Depletion of Petroleum Reserves and Oil Price trends

Denis Babusiaux, Pierre-René Bauquis

ÉCOLE DU PÉTROLE ET DES MOTEURS
INSTITUT FRANÇAIS DU PÉTROLE (IFP)
228-232 avenue Napoléon Bonaparte
92852 RUEIL-MALMAISON CEDEX
téléphone : 01 47 52 62 80 - télécopieur : 01 47 52 70 36

Depletion of Petroleum Reserves and Oil Price trends

Denis BABUSIAUX

Pierre-René BAUQUIS

November 2007

French Academy of Technology
Energy and Climate Change Commission
Report of the Petroleum Working Group

Les cahiers de l'économie - n° 66

Série Analyses et synthèses

Pour toute information complémentaire, prière de contacter :
Denis Babusiaux - Tél. 01 47 52 62 80

Summary

This document is the report of the "Petroleum" working group from the French Academy of Technology, coordinated by the authors in the framework of the Energy and Climate Change Commission chaired by Gilbert Ruelle. Firstly, it present a synthesis of the different points of view about reserves and the peak of world oil production (optimists, pessimists and official organizations). Secondly, it analyzes the mechanisms of oil price formation focusing on the long term without addressing the question of short term market behaviour. The last section is devoted to possible scenarios of the evolution of production profiles and prices in the medium and long term.

Petroleum Working Group:

Pierre Castillon (Academy of Technology)

Xavier Préel (Total)

Pierre Sigonney (Total)

Bernard Tissot (Academy of Science and Academy of Technology)

Team Leaders:

Denis Babusiaux (IFP)

Pierre-René Bauquis (Adjunct Professor, IFP School)

INTRODUCTION

For years confined to discussions among specialists, the question of peak oil production is now regularly debated in the press, with the price of oil often making the headlines of the daily papers. The purpose of this report is to present a summary of the different contemporary points of view. Our emphasis is on the study of medium and long-term, and we refer only briefly to geopolitical factors and their short and medium-term consequences. We do not offer a short-term functional analysis of markets (spot markets and futures markets, hedge fund behavior, the influence of inventory statistics on price formation).

The first part of this document is devoted to a presentation of the data and to assumptions about reserves and production profiles. We then analyze price formation mechanisms. In part three we briefly present several possible scenarios for future developments in this area.

I. RESERVES AND PRODUCTION

I.1. Resources and reserves concepts

In the petroleum industry it is common to distinguish resources from reserves. Resources correspond to hydrocarbons in the ground, whether or not they are recoverable. Reserves in the strict sense (AAPG, SPE, WPC[1] 2000 classification) are formed from known accumulations that are or will be recoverable under current technological and economic conditions from active deposits or those in the process of development. Proven reserves are estimated to be approximately a thousand billion barrels (between 1.0 and 1.3), that is, roughly 150 billion tons, or enough for forty years at the current rate of production. Gas reserves, as tons of oil equivalent, are of a similar order of magnitude, but correspond to a ratio of reserves to production lasting longer than 60 years. Coal reserves, at the current rate of production, should last for 200 years, but the definitions of coal reserves are not consistent with those of oil, primarily because their gitologies are very different.

It is important to note that the exact amount of underground reserves can only be determined once operations are completed and that the term “proven reserves” can be understood in several ways. It does not have the same meaning for the producing countries as it does for the Securities and Exchange Commission (SEC). For companies listed on the New York Stock Exchange, the SEC defines proven reserves as those reserves whose existence has been proven on the basis of geological, technological and economic data “with reasonable certainty.” The magnitude of the upward reevaluations of U.S. reserves shows that these guidelines are fairly conservative. The reserves available to companies complying with the SEC norms represent approximately 5% of global reserves. Outside the industrialized countries, production statistics are provided by governments. These figures are generally not comparable to proven reserves as the SEC understands them but, rather, to the “proven plus probable” reserves, which are defined by oil companies as reserves whose probability of existence is equal to or greater than 50%.

[1] AAPG: American Association of Petroleum Geologists; SPE: Society of Petroleum Engineers; WPC: World Petroleum Congress.

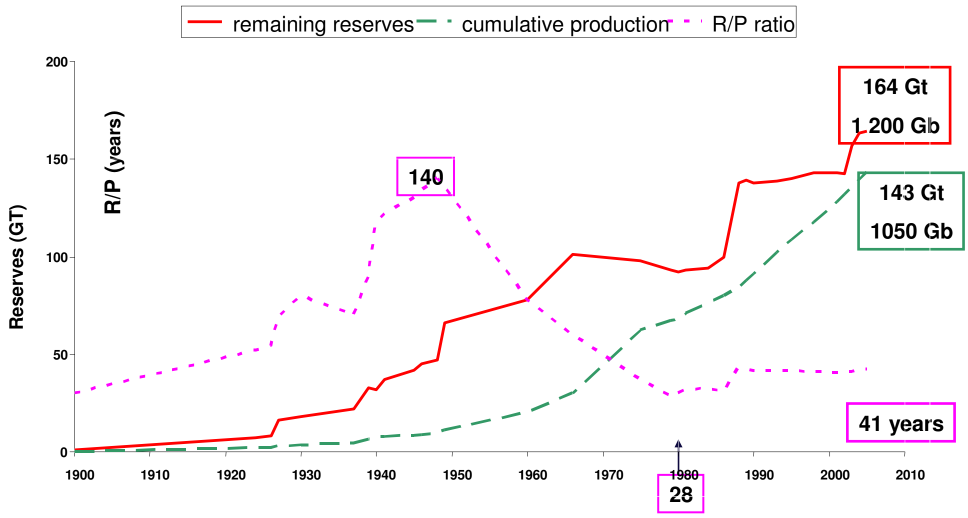

Figure 1. Change in worldwide petroleum reserves

Source: BP Statistical Review

Figure 1 shows the change in proven reserves worldwide over time. We see a sharp increase between 1986–1987. Note that this is not the result of unusual discoveries. Following the oil "price drop," OPEC considered the question of defining its production quotas based on the volume of reserves in each country. Each of the organization's members then reevaluated its stated reserves. Some reevaluations, therefore, are political. They are often, but not always, revised upward. For example, when Mexico joined the North American free-trade zone, it revised its reserves downward to comply with the norms current in the United States. As a result, Mexico divided its "proven" reserves by a factor of three, which again illustrates the considerable uncertainty associated with this type of data.

The principal statistical sources are published by the *Oil and Gas Journal*, *BP Statistical Review*, *World Oil Journal*, and the United States Geological Survey (USGS). The USGS studies are designed not only to analyze known reserves but to estimate total reserves, which include undiscovered reserves and the estimated effect of improvements in rates of recovery in the future. We'll return to this in section 4. The USGS's most recent publication appeared in 2000.

"Conventional" and "non-conventional" oil. The first two publications (*Oil and Gas* and *BP Statistical Review*) appear once a year and are based on data supplied by the individual countries. For a long time their results converged. However, a noticeable difference began to appear in 2003, the year in which *Oil and Gas* included 175 billion barrels of reserves recoverable from the tar sands of Athabasca, Canada, previously considered "*non-conventional*" resources. Until then BP had included only oil being pumped or undergoing development. "Conventional" hydrocarbons are (or, rather, were) referred to as those that can be produced given the technological and economic conditions existing today or in the foreseeable future. Technological progress has considerably shifted the boundary between "conventional" and "non-conventional." For example, in the 1970s, "non-conventional" oil included offshore deposits located below a depth of 200 meters of water, whereas today oil is obtained at depths greater than 2000 meters. Until the 1990s extra-heavy oil from the Orinoco

Belt in Venezuela, as well as in Canadian tar sands, was considered "non-conventional." Although production is now underway, these sources are still generally referred to as "non-conventional." It is also worth noting that the bulk of the reserves in the Orinoco basin are not currently included in proven reserves.

With respect to economic conditions, the reserve level is naturally dependent on the current and anticipated price of crude. In particular, price is a determining factor in establishing enhanced production systems that can appreciably improve rates of recovery, especially for heavy and extra-heavy crude. Globally, the elasticity of reserves with respect to price is low, much lower in fact than what we observe for coal, uranium, or metal mines. It is on the order of one or greater than one for basic metals and uranium but on the order of 0.1 for conventional oil. The most significant effect of a (substantial) increase on prices is—and we'll return to this later—to provide access to new sources of oil such as deepwater offshore deposits, extra-heavy crude, or deeply-buried oil.

Figure 2 shows the geographic distribution of reserves. There is no need to point out the geopolitical implications of this distribution since they are well known.
While the data concerning proven reserves is subject to discussion, the question of undiscovered reserves and improved rates of recovery in the future has led to considerable controversy between "optimists" and "pessimists."

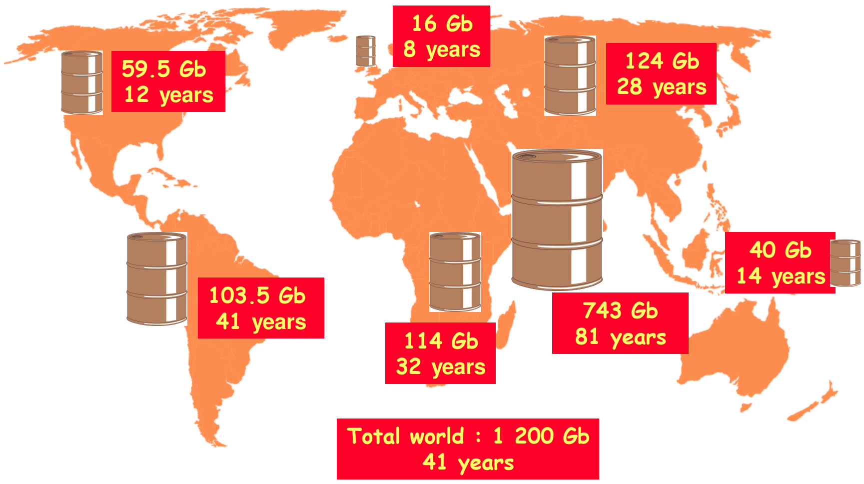

Figure 2. Petroleum reserves and reserves/production ratio for 2006.

Source: BP Statistical Review

I.2. The optimist argument

While most pessimists are geologists, the majority of them retired, today's optimists are, by and large, economists like Morris Adelman and Michael Lynch of MIT. They are quick to point out that previous forecasts of scarcity have always been proven wrong. For example, at the end of the nineteenth century, many experts predicted the cessation of industrial development, then based on coal energy, whose reserves were estimated at 20 years of production (at the time). In 1919 a well-documented article appeared in *La Technique Moderne*, showing that oil production in the United States would level off in the very near future, reserves being estimated to last 22 years at a constant rate, and that imports from Mexico or Venezuela would merely delay the predicted shortage by a few years. Reflecting the skepticism of the time, who was it who said :, “I’ll drink every gallon produced west of the Mississippi?"[2].”

In a more contemporary vein, in 1979 BP published a study titled “Oil Crisis . . . Again?” The study showed a peak in global production (excluding the countries of the former Soviet Union) occurring in 1985. In 1990 there was a near consensus in predicting a production peak for North Sea oil in 1995, a date that was considerably extended. The reprieve was obtained through the improvement of rates of recovery and the presence of infrastructures that had been put into place for large deposits. These turned out to be useful for obtaining oil from small deposits, whose isolated development would not have justified the corresponding investments.

