety of assumptions. Stahl Johannesen's most optimistic price estimate (from a Norwegian point of view) called for a 10 percent increase in oil prices every other year. The most pessimistic provided for a 10 percent increase in 1977 and no increases thereafter. Since the greatest unknown on the cost side is the cost of the development of Statfjord, Stahl Johannesen assumed in some models that it could cost 35 billion crowns (about $7 billion) and in others 50 billion (about $10 billion). He used government production estimates. With these variables, he concluded that the state's income between 1976 and 1985 could vary from about 117 billion to about 193 billion crowns (about $23,4 to $38,6 billion).

Let's now analyze how the oil price has behaved since year 1988. The Hotelling rule suggests that the resource rent (difference between market oil price and marginal extraction cost) increases by the rate of interest (discount rate). But the price development on Figure 5.2 points on deviation from the theoretical price. Thus the yearly average price on Brent Blend in 1998 is 12,7 USD/barrel lower than in previous 1997 year (19,3 USD/barrel). Oil has been produced since the mid-1800s, and since then, prices have been stable for most of that time (with an exception to a period in the late 1970s and early 1980s). It wasn't until 2000 that oil prices began increasing more than the rate of interest and the gradual and predictable price path described by Hotelling. The reasons why the real price deviate from the theoretical price are changing demand for oil, backstop technologies (oil compete with other energy sources), changes in oil supply. Crude oil prices behave much as any other commodity with wide price swings in times of shortage or oversupply. The crude oil price cycle may extend over several years responding to changes in demand as well as OPEC and non-OPEC supply. Let's analyze the events which contributed to the development of oil prices.

December 1986 OPEC price accord set to target $18 per barrel bit it was already breaking down by January of 1987and prices remained weak. The price of crude oil spiked in 1990 with the lower production and uncertainty associated with the Iraqi invasion of Kuwait and the ensuing Gulf War. Yearly average price on Brent Blend was 23,61$ per barrel. The world and particularly the Middle East had a much harsher view of Saddam Hussein invading Arab Kuwait than they did Persian Iran. The proximity to the world's largest oil producer helped to shape the reaction (Williams, 2007).

Following what became known as the Gulf War to liberate Kuwait crude oil prices entered a period of steady decline until in 1994 inflation adjusted prices attained their lowest level since 1973. Average price on Brent Blend in 1994 was 15,76$ per barrel. The price cycle then turned up. The United States economy was strong and the Asian Pacific region was booming. From 1990 to 1997 world oil consumption increased 6.2 million barrels per day (Williams, 2007). Asian consumption accounted for all but 300,000 barrels per day of that gain and contributed to a price recovery that extended into 1997. Declining Russian production contributed to the price recovery.

The price increases came to a rapid end in 1997 and 1998 when the impact of the economic crisis in Asia was either ignored or severely underestimated by OPEC. In December, 1997 OPEC increased its quota by 2.5 million barrels per day (10 percent). The rapid growth in Asian economies had come to a halt. In 1998 Asian Pacific oil consumption declined for the first time since 1982 (Williams, 2007). The combination of lower consumption and higher OPEC production sent prices into a downward spiral. In response, OPEC cut quotas by 1.25 million b/d in April and another 1.335 million in July. Price continued down through December 1998. Yearly average price on Brent Blend in 1998 was 12,7$ per barrel.

Prices began to recover in early 1999 and OPEC reduced production another 1.719 million barrels in April. As usual not all of the quotas were observed but between early 1998 and the middle of 1999 OPEC production dropped by about 3 million barrels per day and was sufficient to move prices above $25 per barrel (Williams, 2007).

With growing US and world economies the price continued to rise throughout 2000 to a post 1981 high. Between April and October, 2000 three successive OPEC quota increases totaling 3.2 million barrels per day were not able to stem the price increases. Prices finally started down following another quota increase of 500,000 effective November 1, 2000.
Russian production increases dominated non-OPEC production growth from 2000 forward and was responsible for most of the non-OPEC increase since the turn of the century (Williams, 2007). Yearly average price on Brent Blend in 2000 was 28,4$ per barrel.

In 2001, a weakened US economy and increases in non-OPEC production put downward pressure on prices. In response OPEC once again entered into a series of reductions in member quotas cutting 3.5 million barrels by September 1, 2001. In the wake of the attack crude oil prices plummeted. Spot prices for the U.S. benchmark WTI were down 35 percent by the middle of November. Under normal circumstances a drop in price of this magnitude would have resulted an another round of quota reductions but given the political climate OPEC delayed additional cuts until January 2002 (Williams, 2007). It then reduced its quota by 1.5 million barrels per day and was joined by several non-OPEC producers including Russia who promised combined production cuts of an additional 462,500 barrels. This had the desired effect with oil prices moving into the $25 range by March, 2002. By mid-year the non-OPEC members were restoring their production cuts but prices continued to rise and U.S. inventories reached a 20-year low later in the year (Williams, 2007).

On March 19, 2003, just as some Venezuelan production was beginning to return, military action commenced in Iraq. Meanwhile, inventories remained low in the U.S. and other OECD countries. With an improving economy U.S. demand was increasing and Asian demand for crude oil was growing at a rapid pace.

