

Capital Expenditure and Depletion

In the future, the increase in oil demand will be covered for the most part by non conventional oils, but conventional sources will continue to represent a preponderant share of the world oil supply. Their depletion represents a complex challenge involving technological, economic and political factors. At the same time, there is reason for concern about the decrease in exploration budgets at the major oil companies.

Capital Expenditure

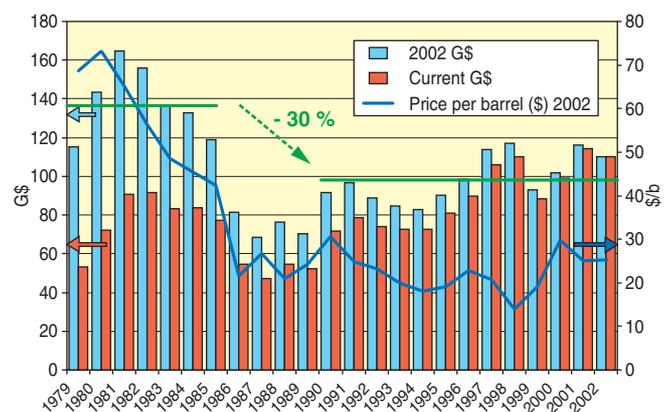
In the course of the last three decades, the oil industry has been completely transformed with the deintegration of the supply chain. In the wake of the nationalizations of the 1960s and '70s and the recomposition of the oil scene, the industry had to face the challenge of industrial adaptation. Until the 1970s, the creation of value was associated with an industrial model for the vertical integration of the oil supply chain, from upstream to downstream. Today, it depends on the performance of each link in the chain.

Two simultaneous constraints caused the majors to reassess their capital expenditure (capex) allocation strategies. First of all, the vertical model of integration had become obsolete; secondly, it became necessary to redeploy access to oil and gas acreage following nationalizations in key producing countries. Consequently, the oil companies immediately revised their capex budgets upwards in volume and modified their breakdown, with a massive emphasis on exploration-production. Capital investment budgets rose from 20 to \$80 billion between the first oil shock and the early 1980s or a rise from 70 to \$160 billion in constant 2002 dollars, the highest level ever observed. This particularly high level was sustained by a price per barrel of \$35, equivalent to nearly \$70 in constant 2002 dollars. In 1985 and 1986, capital spending was hit hard by the counter-shock, falling 30% to \$50 billion. The oil price, relatively low, did not provide much incentive for launching an ambitious capex policy. The Gulf War in 1990 marked the beginning of a new era, because total capital expenditure rose to about \$70 billion and stayed there for years before culminating at nearly \$110 billion in 1998. Starting in late 1997, however, the price of oil declined, which heavily affected all oil-related sectors: in 1999, the capex budget fell by nearly 20%. Prices have been high since 2000, which helps maintain total capital expenditure close to the record high of \$110 billion.

In the 1990s, upstream capital investment reacted to economic conditions. In other words, it seemed to react to fluctuations (upwards or downwards) in the price per barrel

with a time lag of 6 months to one year. Due to inertia, the average capex variations are diminished by a factor of 2 compared to those of crude prices. When the price per barrel rises or falls—especially when it falls—the first type of investment to be affected is exploration. When oil companies reduce their development budgets, the effect is not perceptible until a year later, when they decide to postpone projects. Some regions of the world react faster to crude price variations than others. This is true of North America. For instance, when prices dropped in 1998, capital expenditure in this part of the world was scaled back almost immediately although, elsewhere, it continued to rise and would not show a downturn until 1999.