The pessimists rely on geological research, which leads them to consider that it is highly unlikely that major discoveries are to be made. The largest discovery in the last 30 years, that of Kashagan, Kazakhstan, estimated at ten billion barrels, extended global peak oil production by only three to four months. For several decades sedimentary basins have been well defined and estimates of ultimate recoverable reserves (including past production), even though they are widely dispersed, oscillate between 1.5 and 3 billion barrels (fig. 3). The optimists, however, point to the upward trend over time in estimates of ultimate reserves from a given source. Thus, in 1984, the United States Geological Survey (USGS) published an estimate of 1,700 billion barrels (Gb), increasing to 3,000 Gb in 2000. Similarly, Michael Lynch notes that estimates by the leading pessimist C. Campbell (author of *The Coming Oil Crisis*) went from 1,575 Gb in 1989 to 1,750 in 1995, and to 1,950 Gb in 2002.

Another source of concern for pessimists is the rate of decline in production, which is accelerating. This is the result of the implementation of processes used to increase production and thereby hasten its decline, without any appreciable increase in reserves. The optimists consider that the accompanying technological progress will allow us to more rapidly develop additional deposits to compensate for these losses.

[2] John Archbold, directeur of Standard Oil, 1885, when asked about the possibility of oil being discovered in Oklahoma.

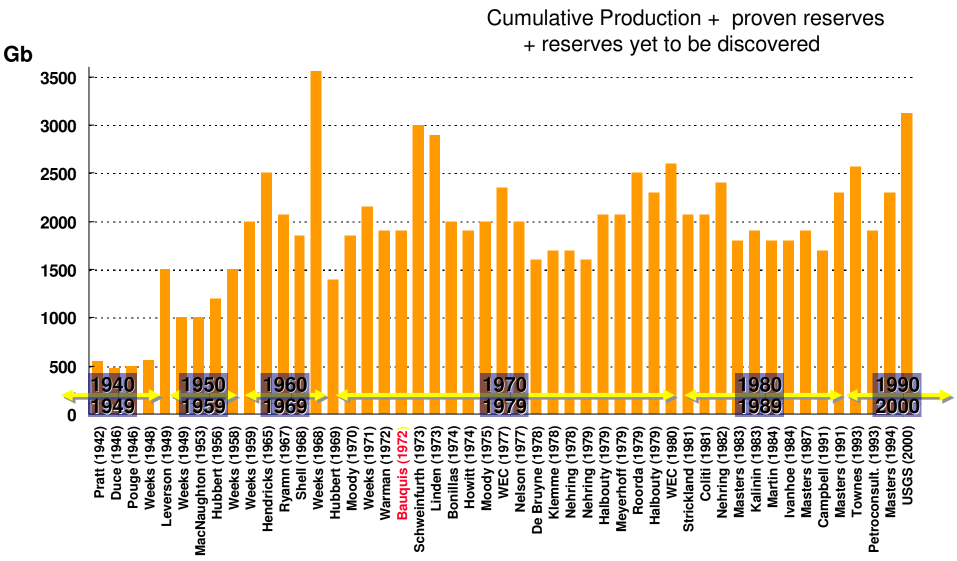

Figure 3. Previous estimates of ultimate reserves

Source: IFP based on Martin (1985), Campbell (1992), and USGS (2000)

John Mitchell, former chief economist at BP (currently at the Royal Institute for International Affairs), notes that, in spite of the forecasts of non-OPEC production leveling off, it has in fact increased with considerable regularity from 1980 to 2005.

Pessimists worry about the fact that only about a third of reserves are renewed through new discoveries. The remainder is obtained from the reevaluation of older discoveries, either through a better understanding of the deposit or an improvement in the rate of recovery. For them, the drop in the volume of discoveries can only lead to a decline in potential future reevaluations. Adelman responds that in the Middle East, the low level of discovery can be simply explained by the fact that reserves obtained using modern technological developments and the reevaluation of reserves of older deposits cost less than those obtained through exploration, which explains the very limited amount of exploration in the region. The majority of exploration wells are found in countries that are the most open and present the least risk politically and economically, that is, in countries that have already been subject to intense exploration. Consequently, the countries offering the best outlook for discovery are subject to less exploration. In non OPEC developing countries, the number of wildcats represents merely 2% of those drilled in the USA.

Alain Perrodon (2004), a geologist and rather pessimistic about ultimate conventional oil reserves, notes that it is through new ideas that new resources are found, and that in geology new concepts appear cyclically, which should “help us avoid pessimism.” He mentions non-conventional oil sources as an example. We should also consider deeply-buried deposits (at depths greater than 5,000 or 6,000 m). While considerable uncertainty prevails regarding the corresponding volumes, we can feel hopeful about improvements in seismic exploration and drilling techniques designed for these purposes. These prospects have long been considered rather favorable to gas production, for the temperatures found at great depths result in hydrocarbon cracking. Specialists estimate that a certain number of basins could present a temperature gradient favorable to the presence of oil. Chevron’s “Jack” discovery in the Gulf of Mexico in September 2006, at a depth of 2,100 m of sea water and 6,000 m of sediment, is a major find that allows us to look forward to other large-scale discoveries at comparable depths. For the play as a whole, estimates of reserves of from 3 to 15 billion barrels oil equivalent, some of it liquid, have been mentioned in the press. However, this is a new undertaking and there is considerable uncertainty concerning the productivity of future production wells as well as possible recovery rates

In short, the optimists acknowledge the finite character of petroleum resources but are confident that industry's capacity for innovation and technological progress will provide access to new reserves. They estimate that only part of today's resources are known. Potential production—again according to Adelman—is the result of a race between the exhaustion of known deposits and technological progress. In the past, technological progress has led the way. In some cases it has led to relatively consistent improvements, decreased drilling costs, improved rates of recovery, and a better picture of underground strata. Other effects are more difficult to predict. In the early 1980s the production of extra-heavy oil in the Orinoco Belt in Venezuela was considered profitable as long as a barrel of crude oil sold for more than $30 to $40 (in 1980 dollars). Technological progress, primarily horizontal drilling, has allowed this threshold to be lowered to less than $20 today (approximately $20 in 1980 dollars).

I.3. The pessimist argument

The pessimists insist on the political nature (as noted in section 1) of reserve reevaluations made by OPEC countries in 1986–1987, which do not correspond to proven reserves. Their point of view can be summarized as follows:

"The peak of global oil production will occur between 2005 and 2010 at around 90 million barrels per day (mb/d), all natural liquid hydrocarbons included."

This is the point of view of the Association for the Study of Peak Oil and Gas (ASPO), or at least its president, Colin Campbell (formerly with BP). The head of ASPO in France, Jean Laherrère, (formely with TOTAL) places the peak between 2010 and 2015, at the same level of 90 mb/d.

There exist a range of views among pessimists, from the ultra-pessimists like K. Deffeyes, currently professor at Princeton (formerly with Shell and former colleague of King Hubbert), for whom the peak has already occurred, to semi-pessimists like P. R. Bauquis (1999), who places the peak around 2020 at 100 mb/d.

The pessimists' main arguments are based on the following:

1. A very convincing argument of the optimists, at least initially, is that the pessimists have always been proven wrong. There is, in fact, no doubt that for more than a hundred years there have been alarming predictions about the end of the growth of oil reserves or the date of the onset of the decline (which amounts to the same thing). The counterargument from the pessimists (even some ASPO members have revised the reserve figures upwards from the figures they gave five, ten, or fifteen years ago) is that, first, we finally have access to all the 3G data (geology, geophysics, geochemistry) for all the oil basins and second, sampling from these basins, in the form of wells, is such that predictive methodologies concerning undiscovered reserves are now reasonably reliable (to within plus or minus 20%). If this is true, the greatest uncertainty about remaining liquid hydrocarbon reserves in the twenty-first century revolves around the evolution of average recovery rates in the future.

2. With respect to average rates of recovery, there is a consensus that the rate is currently 35% on a worldwide scale (however, the rate varies in practice from 5% to 75% depending on the deposit, and the consensus on an average of 35% does not necessarily reflect reality, which remains unknown). The pessimists feel that during the next fifty years, this rate could be improved (through technological progress and at higher prices) by about a third, rising to 45 or 47% (P. R. Bauquis 2004). For the optimists this figure could be as high as 60% (Schlumberger)[3]. Note that this rate is highly sensitive to the price of crude, especially for heavy and extra-heavy oil.

3. The main argument of the pessimists is the global application of a Hubbert methodology. In 1956 the Shell geologist had predicted the beginning of the decline of production in the United States (48 states) starting in 1970 (in fact, this was one of his two scenarios and the one that was, naturally, retained). This approach seems to be solidly grounded, for it is based on the following simple premises:

   - We can only produce barrels that have already been discovered.

   - There exists an average time difference, Δt, between the date of discovery and the date of production of a barrel of oil, and this difference can be estimated based on discovery curves and production curves (Δt is not constant over time and technological progress has an influence). The curve representing discoveries in a given basin as a function of time generally has the shape of bell curve. The curve representing production has a similar shape but is shifted in time, from 10 to 30 years depending on the basin. This phenomenon reflects the fact that the effectiveness of exploration initially increases then decreases (an S, or so-called "creaming," curve).

   - For a group of deposits (oil basin), the production curve is a bell curve and the sum of these curves on a global scale would have the same shape. If we assume that these curves are more or less symmetric, as is roughly the case for the United States, this implies that peak production is reached when half of the ultimate reserves have been produced.

4. The pessimists have an additional argument, namely the low elasticity of reserve volumes (and recovery rates) to price increases, except for heavy and extra-heavy crude oils. This is a key difference between oil and other energy sources such as coal and uranium.

5. Finally, the pessimists consider that the traditional approach to the problem of what "remains to be produced," based on the concept of "proven recoverable reserves" (with enough reserves for 40 years), is intellectually misleading, even if it is the only statistically accessible approach for non-industry observers. Specialists, however, tend to focus on resources and ultimate reserves. The concept of "proven reserve" masks the fact that, during the past thirty years, exploration has contributed only 50% to recoverable reserves and that, during the past ten years, this figure has fallen to approximately 35%. It is obvious that the reevaluation of field reserves cannot be continued indefinitely and that an asymptote will be reached (it remains to be seen whether this asymptote corresponds to an average rate of recovery of 45% or 60%, which would constitute a significant residual uncertainty).

[3] Presentation given by G. Montaron to ENSPM, 2003.

I.4. An intermediate vision

Naturally, there is little point in trying to integrate pessimist and optimist viewpoints, which are so at variance with one another. It is worth noting, however, that for several years the optimists have been less positive about the possibility of pushing peak oil production forward to a distant point in time (the twenty-second century). For example, Adelman has long considered that oil reserves were and would be for decades similar to manufactured inventories of products, exploration and production activities being comparable to manufacturing operations that allowed inventories to be resupplied. However, his latest publication puts greater emphasis on the fact that transactions involving barrels-in-the-ground and observed prices do not appear to be compatible with producer perceptions of imminent scarcity. He mentions the uncertainties in the race between technological progress and consumer demand without assigning a more favorable probability to either factor.

