Prospects for Exploiting Stranded Gas Reserves

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Abstract

A growing share of natural gas reserves is stranded deep offshore, in difficult and remote areas or produced as associated gas. Bringing these so called stranded gas reserves to the market is a challenge, especially when distance makes gas pipelining economically prohibitive.

This paper presents a global estimate of these reserves, their geographic distribution together with their potential contribution in international exchanges. It also provides an overview of the transportation and/or conversion routes which will be needed to meet the challenges ahead.

Introduction

Due to its plentiful reserves, advantages in terms of environment protection and flexibility of use, natural gas appears as a major energy source for the next century. With 158.3 10^{12} m^3 of proven reserves, natural gas world ratio of reserves to production amounts to 60 years, compared to 40 years for oil (1).

On the other hand, a large fraction of these reserves is remote from consuming zones, located in deep offshore or in difficult access areas and in small-size fields, which have to be considered as marginal.

The availability of these reserves for the end-user is therefore hampered by production and transportation costs which can exceed the price at which the gas can be sold.

In such cases, innovative technical options are required for reducing the costs and providing new outlets for natural gas.

I - Stranded gas reserves: what is the potential?

Associated gas

While many gas accumulations exist independently of any oil accumulation, virtually all oil accumulations have natural gas associated with them. The production of associated gas is unavoidably tied to that of crude oil which, generally, represents the priority. Besides, in some OPEC countries in the Middle East, Saudi Arabia and Kuwait for instance, whose share of associated gas in total reserves is high, the impact of OPEC production quotas for crude oil may strongly affect gas production.

With the subsequent levelling off in the oil reserves (until the major reassessment in early 1988) in the Gulf countries, and exploration in zones and horizons more propitious to non-associated gas, the share of associated gas reserves has declined in the world total of gas reserves (compared to about 35% in the 1970 s). It can be estimated that associated gas now accounts for about 25%, geographically distributed as shown in table 1.

	Non-associated gas	Associated gas	Total
North America	5 900	300	6 200
% .	95.2	4.8	
Latin America	3 440	4 300	7 740
% .	44.4	55.6	
Europe	6 430	1 180	7 610
% .	84.5	15.5	
FSU	52 620	4 000	56 620
% .	92.9	7.1	
Africa	5 250	5 770	11 020
% .	47.6	52.4	
Middle-East	32 150	21 650	53 800
% .	59.8	40.2	
Asia/Oceania	13 100	2 210	15 310
% .	85.6	14.4	
World Total	118 890	39 410	158 300
% .	75.1	24.9	

Table 1 - Different types of natural gas in the world
Estimated reserves on January 1, 2000 (10^9 m^3)

Considering the fate of the natural gas "associated" to oil reservoirs, which was often flared, thus wasting a limited natural resource as well as affecting the environment, new policies have been implemented. A growing consideration concerns CO_2 emissions. Initial measures consist in avoiding flaring, in particular in the case of associated gas.

