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Hydrate Non-Pipeline Technology

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Hydrate non-pipeline technology is being developed for the storage and transport of natural gas, in particular stranded gas, both associated and non-associated. The technology concerns the making, moving and melting of natural gas hydrate. Hydrate technology and other non-pipeline technologies based on compressed natural gas and chemical conversion to liquid hydrocarbons are considered appropriate for the transport of stranded gas, because established liquefied natural gas technology is only considered feasible in large-scale development. About 80% of the natural gas fields yet to be developed in the world are medium-to-small-scale and about one-half of the fields are considered stranded gas.

1 Introduction

Stranded gas refers to associated and non-associated natural gas located far away from an existing gas pipeline, and other situations where a gas pipeline cannot be built and operated economically. In some cases the natural gas may be close to markets, but the resources are too small to justify large investments for a pipeline or a large enough LNG (liquefied natural gas) plant. The term marginal gas is also used in the industry for such situations. Associated gas produced in fields in remote locations cannot be piped to gas markets. Flaring of such gas is no longer accepted. Because of the commercial value of stranded gas, ways are being sought to bring stranded natural gas to market. New methods are being developed for this purpose, including CNG (compressed natural gas), GTL (gas-to-liquids) and NGH (natural gas hydrate) technologies.

LNG technology is well established and continues to be improved to give lower costs (Nagelvoort 2000). The liquefaction of methane reduces its volume by about 600-times. Large-scale CNG technology suitable for stranded gas is under development (Stenning and Cran 2000). The compression of natural gas reduces its volume by about 200-times. NGH technology is being developed in Norway for associated and non-associated natural gas applications (Gudmundsson et al. 1998, 1999) and in England (Fitzgerald and Martin 2000). One volume of solid hydrate contains typically 150 volumes of natural gas.

The choice of technology for stranded gas applications depends on many factors. Among the factors are the scale (capacity, size) of development and distance to markets. The feasibility of LNG technology is highly dependent on scale, making development less than 4 BCM per year of limited economic interest. This rules out the use of LNG technology in the majority of stranded gas applications because most of the resources are much smaller (Hove et al. 1999). CNG and NGH technologies are more suitable for stranded gas applications because they better match the scale of development and are reported to cost less (Gudmundsson et al. 1998, Hove et al. 1999, Fitzgerald and Martin 2000, Stenning and Cran 2000).

2 Hydrate Research and Development

Research and Development at the Norwegian University of Science and Technology (NTNU) on the use of hydrates to store and transport natural gas dates back to the early 1990's. The work demonstrated that natural gas hydrate solids produced in a particular way remain practically stable at atmospheric pressure when refrigerated to about –15 °C and stored in air (Gudmundsson et al. 1994). In subsequent laboratory work the production of hydrate in a continuous stirred tank reactor (CSTR) was studied and the flow properties of hydrate slurries measured.

Parallel with the laboratory work at NTNU, Aker Engineering (now Aker Technology), designed hydrate production processes for dry hydrate and slurry hydrate. The dry hydrate process is intended for long-distance transport of natural gas, while the slurry process is suitable for capturing of associated gas on FPSO's (floating production, storage and offloading). The investment costs of the two processes (dry hydrate and slurry hydrate) were estimated and found to be attractive (Børrehaug and Gudmundsson 1996, Gudmundsson et al. 1999). The capital cost of the dry-hydrate process was found to cost about 25% less than established LNG technology, based on one standard LNG train (large-scale), where natural gas was transported from north of Norway to continental Europe. In-house studies in several companies indicate that NGH technology has a special role to play when moderate volumes of natural gas are involved; that is, not the large volumes needed to make LNG technology attractive. Therefore, the capital cost of NGH technology in small-to-moderate sized developments is expected to have a greater margin than estimated by Aker Technology for large-scale development.

