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The Challenge of North Sea Oil and Gas

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Résumé — L'enjeu pétrolier et gazier de la mer du Nord — L'*ENeRG (European Network for Research in Geo-Energy)*, qui regroupe de nombreux organismes de recherche européens impliqués dans la valorisation des ressources énergétiques contenues dans l'écorce terrestre, a suscité une étude sur les « Perspectives de production de pétrole et de gaz en mer du Nord », pour le compte de la Commission des Communautés européennes (DG XVII).

L'*Institut français du pétrole (IFP)* en a été le principal acteur ; les autres intervenants comprenaient : le *Centre for Marine and Petroleum Technology* (*CMPT*, ex-*PSTI*, Royaume-Uni), *Rogaland Research* (*RF*, Norvège), *Geological Survey of Denmark and Greenland* (*GEUS*, en association avec la *Danish Energy Agency*, *DEA*, Danemark) et *Eniricerche SpA* (Italie).

Les principaux objectifs de cette analyse* sont les suivants :

– identifier les besoins en technologies nouvelles ou en améliorations technologiques permettant d'accroître la production d'hydrocarbures en mer du Nord ;
– prévoir les niveaux de récupération résultant de la mise en œuvre de ces développements;
– estimer l'impact de ces prévisions sur le volume d'activité et l'emploi dans le secteur de l'industrie pétrolière et gazière européenne.

Mots-clés : mer du Nord, pétrole et gaz, production, perspectives.

Abstract* — *The challenge of North Sea Oil and Gas — ENeRG, *the* European Network for Research in Geo-Energy, *which groups various European research organizations involved in the development of energy resources contained in the earth's crust, has sponsored a study on "The Outlook for Oil and Gas Production in the North Sea", on behalf of the Commission of European Communities (DG XVII).*

The Institut français du pétrole (IFP) *was the main participant in the group, which included the* Centre for Marine and Petroleum Technology (CMPT, *formerly* PSTI, *United Kingdom),* Rogaland Research *(*RF, *Norway), the* Geological Survey of Denmark and Greenland *(*GEUS *in association with the* Danish Energy Agency, DEA, *Denmark) and* Eniricerche SpA *(Italy).*

The main objectives of this analysis are as follows:*

– *Identify the need for new technologies or technological improvements in order to increase the production of oil and gas in the North Sea.*
– *Forecast recovery levels that result from the implementation of these technologies.*
– *Estimate the impact of these forecasts on the volume of activity and employment in the European oil and gas industry.*

Keywords: North Sea, oil and gas, production, outlook.

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INTRODUCTION

Concretely, this involves preparing and submitting a summary report and the elements of a database that may be used:

– By the industries (SME and larger companies) and European Government organizations, in order to help them prepare their programs and analyze their R&D strategy.
– By the European Commission, in order to facilitate the development of strategies for programs such as Thermie.

In practical terms, the study covers the northwest European continental shelf, but was given the title "The Outlook for Oil and Gas Production in the North Sea", as the term North Sea is commonly used in the oil and gas industry to designate a larger unit. Therefore, the study concerns zones other than the North Sea strictly speaking, including the rest of the British and Norwegian continental shelves (Fig.1) and, in particular, the Barents Sea, the Norwegian Sea, the Faeroe Islands, the West Shetland Islands, the West of Scotland, the Rockall Trough, the Irish Sea, the Celtic Sea, the English Channel, etc.

In addition, the expression “production outlook” should be taken to mean “maximum production potential”, as the associated profiles are not at all linked to demand projections. This can lead to real production levels that are much more spread out, especially for gas.

1 THE SCOPE AND CONSEQUENCES OF THE STUDY

In theory, it is always possible to evaluate the cost of a specific operation in the petroleum industry, particularly when it is simple. However, it is more difficult to evaluate the resulting benefits. In an overall analysis, such as the one envisaged here, the problem is even more complex for other reasons. The geographical coverage quickly becomes a handicap, as does the need to group the results in order to make a coherent presentation.

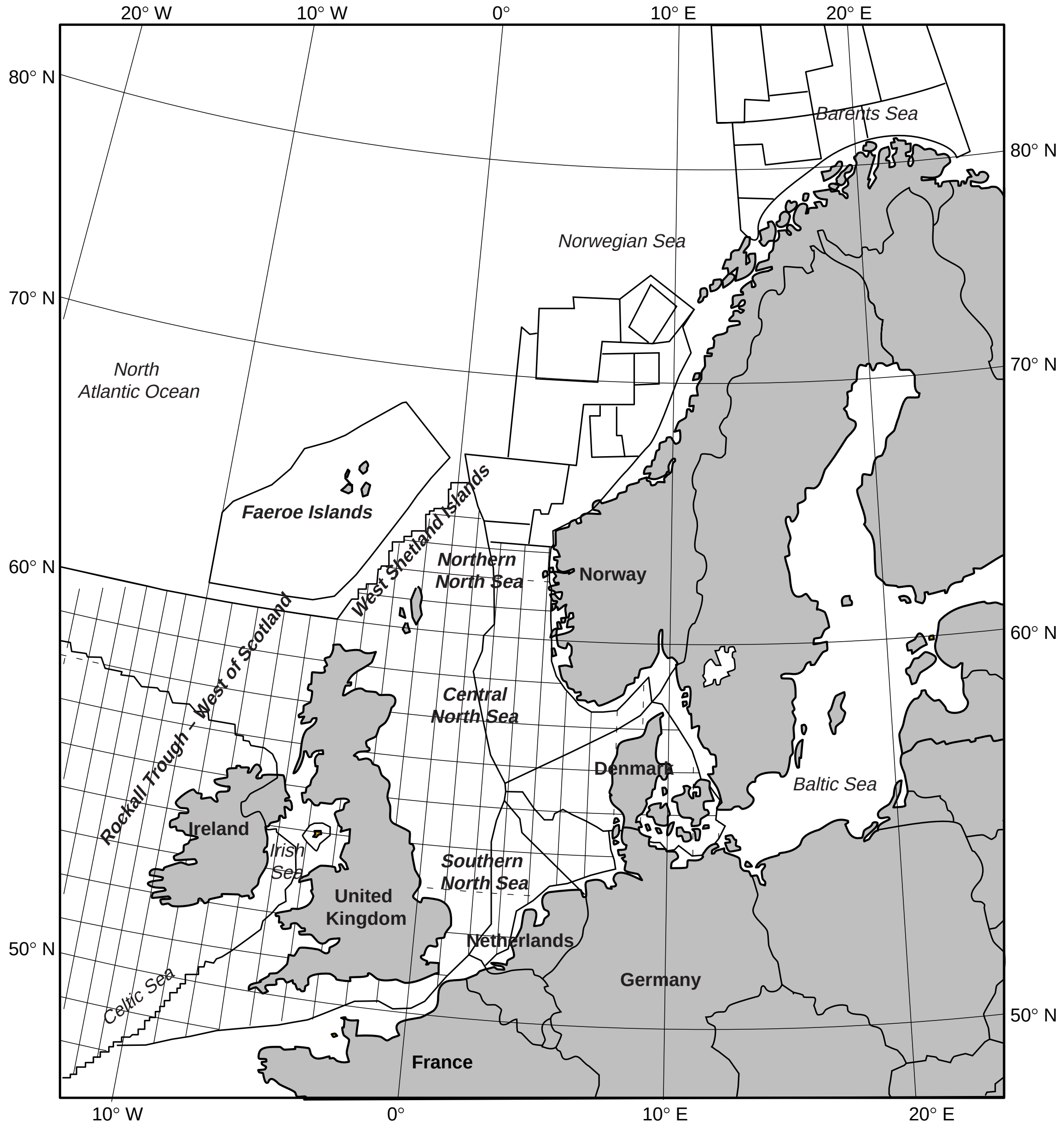


Figure 1

Outlook for oil and gas production in the North Sea geographical context.

In fact, aside from considerations regarding information access and confidentiality, the principal obstacles are technical and economic.

There exists, at present, quite a panoply of technologies for promoting the production of oil and gas, and which act successively or in combination during the entire life cycle of a field. For this reason, it is impossible to identify the effects of each of them separately. This phenomenon is all the more delicate when the benefits of a new procedure can quite often be quantified only several years after its application. In other words, at a given moment, the choice of a new technology rests only on the hope of reduced costs and increased profits in comparison with the initial situation.

Furthermore, the economic conditions applicable to a given field, which depend, in particular, on its geological complexity, the number and type of reservoirs, as well as on the nature of the company operating it and whether its capital comes from private or government sources, cannot be directly transposed or generalized to other fields or other oil and gas companies. An aspect that is unprofitable in one case can become profitable to varying extents under other circumstances.

Finally, it seems to be impossible to associate the development of reserves or of a field's production with a specific technology. Under such conditions, quantifying costs and benefits is not possible on the basis of a “procedure by procedure” examination. It can only be based on approximate and overall hypotheses. This manner of operating is supported by the fact that the petroleum industry is reluctant to take major risks linked to the rapid and massive introduction of new technologies. Experience shows that the penetration of these procedures is both gradual and incremental.

In order to integrate these considerations into the implementation of the study, the accent is placed on a gradual development of future progress through three scenarios that reflect increasingly rapid levels of progress in the introduction of new technologies and the improvements they produce:

– The “low” or “current trend” scenario, which provides a lower limit resulting from a status quo with respect to the current situation of R&D efforts. In other words, the results which are produced are based on the past rate of market penetration by technologies that are already known, but that benefit from adaptations and improvements.
– The “probable” or “technologically probable” scenario, which implies rapid, incremental improvements likely to be attained only if a policy of sustained R&D efforts is implemented.
– The “high” or “technologically ideal” scenario, which represents a higher limit, ideal because improbable in the current political and economic context. It requires deliberate and aggressive action regarding R&D efforts. This case presupposes the development and marketing of technologies that are resolutely innovative and, in addition, a favorable economic and fiscal environment.