All observers are, in fact, aware of a certain number of observations that can't be neglected by even the most optimistic analysts. We have unexpectedly witnessed a ceiling in natural gas production in the United States in spite of an increase in prices and strong growth in "gas" exploration. The North Sea production peak has passed . Oil producers are experiencing difficulties not only in acquiring new resources, for reasons that are often political, but also in identifying new areas for exploration. As a result some feel it will be impossible for them to maintain growth objectives for either production or reserves.

It therefore appears highly unlikely that oil production will continue to grow for more than a few decades. To get some idea of the appearance of a possible peak in production, a choice must be made among several hypotheses concerning ultimate reserves. We have seen that the spread is quite large and that there are a number of uncertainties. Intermediate values are supplied by different teams of specialists from IHS, Energy File, and USGS. USGS estimates ultimate reserves of conventional oil at approximately 3,000 Gb. Of this number nearly 1,000 Gb have already been consumed, with slightly more than 1,000 in proven reserves. The remainder corresponds to undiscovered reserves, primarily in incomplete or still unexplored exploration basins such as the peri-arctic basins. This order of magnitude also corresponds to the estimates supplied by IFP geologists. If we use this value, the Hubbert curve shows a maximum around 2020 (the solid line in figure 4).

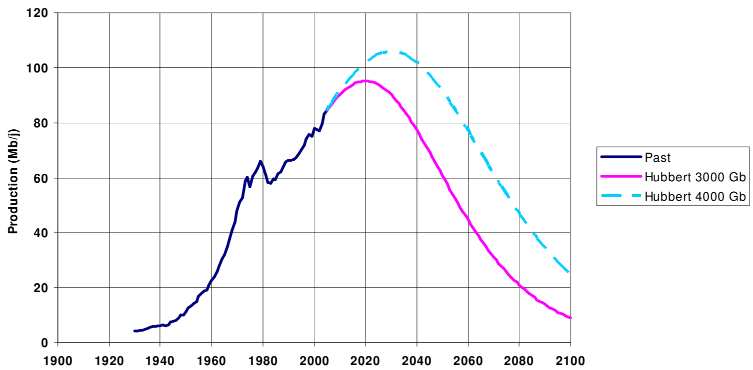

Figure 4. Hubbert curves based on different ultimate reserves assumptions

Source: IFP

To conventional oil reserves should be added reserves from what are often referred to as "non-conventional" oil, primarily extra-heavy oil from Venezuela and tar sand from Canada[4]. Existing resources in each of the two countries are on the order of 1,500 Gb. Reserves that can be produced under present technological and economic conditions are estimated at 200 to 300 Gb, a volume corresponding to an average recovery rate of less than ten percent. There is considerable uncertainty about the evolution of this rate, but foreseeable advances in technology indicate that by 2020 or 2030, that figure could be doubled, increasing the volume of recoverable reserves to approximately 600 Gb, the equivalent of Middle East reserves. This would support the hypothesis that an overall decline in oil production, both conventional and non-conventional, can be pushed forward to 2030. It is this kind of hypothesis that was used to develop the scenarios published by Shell in 2001. The dashed line in figure 4 would correspond to ultimate reserves of 4,000 billion barrels, a number that includes non-conventional oil and undiscovered reserves based on rather optimistic assumptions (new, previously inimaginable geological concepts and marked improvements in rates of recovery). It is worth noting, however, that this "theoretical" approach, using similarity with the Hubbert curves does not take into account necessary rates of investment, to which we shall return.

II. COSTS and PRICES

II.1. Long-term price formation: oil as an exhaustible resource

The first oil crisis revealed the exhaustibility of oil resources, something that had been overlooked during the previous decades, when large discoveries were being made in the Middle East and production increased rapidly. In 1974, economists, following R. Solow [1974], rediscovered Hotelling's rule (see inset), according to which the price of a non-renewable resource increases at a rate equal to the discount rate (when operating costs are negligible). Consequently, crude oil prices reflect its scarcity rather than production costs. Prices observed after 1973, but also after the second oil crisis, have been felt to be consistent with a model based on Hotelling's rule that incorporates the latest assumptions for each period for reserve volumes, the price of alternative energy sources, and demand elasticity. This law is still referred to, explicitly or implicitly, by a number of economists[5].

The theory is based on the premise[6] that resources exist in limited quantities and will have to be replaced when they are exhausted either by some other substitute or by an alternative technology (backstop technology) at a higher cost. Until the mid-1980s, the resource in question could be considered to correspond to "conventional" oil. Available backstop technologies (non-conventional hydrocarbons, biomass and other renewable energy sources, nuclear energy, liquid fuels obtained from coal) appeared to be accessible only at a cost that was considerably greater than oil prices could support. At least this was the case for "white" products, fuels and petrochemical feedstock.

[4] These consist of the same kinds of oil in similar reservoirs, but it is viscous in Venezuela and solid in Canada due to differences in the geothermal gradient.
[5] For example, see P. Artus (2005).
[6] It is also based on different assumptions of the rationality of supply and demand behavior, and, at least in its initial version, perfect information.

Hotelling's rule of exhaustible resources.

Harold Hotelling, a prolific economist active in the nineteen twenties and thirties, is generally considered to be the founder of the theory of exhaustible resources, following a pioneer article by L. C. Gray (1914). His work was rediscovered in the 1970s and brought to attention by a no less famous article by R. M. Solow (1974). We note, however, that Edmond Malinvaud (1972), even though his article is less cited than Solow's, had discovered "Hotelling's Rule" a short time earlier using a different approach.

This rule, for the case where the cost of production is negligible, states that **the price of an exhaustible resource increases at a rate equal to the real rate of interest (or, using a more contemporary approach, to the discount rate).** If the cost of production is not negligible, **it is the rent (marginal cost price) that must increase at a rate equal to the discount rate**.

The theory is rigorously developed (calculus of variation or control theory) but can be explained very simply. If the price of the resource is stable (or increases at a rate less than the discount rate), it would be in the interest of producers to produce goods as quickly as possible, which would cause the price to drop. If it were to increase at a higher rate, producers would delay production to take advantage of a higher discounted value. The only change that would allow for market equilibrium is, therefore, the one that makes the discounted value of future unit revenues stable, thus an increase at a rate equal to the discount rate.

The situation has changed since then. The belief, up until 1985, in an ineluctable growth in prices stimulated significant research and development efforts. The resulting technological progress has led to the discovery of hard-to-find deposits, to noticeable improvements in rates of recovery, and to the development of "non-OPEC" oil, especially offshore. After the 1986 price drop, these efforts were continued and led to a sharp decrease in exploration and production costs in non-OPEC countries, especially for deep-sea oil. The frontier between conventional and non-conventional oil (deep-sea oil, extra-heavy oil, tar sand) is regularly being pushed back. Producers can now access offshore deposits at increasingly greater depths using technologies that are constantly being improved. Figure 5 illustrates the progress made in this field. The difference between the production costs of offshore and on-shore oil is decreasing. As indicated above, the extra-heavy oil in the Orinoco Basin in Venezuela was, until the 1990s, considered to be practical to produce only at a relatively high price per barrel of crude (at the time, $40 or more). The production cost of this type of oil is now around $20 a barrel of crude, and large-scale production has begun. We'll discuss the technological costs in the following section.

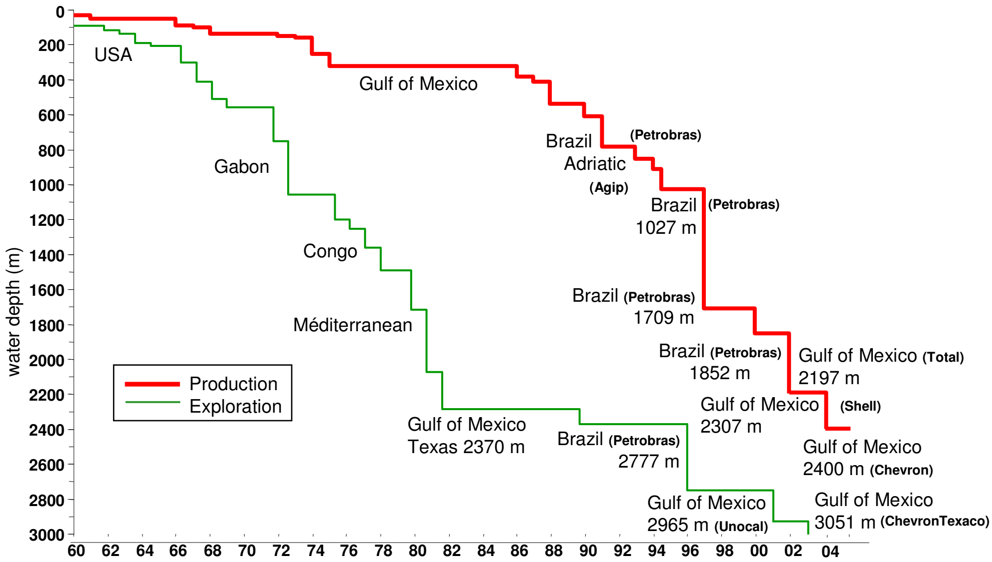

Figure 5. Records for offshore drilling

In fact, there is a *continuum* of hydrocarbon resources: deposits that are difficult to access, traps that are more complex and harder to detect, deep and very-deep offshore sources, extra-heavy oil, tar sand, oil shale, and so on. The traditional distinction between conventional and non-conventional oil makes little sense today. Moreover, this *continuum* is not limited to oil-based hydrocarbons. Considerable research has been done on the development of technologies for producing liquid fuel from natural gas (gas-to-liquid, or GTL, technologies using the Fischer-Tropsch process) and coal (coal-to-liquid, or CTL, technologies using direct liquefaction or indirect liquefaction after gasification). These technologies will be discussed below. This *continuum* extends to biomass fuels that make use of available products or processes (ethanol, ETBE, vegetable oils, methyl esters of vegetable oils) or those that are currently being researched (ligno-cellulose or biomass-to-liquid, BTL). In the more distant future, we may be able to develop technologies for the "carbonation" of hydrogen produced from nuclear or renewable energy sources (P. R. Bauquis, 2004) or, to put it somewhat differently, carbon hydrogenation (hydrogen-to-liquid, or HTL, technology).

Within several decades there will be no hydrocarbon (natural plus synthetic) resource limitation, but there is and will be a need to make use of more complex and more costly technologies (as currently perceived) as conventional deposits are exhausted.

Contrary to the situation that existed until the 1980s, the long term marginal cost of production (development marginal cost, i.e, including investment expenses) can no longer be considered negligible. Therefore, we can no longer say that the price of oil will increase at a rate equal to the discount rate, since the Hotelling rent assumed to increase at this rate represents no more than part of the price of crude. Moreover, if we consider the prices observed in 2006, the difference with the cost of alternative technologies has sharply declined. And there are significant long-term doubts about the cost of alternative resources. As a result, it is difficult to use Hotelling's theory to estimate future developments in the price of oil.

In the short or medium term, a monopoly rent can be created and maintained if OPEC fixes production quotas. What's more, high prices during this period can result in the inability of production to meet potential demand. We'll return to this later. With respect to the analysis of long-term price formation, a determining factor should be the cost of the marginal resource involved.