Fig. 1 Trend in oil and gas capital expenditure in E&P



Source: IFP/DEE

Since 2000, it is true that exploration-production spending has returned to a level more consistent with the crude price, but **the impact of certain economic factors, observed in the 1990s, seems more tenuous.** The high oil prices recorded in 2000 and 2002 did not convince companies to revise their capex budgets upwards, as they did in previous years. Today, each oil company must arbitrate between several objectives: it must divide available funds between the upstream and downstream sectors and set the budget in light of several

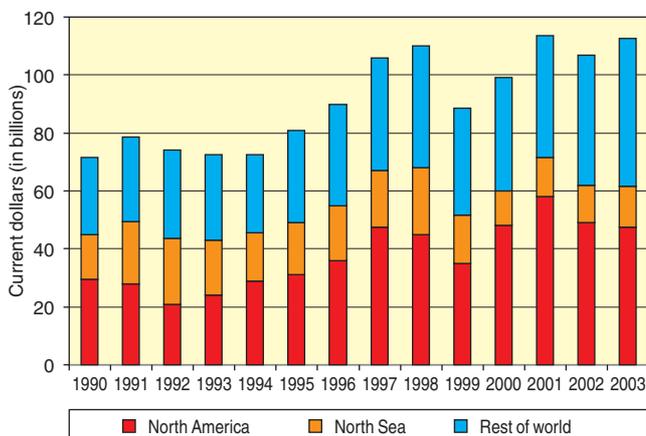
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imperatives (e.g. financial consolidation, debt reduction, external growth or the repurchase of its own shares).

The Reduction of Costs

Following the counter-shock of 1986, the oil and gas industry showed determination in cutting costs in response to the contingencies likely to affect budget policy. Since 1986, cost control has been a key objective. Two mechanisms are mainly responsible for boosting overall productivity: technical progress and reorganization within the industry. **In the 1990s, total technical costs were halved from \$14/bbl in 1990 to \$7/bbl in 2000.** Exploration costs were reduced by a factor of 3 and development costs by 40%. More over companies doubt that current high prices could be sustainable in the future.

Fig. 2 Geographical breakdown of capital expenditure on E&P (not including the CIS or China)



Source: IFP/DEE

Nevertheless, the scale of cost reduction varied for different resources. In the oil sector, **costs were reduced very substantially for higher-cost oils** (offshore, deep offshore, non-conventional). On the other hand, the reduction for lower-cost oils was slight or non-existent. The deep offshore sector is a perfect example. Today, it is estimated that the cost of developing one barrel produced at a water depth of over 1,000 meters has been divided by a factor of 4 to 5, in the last 15-20 years. At the same time, the average water depth of the new fields coming onstream has been rising. At the end of the 1980s, the term “deep offshore” designated depths of over 200 meters, whereas it now indicates development operations at water depths of over 500, or even over 1,000 meters.

More generally, several technological advances have made a great contribution to the reduction of exploration and development costs. In the field of geosciences, the advent of

3D seismic, now commonly used both offshore and onshore, marked a major breakthrough in subsurface imaging. In recent years, this technology itself has been revolutionized. Among other things, data acquisition times in the field have been reduced by a factor of 3. In addition, thanks to larger computing capacities, seismic data processing is vastly superior to what it was only ten years ago. Introducing new drilling technologies has significantly reduced the per-barrel development cost. Implementing directional, horizontal and multibranch wells has increased the number of objectives that can be attained from a single site (such as an offshore platform) and the number of horizontal producers that can be exploited from a single well. These techniques have also helped enhance well productivity: the generalization of horizontal drilling has yielded a threefold increase, on average. As a result, it has been possible to reduce the number of wells and simplify connecting infrastructure.

In constant currency, world E&P capital expenditure (not including the CIS or China) remains below the figure attained in the early 1980s, yet is heavily concentrated in North America and the North Sea, two regions that are mature or declining. This must be put into the proper perspective: global productivity has increased thanks to technology advances and to the cost reductions that they engender.

Conventional Oil Production

Energy forecasts made by a number of prominent organizations, including the U.S. Department of Energy, the International Energy Agency and the World Energy Council, all indicate that, between now and 2030, world demand for primary energy will keep growing. To cover this increase, it will be necessary to mobilize all energy resources, and **hydrocarbons will continue to account for the bulk of energy demand.**

Oils that are difficult to extract—deep offshore, ultra deep offshore and so forth—are going to represent a growing part of the market. In the next ten years, the deep offshore sector should account for nearly 40% of the increase in world production. It is still hard to tell if this rate will be maintained past 2010.