Thus, as indicated elsewhere in this document, each of these scenarios will lead, in practice, to different rhythms of growth of the recovery factor. In the final analysis, this is the best parameter for applying the results of any type of technical progress that may be expected from R&D efforts.

In addition, Figure 2 illustrates the various types of resources which were considered in the study, as well as the principal means taken into account for their contribution to the growth of reserves.

Three principal criteria are normally accepted for identifying the desirability of developing a field, the technical feasibility, the economic interest and the pollution risks. In the present case, for the three scenarios, it is assumed that all the options can be technically realized and that the environmental impact is negligible. Besides, regarding the economic aspects, one must be aware that no such analysis is taken into account. In other words, no estimates are made here of future oil and gas prices or of eventual financial returns.

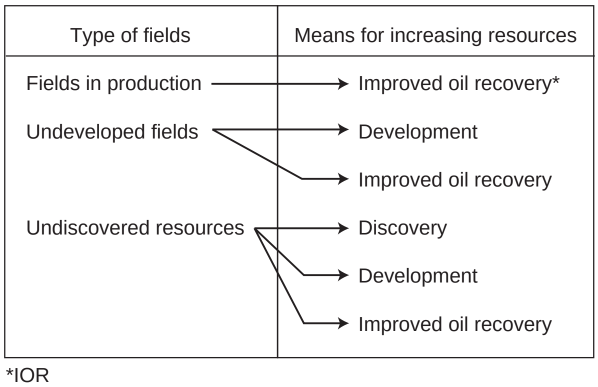


Figure 2

Types of fields and means for increasing reserves considered in this study.

2 THE CURRENT SITUATION

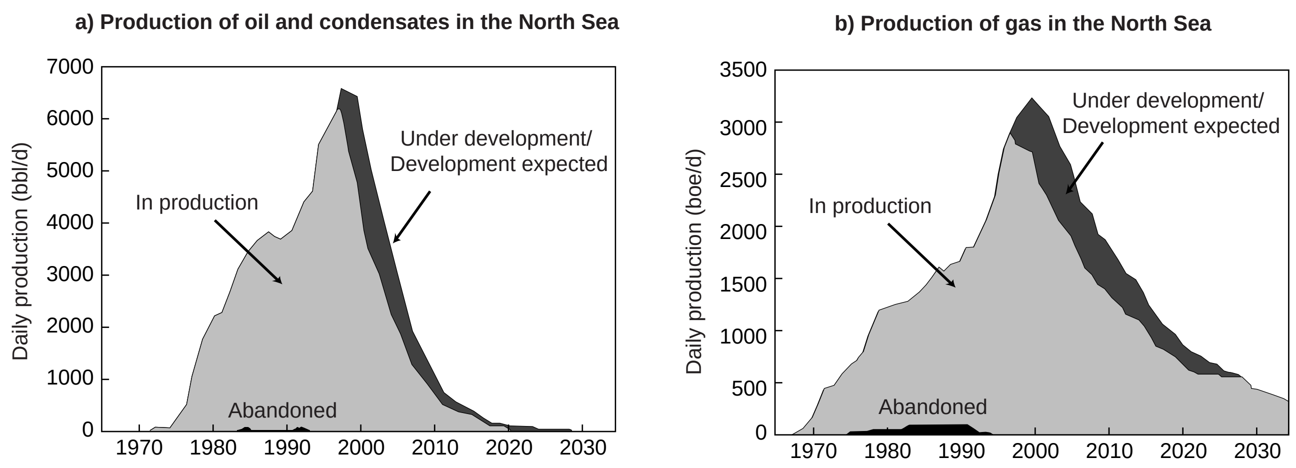
In the context of work already carried out, a distinction can be made between two major areas, the enlarged North Sea area, properly speaking, and the bordering regions.

The North Sea, considered in the widest sense, which provides the essential part of current oil and gas potential, includes six European countries directly, the United Kingdom, including the Isle of Man, Norway, Denmark, including the Faeroe Islands and Shiehallion, the Netherlands, Germany and Ireland. The growth, during the mid-90's, of the supply of non-OPEC oil can be largely imputed to contributions from the North Sea. After increasing to more than 850 000 bbl/d in 1994, production has continued to grow by 270 000 bbl/d and 350 000 bbl/d in 1995 and 1996, so that during the period 1993-1996 the increase in production reached an overall level of more than 1.5 Mbbl/d. As illustrated in Figure 3, the peak of oil and condensates extraction appears in 1997 at more than 6.5 Mbbl/d and that for gas, in 2002, at some 3.2 Mboe/d. Subsequently, the decline will begin, because of Norway, particularly for oil production, which will fall to 5.7 Mbbl/d around the year 2000, and because of an excess availability of natural gas in the European market. At present, the production of hydrocarbons from the North Sea represents 8% of the world total for both oil and gas, thus, contributing to maintaining the current availability of oil at the international level. At the regional level, the impact is equally significant, since it corresponds to 46% of oil consumption in the European Union and to more than 50% of gas needs, which is equivalent to imports from Russia and Algeria.

The European frontier regions all show similar characteristics, in particular:
– the depth of water: 200 to 1500 m;
– difficult meteorological and sea conditions, which limit the windows of opportunity generally to summer for exploration and development activities;
– the distance from infrastructures.

A problem frequently met with in the Atlantic frontier zones is that of the geotechnical stability of the upper 500 m in the sediments beneath the sea floor. They are unstable and tend to slide even when the sea floor is only slightly inclined. This sedimentary layer can also contain hydrates, which cause several problems when they are moved mechanically or by heating. These include fluidization of sediments, release towards the surface with an accompanying risk of fire or explosion, which, in turn, affects the safety and the stability of platforms and makes pipelines fragile.

Of course, each region offers specific features, that are more or less pronounced, in addition to the common characteristics. From this point of view, a brief mention should be made of the Greenland offshore (distance, essentially gas reserves), the Barents Sea (90% gas and 10% oil for a total of 2480 Mboe of reserves, characterized by technically and economically difficult development), the Norwegian Atlantic rim (very deep waters, presence of gas rather than oil), the Faeroe Islands (deep water, difficult



North Sea*	Abandoned		In production		Under development Development expected		Total	
	O/C	G	O/C	G	O/C	G	O/C	G
Initial recoverable reserves	142	469	41 405	30 342	5584	4429	47 131	35 241
Produced on 1/1/1997	142	469	25 957	12 332	21	0	26 119	12 801
Remaining on 1/1/1997	0	0	15 448	18 011	5564	4429	21 012	22 439

* Includes the United Kingdom, Norway, Denmark, the Netherlands, Ireland and Germany
O/C: oil and condensates in millions of barrels, G: gas in millions of barrels of oil equivalent (boe)

Figure 3

Current production of oil, condensates and gas in the North Sea, taking into account fields in production and under development as well as those covered by an official development plan.

meteorological conditions, high coefficient of reflection for the basalts/sediments interface), the Western Shetlands and Western Scotland (oil to the southwest and gas to the northeast, violent ocean currents, highly variable with depth and impossible to predict, leading to major and destructive vibrational problems in the risers), the west and southwest of Ireland. (Eris, Slyne and Rockall Holes as well as the Porcupine Basin, absence of infrastructure).

3 CONDITIONS AND METHODOLOGY FOR THE OUTLOOK ANALYSIS

3.1 Production Fields

Under this heading are grouped fields currently in production, those being developed during the period of the study as well as those for which an official development plan has been announced. The object of the exercise will then be to evaluate, for these fields, the impact due to the application of improved oil recovery methods (IOR: Improved Oil Recovery) and to determine by modeling the quantity of additional reserves that correspond to each of the three selected scenarios, according to the hypotheses that define them. These are based on the compilation and processing of historical data from three European countries, the United Kingdom, Norway and Denmark.

The determining parameter for this type of analysis is the "recovery factor", which is defined as being the ratio between oil reserves supposed to be recoverable at a given moment and those initially in place. It represents, on the one hand, the difficulty (or the ease) of extracting oil from a given field (permeability, porosity, etc.), and can be used, on the other hand, as a measure of the overall technological level accessible during a specific period, by including in it all the procedures capable of leading to an increase in the quantity of recoverable hydrocarbons in a field.

Obviously, this definition is equally valid for gas. Nevertheless, the recovery factor is already so high in this case that there is relatively little interest in trying to improve it. This is not quite true for condensates, but their contribution to reserves is sufficiently modest so as not to justify a specific calculation. In the study, they are grouped with oil, for the sake of simplification.

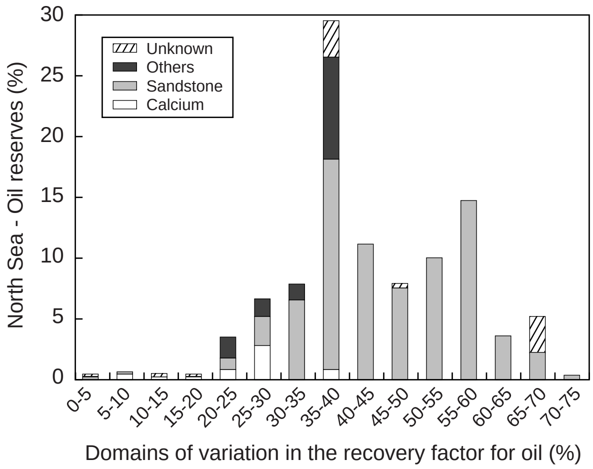
As for IOR, its precise definition deserves by itself a complete examination of all the technologies it covers. In order to simplify the explanation, we may use the definition provided by the *DTI* (*Department of Trade and Industry*, United Kingdom): "*any activity which increases the primary recovery factor*".

It is important to note that some of the largest petroleum fields on the northwest European continental shelf have reached maturity and that their production is declining. Consequently, the IOR is of obvious interest both to companies and to governments. It opens up opportunities not only in the North Sea, but also in the entire world and allows R&D to play its role fully in managing the different technologies it covers.