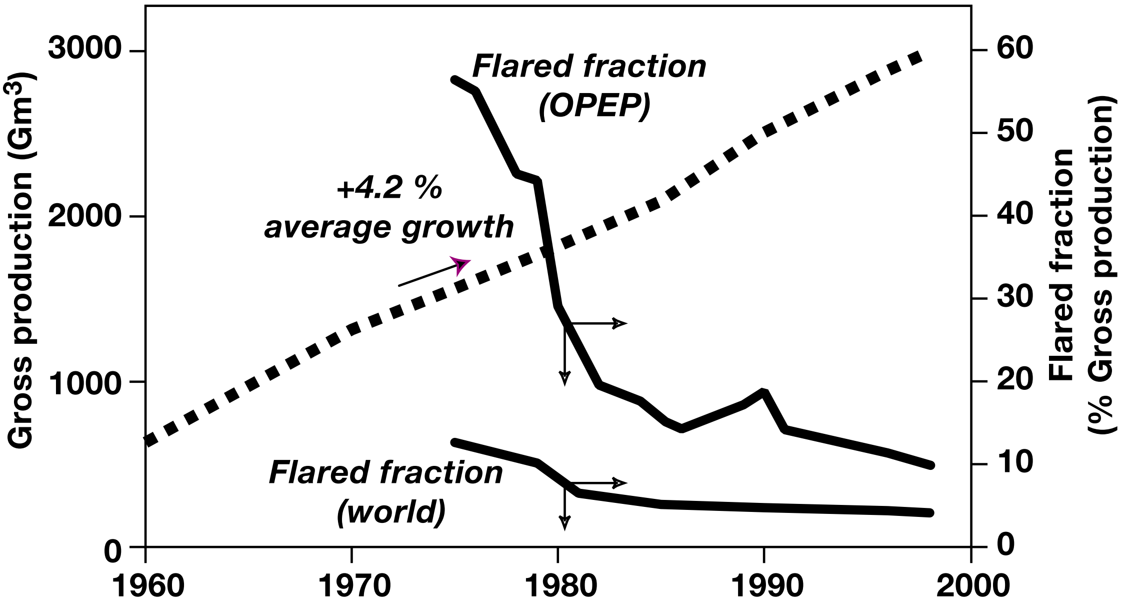

Figure 1 - Evolution of the gas flared fraction

As shown in Figure 1, the proportion of gas flared has been sharply reduced during the last twenty years. With 52 $10^9 m^3$ flared in 1999, the OPEC countries share in world gas flaring steadily decreases and stands at 51%. Flaring now accounts for 9.5% of their gross production against 63% in 1973. This reflects the efforts achieved by the countries in recovering growing quantities of associated gas.

With about 19 $10^{9\circ} m^3$ flared in 1999, Nigeria accounts for 18.6% of the total flaring world-wide. The country aims to eliminate associated gas flaring by 2010. Many projects are under way or planned to reduce the proportion of flaring, but it will be very difficult to implement all of them by 2010 given the increase in oil production.

When no infrastructure for transmission and distribution is available, there is only a limited number of outlets for the associated gas. These include gas re-injection (for pressure maintenance or for future recovery) and gas flaring (which is not a preferred option due to resource conservation and greenhouse gas issues). In the most favourable situations, where a transport network and a market are available, the gas is processed and its heavy fractions are extracted.

To enhance the value of their hydrocarbons potential, several countries in the Middle East (Iran, Abu-Dhabi) and in Latin America (Venezuela) have also implemented significant reinjection programmes. The development of this activity is accelerating and the volumes reinjected which reached 333 10^9 m^3 in 1999, registered a sustained increase (+ 1.6% over 1998). Today, they represent 11.5% of total gas production compared to 6% in 1980. The development of recovery methods in the oil fields, as well as the prospects of the growing use of gas associated with the new environmental constraints argue in favour of less waste and more efficient use of gas resources.

When gas reinjection does not enhance oil recovery, its cost is not compensated by a specific benefit. Therefore, new capital-intensive projects are now more and more considered such as LNG production and GTL schemes. It can be considered that around 30% of associated gas reserves have to be considered as stranded.

Deep offshore gas reserves

The offshore gas reserves in the Arctic zones and Siberia, and other areas of difficult access are taking a growing share of total reserves. They now account for over half of world proven reserves. From 1970 to 1990, this pattern assumed unprecedented importance: 70% of the net additions of reserves resulted from discoveries made in "difficult" zones, where the exploration and production of natural gas lies at the technological and economic "frontiers".

In recent years the industry has been pushing ever further offshore, and into increasingly deep waters, successfully making large discoveries (West Africa) and developing some of them. The potential of deepwater hydrocarbon development is enormous. Deep offshore gas reserves are currently estimated at around 8 10^{12} m^3. In this field of the gas industry, the evolution has been very rapid. Within a 20 year-period, it has proved achievable to produce fields in 1650 m of water (Mensa field in the Gulf of Mexico). The development of deep offshore production was made possible by substantial technological improvements in particular sub-marine wellheads and Floating Production Storage and Offloading units.

Development of these resources will be of growing importance as we enter the new millennium.

Marginal fields

Gas reserves are concentrated in a very small number of giant accumulations. Some 190 known giant reservoirs or so existing on our planet account for 57% of original gas reserves.