According to the International Energy Agency, non conventional oil production will rise from 1.1 Mbbbl/day in 2000 to 3 Mbbbl/day in 2010 and 9.9 Mbbbl/day in 2030, primarily in Venezuela and Canada. The capital expenditure required to exploit these resources is much higher than for conventional petroleum, in spite of the major cost-cutting drives of recent years. Non conventional resources undoubtedly have a contribution to make. But in the years to come, in order to cover the increase in world demand, the problem will be to

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maintain existing conventional oil production capacity while adding new capacity. The size of discovered fields is decreasing and the large fields responsible for the bulk of current world production are declining or will start to decline in the next thirty years.

In the World Energy Investment Outlook 2003, the IEA estimates the current rate of natural depletion (excluding any capital investment) to be 4% a year in the Middle East and 11% a year in Europe. The IEA expects world oil demand to rise from 75 Mbbbl/day in 2000 to 120 Mbbbl/day in 2030. To cover demand while compensating for the natural decline in production, it will be necessary to invest in nearly 200 Mbbbl/day of new supply capacity. This is assuming a rate of natural decline worldwide of 5%. By way of an indication: if this decline rate were 6% instead of 5%, it would be necessary to invest in an additional 30 Mbbbl/day between now and 2030.

The British North Sea is a perfect illustration (see table below). Although production did not decline but remained stable between 1994 and 2003, it was largely due to the efforts made to exploit small accumulations. Currently, production in this area requires nearly twice as many fields as it did in 1994, while average output per field is 42% lower than it was nine years ago. In 1994, giant fields generated 54% of production, but now they only account for 23%.

	1994	2003
Total production ('000 bbl/day)	2,565	2,549
Average field production ('000 bbl/day)	38	22
Number of producing fields	65	113
No. of fields producing over 100,000 bbl/day	7	3
Production represented by giant fields (as a %)	54%	23%

There has been a generalization of assisted, secondary and tertiary production techniques to compensate for this decline and maintain well productivity. For example, water injection is commonly used in the North Sea and increasingly in the Middle East. At some fields, the application of enhanced recovery methods (tertiary) can be spectacular. At Duri Field in Indonesia, where the rate of primary recovery was only 7.5%, a series of enhanced recovery methods were implemented and an oil recovery rate of 55% obtained. These methods serve to augment conventional oil reserves without having to make new discoveries.

Technical progress makes it possible to accelerate field production but also to create reserves, and therefore to produce more. The most obvious examples are those of

horizontal drilling and 3D seismic. By enabling better subsurface imaging and reservoir drainage, these technologies create reserves and improve field exploitation. For instance, one can say that the Girassol Field was discovered thanks to 3D seismic, since 2D seismic proved inadequate to image the complex reservoir channels of its structure. **As we can see, technological progress plays two roles that are in opposition: it creates reserves but accelerates the overall rate of field production and so their depletion.** The question is: which of these roles will prevail? It is still very difficult to isolate each factor's contribution in quantitative terms. This exercise can only be carried out on a case-by-case basis, which limits its scope.

Reserve Replacement: a Symptom?

For the last decade, over 50% of reserve replacement was due to the reassessment or extension of existing fields, not to new discoveries. Since 1998, many mergers and acquisitions have occurred in the oil industry. For the majors, such transactions account for about 50% of their reserve replacement. The proportion of production replacement using enhanced recovery techniques has varied over the last decade, but remained stable in absolute terms at about 700 million barrels a year, equivalent to 2.5% of world production.

The contribution to reserve replacement made by revised estimates of reserves (about 12.5% in 2001) should decrease in the near future as 3D seismic techniques come into generalized use and as the positive effect of using them on mature fields disappears. However, there will be other opportunities to revise reserves upwards, albeit on a smaller scale: for instance, the estimates for offshore fields developed in the late 1990s will have to undergo revision in a few years.