In general, the accepted procedure consists of operating across two stages. The first, which is of an historical nature, is to bring together all the information published in the three countries (the United Kingdom, Norway, Denmark), completing them, generalizing them for the entire northwest European continental shelf and deducing from them useful correlative elements. The second, which is of a predictive nature, is to exploit these results in order to quantify the hypotheses for calculating the scenarios cited above. This entire approach is based on establishing a database for a field by field analysis of the growth of the recovery factor for oil and gas.

As far as the *historical part* is concerned, more precisely, the information available in publications, mostly published before 1996, only partly covers the fields on the continental shelves of the reference countries, for example, only 20% for the United Kingdom. However, based on an approximate geological characterization of reservoirs, this information can be extrapolated to values for the recovery factor of oil, gas and condensates at each of the fields in the production, development or project stage, that are identified in the file. In practice, the problem becomes complex to the extent that even though each field is generally composed of more than five reservoirs, the indicated recovery factor is an average for all of them. More often, one of the reservoirs makes a dominant contribution, but it is not possible to obtain its particular value. As a counterpart, the fact that the majority of reservoirs are sandstone constitutes an interesting simplifying element. One then proceeds to weight the recovery factors, collected or assigned, depending on the recoverable reserves in each field, rather than correlating them with those of hydrocarbons initially in place, to the extent that this type of information is not generally directly available. A distribution is made depending on the geological nature of the reservoirs. The number of possibilities is, nevertheless, limited to four, chalk, sandstone, others, which covers combinations of chalk, sandstone, dolomite, etc., and unknown, where information not available. An index of "representativeness" allows one to judge the credibility of the results. It is defined using the ratio between the sum of reserves considered in the calculation and those indicated in the file, for each of the geological categories that have been retained. This procedure, extended to the entire North Sea region, is used to establish the summary graphs and tables shown in Figures 4 and 5, for oil and condensates, on the one hand, and for the gas, on the other.

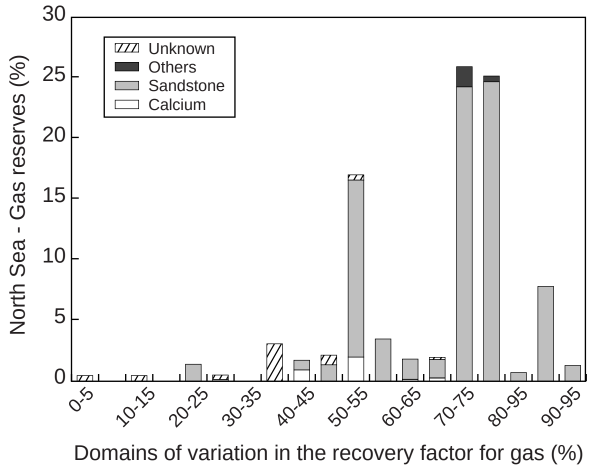
To conclude this retrospective analysis, the average recovery factor for the northwest European continental shelf seems to be close to 43% for the period 1995-1996. In addition, it would appear from these data that over the last five years the upstream petroleum industry has demonstrated it ability to increase this parameter by about 1% per year.



Oil - North Sea	Chalk	Sandstone	Others	Unknown	Total
Representativeness (%)	89.6	87.1	94.8	54.9	85.8
Average recovery factor for oil (%)	26.4	46.5	33.8	35.9	43.5

Figure 4

Distribution of oil reserves in the North Sea, based on the recovery factor.



Gas - North Sea	Chalk	Sandstone	Others	Unknown	Total
Representativeness (%)	66.3	48.9	18.5	27.2	44.4
Average recovery factor for gas (%)	50.1	70.9	65.3	64.5	69.4

Figure 5

Distribution of gas reserves in the North Sea, based on the recovery factor.

Regarding the *future*, it appears that growth of less than 0.25 to 0.50% per year would be a reasonable expectation for the next decade, based on the fact that:

– The high growth rates realized in the past are principally the consequence of the generalized use of 3D seismic and the introduction of horizontal drilling. These technologies have provided the best examples of change in the current trend scenario and are considered to be resolutely original procedures. They form, at present, part of the panoply of tools commonly and/or systematically used by the petroleum industry. It seems difficult to envisage maintaining or increasing the rate of growth of the recovery factor thus generated exclusively through improvements of these techniques alone.

– The largest offshore fields of Britain and Norway have reached maturity and their production is declining. Therefore, it is more urgent than in the past to maintain or improve their reservoir pressure.

– Recent fields, generally much smaller, are developed using the minimum means. Under these conditions, their recovery factors are probably lower than those for larger fields. Moreover, for a significant number of these fields, their development has been deferred until now because it is "more difficult to exploit them", all things being equal. In other words, this will provide lower recovery levels.

Consequently, during the next decade, the average recovery factor may not grow at the same high rate as has been observed during the past decade. The only means available to attain these rates is to undertake sustained R&D efforts in order to generate technological improvements comparable to those already realized.

Under these conditions, and with a view to determining the impact of IOR on the production of fields currently in production, development or firm project, three working hypotheses may be retained regarding the increase of the recovery factor, 0.25, 0.50 and 1% per year associated with three upper limits, 50, 55 and 60%. This leads, in theory, to nine possible combinations. Among the other hypotheses necessary for pursuing the calculations, are:

– The initialization of the process, which is assumed to be identical for the entire North Sea belt, based on knowing the production file for each field.

– The choice of 1996 as the reference year.

– The flaring of gas associated with oil production or its use on the platform itself.

– Maintaining oil reserves in place at a level that is assumed to be constant. In other words, any additional reserves resulting from an extension, new delineation, for example, which can lead to an increase in the quantity of oil in place is not accounted for here, but as undiscovered resources.

– Reaching in thirty years, starting from the current value of 40%, the upper limit of the recovery factor (50, 55 or 60%), depending on a diffusion model such as the Gompertz ("S" curve).

Results of calculations based on this set of hypotheses for the nine possible combinations lead to keeping only three of them, which are likely to match the initial definitions of the scenarios. The six other combinations do not, in fact, provide sufficient contrast with respect to the first three. The analysis leads to the following conclusions:

– Low scenario: Increase of the recovery factor at a rate of 0.25% per year to an upper limit of 50%. The additional reserves in this case will be 6279 Mbbl, that is, 13% of those currently recoverable in the North Sea. The life time of the fields is extended by three years at the 1996 production level.
– Probable scenario: Increase of the recovery factor at a rate of 0.5% per year to an upper limit of 55%. The additional reserves will reach 13 282 Mbbl, that is, 28% of those currently recoverable in the North Sea. The life time of the fields is extended by six years.
– High scenario: Increase of the recovery factor at a rate of 1% per year to an upper limit of 60%. The additional reserves will reach 19 451 Mbbl, that is, 41% of those currently recoverable in the North Sea. The life time of the fields is extended by nine years.

As regards the "low" scenario, the respective views of the NPD (Norwegian Petroleum Department) and the *DTI* on the impact of IOR in Norwegian and British offshore are quite close to the results reached in this study, 4081 Mbbl compared with 4965 for the NPD for Norway. This is not so for Britain, 1663 Mbbl rather than 8565 for the *DTI*. Except for methodological reasons, such a difference seems to be difficult to explain. However, the value indicated by the British is surprising, as it is even higher than the value obtained from the "high" scenario, 7541 Mbbl.

3.2 Undeveloped Fields

These are fields that were not yet in production during April, 1997. They are listed as oil and gas discoveries in the database and can be classed in four categories:

– Fields which can seriously be expected to start production within the next five years, from 1998, and which are classified in this document as "probable". In many cases the operator has conducted, or is conducting, development studies regarding these fields.
– Fields whose development and production will require the application of innovative technologies for various reasons, including difficult environments, as in the Barents Sea and the West Shetlands, and/or deep offshore or distance from mature zones and infrastructures. Also included in this category are groups of smaller structures which require overall development. In addition, recent discoveries, from 1996 and 1997, are also included. All such fields are classified as "possible". Nearly two thirds of these reserves are gas. The main difficulty is to find a commercial outlet, which would justify bringing these fields into production.
– Completely isolated very small fields, less than 10 Mboe. Because of this, it seems unlikely that they would be developed, regardless of the level of future technologies. They are classified as "improbable".
– Fields whose reserves are not available. Very often, they are limited to an exploratory well, and they are considered "confidential".

Some of these, classed as possible and improbable, are discoveries for which formation tests are poor or inconclusive or have not yet been conducted. Therefore, the undeveloped fields are subjected to a high level of uncertainty. Nevertheless, an overall estimate of their value broken down by country and category is provided in Table 1 and Figure 6.

A total of 573 hydrocarbon accumulations have been identified for the four categories, but the analysis covers only 394 oil, condensates and gas fields classified as "probable" and "possible". However, it is necessary to insist on the fact that a significant number of fields in these categories may emerge from the "*confidential*" class.

The goal of this study is to propose, in that case, production graphs for the undeveloped reserves, mostly probable and possible, for the three selected scenarios and also to consider the impact of the IOR depending on the hypotheses expressed previously for the fields in production.

By applying the IOR model developed during this work to oil reserves from 1997, it is implicitly assumed that the result of improvements made from 1997 up to the date that each field goes into production corresponds to a better knowledge of the accumulation characteristics and, consequently, to an increase in the recoverable quantities directly linked with the increase in the recovery factor. From the year that production begins, the additional reserves linked with the impact of IOR are calculated as before.

Because of this, a starting date is assigned to each field based on current economic and technological considerations. Logically, this date will change from one scenario to another, since the estimated reserves increase with the IOR and the performance levels linked with technological improvements are different.

However, considering the difficulties met with while selecting three different dates for the three scenarios and for each field, it was finally decided to use only one, in order to simplify matters.