By the end of the 1990's the various properties of natural gas hydrates for industrial use had been studied and several flow diagrams developed for the "making, moving and melting" processes. The focus of the work shifted gradually from dry-hydrate to slurry-hydrate

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processes for FPSO applications, largely due to the interest from the oil industry. Current work at NTNU is on the rate of hydrate formation in a CSTR (Mork et al. 2001; Mork and Gudmundsson 2002). The work aims to extend the previous reactor results to higher superficial velocities and to model the rate of hydrate formation at conditions planned in pilot-scale and eventually commercial-scale reactors. In previous work the production rate achieved in a 9 litre reactor was about 1 tonne/day. In the current work the production rate obtained is about 2 tonne/day of hydrate. Several doctoral studies have been completed under the umbrella of the NGH at NTNU project, including Khokhar (1998), Andersson (1999) and Levik (2000).

3 Dry Hydrate Applications

Natural gas hydrates contain 150-180 Sm^3 of natural gas per m^3 of solid, depending on the pressure and temperature of production. This property makes hydrates economically interesting for storage and transport of natural gas, especially when refrigerated at the right conditions to a low-enough temperature to be practically stable at atmospheric pressure. In situations where associated and non-associated gas resources are located far away from gas markets, natural gas can be converted to frozen dry hydrate. The frozen hydrate is transported at atmospheric pressure in large bulk carriers to market, where the hydrate is melted and the natural gas recovered. In situations where gas storage is required, natural gas can be converted to hydrates and stored at atmospheric pressure and refrigerated. The storage operations can be small or large, and can be land-based or offshore.

An early study of a dry-hydrate application is that of Gudmundsson and Børrehaug (1996). The situation studied was an offshore natural gas field in the Barents Sea of Norway. The natural gas was assumed piped to shore and two alternative gas chains were studied: LNG chain and NGH chain. Both chains consisted of on-land production facilities, sea-transport by tankers and on-land regasification. The capacity of the chains was assumed 4.1 BCM per year (same as one standard LNG train of 400 MMscfd) and the transport distance from Norway to Continental Europa was assumed 3500 nautical miles. The results obtained are shown in Table 1. It was found that the capital cost of NGH technology was about 25% lower than the capital cost of LNG technology.

Dry-hydrate and slurry-hydrate technologies can be floater-based or land-based. FPSO-based technology will be most appropriate for isolated fields at great distance from processing facilities. If the distances are not too long, gas and oil from one or more fields can be piped to land in two-phase flow lines and processed to hydrate products, dry hydrate and/or hydrate slurry. Refrigerated hydrate will be transported by ship to market for processing, supplying crude oil and natural gas.

Table 1 - Comparison of capital cost of NGH and LNG chains for 400 MMscfd production and transport over 3500 nautical miles (6475 km). Million US dollars mid-1995 (Børrehaug and Gudmundsson 1996).

Chain	LNG	NGH	Difference
Production	1220 (51%)	792 (44%)	428 (35%)
Carriers	750 (32%)	704 (39%)	46 (6%)
Regasi-fication	400 (17%)	317 (17%)	83 (21%)
Total	2370 (100%)	1813 (100%)	557 (24%)

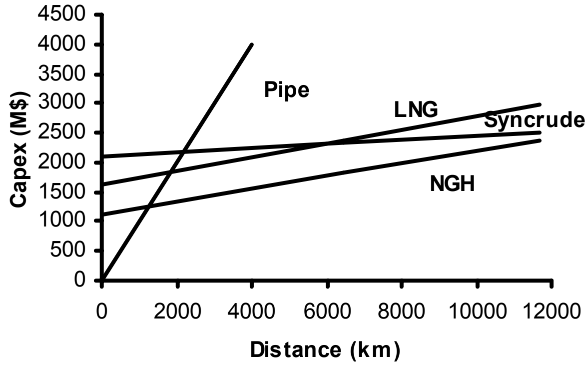

Figure 1 Approximate capital cost with transport distance, dry-hydrate case.

NGH technology has the potential to be considerably lower in capital cost than syncrude and methanol production from natural gas (Gudmundsson et al. 1998). This result opens for the possibility of producing hydrate slurry and mixing it with the crude oil for transport by pipeline. The temperature and pressure of the mixture needs to be adjusted to make sure the hydrates will be stable in the pipeline (at pipeline pressure, the hydrates need not be refrigerated).