The loss of production capacity in Iraq and Venezuela combined with increased OPEC production to meet growing international demand led to the erosion of excess oil production capacity. In mid 2002, there was over 6 million barrels per day of excess production capacity and by mid-2003 the excess was below 2 million. In a world that consumes over 80 million barrels per day of petroleum products that added a significant risk premium to crude oil price and is largely responsible for prices in excess of $40-$50 per barrel (Williams, 2007).

Other major factors contributing to the current level of prices include a weak dollar and the continued rapid growth in Asian economies and their petroleum consumption. The 2005 hurricanes and U.S. refinery problems associated with the conversion from MTBE as an additive to ethanol have contributed to higher prices.

In 2008, after almost four years of climbing to the $145 pick, everybody was surprised with the sudden brutal downfall of the oil price to $30-40 (lowest prices so far — Brent spot last 24 Dec. at $34.04). Many experts had predicted that oil would rise to $200 by the end of year 2008, but according the peak oil theory, it was obvious that the rise could not last for long. Climbing phase of the oil prices is the result of the economy trying to adjust to increasing costs of extraction (Rodrigues, 2008). High prices tell to the industrial system that it is necessary to invest more and more resources into oil prospection and extraction for maintaining production at the same level. At some point, however, the system reacts by contracting its demand for oil. At this point, prices collapse, too. That causes also production to contract and is the mechanism that generates the Hubbert peak (Rodrigues, 2008).

The exact moment for the turning point couldn't be predicted, but it was expected. As a reaction on this price situation OPEC recent cuts that amount to 4.2 million barrels a day (Mbd) from September production levels. They announced at Vienna, Austria, in October, a cut of 1.5 Mbd for November and December 2008 and 2.4 Mbd cut for January and February 2009 (Rodrigues, 2008). It seems also that the Russians (second largest exporter, after Saudi Arabia) and the Azeris can announce export cuts of more than 600,000 barrels a day in an eventual political coordinated movement. Despite the vagaries of prices, the cost of oil extraction has been gradually increasing over the past years.

6. Conclusion

It is inevitable that petroleum will continue to play the crucial role in satisfying the world's energy requirements over at least the next two decades. Also, around four-fifth of all produced oil is exported. With this international outlook, the oil industry has already adjusted to many changes and grown used to the risks and benefits that a global market provides. Recent developments have presented new challenges to the way the oil industry, and oil producers, in particular, function in a truly globalized world.

When viewing the market situation towards the end of 2008, it is clear that a combination of factors has been at work over the past years, leading to the persistent price rises and volatility. Oil market reveals oil's centrality to global economic growth and mankind's associated energy needs, its dynamic, constantly changing nature and its inherent volatility. At the same time, it underlines OPEC's important role in seeking to achieve market order and stability, as successfully demonstrated and recognized in recent times. With capacity expansion plans under way in both OPEC and non-OPEC countries, ample crude supply should be available over the medium term.

Over the long term, the next few decades are expected to see fossil fuels continue to account predominantly for increases in energy demand, with oil set to maintain its major role as a source of energy. There is also a clear expectation that the oil resource base is sufficiently abundant to satisfy this demand growth. Yet, the expected ranges of demand growth reveal large uncertainties in the absolute magnitudes of demand. Although non-OPEC production is seen as continuing its recent expansion over the medium term, it is generally agreed that OPEC will gradually be relied upon to supply the incremental barrel, with its market share eventually set to rise.

Maintaining stable prices will be complicated by the uncertainties about the future, with regard to how demand will evolve, as well as how non-OPEC supply behaves. Uncertainties over future economic growth, consuming governments' energy and environmental policies, and the rate of development and diffusion of newer technologies, raise questions over the future scale of required investment. This uncertainty, coupled with long lead times, inevitably complicates the task of maintaining market stability. The key to ensuring that sufficient investment takes place is oil market stability, whereby prices at reasonable levels need to be maintained to secure adequate sources of investment.

The future of the Norwegian oil adventure will be largely determined by the combination of the cost of producing oil and gas in the North Sea and the price of these commodities on the world market. World price of oil is established by a number of factors, none of which is subject to Norwegian control. The theoretical lower limit of the price of oil is established by the cost producing oil in the Middle East, plus the cost of shipping it to market. This is very low as compared with the cost of producing Norwegian oil. Nobody knows the upper limit of the world price of oil, but it is presumably set by the cost of alternative energy sources. However, it should never be forgotten that the present price of oil depends on the ability of the OPEC countries to hang together.

In this work I did investigated mechanism of international oil market by giving the main features of historical development of oil market, economical fundamentals, market strategies for crude oil and relationship between oil and gas prices. In chapter three I described main theoretical models of the oil market: models of monopoly behavior, models of competitive behavior and Hotelling’s model. In chapter four I showed main features which characterize Norwegian oil market: location of crude oil, facts about production and prices of oil.

In chapter five I analyzed price development on Norwegian oil market and as we can see the real market oil price deviate from theoretical price ascertained by Hotelling’s rule. According to that the rate of change in resource price is directly related to the discount rate, so a lower rate of discount implies a less rapid increase in price. What are the reasons for deviation from the theoretical price? The possible price paths become diverse when exploration, capital investment, ore quality selection, market imperfections and other factors are taken into account.

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