The production hypotheses assigned to the various categories of undeveloped resources for the three scenarios are as follows:

– Low scenario: production of probable reserves only, additional resources due to IOR based on an increase of the recovery factor of 0.25% per year and an upper limit fixed at 50% (Fig. 7).
– Probable scenario: production of probable and possible reserves, additional resources due to IOR based on an increase of the recovery factor of 0.50% per year and an upper limit fixed at 55% (Fig. 8).
– High scenario: identical with probable scenario but with additional resources due to IOR determined on the base of an increase of the recovery factor of 1% per year and an upper limit fixed at 60% (Fig. 9).

TABLE 1

Distribution of undeveloped discoveries in the North Sea

		CATEGORY				
		Probable fields	Possible fields	**Total per country for probable and possible fields**	Improbable fields	Confidential discoveries
United Kingdom	Number of fields	48	157	**205**	47	67
	O/C	989	2303	**3292**	400	–
	G	691	2246	**2937**	181	–
Norway	Number of fields	12	89	**101**	14	11
	O/C	734	2355	**3089**	83	–
	G	319	5029	**5378**	49	–
Netherlands	Number of fields	20	54	**74**	14	11
	O/C	2	143	**145**	7	–
	G	341	787	**1128**	45	–
Denmark	Number of fields	5	1	**6**	1	5
	O/C	172	10	**182**	0	–
	G	130	0	**130**	0	–
Germany	Number of fields	0	4	**4**	0	3
	O/C	0	0	**0**	0	–
	G	0	155	**155**	0	–
Ireland	Number of fields	1	3	**4**	5	1
	O/C	0	8	**8**	23	–
	G	5	97	**102**	9	–
Total per category of field	**Number of fields**	**86**	**308**	**394**	**81**	**98**
	O/C	**1897**	**4819**	**6716**	**513**	**–**
	G	**1486**	**8344**	**9830**	**284**	**–**

O/C:estimated recoverable reserves of oil and condensates in thousands of barrels
G:estimated recoverable reserves of gas in thousands of barrels of oil equivalent (boe)

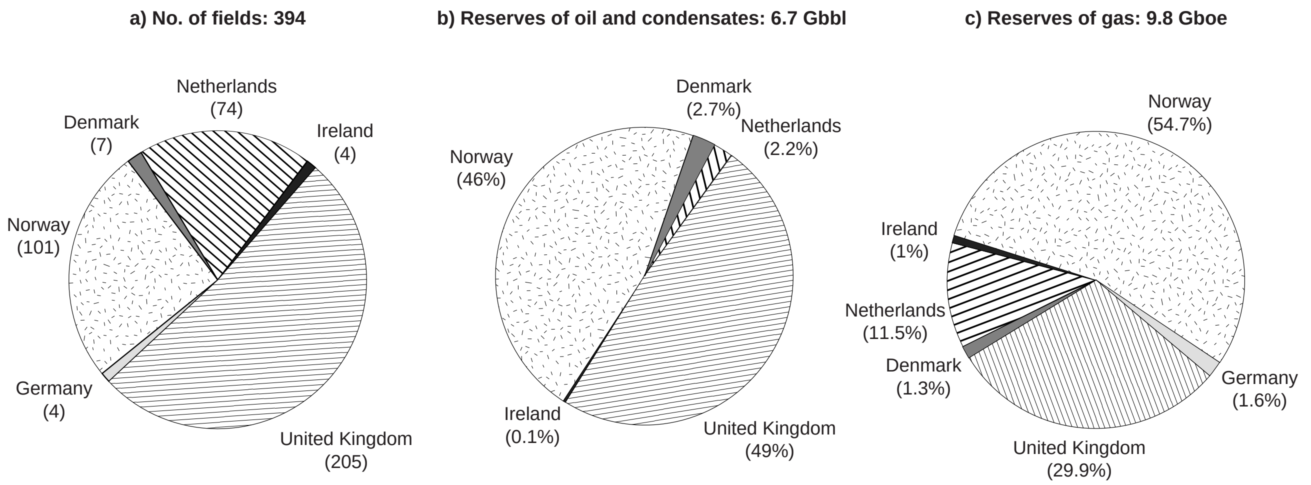


Figure 6

Distribution of 394 undeveloped discoveries in the North Sea.
– Country and estimated number of fields
– Country and estimated size of oil and condensates reserves
– Country and estimated size of gas reserves.

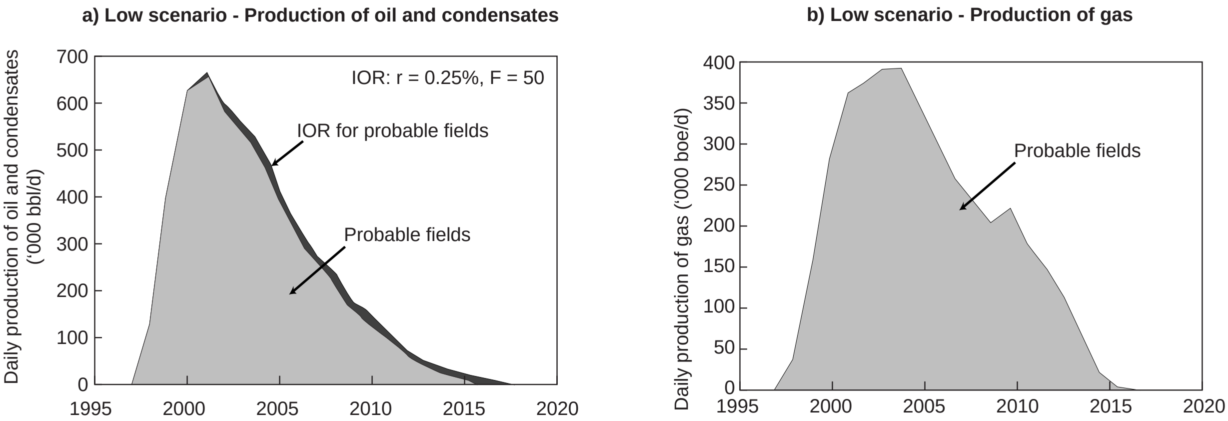


Figure 7

Low scenario – Undeveloped fields: production curves for oil, condensates and gas.

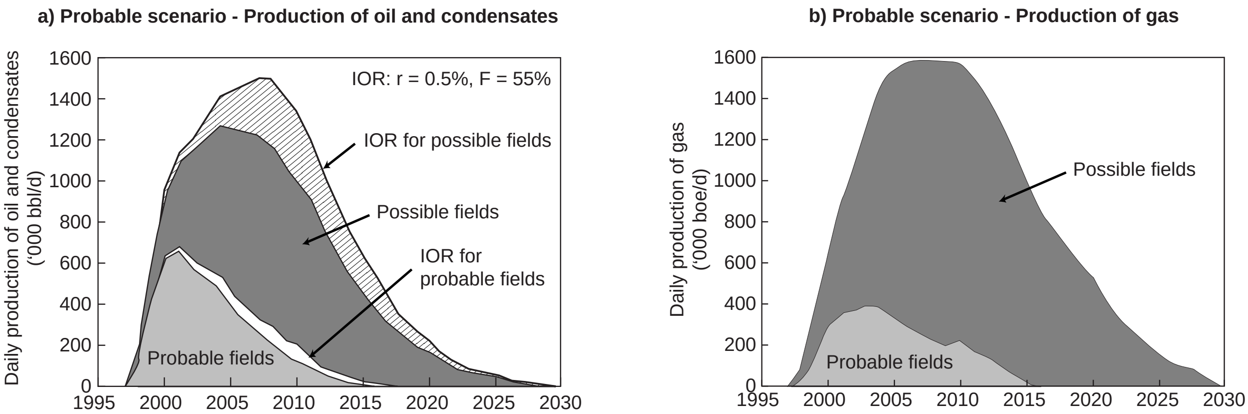


Figure 8

Probable scenario – Undeveloped fields: production curves for oil, condensates and gas.

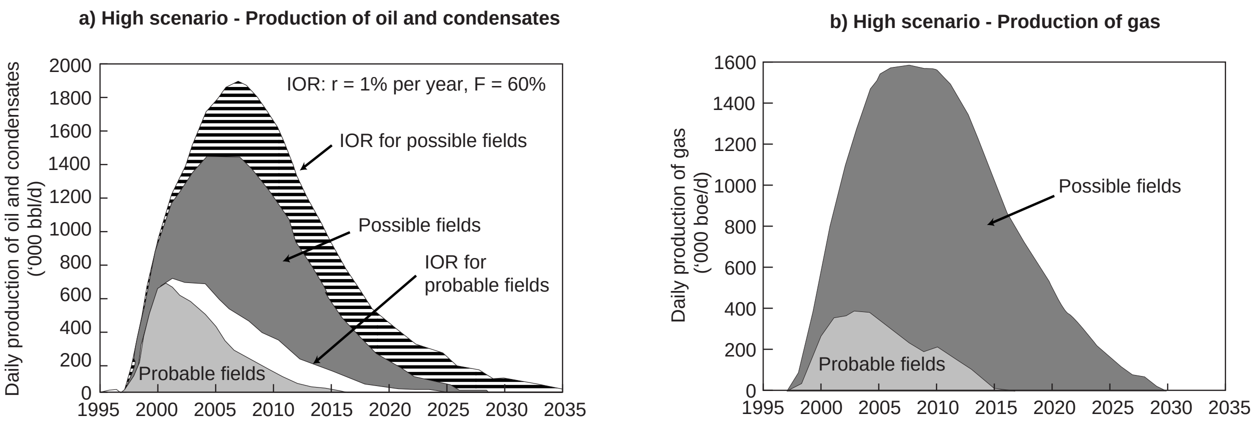


Figure 9

High scenario – Undeveloped fields: production curves for oil, condensates and gas.

TABLE 2

Recoverable undeveloped reserves corresponding to the three scenarios

Scenario	Probable fields			Possible fields				
	Initial reserves of recoverable oil	Additional reserves of oil by IOR	Recoverable gas reserves	Initial reserves of recoverable oil	Additional reserves of oil by IOR	Recoverable gas reserves	**Total oil reserves**	**Total gas reserves**
Low	1897	85	1486	–	–	–	**1982**	**1486**
Probable	1897	267	1486	4819	1203	8344	**8186**	**9830**
High	1897	1026	1486	4819	3142	8344	**10 884**	**9830**

Oil and condensates reserves in Mbbl.
Gas reserves in Mboe.