Slightly fewer than 25,000 small and often marginal reservoirs (less than $10^{\circ}10^{9}$ m^3) represent the largest number of discoveries made, but only about 28% of world reserves. It has also to be stressed that about 80% of these reservoirs are located in North America. In Western Europe, marginal fields exist in the United Kingdom.

However, a major share of the marginal fields cannot be considered as stranded. Indeed, the huge transport infrastructure already existing in the United States and in Europe allows the commercial development of the fields located close to the large consuming centres.

As a whole, marginal fields account for 15% of gas reserves, or about 24 10^{12} m^3. Around 20% of these reserves can be considered as stranded, representing 5 10^{12} m^3.

Remote gas

Large gas reserves, far-distant to consuming areas, are located in Africa and in North Siberia. A significant share of Middle Eastern fields has also to be considered as too remote from consuming areas for being exploited economically.

The estimation of the share of such remote reserves which has to be considered as stranded, is very sensitive to the evaluation of transportation costs and potential cost reduction. The impact of innovative technology will represent an essential factor for monetizing such reserves.

A rough estimate of the amount of remote gas reserves to be considered as stranded is in the range of 15 to 25% of the overall gas reserves.

The potential of stranded gas is therefore summarized in Table 2.

	10^{12} m^3	Gtoe
Associated gas	12	11
Deep offshore	8	7
Marginal fields	5	4
Remote gas	24-40	22-36
Total	**49-65**	**44-58**

Table 2 - Stranded gas potential

It represents therefore a huge potential, which requires innovative technologies for reducing transportation costs and developing new outlets.

II - Main options for monetizing stranded gas

The two main parameters to be considered are the quantity of gas available and the distance to the final market.

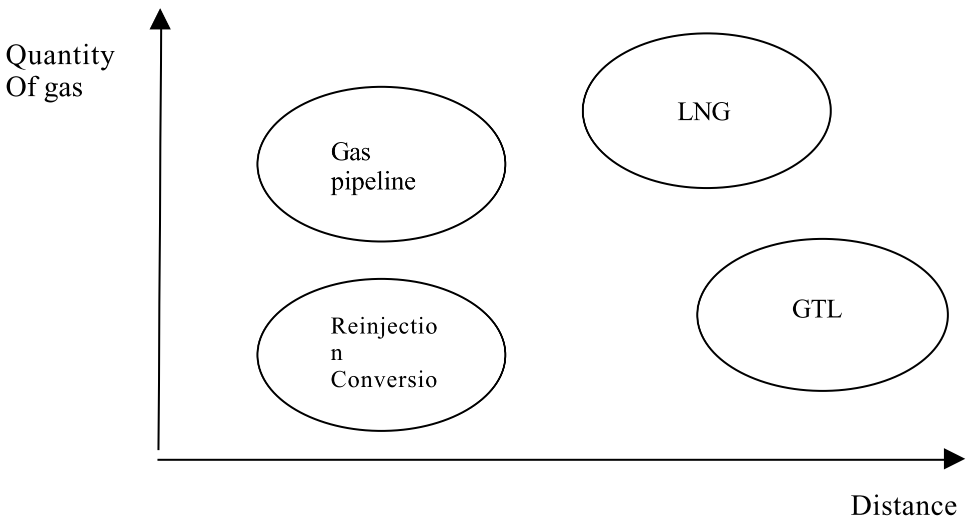

Figure 2 - Main options for monetizing stranded gas

Referring to the diagram in Figure 2, the following cases can be considered.

- For quantities of gas large enough, pipeline or LNG transportation remain the most competitive options. By reducing the transportation cost, technical innovation can contribute to widen significantly the conditions for which these options are economically acceptable, which means increasing the maximum distance or reducing the minimum capacity for which a new project will be considered as feasible.

- For large distances and mid-to-large quantities of gas, GTL (Gas-To-Liquids) conversion appears as a potentially attractive option, especially if pipe or LNG transport is not feasible due to distance.

- For small quantities of gas, reinjection is presently the only available solution, if no consuming market exists at a short distance. Different options are considered such as production of chemicals, of electricity or transport of compressed natural gas (CNG), but the economic profitability of such options remains questionable.

The diagram in Figure 2 is only schematic. In practice, many other parameters have to be taken into account, leading to significant overlaps between the different options to be considered.

