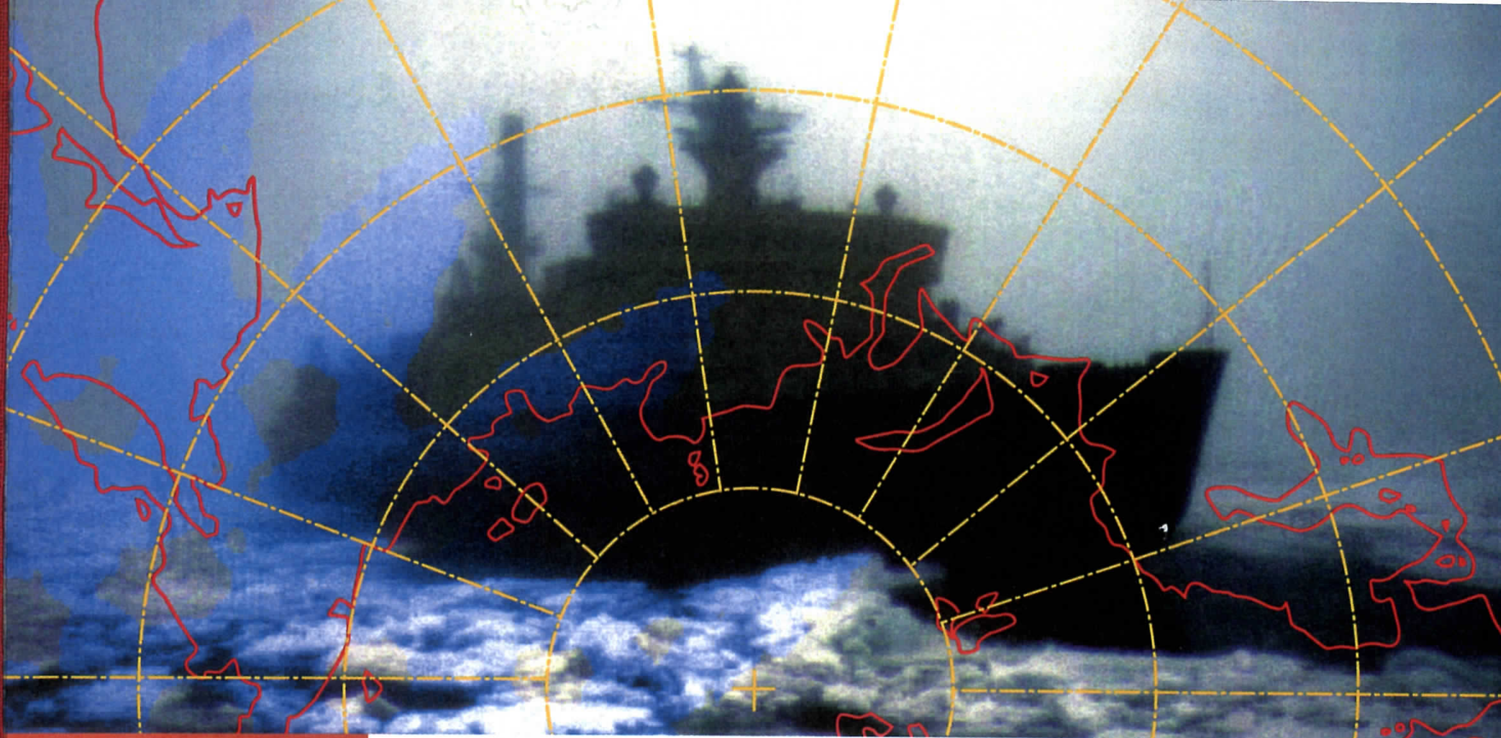

INSROP WORKING PAPER
NO. 77 - 1997, III.07.4

Northern Gas Fields and NGH Technology
- A feasibility Study to Develop Natural Gas Hydrate Technology for the International Gas Markets

By Trond Ragnvald Ramsland, Erik F. Loy
and Sturle Døsen

INSROP International Northern Sea Route Programme

Central Marine Research & Design Institute, Russia

The Fridtjof Nansen Institute, Norway

Ship and Ocean Foundation, Japan

International Northern Sea Route Programme (INSROP)