For each scenario, Table 2 indicates the total reserves for undeveloped fields.

In this context, the question of how to account for marginal fields is posed. In fact, this generally vague term refers to varying types of oil and/or gas accumulations and depends on their location as well as prevailing economic conditions. For the sake of clarity, the “marginality” is linked to oil prices and development costs. Paradoxically, this notion intervenes when the exploitation of an oil or gas field provides the operator with an uncertain profit margin. In practice and from this point of view, the oil and gas resources at a given moment can be classified into three categories:

– Profitable fields for which, taking into account the usual risks associated with production activities, geological, technical, political, economic, etc., the development must lead to profitable operation for the producing company.
– Unprofitable fields for which the situation is risky and, therefore, does not appear to be profitable.
– Marginal fields: these are found in an intermediate situation, that is, they seem to be profitable if the parameters are favorable but are otherwise difficult to operate.

This classification clearly highlights the dependence of marginality on both economic and technical considerations, such as crude prices, the availability of outlets for gas and market situation. In a given environment, this notion may be described by a limited number of parameters which appear to be sufficient to characterize a reservoir. In the North Sea the two principal parameters are the size of the reserves and the distance from existing infrastructures. However, distance is now losing its influence through the increasing use of floating production systems.

To the extent that the study is conducted independently of all economic considerations, it is easy to explain why the notion of marginal fields is deliberately avoided. However, a link may be established with the various categories of fields listed under the classification of undeveloped fields:

– The “possible” and “probable” resources can be considered for the present as marginal.
– Under the low scenario the “probable” resources become profitable while those considered “possible” remain in the marginal category.
– Under the other two scenarios, all these fields become profitable.
– The category “improbable” is made up in all cases of unprofitable accumulations.

3.3 Undiscovered Resources

There are no means available to evaluate undiscovered North Sea resources, other than to seek out existing sources of information, which concern essentially the United Kingdom, Norway and, to a lesser extent, the Netherlands, but only for gas. For other countries, there do not currently seem to be any data available. However, it is quite possible to proceed, as before, with an extension of the information thus collected to the entire zone under study.

For the United Kingdom, some of the estimates are based on the creaming curve. This procedure is valid only for mature regions with forecasts based on the processing of results and on past trends, the initial discovery of large fields followed by diminishing average size in the mature period. This does not apply to frontier zones, such as the West of Scotland and the West Shetlands. For its part, the DTI uses an analysis of the maps of basins, across hydrocarbon traps, reservoir parameters, recovery factors and success rates, eliminating small and potentially unprofitable reserves. Obviously, this procedure is not applicable to unmapped zones, such as the West of Scotland. This produces results that are not only more modest on average but also more dispersed: 2060 to 17 710 Mbbl of oil and 2765 to 9930 Mboe of gas for the United Kingdom.

For Norway, the undiscovered resources are estimated from forecasts made on mapped prospects and on other zones where prospecting models are defined. If one considers the total values of oil and gas proposed, from 10 600 to 47 260 Mboe, 39% of undiscovered reserves concern the North Sea itself, 37% the Norwegian Sea and 24% the Barents Sea. Of the total, 60% are considered to be gas.

For the Netherlands, some information on gas without details, is available from the Ministry of Economic Affairs.

The official figures published by these three countries illustrate efforts made to indicate the extent of incertitude in low and high estimates. Only the NPD provides a probable value. In order to estimate median results for the United Kingdom and the Netherlands, the ratios have been calculated based on those observed for Norway at low, high and probable levels.

Table 3 also provides results which were used to perform this analysis. The cumulative results for the potential for undiscovered resources in comparison with current recoverable results are:
– for oil: 13, 31 and 77%,
– for gas: 16, 35 and 79%,
depending on whether the estimate is low, high or probable.

The problem is to process these results in order to arrive at production curves corresponding to the three scenarios that have been retained, by distributing the reserves in fields of different sizes and fixing for each of them a starting date for extraction.

To estimate the distribution frequency of sizes and a forecast of the number of fields as well as their future production, one refers to overall historical data concerning the northwest European continental shelf. The parameter considered here is the average annual statistical frequency of the oil and gas fields entering into production, classed by size ranges for fields in production, under development or with a probable development plan. The steps selected for distributing the reserves by size is 10 Mboe. The period covered is 37 years, and 513 oil and gas fields with total reserves of 49 Gbbl and 3.5 Gboe respectively are concerned. Only fields whose reserves are greater than 2350 Mboe are taken into consideration.

Among the other working hypotheses adopted, are the following:
– The period necessary to develop an undiscovered resource is evaluated from the historical information already mentioned for each region.
– For each oil or gas bearing province, the number and size of fields entering into production are determined according to the frequency parameter defined above. For a given zone, the total resource is distributed by increasing sizes until the total value of the undiscovered field is reached. For each field, a production curve is then modeled.
– The oil and gas resources are analyzed separately.
– The modeling does not take into account economic considerations.

Passage to the three initial scenarios takes place by a simple projection of results from Table 3 concerning the

TABLE 3

Undiscovered North Sea resources with correction applied. In order to standardize the various figures, the oil and gas discoveries made in 1996 and 1997 (up to April 1) have been deducted from the totals

		Oil and condensates (Mbbl)			Gas (Mboe)			Total oil and gas (Mboe)		
		Min.	Max.	Prob.	Min.	Max.	Prob.	Min.	Max.	Prob.
United Kingdom*	Northern and Central North Sea	1455	8290	3055	90	1095	325	1545	9385	3380
	West Shetlands	590	5290	1980	1225	5090	2365	1815	10 380	4345
	West of Scotland	0	3820	1330	-	-	-	0	3820	1330
	Southern North Sea. Irish and Celtic Seas	0	295	70	1430	3725	1965	1430	4020	2035
	Total	**2045**	**17 695**	**6435**	**2745**	**9910**	**4655**	**4790**	**27 605**	**11 090**
Norway**	Northern and Central North Sea	2010	6025	2950	3220	9060	4585	5230	15 085	7535
	Norwegian Sea	1250	8175	3295	1280	11335	4250	2530	19 510	7 545
	Barents Sea	720	4730	2115	1050	6870	3070	1770	11 600	5185
	Total	**3980**	**18 930**	**8360**	**5550**	**27 265**	**11 905**	**9530**	**46 195**	**20 265**
Netherlands***		-	-	-	**255**	**935**	**415**	**255**	**935**	**415**
Total		**6025**	**36 625**	**14 795**	**8550**	**38 110**	**16 975**	**14 575**	**74 735**	**31 770**

* Corrected for discoveries after 1997 — Oil: 15 Mbbl in the central North Sea; Gas: 5 Mboe in the central North Sea and 15 Mboe in the southern North Sea

** Corrected for discoveries after 1997 — Oil: 345 Mbbl in the central North Sea; Gas: 195 Mboe in the northern North Sea and 350 Mboe in the Norwegian Sea

*** Corrected for discoveries after 1997 — Gas: 310 Mboe in the southern North Sea values of undiscovered resources evaluated as low, probable or high, according to previous hypotheses regarding distribution, which remain identical for the three cases. These procedures may appear to be unsophisticated and raw, but they do not lead to any degradation in the credibility of data. By comparison, any other methodology, even if it is more advanced, would seem baseless. It is also for this reason that additional resources likely to be brought in by IOR, and that are already supposed to be accounted for in the official figures, are not taken into account.

Figure 10 provides the distribution for the three scenarios for undiscovered oil and gas resources. The following points emerge from these simple projections:

– 78 out of 216 oil fields and 105 out of 269 gas fields taken into account have sizes close to 10 Mboe;
– 35 to 65% of these resources are made up of fields with sizes less than 50 Mboe.

These estimates depend to a large extent on the type of analysis that is carried out. Thus, on the basis of a statistical study of the distribution frequency by reservoir size, the expected size of the fields seems low. This phenomenon is further emphasized by the fact that oil and gas are disassociated.

3.4 Expenditures and Employment

It is commonly thought that technological development, which improves productivity and growth, has the counterpart of reducing employment. However, introducing innovations can increase profits, which can, in turn, generate new activities through reinvestment. Innovation can also open up opportunities to penetrate new markets and, thus, strengthen companies' organization and increase their ability to act. In the present case, by making fields economically profitable, the technological progress from the R&D can generate an increase in activity and thus lead to increased employment.

Concerning more directly the North Sea belt, one of the objectives of the study is to demonstrate that even if technological progress and cost reduction are often linked with reduced personnel requirements, their impact on additional reserves, and especially on the international competitiveness of Europe, lead, in the final analysis, to increased employment in the European oil and gas sector.

Here, the preceding results concerning growth projections for reserves and production curves must be processed in such a way as to make forecasts based on historical data that has already been collected, regarding the future variation of expenditures and employment. This analysis is carried out annually for the three scenarios that have been selected. However, one is faced with the problem of access to information, which is possible, although not completely, only in Norway and the United Kingdom. Under these conditions, it becomes necessary to multiply working hypotheses and simplifications. The different stages in the procedure are summarized in Figure 11.