II.2. Production costs

Aside from scarcity rent, the average and marginal costs of production are the first elements used to analyze price formations. As indicated above, the average costs of production have sharply declined over the past twenty years. The average cost borne by the ten largest international companies dropped from approximately $14 a barrel in 1990 to less than $8 a barrel in 2000. Since then, however, we've seen a rise in costs, at least part of which is associated with the increased cost of services and equipments provided by the petroleum services and supply industries.

Conventional oil

Figure 6 shows the results of a somewhat dated but rather complete study of the costs related to conventional oil; the values shown have been confirmed by an IFP study. Note that these are technical production costs that include development costs but exclude taxes and royalties. The figures also show the operating production costs, which provide orders of magnitude of short-term marginal costs, currently on the order of a few dollars a barrel. Finally, these are average values, given that costs are highly variable from one field to another. In the majority of regions shown, the production cost of some deposits is close to the threshold set by the oil companies for their investment decisions. This threshold can give some idea of the magnitude of marginal long-term costs (comprising investment expenses), at least in regions where the tax situation doesn't introduce an excessively high bias.

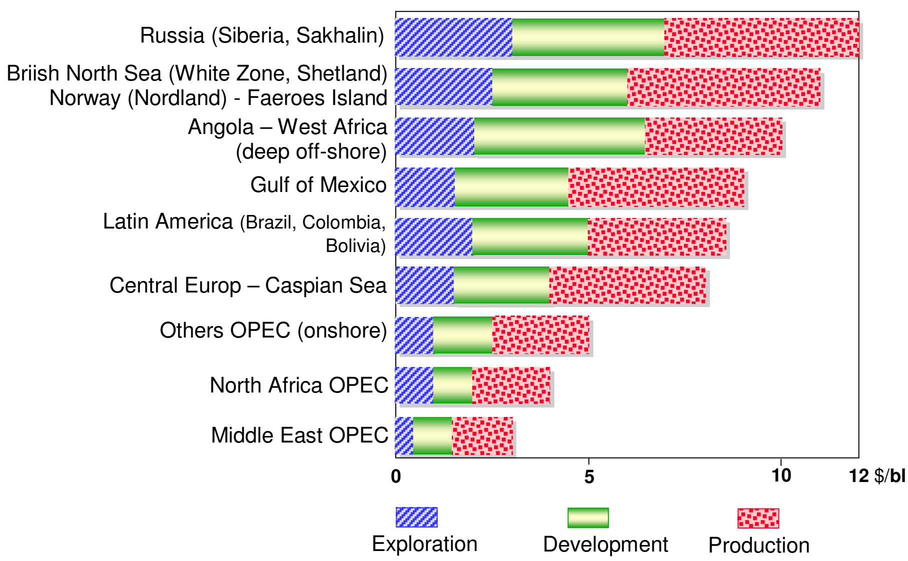

Figure 6. Production cost of a barrel of crude in 1999 dollars

Source: ADL, Long-Term Outlook*, 1999*

The thresholds used by the companies were generally $14 or $15 a barrel during the 1990s. Ever since the rise in prices that began in 2000, these figures have been revised upwards, initially to around $17 a barrel. After 2004 they rose to values on the order of $25 a barrel for large-scale projects, and sometimes higher. Note, however, that the development of tax rules and their diversity makes the use of a profitability threshold based on technological cost less relevant.

To complete this study, we need to provide some idea of the costs of non-conventional oil, synthetic hydrocarbons, and alternative fuels.

Extra-heavy oil and tar sand

The average cost of production of **Venezuelan extra-heavy oil** is of the order of $15 a barrel, with variable costs of the order of $6 a barrel for projects carried out before the rise in equipment and services prices of the last few years. Average costs could be around $20 a barrel for new projects. These are costs associated with so-called “cold” production, that is, using natural drainage in horizontal wells, a technology that leads to rather low rates of recovery (8–10%). The injection of steam would increase costs but would result in appreciably better recovery rates.

The cost of oil extracted from the **Athabasca tar sands** fell to less than $20 for ongoing production activities before the recent rise in gas prices, to which production costs are highly sensitive. According to the IEA (2006), these would range from $16 to $33 a barrel, whether production made use of mining technologies or petroleum technologies with steam injection (steam assisted gravity drainage, SAGD). The latter technologies consume natural gas for the production of heat at a rate that is at least twice as great as that for mining technologies. (The steam injected into horizontal wells fluidizes the crude, which is collected in other horizontal wells situated at a lower level). These elements take into account so-called “upgrading” facilities, which convert ultra-heavy crude with an API gravity of 9 to 11 degrees into lighter, “synthetic” crude of 25 to 35 degrees API.

While shale oil production has been around for a very long time, end of the 19th century, the process requires very high energy consumption. Research is being done in this area, especially by Shell in Colorado, using techniques for the transformation of kerogen by in situ heating. However, it is unlikely that this research will lead to any significant commercial production before 2020.

Synthetic hydrocarbons obtained from coal and gas

There are two methods for producing **synthetic hydrocarbons from coal** (coal-to-liquid or CTL). One entails direct conversion through the hydrogenation of coal, the other makes use of indirect conversion, coal gasification initially producing a synthesis gas (CO + H2), which is then transformed into liquid hydrocarbons by the Fisher-Tropsch process. The products obtained, primarily diesel fuels, are of excellent quality (free of sulfur and with a very high cetane number). During World War II, Germany made use of both types of processes. Currently the only factories of industrial capacity still using the Fischer-Tropsch process are the Sasol factories in South Africa. Several facilities are currently under construction in China. As for the direct hydrogenation process, a large-scale project is currently underway in China, with the participation of the IFP-Axens group (providing technology and engineering).

Prior to the recent (2004-2007) rise in the price of steel, raw materials, and services, CTL technologies were considered profitable for per-barrel prices of $50 and above (excluding costs associated with CO_2 emissions) for production units located near low-cost coal mines. Since then, estimates of breakeven points have been revised upwards to around $70–80 a barrel. Recall that coal reserves represent on the order of 200 years of production at the current rate (with considerable uncertainty however). The limitations of CTL will most likely arise not from constraints on raw materials but from the costs associated with CO_2 emissions.

The production of **liquid hydrocarbons from natural gas** (gas-to-liquid or GTL) also makes use of the Fischer-Tropsch process. The first plant of this type was built in 1991 by Mossgas (now Petro) in South Africa. Shell than brought on line a 14,500 barrels-per-day (b/d) facility in Malaysia. The rise in oil prices that began in 2000 has promoted studies for several new projects. Two of them were begun in Qatar, the first with a capacity of 34,000 b/d by Sasol at the end of 2003, the second by Shell in 2005 (70,000 b/d in the first phase and 70,000 b/d in the second phase, for a total capacity of 140,000 b/d). The first, which began testing in 2006, is scheduled to go on line in March 2007. The announced costs should be on the order of $25 per barrel when the gas is produced at low cost and supplied at low price ($0.5–1/MBTU) to produce high-quality diesel fuel. Assuming a crude oil price of $30 a barrel would ensure the profitability of the project. The higher cost of raw materials and services seen since 2004 has raised the stakes. With unit investment costs that are three times greater and a higher gas price, the Shell project would only be profitable with crude prices at $50–60 a barrel. The success of these initial projects will have a decisive effect on developments in this field. Different projects are being studied but developments will probably remain limited to niche production activities. These costs are, in fact, provided without considering the cost of CO_2 emissions, and GTL like CTL involves a significant consumption of energy. Additionally, opportunities risk being limited by the appearance of the global production "peak" for gas, which could follow the oil "peak" by ten to fifteen years, based on estimates by P. R. Bauquis[7]. Note, however, that according to other authors, the uncertainties concerning peak gas are stronger than those for peak oil. In particular, in the distant future, we cannot entirely exclude the development of production technologies that make use of methane hydrates (clathrates). These resources are poorly understood at present but could become highly significant.

Biofuels

The **biofuels** used today, so-called **first-generation** fuels, consist primarily of ethanol for gasoline engines and the methyl esters of vegetable oils for diesel engines. In 2005 worldwide production of ethanol fuel was 30 million tons compared to 4 million tons for biodiesel. Brazilian ethanol is produced from cane sugar at costs similar to, if not less than, those for traditional gasoline. Outside Brazil, the cost of biofuels is roughly double that (excluding taxes) of oil-based fuels (0.4–0.6 compared to 0.2–0.3 euros per liter in 2006). Although quantification is controversial, their contribution to the reduction of CO_2 emissions is significant. Their substitution potential for oil-based fuels is limited to a few percent because of competition with food production.

To go further it will be necessary to develop **second-generation systems**, which make use of **ligno-cellulosic** biomass (wood straw and entire plants). Optimistic estimates indicate a substitution potential of 30% by 2030. Biomass-to-liquid (BTL) systems involve gasification of the biomass followed by the production of kerosene and diesel fuel using the Fisher-

[7] "Les pics mondiaux du pétrole et du gaz" [Global Peaks in Oil and Gas], presentation to the Conseil d'Analyse Stratégique, Paris, Oct. 28, 2006.

Tropsch process. The second method is comparable to the production of ethanol by fermentation. These approaches are subject to considerable research in an attempt to reduce production costs, which can be estimated to be of the order of a euro per liter of oil equivalent at the present time (2007).

The role of technological progress

What about future developments? The hydrocarbon resources constituting the *continuum* mentioned above could be classified today by increasing cost. It is therefore likely that with the exhaustion of deposits that are easy to access, costs and prices will increase. This is not certain, however. Recall that in the early 1980s all the published scenarios for the development of oil prices pointed upward and technological progress played a determining role in proving those assumptions wrong. But if there is one field in which forecasting is an especially difficult art, it is that of technological change. There are many examples of this. In the energy sector, aside from the spectacular drop in production costs for extra-heavy oil already discussed, there have been improvements in the yield of combined cycle electrical production plants. Progress is often faster than anticipated, although it does not always occur when we expect it, as the case of nuclear fusion illustrates. Fifty years ago, it was believed that it could be controlled for applications to produce electricity within 35 to 50 years. We are still talking about a fifty-year horizon today, with little certainty about commercial prospects.

II.3. External costs and greenhouse gases

Available options in the energy sector must take into account concerns about climate change. Greenhouse gas emissions, associated with the use of fossil fuels, increase the temperature of our atmosphere. By the end of the century, the change could amount to as much as 1.5 to 6 degrees Celsius on average, according to experts from the Intergovernmental Panel on Climate Change (IPCC). Although there are considerable uncertainties about the scope and consequences of such emissions, there appears to be little doubt that it will lead to an increase in the frequency of "extreme events," including violent storms, floods, and heat waves. In spite of the United States' failure to ratify the Kyoto Protocol, European Union directives adhere to the logic of the commitments made in Kyoto, and a European market for CO_2 emissions permits has been in place since January 1, 2005. The different steps that will need to be taken to limit emissions will entail costs that will have to be tied to hydrocarbon use. Many analysts feel that constraints on greenhouse gases will have a greater effect on limiting the use of fossil fuels, and oil in particular, than resource scarcity.