In a feasibility study reported by Børrehaug and Gudmundsson (1996), the NGH and LNG chains were compared. The capital cost of the production and regasification plants were estimated, also the transport cost by ship. Gudmundsson et al. (1998) plotted the cost data with transport distance, here shown in Figure 1. The figure shows the 1995-money capital costs for the NGH and LNG plants (production plus regasification) plotted at zero distance. The transport distance was assumed 3500 nautical miles, which equals 6475 km. By adding the capital costs of the ships to the plant costs, the total capital costs for a chain distance of 6475 km can be plotted. Therefore, Figure 1 shows also how the total capital cost of an NGH chain and a LNG chain depend of transport distance. The two lines diverge a little with distance because the NGH ships were estimated lower in capital costs than the LNG ships.

The line for “Pipe” in Figure 1 represents the capital cost of a typical pipeline transporting natural gas. The capital cost was assumed 1 million US dollars per km. The capacity of such a pipeline will likely be greater than the 4.1 BCM per year reported by Børrehaug and Gudmundsson (1996). The “Pipe” line illustrates the overall relationship to transport by ship. For distances greater than about 1000 km the capital cost of a pipeline is higher than for NGH. In the case of LNG the cross-over distance is about 1800 km. The fourth line in Figure 1, identified as “Syncrude” represents the capital cost of natural gas transport chain based on synthetic petroleum. The background data and details used to arrive at the “Syncrude” line, were presented by Gudmundsson et al. (1998). The cross-over distance from LNG to syncrude is about 6000 km. That syncrude is lower in cost than LNG for long distances has been stressed by Singleton (1998).

Fitzgerald and Martin (2000) have presented cost data slurry-based hydrate technology. For the transport of 4.1 BCM per year of natural gas over a distance of 1710 km, the cost was estimated 2.5 US$ per million BTU.

4 Other Non-Pipeline Technologies

Liquefied natural gas (LNG) technology is widely used for large-scale transport of natural gas for long distances by ship. Annually, about 100 million tonnes of LNG are transported and traded world-wide, equivalent to 137 BCM of natural gas (BP 2001). For comparison, the world-wide transport and across-border trading of natural gas by pipeline was 390 BCM. The world-wide natural gas consumption in 2000 was 2405 BCM. Therefore, LNG trade is 35% compared to pipeline trade, while LNG trade and pipeline trade are 6% and 16% of the world-wide consumption, respectively. LNG is transported in ships over long distances, primarily in the Far East. Japan is the largest importer of LNG, representing more than one-half of the world-wide LNG trade (BP 2001). For stranded gas in Norway it was stated by Helgøy et al. (1997) that offshore LNG was not considered a competitive solution.

Compressed natural gas (CNG) technology is widely used to store energy in cars and buses. Such small-scale use of CNG is expanding world-wide. Natural gas storage in high-pressure bottles exists. However, large-scale use of CNG technology is non-existent, but under development. Stenning and Cran (2000) are developing CNG technology for large-scale use, based on coiled pipes six-inch in diameter. The pipes are coiled to make a carousel weighing 445 tonnes. Each carousel has 16 km of pipe. A CNG carrier with a capacity of 9 million standard cubic metres needs 108 carousels, in total length about 1710 km. Stenning and Cran (2000) presented transport costs for CNG and LNG assuming 4.1 BCM (400 MMscfd) annual capacity, typical for one-train LNG plant. The CNG costs were estimated well below the LNG costs. For a transport distance of 1710 km, for example, the LNG transport cost was about 2.5 $ per million BTU while the CNG cost was about 1.5 $ per million BTU.