One of the most effective ways to evaluate employment levels in the petroleum sector is to carry out evaluations based on activity deployed in the field. This activity is translated into expenses engaged by the operators and into turnover for service companies. Because of this, rather than make use of the usual economic criteria, such as internal rate of rentabilities (IRR), net present value (NAV), etc., it seems more pertinent to reason in terms of investments (Capex or even better, Capex per barrel) and operating expenses (Opex, or even better, Opex per barrel). However, the Capex are engaged before and around the starting date of exploitation, while the Opex are spread over the entire period of

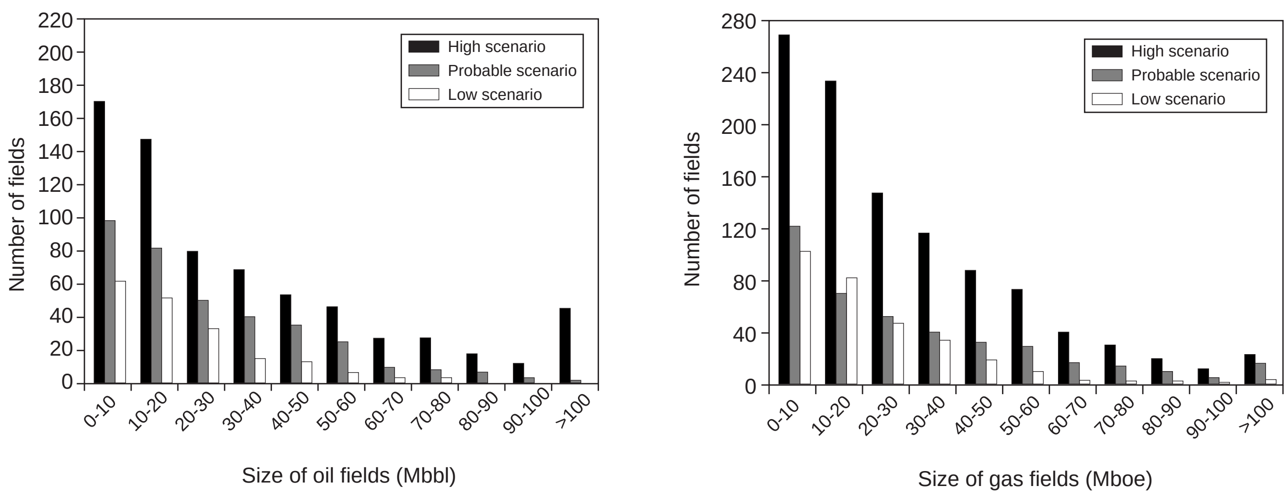


Figure 10

Distribution of undiscovered oil reserves in the North Sea by size and by scenario.

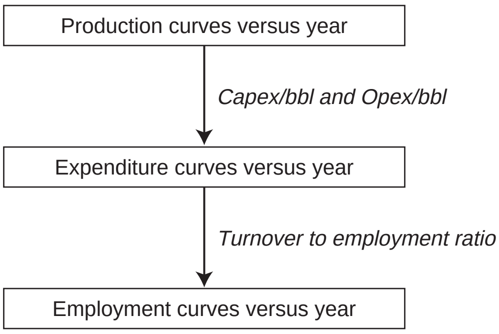


Figure 11

Relationship between expenditures, production and employment curves.

exploitation and depend generally on annual production levels. Consequently, rather than considering an overall technical cost such as (Capex + Opex)/bl as the correlating element, it is better to dissociate the effects of the two components, Capex/bl and Opex/bl.

Typical values are determined for each field in the North Sea (Table 4). They are obtained statistically from the database by retaining only the most recent fields producing oil and gas, over the period 1992-1996. The distribution is based both on geographical location and on size. These parameters are, in fact, the only ones that are systematically accessible from the publications, for probable, possible and undiscovered resources. Because it is found to be difficult, or even impossible, to cover the entire size domain being studied for certain regions, aggregation becomes necessary, in spite of similar conditions. Two large zones were inventoried, the northern and southern parts of the northwest European continental shelf. For the bordering resources, values for the northern part are used.

For the three scenarios, the cumulative production curves plotted previously served as a starting point for the calculations. Nevertheless, before translating these results into expenditures, additional hypotheses are required:

– No eventual cost reductions are take into consideration. Consequently, the values indicated in Table 4 are supposed to be constant over time. One considers, in fact, that a major part of the cost reduction has occurred over the last ten years and that the character of fields classified as "difficult to produce" will not permit a more significant reduction of expenses. Besides, the systematic implementation of IOR will introduce a natural trend toward cost increase. Lastly, the most plausible hypothesis seems to be that current levels will be maintained.
– Only resources from fields classified as probable, possible and undiscovered are taken into account. The spending corresponding to additional expenses resulting from IOR are not included. In fact, the figures for Capex and Opex directly reflect development and production activities, respectively. Because of the initial amalgamation of all IOR procedures, it is difficult, if not impossible, to decide whether the notion of Capex and/or Opex is to be applied to the additional reserves.

For each of the countries covered in the study, the passage from expenditures to employment levels takes place on the base of a correlation factor, employment/spending. These results are due to the statistical analysis of official historical annual information sources, both for employment and for spending, that have been integrated into the database.

The diversity of information sources and modalities for the classification or accounting of these elements makes all interpretation extremely difficult, particularly for employment. In other words, there is no universal definition available, that would permit the segmentation and aggregation in a very coherent manner from one country to another. It is possible to understand this situation to the extent that the companies concerned deploy their activities in varying domains, often without relation to the sector being studied, and assign their personnel to tasks which have priority at the moment, without necessarily ensuring that they be monitored at an accounting level or that the traceability of results be maintained.

However, a majority of organizations seems to agree that three major categories of employment can be distinguished, direct, indirect and induced. Even if they do not agree on the real profiles of these segments, one can consider, during an initial estimation, that under the category "direct" one can find, as applicable to the sector being examined, the personnel of both oil companies and oil and gas service and equipment

TABLE 4

Current typical values of Capex/barrel and Opex/barrel for the north European continental shelf, summarized for overall oil and gas reserves

Size of field (in Mbbl and Mboe)	< 50		50-100		101-250		251-500		> 500		All sizes	
	Capex*	Opex*	Capex*	Opex*	Capex*	Opex*	Capex*	Opex*	Capex*	Opex*	Capex*	Opex*
Southern North Sea, Irish Sea, Celtic Sea	4.07	4.43	4.19	4.17	4.24	3.83	2.46	3.04	**	2.88	3.74	3.56
Central and northern North Sea, Norwegian Sea	4.29	5.64	3.63	5.16	4.58	5.36	2.95	4.28	3.46	4.64	4.45	4.68
North Sea (in general)	4.16	5.01	3.94	4.33	4.49	4.78	2.76	3.95	3.08	4.53	4.08	4.46

* In 1997 – $/boe

** Data not available

companies that realize more than 80% of their turnover in this sector of activity. Under the category "indirect" one can include other oil and gas service and equipment companies and account for their employee strength on a pro rata basis, proportional to their turnover resulting from their work with oil and gas, or other more elaborate rules may be established. By "induced" employment, one indicates personnel of any other company working more or less for the oil and gas service and equipment sector. Unfortunately, the situation is further complicated by the fact that, for this study on the North Sea, one must consider, on the one hand, only the offshore activities of all the companies and, on the other, retain only those activities concerning the exploration-production on the northwest European continental shelf.

As far as the United Kingdom, Norway, the Netherlands and Denmark are concerned, retrospective data for these countries are available and the correlation between employment and spending is shown to be effective[1].

If i is the country being considered:

E_i the annual turnover or expenses (Opex and Capex);

L_i labor, expressed in man-years, in the oil and gas service and equipment sector,

one obtains:

$k_i = L_i/E_i$, the factor that translates the number of employments generated or directly ensured by spending employment M$1.

For Germany and Ireland, where there is a lack of information, we apply an average value for the factor k, calculated from past results, to available expenses data in order to estimate the number of employments. For France, it is assumed that companies engaged in North Sea activities are already accounted for, either by Norway and by the United Kingdom. The total for 1995 is shown in Table 5, illustrating and summarizing the process that was used.

(1) The increase in productivity is implicitly taken into account to the extent that technological improvements which are at the source of this increase, are translated elsewhere, all things being equal, into lower Capex and Opex and, thus, into a correspondingly reduced number of direct employments.

The values in Table 5 are then used as a reference in order to determine the outlook for employment growth until the year 2015 according to high, low and probable scenarios.

In order to obtain a much wider and more realistic view of the situation generated by the activities of the oil and gas service and equipment sector, a calculation was made to determine the number of so-called direct and indirect employments. In this context, a recent work conducted by Rogaland Research (Norway) is referred to, which makes use of a multiplication factor, that applies only to direct employments, between 1.6 and 2.0

4 RESULTS AND INTERPRETATION

4.1 Production Outlook for Oil, Condensates and Gas

These figures are the cumulative results of the estimates made for the implementation of improved recovery in fields in production, as well as undeveloped and undiscovered resources. An overall presentation is provided in Table 6 for the northwest European continental shelf for oil and condensates, on the one hand, and for gas, on the other. Figures 12, 13 and 14 correspond to the three scenarios that have been examined, low, probable and high, also denominated as current trend, probable and ideal.

These conclusions are based on the various hypotheses introduced in the model and refer to different levels of technological improvement. They can change significantly if the calculation conditions are modified. However, they appear to be coherent, on the whole, as is confirmed by the most recently published estimates of reserves and which are included in the data bases or issued by official sources such as the DTI and the NPD.

TABLE 5

Correlative factors for 1995 calculated from direct employments and total expenditures for the United Kingdom, Norway, the Netherlands and Denmark. Estimates of direct employments for Germany and Ireland based on an average value of these factors and expenditures

1995	Total spending* (M$)	Direct employments (man-years)	Average ratio
United Kingdom	13 365	102 000	7.63
Norway	12 563	70 072	5.58
Netherlands	1224	17 020	13.9
Denmark	1149	3800	3.31
Total	**28 301**	**192 892**	**6.82**
Germany	41	279**	
Ireland	24	184**	
Grand Total	**28 366**	**193 335**	

*Capex + Opex source: Data bank.