Steam-assisted recovery, the processing of extra-heavy fuel, the use of tar sand or oil shale, and the conversion of gas or coal into liquid hydrocarbons all require high energy consumption and result in significant CO_2 emissions. The internalization of the corresponding external costs or the use of carbon capture and storage (CCS) can modify the hierarchy of direct costs. This may restrain the development of non-conventional oil and enhanced oil recovery processes intended to increase recovery rates. In this area technological progress plays a key role. To limit CO_2 emissions, the heat needed for enhanced oil recovery projects and the production of non-conventional oil could be provided by nuclear reactors. The capture and geological storage of carbon dioxide provide a number of alternatives, but the development of the corresponding costs is difficult to predict. Reduced capture and storage costs could promote new developments in the coal industry.

II.4. Geopolitical factors and short- and medium-term price formation

Oil is a strategic product for producing and consuming countries alike. Two-thirds of global reserves of conventional crude are located in the Middle East and 80% of proven global reserves are owned by National Companies. We all know how oil has influenced political events and the repercussions political events have had on the oil market. Oil market is a global market to the extent that transport costs are low and much lower than those associated with other energy sources. Geopolitical issues, therefore, are considerably different for oil and natural gas, which are related energy sources. Contemporary events that have had a major impact include the Six-Day war and Arab embargo, the Yom Kippur war, the Iranian Revolution, the Iran-Iraq war, and the two so-called "Gulf" wars. Figure 7 presents a summary of the history of the price of crude in relation to some of these events. Although of more limited impact, the uncertainty in Venezuela concerning the policies of President Chavez, or Europe's fears concerning Russian supplies, in particular issues related to energy transport through gas and oil pipelines, are important. OPEC's decisions also play a significant role in geopolitical events. However, although the 1973 conflict was a factor in triggering the first oil crisis, the price rise was inevitable given the rate of increase in demand (7–8% annually), which was considerably higher than the rate of increase in new reserves discoveries and production capacity.

Finally, in the producing countries the willingness to allow international companies to exploit natural resources is the result of political decisions. In Mexico and Saudi Arabia, for example, oil exploration and production are a monopoly of PEMEX and ARAMCO respectively, which are national companies. In Iran, foreign companies have limited access to exploration and production activities. The country has created an original type of contract known as the "buy back" contract, which is a short-term risk-service contract. It is designed to adhere to the principles embodied in the Iranian constitution, according to which the state has a monopoly on the development of petroleum resources. Such complex contractual arrangements represent a significant limitation for the host country and for international firms. For the past several years, we have seen how the Russian government has reasserted control over the oil and gas sectors; and more recently Latin America (Venezuela, Bolivia) has followed suit.

Figure 7. Price of crude oil (current dollars)

Source: DOE, USA

The cartel

Ever since the first oil crisis, increases in crude oil prices have been considered the result of behavior by the OPEC cartel[3], with Saudi Arabia playing a dominant role. Outside periods of sharply rising and falling prices, it has served as a price regulator, by agreeing to be the (or the principal) swing producer. To meet demand, the country increased sales in 1977–78. In 1979–80, limited by its production capacity, it was unable to meet the increased demand that was partly the result of speculative behavior (following the Iranian revolution) and allowed prices to "float." To maintain them at their new level, it reduced production from 1981 to 1985. This situation is atypical, however. The Persian Gulf reserves, which are very inexpensive to produce, should be sold before those with a higher marginal cost, assuming the existence of centralized global economic management or the presence of a competitive environment. The result was just the opposite, however. When demand contracted following the introduction of alternative energy sources and energy saving policies, non-OPEC production, as a result of the technological progress mentioned above, continued to grow while OPEC production fell, especially in Saudi Arabia. In 1985 it hit bottom (2.5 mb/d compared with 11 in 1980). The decline in revenues led to tensions within the organization. Saudi Arabia decided to regain its market share. This was the start of the "counter shock" and the drop in oil prices (figure 7).

What is the role of the market when Saudi Arabia has the will and ability to regulate activity? R. Mabro once quipped that Saudi Arabia and the market divide the work of determining crude oil prices: Saudi Arabia gets to determine the first two figures before the decimal point, while the market gets to determine the two figures following the decimal point! Note that Saudi Arabia assumed the bulk of oil production cuts between 1980 and 1985, but it refused to act alone in this role in 1998–99. The time needed to rally its OPEC partners as well as non-OPEC producers (Norway, Mexico, Russia) explains the lag before prices found a level that was considered satisfactory by the producing countries. In the interval, the low price levels led some analysts to speak of a loss of power on the part of OPEC. However, between 2000 and 2003, including during the American intervention in Iraq, OPEC demonstrated that it could exercise close control over the situation to hold prices within the range ($22–28 a barrel) it had established in March 2000, or at least could maintain the lower limit. The possibilities for regulation disappear, however, when excess production capacity becomes inadequate, as was the case in 1979 and after 2004.

The restoring force of the market

Along with P. N. Giraud [1995], we can consider that there is no single equilibrium price (or a single pathway for equilibrium prices) but a range of prices whose limits are difficult to quantify. Within this range, Saudi Arabia and its partners can maintain a target price over time. But if this price is too high (the 1980–85 period), the market forces, notwithstanding inertia, become effective: alternative sources, energy savings, investment in non-OPEC regions. Moreover, among the members of the cartel, the temptation to ignore quotas increases whenever prices are high. As S. Boussena[8] remarked, "OPEC is strong when prices are weak, but weak when prices are strong." The temptation becomes even greater when there

[3] More specifically, it is a dominant oligopoly with a competing fringe. The Arab countries with small populations and extensive reserves (Saudi Arabia, Kuwait, the Emirates), whose cash flow needs are less pressing and can more easily limit production, constitute the heart of the oligopoly (see, for example, P. N. Giraud [1995]).

[8] Associate professor at the University of Grenoble, former Algerian Energy Minister, former president of OPEC.

is significant excess capacity. It is then even more difficult to conclude agreements designed to distribute additional limits on productions levels among the members of the oligopoly.

On the other hand, when prices are low, investments by exploration and production companies are scaled back because of the reduced profit potential of new projects as well as a limitation on financing ability. Low prices also promote increased consumption, which can increase more rapidly than the growth in production capacity. This was the situation observed between 1998 and 2000. Moreover, considerable degradation in revenue could, in some countries, result in the growth of social movements and political instability that all participants seek to avoid.

We could summarize this by noting that in the petroleum industry, as in the majority of other industries, production capacities are sometimes excessive, sometimes saturated. When there is excess capacity, as always prices trend downward. It is primarily in such circumstances that OPEC can intervene. When production capacities are saturated, the price increases until capacities are restored. Since 2004 not only has excess production capacity been strongly reduced but refinery processing capacity has been saturated. The initial question was whether, following a transitional "squeeze" between supply and demand, prices could return to an equilibrium not very different from that of the 1990s, or if the rise seen in recent years reflects a structural modification, the increase in demand necessitating the search for production sources at higher marginal cost. Since 2005 many economists and politicians have come to believe that the latter is the correct view, and speak of a "paradigm shift" in the price of oil and other energy sources.

For the restoring force to be effective, several conditions are needed. For decisions to be made, actions to be taken, and investments made, it is not enough for prices to be high, one must assume they will remain high.

Expectations

Investment decisions are naturally based on assumptions about demand and medium- and long-term prices. But price forecasts are always difficult and, it is worth pointing out, in the petroleum market, often self-destructive. One especially relevant example relates to the 1985 price drop. Until then, all oil price forecasts pointed upward, as shown in figure 8? and this was true for several different scenarios. For example, in 1980 the French Planning Administration (Commissariat général du Plan) had defined three scenarios that revealed increases, in constant money units, of 2, 7 and 14% annually. Naturally, political decisions, such as those involving the French nuclear program, were made for reasons of energy independence, these immediately followed the first oil crisis. But significant energy savings, the use of alternative energy sources, research and development, and investments in the exploration and production of "difficult" oil in non-OPEC regions occurred not simply because the price of crude was high but because it was considered unlikely that prices would not continue their rise.

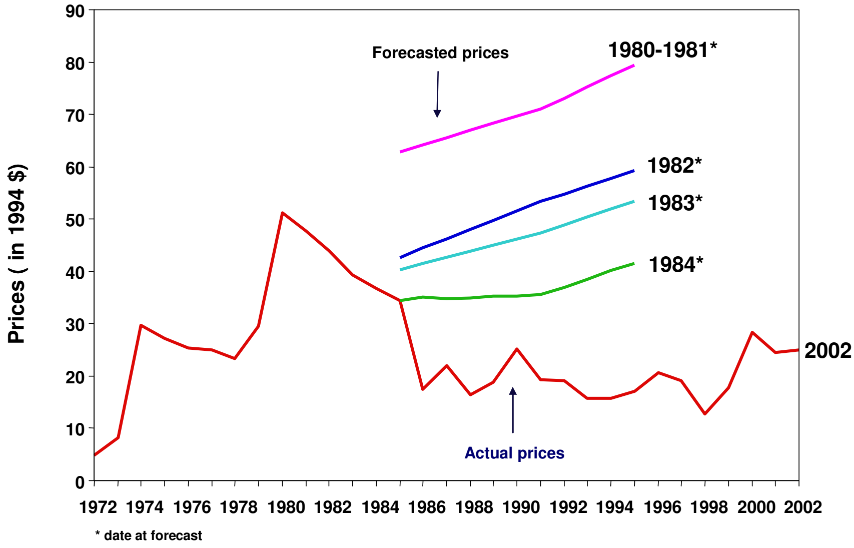

Figure 8. Changes in crude oil price forecasts

Source: ENSPM-FI based on Platt's, IEA, and BP Statistical Review

Expectation certainly played a role in the sequence of events leading to the saturation of production and refining capacity in 2004. The rate of growth of demand, especially in China since 2003, had not been anticipated. And, until the summer of 2003, nearly all analysts assumed Iraq would again participate in the market, with the development of new production capacities in the country, which would have resulted in significant overcapacity for OPEC. Increased Iraqi exports would have led to a necessary reduction in production from other OPEC countries, primarily Saudi Arabia. Such a consensus was obviously unfavorable to investment in those countries. Coupled with the slowdown in demand observed after the events of September 11, 2001, this led to a reduction in worldwide exploration and development expenditures in 2002 and 2003, on top of that of 1998–1999. In short, the prevailing consensus until mid-2003 on the existence of excess capacity contributed to the disappearance of that excess.

III. POSSIBLE DEVELOPMENTS

III.1. Demand

The first determinant of oil demand, as for energy demand in general, is economic growth. The elasticity of demand to GDP[9] is, in general, on the order of one or greater than one in developing nations. It is lower (0.7 to 0.9) in industrialized nations, where energy intensity[10] has been decreasing regularly for several decades. This trend should continue into the future. Thus, the IEA (2006) and the Energy Information Administration (EIA) of the United States Department of Energy (DOE) both predict a decline in worldwide energy intensity: a 1.7% annual decline until 2030 according to the IEA and 1.8% according to the EIA (this decline is

[9] The ratio of the relative variation in demand (expressed as a percentage) to the relative variation of gross domestic product (GDP), expressed in the same unit (a percentage, for example).