Gas-to-Liquids (GTL) technologies are used to convert natural gas to hydrocarbon liquids. Several GTL technologies exist and are being developed, producing products ranging from methanol to middle distillate and syncrude (synthetic crude). GTL technologies are considered viable to solve the stranded gas problem. Syncrude options for remote locations have been presented by Singleton (1997). GTL technologies and projects have been presented by Knott (1997), Skrebowski (1998) and Thomas (1998). Methanol is one of several GTL technologies. Mellerud and Lund (2001) presented a commercial solution for stranded gas based on a FPSO-based methanol process. For natural gas to methanol processes, about 336,000 scf are required per tonne. A modular system based on 225 tonne/day methanol reactors was presented by Mellerud and Lund (2001) for production rates up to 1,800 tonne/day. The overall thermal efficiency claimed was 73%.

A middle distillate GTL technology was presented by Nagelvoort (2000) and compared to LNG. A natural gas resource delivering 6.2 BCM per year (600 MMscfd) was assumed. The natural gas can be converted to 6 million tonne per year of methanol, 4 million tonne year of LNG or 3 million tonne per year of middle distillate. The products represent 20%, 4% and 0.1% of the world market, respectively. Therefore, GTL technologies are favoured because of the large world-wide market. A further conclusion reach by Klein Nagelvoort (2000) was that LNG and GTL (middle distillate) are complementary and suitable for large-scale projects for long-distance transport of natural gas.

5 Offshore Slurry Process

In situations where associated gas is available in locations without a pipeline, the gas can be converted into frozen hydrate and mixed with refrigerated crude oil and transported as slurry at atmospheric pressure in shuttle tankers. Associated gas can also be converted into hydrate and mixed with crude oil and transported as slurry under pressure in a pipeline. A hydrate slurry process on a FPSO suitable for conditions world-wide was described by Gudmundsson et al. (1999) and Hove et al. (1999). For a complete NGH slurry chain, a shuttle tanker and a land-based melting process (regasification) are required, illustrated in Figure 2 (Offshore Production, Shuttle Tanker and Receiving Terminal). The main units in a typical hydrate slurry process are shown in Figure 3; this is the process identified at NGH on the FPSO in Figure 2. The fluids enter the process from the production wells and are piped to a separator. For the sake of simplicity, it is assumed that produced water is not present. It is possible to use produced water in the hydrate process, but this option will not be discussed further. In the separator the gas phase and liquid phase are separated. The quality of this separation is not crucial.

The operating pressure and temperature of the separator depends on the field and well conditions. Both variables have an impact on the hydrate process. A separator pressure of 20 bara and temperature 30 °C were assumed in the cost estimate presented below. The higher the pressure the less gas compression required; the higher the temperature the more cooling required. The gas from the main separator enters a compressor and the pressure is increased to 90 bara.

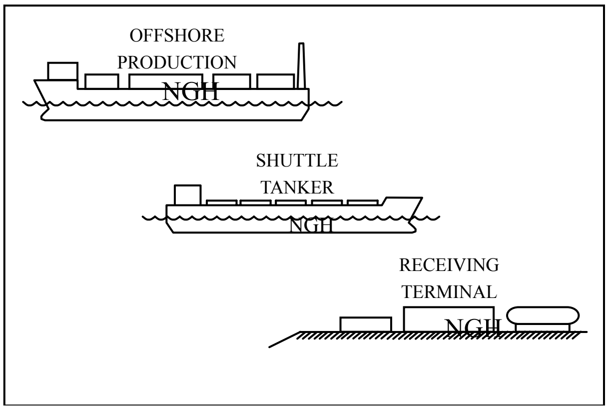

Figure 2 Making, moving and melting of slurry hydrate.

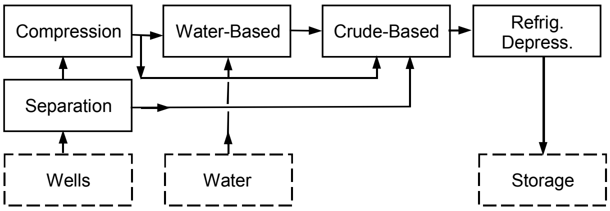

Figure 3 Main units of a hydrate slurry process.