III - Reducing the cost of gas transportation

Reducing the cost of gas transportation makes possible either to increase the maximum distance for which a project remains profitable or to decrease the minimum capacity for a given distance.

- Very significant evolutions have been observed in the area of offshore pipelines.

The laying rate has increased even when handling large diameter pipes from 2 up to 6 km/day. Entirely automatic welding equipments can be used. Gas pipelines can be installed in very deep waters by using a J type laying method as shown by the Blue Stream project (connecting Russia to Turkey with water depths up to 2150m).

Offshore pipelines tend to be operated at high pressures, around 150 bars at the pipe inlet, whereas onshore the pressure generally does not exceed 70 to 80°bars.

By operating an onshore pipeline at a similar pressure and using a high-grade steel (X-80 or X-100 instead of X-70), it is possible for a large capacity to reduce substantially the transportation cost and therefore increase the maximum distance for which a new project remains economic. Thus, the recent GATE 2020 study conducted by ENI and IFP for the European Commission (3) has shown the possibility to double this maximum distance, from 3000 km to around 6000 km in the case of a very large project (30 10^{9}° m^3/year).

- The cost of LNG production and transportation is also expected to decrease as a result of a further technical progress.

The cost of the liquefaction plant which represents around half of the total chain investment has been steadily decreasing in the past and is expected to decrease further as a result of different factors. It is estimated that during the last decade the cost of process and utilities has been reduced by some 50% (4).

Increasing the maximum train size capacity is a first factor. By increasing the unit train capacity from 2.5 to 4.5 Mt/year, it is possible to reduce by 16% the investment per ton of produced LNG for process units. New equipments: plate heat-exchangers, more powerful gas turbines, liquid expanders are also contributing to this evolution.

Finally, new generation liquefaction processes such as the CII-1 and CII-2 processes proposed by Gaz de France and IFP can have a most significant impact on the liquefaction cost (5).

The design of LNG tankers is also progressing. Larger capacity tankers are considered. By bringing the capacity from 125,000 m^3 to 200,000 m^3, it is possible to reduce the investment per ton of transported LNG by around 15%. Membrane technology makes possible to use the full capacity available in the hull and further cost reductions are expected.

Operating liquefaction units on a floating support of the FPSO type (Floating Production and Offloading System) should represent in the future an attractive option for monetizing deep offshore gas. Various projects have been considered by Mobil, Shell, and Bouygues-Offshore (Azure Project). Loading LNG in open sea represents a critical issue and Coflexip Stena Offshore is currently developing with IFP's support a cryogenic flexible pipe for this application.

IV - Gas-To-Liquids conversion

The main options for GTL conversion are summarized in Figure 3.