** Estimated.

TABLEAU 6

Cumulative estimates of outlook for recoverable oil, condensates and gas reserves according to the three scenarios (oil and condensates in millions of barrels and gas in millions of barrels of oil equivalent)

		Low scenario		High scenario		Probable scenario		
Category of fields	Type of reserve	Oil and condensates	Gas	Oil and condensates	Gas	Oil and condensate	Gas	
Fields in production, under development and with planed development	Initial recoverable reserves	47 132	35 242	47 132	35 241	47 132	35 241	Produced with current technology
	Additional reserves recoverable with IOR	6279		19 451	–	13 282	–	Produced through technological improvements
Probable fields	Initial recoverable reserves	1897	1486	1897	1486	1897	1486	
	Additional reserves recoverable with IOR	85	–	1026	–	267	–	
Possible fields	Initial recoverable reserves	–	–	4819	8344	4819	8344	
	Additional reserves recoverable with IOR	–	–	3142	–	1203	–	
Undiscovered resources		6025	8550	36 625	38 110	14 795	16 975	
Total		**61 418**	**45 277**	**114 092**	**83 181**	**83 395**	**62 046**	

To the extent that forecasts are always subject to a degree of uncertainty, results for the different scenarios are presented in such a way as to measure the level of technological improvement, that is, the R&D effort required in exploration-production in order to satisfy expectations regarding such performances. Under these conditions it is perhaps better to emphasize the trends that emerge from the study, rather than the bare numbers.

The low and high scenarios form, respectively, the lower and upper limits of potential North Sea resources.

- Based on the hypotheses concerning the lowest level of technological improvement, the curves relating to the low or "current trend" scenario, which assumes that the status quo will be maintained in R&D, are cause for extreme concern, at least for oil. They do not indicate any rapid change alleviating the rapid decline that is expected to occur before the end of the century in the production of oil from existing fields or from those under development. In other words, with regard to the criteria defining this scenario, the petroleum history of the North Sea is coming to an end:
  - after a peak of 7 Mbbl/d in 2000, oil production will fall to about 3 Mbbl/d in 2010 and less than 1 Mbbl/d in 2020;
  - gas production may reach 3.7 Mboe/d in 2000, continue to be more than 3 Mboe/d in 2015 and fall to less than 1 Mboe/d in 2025.

There are different reasons for this. The decline in the number of giant fields discovered during the '70s and, at the same time, the rapid depletion of those of lesser importance that started production during 1980-90. In addition, most of the new discoveries are small and far more difficult to exploit. Besides, many of them cannot be brought into production under current technical and economic conditions.

In the current trend scenario, the remaining reserves of the northwest European continental shelf continue to be highly significant, 35 Gbbl of oil and 32 Gboe of gas, as compared to the quantities already produced, 26 Gbbl of oil and 12 Gboe of gas.

- In comparison, the high scenario produces spectacular curves for production growth of both gas and oil, justifying its description as "ideal". In this case, the North Sea has not yet reached half of its potential production. New production records will be set each year up to 2015:
  - after a peak of nearly 9.5 Mbbl/d during 2010-2015, oil extraction will fall to 3 Mbbl/d in 2027 and to 1 Mbbl/d in 2032;
  - for gas, the maximum will also be reached during 2010-2015 with 5.5 Mboe/d, with a fall to 1 Mboe/d sometime after 2040.

In this scenario, which can be envisaged only if it is accompanied by the determination to implement all the available technologies, currently or in the future, and also to

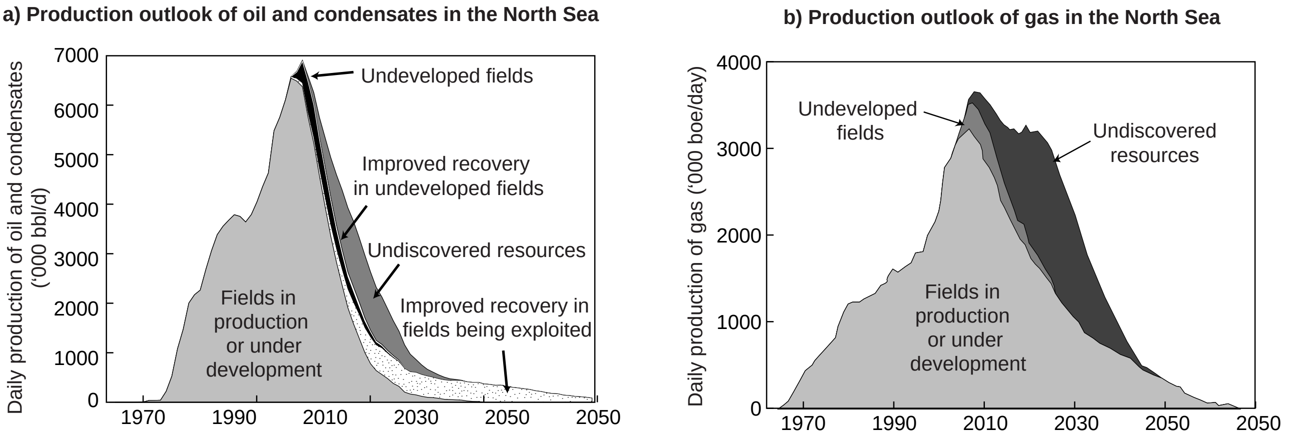


Figure 12

Production outlook of oil, condensates and gas in the North Sea (low scenario).

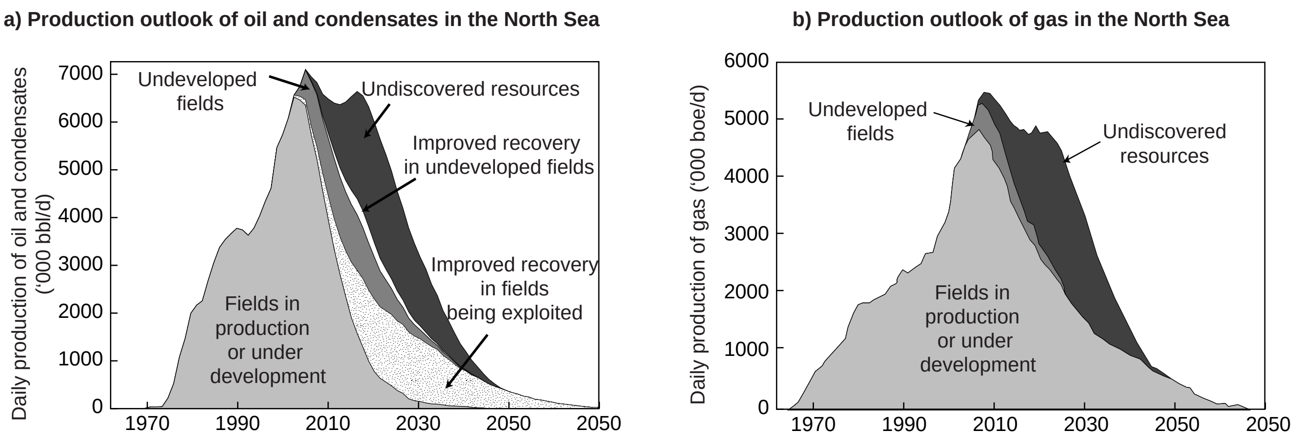


Figure 13

Production outlook of oil, condensates and gas in the North Sea (probable scenario).

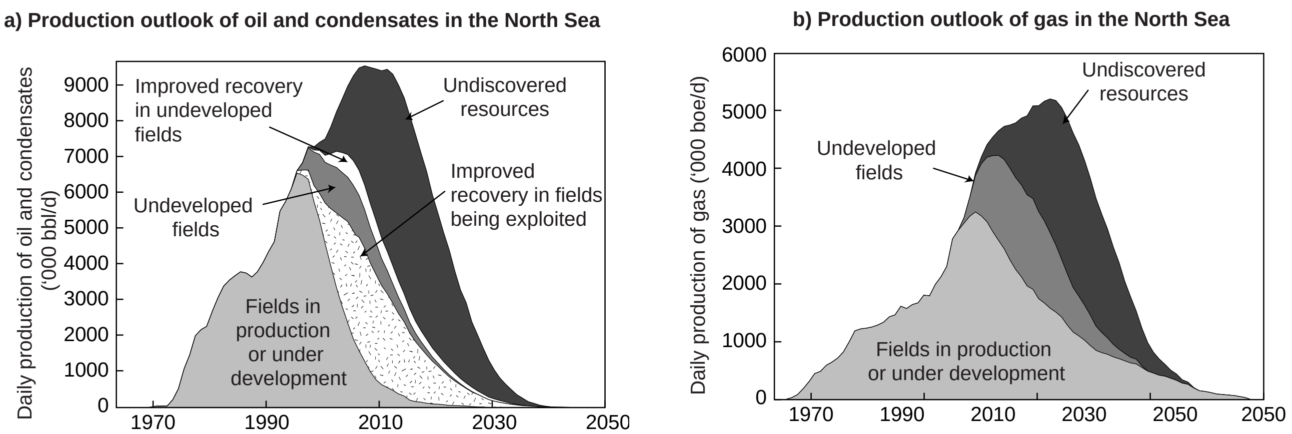


Figure 14

Production outlook of oil, condensates and gas in the North Sea (high scenario).

provide a favorable economic and fiscal situation, the stakes, in comparison with the trend-setting scenario, are:
– additional oil reserves: 53 Gbbl;
– additional gas reserves: 38 Gboe;
– corresponding current market value: 1200 G€;
– additional production of oil in 2010: 6.5 Mbbl/d;
– additional production of gas in 2010: 2.3 Mboe/d.

The British experience over the period 1985-1995, as evaluated by a recent study by the *Oxford Institute for Energy Studies*[2], demonstrates that technological innovation and encouraging fiscal measures can act in a complementary manner to influence production levels strongly.

In the meantime it is possible to envisage a realistic, technologically more probable and more optimistic scenario than the status quo when a policy of strengthening R&D is rapidly engaged. In this case, the goal is to increase the ultimate recovery of fields in production and to exploit the majority of those not yet developed. Currently more than 400 fields in the North Sea are not developed because technologies that would permit profitable exploitation are not yet available. Under this scenario the production levels must spread out more over time and delay the decline, which can be expected after about ten years:
• Oil production may reach more than 7 Mbbl/d in 2000 and remain at a level above 6.5 Mbbl/d up to 2010, declining to 3 Mbbl/d around 2020 and to 1 Mbbl/d around 2030.
• Gas production may exceed 5 Mboe/d in 2015, falling to 3 Mboe/d around 2025 and to below 1 Mboe/d beyond 2030.