The crude oil from the main separator at 20 bara and 30 °C enters a heat exchanger and is cooled as far down as practicable. The crude oil is under pressure and contains gas in solution, so operational difficulties due to low viscosity and waxing are expected to be manageable through traditional means. The heat exchange system will be designed to minimize difficulties arising from handling cold crude oil. Assuming that the hydrate reactors and cooling units operates at 90 bara the crude oil must be pumped to the same pressure.

In the hydrate slurry process, natural gas hydrate is formed/produced from associated gas and liquid water. In principle, the water used in the process can be fresh water, seawater or produced water. Using fresh water has several advantages. Fresh water can be supplied from a shuttle tanker returning from a slurry receiving terminal, preferably at low temperature and saturated with natural gas. The water will be stored in tanks on the FPSO and further cooled before it enters the hydrate reactors and cooling units. The streams entering the hydrate reactors and cooling units will be separated gas, cooled crude oil and cooled fresh water. Several reactor and cooling unit designs are possible and are under development at Aker Technology and NTNU. The function of the reactors and cooling units is to bring gas and water into intense contact at 90 bara and low temperature, to make hydrate.

The storage tanks on the FPSO need to have some insulation, to maintain the crude/hydrate slurry at -10 °C or lower. The pressure in the tanks will be close to atmospheric pressure. Typically, the crude/hydrate slurry will be transferred from the FPSO tanks to a shuttle tanker at regular intervals. Slurry pumping will be used for this purpose. A shuttle tanker will transport the slurry product to a receiving terminal on land. The shuttle distance can be short or long, depending on the situation. At the receiving terminal the crude/hydrate slurry will be pumped to a recovery process. The slurry is pumped to storage (insulated tank or rock cavern) and from there to a heating (melting) process.

Several designs of receiving terminal process are possible. In the heating process the crude/hydrate slurry is heated to a temperature suitable to hydrate melting and subsequent three-phase separation. The recovery process delivers natural gas saturated in water vapour, crude oil saturated in gas and water, and liquid water saturated in natural gas.

The capital cost/expenditure (CAPEX) and operational and maintenance cost (OPEX) of a FPSO-based hydrate slurry chain have been estimated by Hove et al. (1999). The cost analysis was based on marginal costs; that is, the additional costs to convert associated gas to hydrate and mix with the produced oil. For an offshore slurry process the capital cost was estimated for a typical FPSO-based situation with an oil production rate of 100,000 bbl/day, a gas-oil-ratio (GOR) of 100, giving a gas production rate of 56 MMscfd. Gas for fuel was assumed 10% of the total gas rate (7% for hydrate production and 3% other use). The natural gas converted to hydrate was therefore 51 MMscfd. This gas rate corresponds to 8000 cubic metres of hydrate per day assuming a specific gas content of 180 volumes gas per volume hydrate. The volume of the slurry will be the oil volume 16,000 cubic metres and the hydrate volume 8000 cubic metres, in total 24,000 cubic metres.

The transport cost the FPSO-based hydrate-slurry was estimated based on a 20 years project life and 9% annual interest on capital. It was reported that the transport cost was 1.9 US dollars per million BTU (1.8 US dollar per GJ) for "zero" distance and 3.4 US dollars per million BTU (3.2 US dollars per GJ) for a transport distance of 3000 km, increasing linearly from zero. The results are shown in Figure 4. For a distance of 1710 km the transport cost was estimated 2.75 US dollars per million BTU. The operating cost was assumed 4% of the capital cost, the fuel consumption was assumed 7% of the natural gas converted to hydrate, and the fuel cost was assumed 0.5 US dollars per million BTU.

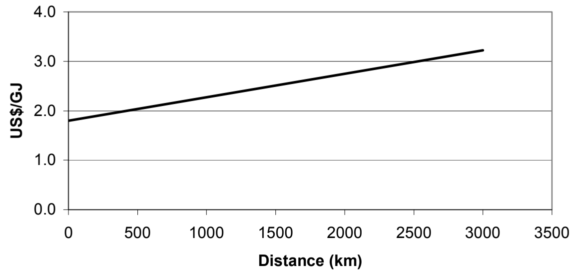

Figure 4 - Approximate transport cost of 50 MMscfd natural gas as slurry-hydrate.