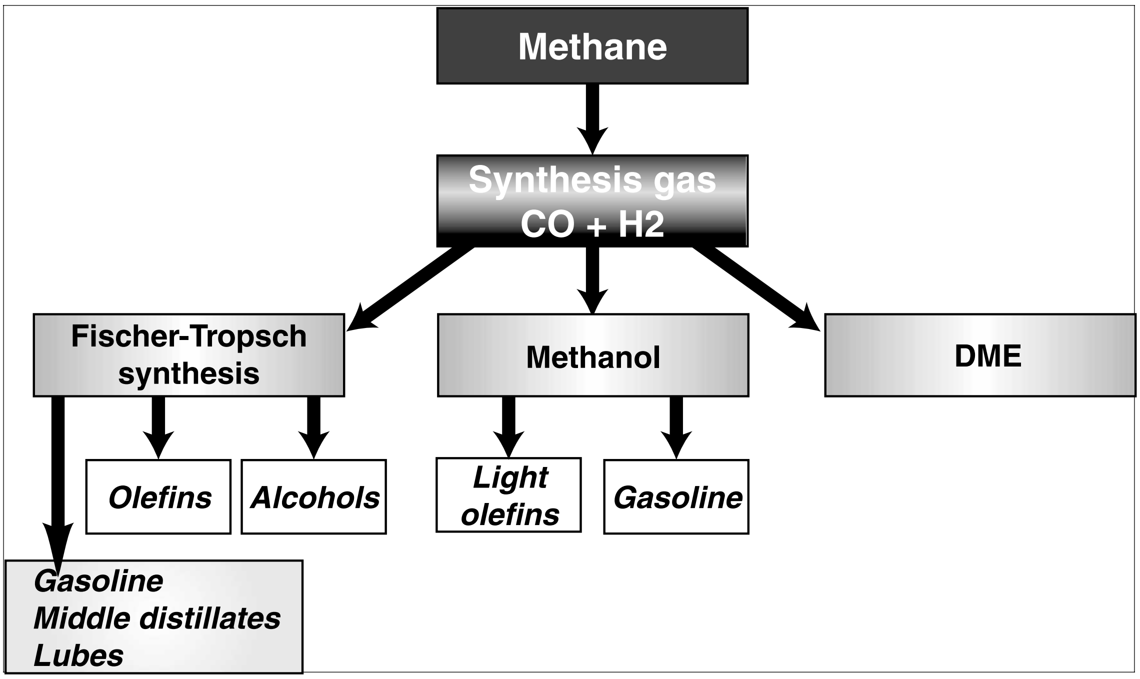

Figure 3 - Main options for GTL conversion

Fischer-Tropsch synthesis appears as most promising, as it produces high-quality fuels for which the market is very wide, almost unlimited, whereas the market for methanol tends to be saturated and the market for dimethylether (DME) has to be established with no existing present infrastructures.

Diesel fuels produced by a Fischer-Tropsch unit followed by a hydro-cracking/hydro-isomerization sections contain no sulfur, have a high cetane number and a very low aromatics content.

The need for cleaner fuels represents therefore a good opportunity for Fischer-Tropsch synthesis.

Recent progresses in catalyst formulation and reactor design have contributed to make such a process more competitive.

Fischer-Tropsch units appear as economically feasible under present economic conditions if the price at the well-head is low enough and the products benefit from a premium due to their quality.

Under such conditions, an investment cost below 25 000 US $/bpsd enables profitable returns at crude oil prices around 15 US $/bbl (6).

Associated gas which cannot be monetized directly and has only a "negative" value if reinjected appears therefore as a very appropriate feedstock.

The main FT technology developers include Exxon, Sasol, Shell and Syntroleum. IFP is involved in the development of a new FT process in association with an oil company.

V - Monetizing remote and deep-offshore marginal fields: a further challenge

Appropriate solutions exist for large fields even when they are remote from consuming areas and technical progress contributes to widen progressively the range of conditions for which economically feasible projects can be set-up.

In the case of marginal fields with no consumer at a close distance, no satisfactory solution exists. Associated gas produced from a deep-offshore field represents also a challenging issue.

Some of the options which are considered are the following:

- ***Offshore:***

- Floating LNG or GTL plants. Various projects are investigated. Projects concerning floating LNG units have already been mentioned. Floating Fischer-Tropsch units have also been investigated but require further development work, security being one of the most critical issues.

- Transport of compressed natural gas in tankers on a short distance, for instance for bringing the gas onshore. The Coselle CNG carrier concept is based on the transport of compressed gas in several miles of small diameter pipe coiled into a carousel. A ship transporting 108 such coselles would have a capacity around 9.3 Mm^3 equivalent to 15 000 m^3 of LNG. This concept is only appropriate for short distances, which means that the gas has to find a market onshore at a close distance (7).

- ***Onshore:***

- Transport of electricity. Progresses in the transportation of DC-current make this solution as potentially attractive for small capacities.

- Production of chemicals, which means in fact creating a local market on the basis of a low cost energy source.

A further option considered for associated gas, produced either onshore or offshore, is the natural gas hydrate (NGH) technology, transporting a hydrate-crude slurry (8).

Conclusion

Stranded gas accounts for a very significant proportion of the world gas reserves. Monetizing such stranded gas reserves will depend upon different factors. A first major factor is of course the evolution of the price that the final user is ready to pay.

Technical innovation will have a major impact, reducing production and transportation costs, but also providing new options, such as GTL conversion.

Environment protection and the need for a sustainable development might also represent a strong drive, favouring the use of natural gas, leading to the suppression of gas flaring and requiring cleaner fuels.

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