[10] The ratio of energy consumption to GDP.

considerably sharper than the one predicted by the IEA in 2004, which was 1.2% annually, based on higher price assumptions). In the case of oil, most analysts predict that the bulk of future growth in consumption will come from the developing countries, especially China and India. The transport sector should see its share of total consumption continue to grow. According to the IEA, this will account for three-fourths of the global rise in consumption during the next thirty years. Moreover, it is in the transport sector that it is more difficult to develop alternative energy sources.

The second determining factor in demand is, naturally, price. The elasticity of demand to the price of oil is difficult to estimate. It is low but not negligible. A figure that is currently cited, -0.05 for the short term, would imply a worldwide drop in consumption on the order of 2 mb/d if the price increases by 50%. This elasticity changes over time following the growth of uses for which there are no alternative sources and the modification of the behavior of consumers. Automobile drivers, for example, are less sensitive to increased fuel prices when their income is high. It should be pointed out that, while crude prices are approaching, in constant money , their value in the early 1980s, the price of a liter of gasoline compared to household income in the industrialized countries is approximately half that for the earlier period[11]. Analysis of the impact of a price increase on economic growth is also difficult. The IEA (2004) study gave an estimate of a drop of approximately 0.5% for a ten dollar increase in the price of a barrel of oil. The effects observed in 2003 to 2006 appear much less significant. Finally, in many countries a factor affecting the low sensitivity of demand remains the subsidies given to petroleum products, which masks the signals reflected in the price of crude oil. In other countries, as in Europe as a whole, it is the effect of taxes on automotive fuels, partly independent of the price of crude oil, which diminishes the impact of crude oil price changes.

For the next twenty or thirty years, official organizations, at least in their "business as usual scenarios" foresee increased growth in oil demand, with the IEA (2006b) predicting 1.3% per year, the European Commission (2007) 1.5%, and Shell (2005) from 1 % to 1.9%. Note that the majority of these organizations have lowered their estimates from previous years because of the rise in prices and the reduced likelihood of a significant drop in prices in the future. Thus, the rate of growth in world oil demand predicted by the IEA (2006) dropped from 1.9% to 1.1% annually between the 2004 and the 2007 issues of their Annual Energy Outlook.

These scenarios present two problems. The first is the availability of resources. Earlier we discussed the various points of view, and we'll return to this issue below. The second is that of greenhouse gas emissions, which are increasing roughly in proportion to the consumption of fossil fuel. Therefore, because the IEA (2006b) reference scenario shows unacceptable levels of carbon dioxide emissions, the agency recommends greater use of pro-active policies, which should give rise to an "alternative" scenario that will limit oil demand to 103 mb/d in 2030 rather than 116. To go beyond this, it will be necessary to accelerate the development of the appropriate technologies, which is possible, as shown by the Accelerated Technologies (IEA 2006a) scenarios for 2050, allowing for a reduction of 56% in the growth of oil consumption compared to the 2050 baseline scenario. These scenarios would lead to emissions for the entire energy sector undergoing growth, compared to 2003, of 6–27% rather than the +137% given in the reference scenario. The most favorable, Tech Plus, would result in a 16% decrease.

11 A certain stability in the share of household income devoted to fuel consumption has been observed. See F. Lescaroux and O. Rech (2006).

Similarly, the European Commission's "carbon constraint" scenario is a "factor 2" (cuts emissions in half) scenario for the European Union. Globally, it shows emissions to be 25% greater than in 1990. It assumes the growth of the price of a ton of CO_2—which is linear for the industrialized countries, slower for the developing countries—with prices reaching €200 a ton by 2050. It anticipates a reduction compared to the reference scenario of approximately 20% in oil consumption by 2050, a little more than 100 mb/d, once a very flat peak is passed around 2040.

These values are still very far from the objectives issued by the European Union and other countries, including France, that want to cut worldwide emissions in half and emissions in the industrialized countries by a factor of four. Such objectives would require much more profound changes in behavior and would result in a cost per ton of CO_2 of several hundred euros (see ENERDATA [2005]).

The need for pro-active policies was also highlighted by the World Energy Council (2003). They presented two scenarios for the first half of the twenty-first century. One of them is characterized by a lack of long-term vision on the part of the various decision-makers, in particular, investment decisions, the emphasis being on short-term market considerations. The resulting inertia would make the necessary changes more difficult. The lack of international coordination and the inability to conduct essential activities in the desired time frame, would lead to the "threat of an unlivable world." The rise in temperatures would result in drought, famine, and an increase in tropical diseases at high latitudes. In the second scenario, "the possibility of a livable world" would appear after two or three decades of deterioration in our environment, once policies of sustainable development were implemented and essential behavioral changes had been established.

III.2. Production

The Hubbert Curve

A first approach to analyzing possible future production consists in using the method of M. King Hubbert, in which the curve for worldwide oil production resembles a nearly symmetric bell curve. Although the likelihood that it will be verified is very small, as we'll see later on, we will use it for a first hypothesis. As noted previously, the amount of USGS ultimate reserves could lead to the appearance of a production maximum between 2020 and 2030. We should note that the curve for discoveries of a basin is not always symmetric and resembles a log-normal curve more often than a Gaussian curve. It is also important to note that a bell curve displays the appearance of a shift, a slowdown in the growth of production, and therefore the impossibility of responding to increased demand long before the date of the "peak." Thierry Desmaret, then chairman and CEO of Total, presented a curve of this type[12] in 2004, illustrating the inability of supply to meet demand around 2010. Similarly, figure 4, presented in section I.4, shows Hubbert curves for different supply assumptions.

In fact, regardless of the anticipated date of the "peak," it is unlikely that the worldwide production curve would have the regular and symmetrical shape Hubbert predicted in the case of the United States. This can be explained by the ability of the U.S. to make use of imports. Globally, the appearance of a peak or awareness of its arrival risks generating a spike in prices, a third oil crisis of varying severity depending on the degree of expectation. As in 1980 the use of energy savings and alternative fuels could slow demand. The production curve could then shift more rapidly than the Hubbert curve, as was the case with the first two oil crises. This could also occur if investment does not follow growth in demand.

The role of investment

The preponderant factor today and in the near future is, no doubt, associated with the rate of investment needed to develop production capacity. As we have seen, the present situation is characterized by the near disappearance of excess production capacity, explained by insufficient investment to meet accelerating demand that was not anticipated in 2003 and 2004. We discussed the role of expectation and the lack of sufficient opportunities in the exploration field. Oil companies can only invest in countries open to outside investment. That was not the case in the recent past in many of the OPEC countries. Those countries with the best potential for discovery and development are closed or provide few opportunities for foreign investment.

The growth of investment in upstream petroleum processes has certainly resumed, stimulated by the increase in prices. However, investments have been proportionally smaller than those we might have expected based on the observation of previous price increases (approximately half as much). Investment growth has encountered not only the problem of opportunities in the field of exploration but also the saturation of capacity in the oil services industry. This has led to a sharp rise in prices in the oil services field during the recent past (2004–2007), with the cost of renting offshore drilling platforms increasing by a factor of three. The insufficient availability of this type of equipment naturally constitutes a brake on investment. Moreover, statistics for investment expenses can be misleading, for they indicate increases in monetary values that only partly correspond to increases in volume.

[12] Oil Summit, Paris, April 29, 2004.

Paradoxically, the rise in prices, which should have a positive effect on investment, can actually limit it, because it encourages some producing countries to revise the contract terms and tax requirements of international companies operating within their borders. The availability of significant financial resources gives them new bargaining power, which extends the deadlines for decision-making and implementation. Finally, uncertainty about continued growth in demand and the possibility of an oil price drop results in caution on the part of national corporations in the producing countries.

In the coming years, tension over prices in the oil services industries should attenuate, and we should see new developments in the means and capacities of the oil services industries that promote investment. An increase of excess capacity is possible by 2010–2012, on the order of a few million barrels per day, as shown by various studies (IFP, CERA, Société Générale).

In the longer term, there are many uncertainties but nearly all the studies indicate an inevitable leveling off of non-OPEC production that could occur around 2010 for geological reasons. As for the OPEC countries, some of them, especially Saudi Arabia, would like to limit their production and, therefore, their capacity, to values that can be sustained in the long term or very long term.

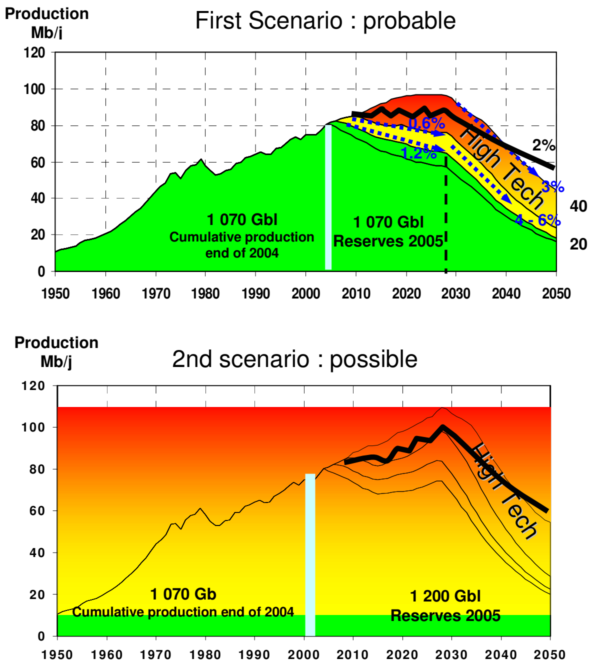

Figure 9. Production scenarios

Source: Yves Mathieu (2006)

Following a series of studies conducted by the IFP on planned investment and potential, region by region, Y. Mathieu (2006) considered that we were most likely to see a fluctuation in worldwide production around 90 mb/d during the next two decades (the solid line in the graph in figure 9). This production includes non-conventional oil sources. Therefore, the production of Canadian tar sand, which was 1 mb/d in 2005, could reach 3 mb/d by 2015 and 5 mb/d by 2030. However, this would most likely be insufficient for delaying the date when global production levels off, a production figure that is appreciably lower than that given by the Hubbert curve because of the insufficient investment. This "undulating ceiling" around 90 mb/d, possibly 100 mb/d (dotted line in figure 9), could be maintained until 2025–2030 through the use of non-conventional oil sources. Beyond that, worldwide production would inevitably decline, although continuing past the end of the century.

III.3. Prices

We do not intend to provide any forecasts, those made in the past by the majority of experts having been proven wrong. We will simply offer a few elements for further study and present the principal scenarios developed by various organizations.

Short and medium term

We mentioned restraints on investment and the low elasticity of demand to price. Except for a major global economic crisis, it is hard to imagine a rapid restoration of significant excess production capacity. Consequently, it is not impossible that prices will remain high in the coming years, and may even be subject to new tensions as a result of geopolitical events. If excess capacity does appear, as indicated above (CERA, IFP and other studies), these will most likely be limited to values that can be managed by OPEC. Prices should be able to be maintained at a level considered desirable by Saudi Arabia and its partners. They have learned the lesson of the 1986 price drop and are likely to define a price, or range of prices, that do not lead to a collapse of demand for OPEC oil through the use of alternative fuels and energy savings. It is hard to estimate that level. It will most likely be less than the price reached during the summer of 2006, but will certainly be greater than that of the 1990s. Indeed, the growth in demand and the next occurrence of a leveling-off of non-OPEC production make it unlikely we will see any substantial erosion of OPEC market share at prices of $40, or even $50 a barrel. In the medium term, such levels could form a lower limit for declining prices. In the longer term, there are a variety of possible scenarios.