6 Capacity-Distance Diagram

Factors that influence the feasibility of natural gas developments include the size of the resource, the distance to the market, the size of the market and the technology used. Of the 150 TCM world reserves of natural gas, 38% are in the Former Soviet Union, 35% in the Middle East, 9% in OECD-countries and 18% the rest of the world (BP 2001). Of the natural gas fields world-wide still to be developed, about 80% are less than 7 BCM in size, and about one-half of the fields are considered to contain stranded gas (Nordic Consulting Group 1997, Hove et al. 1999). Assuming a project life of about 20 years, a 7 BCM field size will sustain a delivery of 0.35 BCM per year. The technology used needs to be appropriate for the size of the resource.

Pipelines are universally used to transport natural gas from field resource to market. Economy-of-scale effects influence what transport capacity and distance a particular pipeline will be feasible. The shorter the distance and larger the capacity, the more feasible a particular natural gas pipeline.

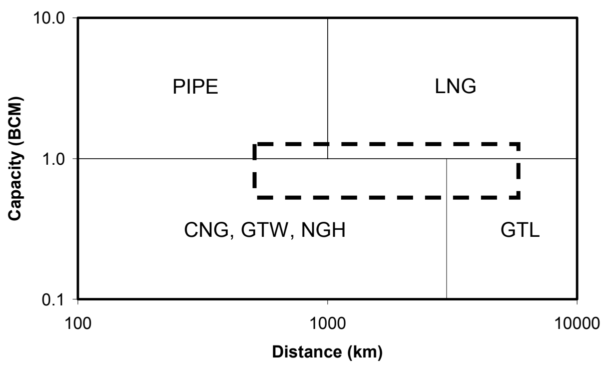

Figure 5 - Capacity-distance diagram (BCM per year versus km).

The size of the market influences the transport capacity of a particular pipeline. Furthermore, with increasing distance the feasibility of a particular pipeline decreases. The distance the feasibility of a particular pipeline becomes marginal depends on many factors. When the feasible pipeline distance is exceeded, other natural gas transport technologies become appropriate.

Several companies have presented diagrams to illustrate how the transport distance of natural gas relates to the different technologies, such as CNG, GTL, LNG and NGH. Examples include Shell International Exploration and Production (Wolff 1999, also presented by Vareide 2000), BG Group (Fitzgerald and Martin 2000) and Statoil (Vareide 2000). In addition to the above technologies, Gas-to-Wire (GTW) can be used to transport stranded gas to market. In GTW technology the natural gas is used to generate electric power at the site where natural gas is available, and then transported by cable (direct current) or wire (alternating current) to market.

A new capacity-distance diagram for the transport of stranded natural gas is shown in Figure 5. The diagram illustrates what stranded gas technologies are likely to be appropriated with respect to distance and capacity. LNG is generally considered appropriate for large-volumes for long-distances; GTL is generally considered appropriate for medium-to-low volumes for long-distances. Offshore pipelines in Norway are less than 1000 km in length are generally considered appropriate for large-volumes, for example above 1 BCM. CNG, GTW and NGH technologies are considered appropriate for medium-to-low volumes and medium-to-short distances. An overlap region is shown in Figure 5, to reflect the wide range of conditions that affect the stranded gas technology selected for a particular application.

7 Conclusions

There is a need for non-pipeline technologies that can capture stranded gas and transport to market. NGH technology is being developed for this purpose and is increasingly recognised as an attractive alternative. Several groups are developing NGH technology world-wide, including NTNU in Norway.

LNG technology is recognised as the technology of choice for large-volume, long-distance transport of natural gas. However, about 80% of the natural gas resources yet to be developed world-wide are too small for state-of-the-art LNG technology and about one-half of these (40% of total) are stranded.

The cost of transporting stranded gas to market using non-pipeline technologies has been estimated in the range 1.5 to 3.0 US$ per million BTU, depending on scale of development and distance to market. CNG and NGH are appropriate/competing technologies in similar stranded gas situations.

Acknowledgements

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