Reserves include both oil and gas, whose characteristics differ: distance to market, development time, regulatory and/or political risks and constraints associated with OPEC production quotas. For the majors, reserve replacement in recent years has benefited from large gas discoveries (in Bolivia, for instance). On the other hand, it will take a long time to bring this gas to market. Given this time lag between production and commercialization, there is no immediate need for exploration operations to ensure replacement. Now that the majors have replaced production and maintained the level of hydrocarbon reserves, they should concentrate on **prospecting and the development of reserves (especially oil) that can be exploited relatively quickly.**

It would seem that exploration efforts will have to make a very substantial contribution to reserve replacement, and that this represents a key challenge. For the 14 largest companies, **exploration budgets in 2000-2002 were down by about 30%**

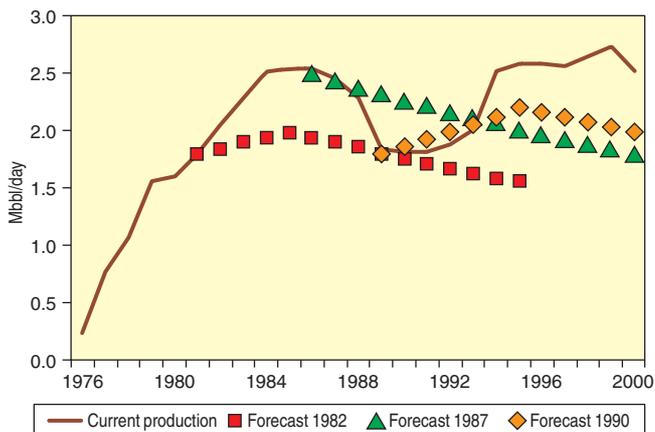
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compared to 1995-1999. **In volume terms, there was a decrease of almost 50%, which is not proportional to the rate of discoveries, but higher** if one excludes the Kashagan Field, an exceptional case. Granted, this trend has only been observed for a short period and will need confirmation, but does it indicate that the majors have difficulty positioning themselves on oil assets that can be brought onstream rapidly?

A Multi-Faceted Problem

Among analysts, there exists a broad consensus: capital expenditure should be maintained or increased to cover oil and gas demand in the next three decades. In the past, the oil industry was able to ease concern because there were so many basins yet to be explored. But a new era is starting: conventional oil reserves are reaching depletion (signs indicate that reserve replacement is slackening, compared to the latter half of the 1990s) and virgin areas are becoming ever scarcer. Under these circumstances, capex mobilization capability will depend on a range of solutions. On the strength of their success and experience accumulated in the last 20 years, oil companies will continue to play a key role in the financial and technical areas. **But a recomposition of the oil scene will probably be necessary to respond to the challenges of the future.**

Fig. 3 United Kingdom oil production and forecasts



The upstream sector has introduced stringent project selection procedures. Some large companies have **sold off small or greatly depleted fields**. These transactions work to the benefit of independents, which have lighter cost structures. Paradoxically, independents are in a better position to deal with the

constraints typical of mature zones, but they have less experience and expertise in this area than the large companies (e.g. in 2003, BP sold the Forties Field to Apache). Are these transactions really a source of efficiency for the industry at large?

In addition, while **certain producing countries**, including OPEC members, **have begun to open up their oil and gas acreage** and many companies hope to gain access to extremely promising areas (Saudi Arabia, Kuwait and Mexico, in particular), recent events in Iraq, Russia, Venezuela, Nigeria and Colombia illustrate that the political and regulatory risks are growing and may need to be reassessed in the near future.

The price per barrel has been high and stable since 2001, which has produced **a shift in the basic financial assumptions used by oil companies**. The companies used to take \$10 per barrel as the floor price; now they use \$12 or \$13. In the past, certain areas were not explored because access costs were found prohibitive and certain small fields thought unlikely to be profitable. These prospects may now be reassessed and developed, which would help cover oil and gas demand.

The depletion of convention reserves represents a challenge that cannot be dissociated from technology advances. The risks associated with exploration-production activities are higher than they used to be. This not only underscores the perils of reducing R&D budgets, which have been falling for about ten years, but also the threat of higher E&P costs.

Conclusion

The oil industry is now entering the third phase of a transformation brought on by the events of the 1970s. The first phase involved a redeployment of oil capital expenditure and the deintegration of the vertical chain that, ultimately, was responsible for structuring today's international markets. The second phase was marked by the major role played by technological advances in exploration-production and by cost-cutting campaigns. **In the third phase, it would seem, the top priority will go to risk management relative to capital expenditure decisions.**

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Final text received on December 1, 2003



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