In comparison with the current trend scenario, the quantitative stakes are:
– additional oil reserves: 22 Gbbl;
– additional gas reserves: 17 Gboe;
– corresponding current market value: 500 G€;
– additional oil production in 2010: 3.4 Mboe/d;
– additional gas production in 2010: 1.8 Mboe/d.

5.2 Outlook for Growth in the Volume of Activity and Employment in the European Petroleum Service and Equipment Sector

The growth of total expenses for future development in oil and gas fields on the northwest European continental shelf is summarized in Figure 15 for the three study hypotheses, low, probable and high scenarios. Considering the uncertainty inherent in this type of estimate, the period covered is deliberately limited to 1995-2015. The principal results that emerge are:
– Current trend scenario: The annual volume of activity in 1998 may reach about 25 G€. It will then fall and stabilize around 20 G€ until 2007. The slow decline will continue to about 15 G€ during 2015. Over the period 1997-2010, the cumulative volume of activity will be 290 G€.
– Probable scenario: the maximum should be reached in 2007 with nearly 32 G€. Then stabilization will occur until 2011 at around 29 G€. This will be followed by a quite rapid fall, the expected level in 2015 being 22 G€. Over the period 1997-2010, the cumulative additional volume of activity compared to the current trend scenario will reach +110 G€.
– Ideal scenario: the expenses is expected to follow an upward trend until 2012, to reach 38 G€. The decline will then start, falling to 32 G€ in 2015. Over the period 1997-2010, the cumulative additional volume of activity compared to the current trend scenario will be +150 G€.

Figure 16 brings together results concerning the growth of employment during 2015 for the three cases that have been studied. It highlights, particularly for the two most optimistic scenarios, the influence of calculation hypotheses on maintaining and creating employments, respectively.

The low scenario is used as a reference just as in the previous case. The number of man-years, in this case, reaches 210 000 during 1998, only to fall rapidly, stabilizing at around 170 000 until 2007. In the last part, the fall continues rapidly to 100 000 man-years in 2015.

For the other two scenarios, the fluctuations in the number of employments are the direct consequence of fluctuations in production and in the volume of activity. Thus, under the most optimistic calculation hypotheses, when resources increase, the impact on employments is positive. Obviously, this is difficult to verify and correct in practice. Consequently, the implementation of new technologies, as envisaged by the probable and high scenarios has the effect of stopping and even reversing the trend towards a decline in the number of employments, that characterizes the low scenario.

For the beginning of the next century, the probable scenario may make a significant contribution towards maintaining employments, allowing for up to 260 000 man-years in 2007, that is, 90 000 more than in the previous case. This considerable difference can be partially imputed to the development of large reserves that are classified as possible and currently unexploited. Thereafter, the decline begins, with a fall to less than 170 000 man-years in 2015.

The considerable R&D efforts underlying the high scenario, leading to the development of significant undiscovered resources, can also produce significant and continuous growth in the number of direct employments until 2006, followed by leveling off after 8 years at around 290 000 to 310 000 man-years, that is, 60 000 to 70 000 more than in the probable scenario. After 2013, the decline may start, but the number of employments ought to remain above 250 000 in 2015.

As has already been mentioned, this type of analysis can be extended to all types of direct and indirect employments by using an average multiplication factor. It should be remembered that this coefficient can fluctuate in significantly, from 1.6 to 2, according to Rogaland, for the

(2) *Tax or Technology? The Revival of the United Kingdom North Sea Oil Production.* Oxford Institute for Energies Studies, SP8, October 1997.

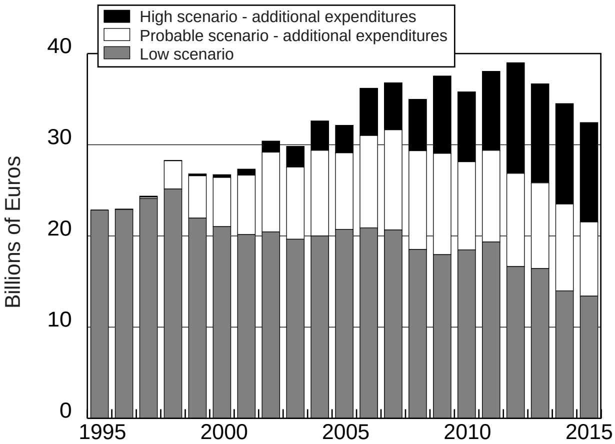


Figure 15

Outlook for expenditures in North Sea, comparison of three scenarios.

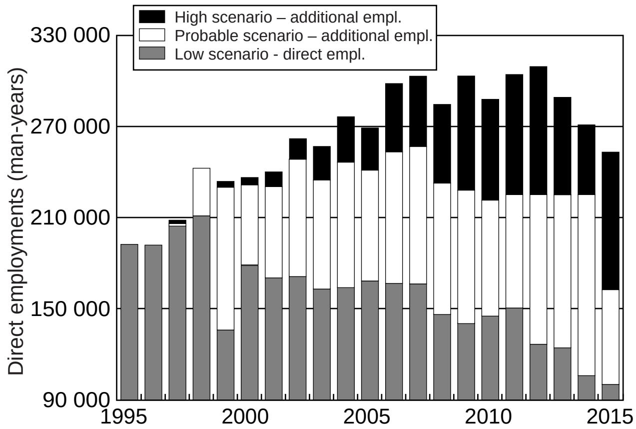


Figure 16

Direct employments outlook according to the three scenarios.

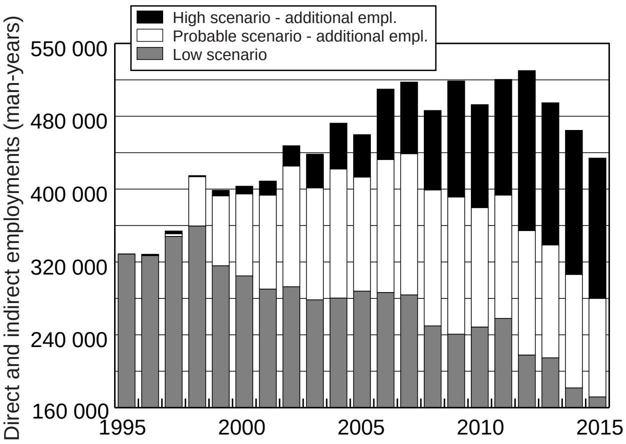


Figure 17

Outlook for direct and indirect employments in the North Sea, comparison of three scenarios.

different countries, depending on the economic and industrial structures that characterize each country. The total number of direct and indirect employments varies, under these conditions, from 310 000 to 390 000, as a present. By retaining the highest value, depending on which scenario is being considered, one obtains for 1998 an estimate of 420 000 to 480 000 man-years. When these figures are compared to those for Norway, the most realistic estimate for this factor seems to be situated between 1.6 and 1.8. Therefore, one can use the median value of 1.7 for which the results are presented in Figure 17.

It is shown that the highest total level of employment in the North Sea, linked to the impact of new technologies, will be around 400 000 to 440 000 man-years during the period 2003-2008, for the probable scenario and between 480 000 to 530 000 for the high scenario during the period 2006-2013.

In practice, starting from an initial strength of around 320 000 in 1995, for a reference date such as 2010, the current trend scenario indicates a fall in employment to 250 000 people, while the probable version shows an increase to 380 000, that is, 130 000 more than in the previous case. For the ideal case, the employment level will be 490 000, that is, 240 000 additional man-years.

CONCLUSIONS

In the probable technological scenario, the North Sea will be a superb showcase for the European oil service and equipment industry, allowing it to progress to a new stage in its development (Table 7).

Currently, according to another *ENeRG* study of the European[3] petroleum service and equipment industry, this sector represented in 1996, for upstream activity alone, exploration-production of oil and gas, a turnover of 28 G€, representing around 30% of the world market, which is evaluated at 95 G€. About half of this volume of activity for European companies comes from the North Sea, and the other half comes from other markets abroad in continental Europe.

According to *Eurogif*[4], the European petroleum service and equipment industry employs around 750 000 people, which corresponds to a turnover of approximately 40 000 € per employment.

(3) A global view of the European Oil and Gas Supply Industry. EC Contract STR-O449-95-NL led by TNO.

(4) *Eurogif*: *European Oil and Gas Innovation Forum,* an organization that represents more than 2 600 European companies in the petroleum service and equipment industries.

TABLE 7

Comparison of the probable and high scenarios to the low scenario

	Remaining recoverable reserves		Daily production in 2010			
	Oil (Gbbl)	Gas (Gboe)	Oil (Mbbl/d)	Gas (Mboe/d)	Volume of activity (1997-2010) (G€)	Employments in 2010 (direct and indirect)
Low scenario	35	32	3	3.3	290	250 000
Probable scenario	+22	+17	+3.4	+1.8	+110	+130 000
High scenario	+53	+38	+6.5	+2.3	+150	+240 000

By assuming that it will maintain its market share in the North Sea, currently 70% according to the same source, its volume of activity in this favorable zone will remain at 20 G€ in the year 2010, according to the technologically probable scenario as opposed to 14 G€ under the current trend scenario.

On the overall international level, it is reasonable to envisage that the European petroleum service and equipment industry, under the hypotheses of the technologically probable scenario, may continue to increase its market share by 1% per year, as has been the case during the last 20 years, to reach 40% of the world market in 2010.

To sum up, commercial competitiveness, the potential for additional employments and increasing exports, in addition to reducing dependence on external energy sources, all provide convincing arguments in favor of an active research, development and innovation policy for the European petroleum service and equipment industry. It becomes increasingly an essential responsibility for companies working in this sector to develop and implement new technologies.

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