Low-price scenarios

Until 2003, and even 2004, most reference scenarios put forth by official organizations such as the IEA, EIA, and European Commission offered an optimistic picture of possible production through the increased use of Mideast oil, exploration activities, and the improvement of recovery rates. This meant a limited rise in prices with, for example, the IEA (2004) predicting an increase to $25 a barrel by 2020 and to $29 by 2030. Shell (2001) constructed longer term scenarios (2050). These assumed technological progress for recovery of non-conventional oil, the production of liquid fuels from natural gas or biomass, as well as the continued improvement in the efficiency of automobile engines and technologies for other uses. Assuming, as well, a strong reduction in the use of petroleum products outside the transport sector, the slack would have been picked up in time by renewable energy sources and, therefore, without a significant impact on prices, which would remain around $20 a barrel. An appreciable decrease in petroleum production would then be delayed until around 2040.

Low-price scenarios or, more exactly, a return to low prices, seem unlikely today. They cannot be completely excluded, however. They could result from the implementation of very pro-active policies for reducing greenhouse gas emissions. They would entail very significant changes in behavior and considerable investment in all energy sectors: energy efficiency, oil production capacity, renewable and nuclear energy. Thus, the 2050 DGEMP-ENERDATA

(2005) “Factor 4” scenario (where greenhouse gases in France would be reduced by a factor of four by 2050) results in crude oil prices of $20–30 a barrel, the essential reduction in the consumption of fossil fuel pushing the problem of resource scarcity into the background. Other factors leading to a long-term price drop would include a generalized slowdown in growth worldwide (for example, associated with an economic crisis caused by U.S. deficits). In the most optimistic assumptions, unanticipated benefits could arise from geology (such as significant reserves of deeply buried hydrocarbons) or major technological advances that are now hard to imagine (such as significant improvements in rates of recovery).

The outlook of the official organizations

With the rise in prices over the past few years, official organizations have revised their price assumptions upward (and lowered their assumptions for the growth of oil demand, as indicated above). For example, between the 2005 and 2006 Annual Energy Outlook, the EIA raised the price for its reference scenario for 2030 to $57 a barrel, an increase of $20 a barrel (somewhat surprising given that there was hardly any change in the long-term data from the previous year). In the 2007 edition, the price of crude moderates to $50 a barrel in 2014, because of the increase of production capacity, and rises to $59 (2005 dollars) in 2030, given the need to make use of more expensive resources. In the IEA (2006b) “Business as Usual” scenario from its 2006 World Energy Outlook, the price of crude oil (average supply of IEA member countries in constant dollars) is $47 per barrel in 2012, $50 in 2020, and $55 in 2030, while the previous edition gave figures of $35 per barrel in 2010 and $39 in 2030. In the case where restraints on investment, which we have spoken of, could not be lifted (“Deferred Investment” scenario), prices would be increased by a third. The European Commission has prices of $40 per barrel in 2010, $60 per barrel in 2030, and $110 per barrel in 2050 in the reference scenario. In the “Coal Constraint” scenario, the 2050 price would be $90 per barrel.

“Dual-crisis” scenarios

Since 1987 price volatility has increased and it seems unlikely it will be reduced. The representative curve of price change would resemble a “two-hump camel,” to borrow an expression from Pierre Radanne (2004). It also corresponds to the scenario considered to be the most likely by D. Babusiaux (2006) and P. R. Bauquis (2006). It reflects a “dual-crisis” scenario, which would present a number of similarities with the developments observed between 1973 and the end of the 1980s. It has often been said that the recent rise in prices was not comparable to that of 1973, the first oil crisis having been triggered by a reduction in supply while the latest one would be due to runaway demand. Note, however, that during the 1960s, worldwide consumption of petroleum products increased by 7 to 8% annually, but production capacities did not increase at the same rate. The events associated with the Israeli-Arab conflict (the Yom Kippur war) accelerated the rise in prices, but that rise would most likely have occurred anyway, although spread out over time. In short, the rise in prices over the past several years, as in 1973, reveals the need for consuming countries to make decisions. Several steps have been taken. However, these may prove to be inadequate if demand growth continues. As indicated above, in the absence of geopolitical events, it is possible that production capacities will be restored if all development projects are realized as planned. We might then see a stabilization or an erosion of prices for several years. The decline observed during the final months of 2006 is consistent with this. Then, even if the “oil peak,” strictly speaking, only occurs around 2030, it is likely, as we have seen, that the production of natural hydrocarbons will be unable to follow demand beginning in the next decade. Before prices return to the new long-term equilibrium mentioned above (estimated by P. R. Bauquis at approximately $100 a barrel in 2000 dollars), it is highly likely that an additional “crisis” will occur, with price levels of $200 per barrel or more. It may be necessary for investments to be made both on the supply side as well as on the demand side in order to:

- implement energy savings policies
- strongly reduce consumption associated with automobile transport
- develop renewable energy sources without major subsidies
- stimulate the production of synthetic fuels
- renew nuclear programs
- develop the production of hydrogen from nuclear or renewable energy

Paradoxically, to avoid this and promote an intermediate scenario such as those presented by the IEA or the DOE, this “dual-crisis” scenario and a scarcity of natural hydrocarbons would have to be considered inevitable. Bear in mind the role played by expectations and how forecasts can be self-destructive in the oil industry. The most effective factor for avoiding scarcity would be the appearance of a consensus about its arrival. This would encourage all participants to make decisions on a timely basis, industrial producers to make investments, governments to carry out the necessary measures, and regulations promoting energy efficiency to be implemented, or even taxes to be levied. Such measures have been proposed by J. M. Jancovici (2006); others were put forth by H. Prévot (2006) for the purpose of reducing greenhouse gas emissions.

CONCLUSION

A future without oil crises is quite unlikely, even if we retain optimistic hypotheses of technological progress in the exploration and production sector, in the use of petroleum products, and in the field of alternative technologies. It is not enough that resources and technologies are available, timely investments must be made in energy management and alternative fuel technologies, and in the development of oil production capacity. This last point would assume a continuous pro-active effort on the part of OPEC countries to make investments with a certain amount of foresight. The investments in question are often considerable and just-in-time management is not favorable to the existence of excess capacity. Moreover, it is not clear that such behavior is in OPEC’s interest.

Finally, we must not forget that the question of the future of oil is only one of the elements of a much larger problem—the ability to ensure a sustainable development of human societies. Water and agriculture are the major factors, along with health, and will require increasingly greater amounts of energy. The real question is not about hydrocarbons but about all energy sources. The twenty-first century will only be able to resolve these problems if we make a concerted effort to rid ourselves of our addiction to the use of energy. We will also need to make use of synergistic effects in promoting the use of different forms of energy: upstream and downstream cooperation between oil and nuclear energy, cooperation between renewable energy and nuclear energy.

BIBLIOGRAPHY

Adelman M. A., Lynch M. (1997), "Fixed view of resource limits create undue pessimism", *Oil and Gas Journal,* 4/7

Alba P., Bourdaire J. M. (2000), “Le prix du pétrole,” *Revue de l'Énergie*, 516, May.

Artus P. (2005), “Un baril à 300 dollars,” *La Tribune,* 2, December.

Babusiaux D., Lescaroux F. (2006), “Prix du pétrole et croissance économique,” *Réalités industrielles*, August.

Babusiaux D., Bauquis P. R., *et al.* (2002), *Recherche et production du pétrole et du gaz, Réserves, coûts, contrats* (Paris: Technip).

Bauquis P. R. (2004), “Quelles énergies pour les transports au 21ème siècle?” *Les Cahiers de l'Economie,* 55, Institut français du Pétrole, October.

Bauquis P. R. (2006), Oil and Gas in 2050, Energy Forum, Cambridge, U.K., March15, 2006.

Bramley D., Ferrero C. (2007) "Global Hydrocarbon resources" *SPE Executive summit,* June

Campbell C. J. (1997), *The Coming Oil Crisis* (Essex, England: Multi-Science Publishing).

Deffeyes K. S. (2002) *Hubbert's Peak : The Impending Oil Shortage* (Princeton, NJ : Princeton University Press)

Giraud P.N. (1995), “The Equilibrium Price Range of Oil – Economics, Politics and Uncertainty in the Formation of Oil Prices,” *Energy Policy*, 23, 1.

Hotelling H.(1931), “The Economics of Exhaustible Resources,” *Journal of Political Economy*, 39, 2.

Hubbert M. K. (1956) "Nuclear energy and the fossil fuels" *Drilling and production practice* American Petroleum Institute, Proceedings Spring Meeting, San Antonio, Texas, 7-25.

Jancovici J.-M., Granjean A. (2006), *Le plein s'il vous plait!* (Paris: Le Seuil).

Laherrere J. (2006) "Uncertainty in data and forecasts", ASPO conference, Italy

Lescaroux F., Rech O., (2006) “L'origine des disparités de demande de carburant dans l'espace et le temps: l'effet de la saturation de l'équipement en automobiles sur l'élasticité revenu,” *Les cahiers de l'économie* n. 60, June, Institut Français du Pétrole.

Lynch M. (2007) "Crying wolf. Peak oil alarmism : fact or fiction?" *CLSA U Blue book* www. clsau.com, March.

McCabe P. (1998) "Energy resources-cornucopia or empty barrel?" *AAPG Bulletin*

Mathieu Y. (2006), “Quelles réserves de pétrole et de gaz?” *Conférence AFTP-SPE-Université Total,* Paris, June 14.

Mitchell J. (2006) “A New Era for Oil Prices,” Chatham House, London www.chathamhouse.org.uk, August.

Perrodon A. (2003), “Des grandes vagues de l'exploration à l'estimation des réserves ultimes,” *Pétrole et technique*, May-June.

Prevot H. (2007), *Trop de pétrole! – énergie fossile et réchauffement climatique* (Paris: Le Seuil).

Radanne P. (2003), “Chocs et contre-chocs pétroliers (1960 2060),” *Annales des Mines - Responsabilité Environnement,* October.

Simmons M. R. (2005) *Twilight in the desert* (Hoboken, N. J. : J. Wiley)

Solow R.M. (1974), “The Economics of Resources or the Resources of Economics,” *American Economics Review*, 64.

Conseil d'Analyse Economique (2001), Joël Maurice, *Prix du pétrole* (Paris: La Documentation Française).

Conseil Mondial de l'Energie (2003), *Une seule planète pour tous* (Paris: Conseil Français de l'Energie.

DGEMP-Observatoire de l'Energie (2004), “Scénario énergétique tendanciel à 2030,” *BIP* 10129 and 10130, July 5 and 6, 2004.

Enerdata (2005), *Etude pour une étude prospective concernant la France*, DGEMP, February 1.

Energy Information Administration (2006), *Annual Energy Outlook 2007 with Projections to 2030* (Early Release) (Washington D.C.: United States Department of Energy), December, http://www.eia.doe.gov.

European Commission (2007), *World Energy Technology Outlook – 2050 – WETO H2* (Luxembourg: Office for Official Publications of the European Communities).

European Commission (2003), *World Energy, Technology and Climate Policy Outlook* (Luxembourg: Office for Official Publications of the European Communities).

International Energy Agency (2006a), *Energy Technology Perspectives 2006, Scenarios & Strategies to 2050* (Paris: IEA Publications).

International Energy Agency (2006b), *World Energy Outlook 2006* (Paris: IEA Publications).

International Energy Agency (2004), *Analysis of the Impact of High Oil Prices on the Global Economy* (Paris: IEA Publications).

Royal Dutsch Shell (2005), *The Shell Global Scenarios to 2025. The Future Business Environment: Trends, Trade-Offs, and Choices* (London: Royal Dutch Shell).

Shell International (2001), *Energy Needs, Choices and Possibilities, Scenarios to 2050* (London: Shell Center).

United States Geological Survey (2000), *World Petroleum Assessment 2000* (Washington D.C.: United States Geological Survey).

Already appeared

CEG-1. D. PERRUCHET, J.-P. CUEILLE,
Compagnies pétrolières internationales : intégration verticale et niveau de risque.
Novembre 1990

CEG-2. C. BARRET, P. CHOLLET,
Canadian gas exports: modeling a market in disequilibrium.
Juin 1990

CEG-3. J.-P. FAVENNEC, V. PREVOT,
Raffinage et environnement.
Janvier 1991

CEG-4. D. BABUSIAUX,
Note sur le choix des investissements en présence de rationnement du capital.
Janvier 1990

CEG-5. J.-L. KARNIK,
Les résultats financiers des sociétés de raffinage distribution en France 1978-89.
Mars 1991

CEG-6. I. CADORET, P. RENOU,
Élasticités et substitutions énergétiques : difficultés méthodologiques.
Avril 1991

CEG-7. I. CADORET, J.-L. KARNIK,
Modélisation de la demande de gaz naturel dans le secteur domestique : France, Italie, Royaume-Uni 1978-1989.
Juillet 1991

CEG-8. J.-M. BREUIL,
Émissions de SO2 dans l'industrie française : une approche technico-économique.
Septembre 1991

CEG-9. A. FAUVEAU, P. CHOLLET, F. LANTZ,
Changements structurels dans un modèle économétrique de demande de carburant.
Octobre 1991

CEG-10. P. RENOU,
Modélisation des substitutions énergétiques dans les pays de l'OCDE.
Décembre 1991

CEG-11. E. DELAFOSSE,
Marchés gaziers du Sud-Est asiatique : évolutions et enseignements.
Juin 1992

CEG-12. F. LANTZ, C. IOANNIDIS,
Analysis of the French gasoline market since the deregulation of prices.
Juillet 1992

CEG-13. K. FAID,
Analysis of the American oil futures market.
Décembre 1992

CEG-14. S. NACHET,
La réglementation internationale pour la prévention et l’indemnisation des pollutions maritimes par les hydrocarbures.
Mars 1993

CEG-15. J.-L. KARNIK, R. BAKER, D. PERRUCHET,
Les compagnies pétrolières : 1973-1993, vingt ans après.
Juillet 1993

CEG-16. N. ALBA-SAUNAL,
Environnement et élasticités de substitution dans l'industrie ; méthodes et interrogations pour l'avenir.
Septembre 1993

CEG-17. E. DELAFOSSE,
Pays en développement et enjeux gaziers : prendre en compte les contraintes d'accès aux ressources locales.
Octobre 1993

CEG-18. J.P. FAVENNEC, D. BABUSIAUX,*
L'industrie du raffinage dans le Golfe arabe, en Asie et en Europe : comparaison et interdépendance.
Octobre 1993

CEG-19. S. FURLAN,
L'apport de la théorie économique à la définition d'externalité.
Juin 1994

CEG-20. M. CADREN,
Analyse économétrique de l'intégration européenne des produits pétroliers : le marché du diesel en Allemagne et en France.
Novembre 1994

CEG-21. J.L. KARNIK, J. MASSERON,*
L'impact du progrès technique sur l'industrie du pétrole.
Janvier 1995

CEG-22. J.P. FAVENNEC, D. BABUSIAUX,
L'avenir de l'industrie du raffinage.
Janvier 1995

CEG- 23. D. BABUSIAUX, S. YAFIL,*
Relations entre taux de rentabilité interne et taux de rendement comptable.
Mai 1995

CEG-24. D. BABUSIAUX, J. JAYLET,*
Calculs de rentabilité et mode de financement des investissements, vers une nouvelle méthode ?
Juin 1996

CEG-25. J.P. CUEILLE, J. MASSERON,*
Coûts de production des énergies fossiles : situation actuelle et perspectives.
Juillet 1996

CEG-26. J.P. CUEILLE, E. JOURDAIN,
Réductions des externalités : impacts du progrès technique et de l'amélioration de l'efficacité énergétique.
Janvier 1997

CEG-27. J.P. CUEILLE, E. DOS SANTOS,
Approche évolutionniste de la compétitivité des activités amont de la filière pétrolière dans une perspective de long terme.
Février 1997

CEG-28. C. BAUDOUIN, J.P. FAVENNEC,
Marges et perspectives du raffinage.
Avril 1997

CEG-29. P. COUSSY, S. FURLAN, E. JOURDAIN, G. LANDRIEU, J.V. SPADARO, A. RABL,
Tentative d'évaluation monétaire des coûts externes liés à la pollution automobile : difficultés méthodologiques et étude de cas.
Février 1998

CEG-30. J.P. INDJEHAGOPIAN, F. LANTZ, V. SIMON,
Dynamique des prix sur le marché des fiouls domestiques en Europe.
Octobre 1998

CEG-31. A. PIERRU, A. MAURO,
Actions et obligations : des options qui s'ignorent.
Janvier 1999

CEG-32. V. LEPEZ, G. MANDONNET,
Problèmes de robustesse dans l'estimation des réserves ultimes de pétrole conventionnel.
Mars 1999

CEG-33. J. P. FAVENNEC, P. COPINSCHI,
L'amont pétrolier en Afrique de l'Ouest, état des lieux.
Octobre 1999

CEG-34. D. BABUSIAUX,
Mondialisation et formes de concurrence sur les grands marchés de matières premières énergétiques : le pétrole.
Novembre 1999

CEG-35. D. RILEY,
The Euro
Février 2000

CEG-36. et 36bis. D. BABUSIAUX, A. PIERRU,*
Calculs de rentabilité et mode de financement des projets d'investissements : propositions méthodologiques.
Avril 2000 et septembre 2000

CEG-37. P. ALBA, O. RECH,
Peut-on améliorer les prévisions énergétiques ?
Mai 2000

CEG-38. J.P. FAVENNEC, D. BABUSIAUX,
Quel futur pour le prix du brut ?
Septembre 2000

ECO-39. S. JUAN, F. LANTZ,
La mise en œuvre des techniques de Bootstrap pour la prévision économétrique : application à l'industrie automobile
Novembre 2000

ECO-40. A. PIERRU, D. BABUSIAUX,
Coût du capital et étude de rentabilité d'investissement : une formulation unique de l'ensemble des méthodes.
Novembre 2000

ECO-41. D. BABUSIAUX,
Les émissions de CO_2 en raffinerie et leur affectation aux différents produits finis
Décembre 2000

ECO-42. D. BABUSIAUX,
Éléments pour l'analyse des évolutions des prix du brut.
Décembre 2000

ECO-43. P. COPINSCHI,
Stratégie des acteurs sur la scène pétrolière africaine (golfe de Guinée).
Janvier 2001

ECO-44. V. LEPEZ,
Modélisation de la distribution de la taille des champs d'un système pétrolier, LogNormale ou Fractale ? Une approche unificatrice.
Janvier 2001

ECO-45. S. BARREAU,
Innovations et stratégie de croissance externe : Le cas des entreprises parapétrolières.
Juin 2001

ECO-46. J.P. CUEILLE,
Les groupes pétroliers en 2000 : analyse de leur situation financière.*
Septembre 2001

ECO-47. T. CAVATORTA,
La libéralisation du secteur électrique de l'Union européenne et son impact sur la nouvelle organisation électrique française
Décembre 2001

ECO-48. P. ALBA, O. RECH,
Contribution à l'élaboration des scénarios énergétiques.
Décembre 2001

ECO-49. A. PIERRU,*
Extension d'un théorème de dualité en programmation linéaire : Application à la décomposition de coûts marginaux de long terme.
Avril 2002

ECO-50. T. CAVATORTA,
La seconde phase de libéralisation des marchés du gaz de l'Union européenne : enjeux et risques pour le secteur gazier français.
Novembre 2002

ECO-51. J.P. CUEILLE, L. DE CASTRO PINTO COUTHINO, J. F. DE MIGUEL RODRÍGUEZ,*
Les principales compagnies pétrolières indépendantes américaines : caractéristiques et résultats récents.
Novembre 2002

ECO-52. J.P. FAVENNEC,
Géopolitique du pétrole au début du XXI^{e} siècle
Janvier 2003

ECO-53. V. RODRIGUEZ-PADILLA,
avec la collaboration de T. CAVATORTA et J.P. FAVENNEC,*
L'ouverture de l'exploration et de la production de gaz naturel au Mexique, libéralisme ou nationalisme
Janvier 2003

ECO-54. T. CAVATORTA, M. SCHENCKERY,
Les majors pétroliers vers le multi énergies : mythe ou réalité ?
Juin 2003

ECO-55. P.R. BAUQUIS,*
Quelles énergies pour les transports au XXI^{e} siècle ?
Janvier 2004

ECO-56. A. PIERRU, D. BABUSIAUX,
Évaluation de projets d'investissement par une firme multinationale : généralisation du concept de coût moyen pondéré du capital et conséquences sur la valeur de la firme.
Février 2004

ECO-57. N. BRET-ROUZAUT, M. THOM,
Technology Strategy in the Upstream Petroleum Supply Chain.
Mars 2005

ECO-58. A. PIERRU,
Allocating the CO_2 emissions of an oil refinery with Aumann-Shapley prices.
June 2005

ECO-59. F. LESCAROUX,
Les conséquences économiques de la hausse du prix du pétrole.*
Mai 2006

ECO-60. F. LESCAROUX, O. RECH
L'origine des disparités de demande de carburant dans l'espace et le temps : l'effet de la saturation de l'équipement en automobiles sur l'élasticité revenu.
Juin 2006

ECO-61. C. I. VASQUEZ JOSSE, A. NEUMANN,
Transatlantic Natural Gas Price and Oil Price Relationships - An Empirical Analysis.
Septembre 2006

ECO-62. E. HACHE,
Une analyse de la stratégie des compagnies pétrolières internationales entre 1999 et 2004.
Juillet 2006

ECO-63. F. BERNARD, A. PRIEUR,
Biofuel market and carbon modeling to evaluate French biofuel policy.
Octobre 2006

ECO-64. E. HACHE,
Que font les compagnies pétrolières internationales de leurs profits ?
Janvier 2007

ECO-65. A. PIERRU,
A note on the valuation of subsidized Loans - Working paper
Janvier 2007

* une version anglaise de cet article est disponible sur demande