Central Marine Research & Design Institute, Russia

The Fridtjof Nansen Institute, Norway

Ship & Ocean Foundation, Japan

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Supervisors:	Trond R. Ramsland and Tom Eldegard
Title:	**Northern Gas Fields and NGH Technology** - A feasibility Study to Develop Natural Gas Hydrate Technology for the International Gas Markets.
Authors:	**Trond Ragnvald Ramsland, Erik F. Loy & Sturle Døsen**
Address:	Foundation for Research in Economic & Business Administration (SNF) Breiviken 2 5035 Bergen-Sandviken, NORWAY
Date:	28 April 1997
Reviewed by:	Michael Tamvakis, City University Business School, London, Great Britain.

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FOREWORD - INSROP WORKING PAPER

INSROP is a five-year multidisciplinary and multilateral research programme, the main phase of which commenced in June 1993. The three principal cooperating partners are **Central Marine Research & Design Institute (CNIIMF)**, St. Petersburg, Russia; **Ship and Ocean Foundation (SOF)**, Tokyo, Japan; and **Fridtjof Nansen Institute (FNI)**, Lysaker, Norway. The INSROP Secretariat is shared between CNIIMF and FNI and is located at FNI.

INSROP is split into four main projects: 1) Natural Conditions and Ice Navigation; 2) Environmental Factors; 3) Trade and Commercial Shipping Aspects of the NSR; and 4) Political, Legal and Strategic Factors. The aim of INSROP is to build up a knowledge base adequate to provide a foundation for long-term planning and decision-making by state agencies as well as private companies etc., for purposes of promoting rational decisionmaking concerning the use of the Northern Sea Route for transit and regional development.

INSROP is a direct result of the normalization of the international situation and the Murmansk initiatives of the former Soviet Union in 1987, when the readiness of the USSR to open the NSR for international shipping was officially declared. The Murmansk Initiatives enabled the continuation, expansion and intensification of traditional collaboration between the states in the Arctic, including safety and efficiency of shipping. Russia, being the successor state to the USSR, supports the Murmansk Initiatives. The initiatives stimulated contact and cooperation between CNIIMF and FNI in 1988 and resulted in a pilot study of the NSR in 1991. In 1992 SOF entered INSROP as a third partner on an equal basis with CNIIMF and FNI.

The complete series of publications may be obtained from the Fridtjof Nansen Institute.

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PROGRAMME COORDINATORS

- **Yury Ivanov, CNIIMF**
  Kavalergardskaya Str.6
  St. Petersburg 193015, Russia
  Tel: 7 812 271 5633
  Fax: 7 812 274 3864
  Telex: 12 14 58 CNIMF SU
- **Willy Østreng, FNI**
  P.O. Box 326
  N-1324 Lysaker, Norway
  Tel: 47 67 11 19 00
  Fax: 47 67 11 19 10
  E-mail: sentralbord@fni.no
- **Ken-ichi Maruyama, SOF**
  Senpaku Shinko Building
  15-16 Toranomon 1-chome
  Minato-ku, Tokyo 105, Japan
  Tel: 81 3 3502 2371
  Fax: 81 3 3502 2033
  Telex: J 23704

INSROP

SUB-PROGRAMME III

Project III.7.4

"NORTHERN GAS FIELDS AND NGH TECHNOLOGY"

"A Feasibility Study to Develop Natural Gas Hydrate Technology for the International Gas Markets".

Final Report

Prepared by

Trond Ragnvald Ramsland (Msc), Erik F Loy & Sturle Døsen

Bergen, March 1997

EXECUTIVE SUMMARY.

In this study two different natural gas fields have been studied for three different technological solutions, using two different economic theories. The goal of the analysis was to examine whether a new technology for transporting natural gas, Natural Gas Hydrates (NGH) , can compete with the existing technologies pipeline and Liquefied Natural Gas (LNG).

Natural gas is today an important source of energy world-wide. However, natural gas can rarely be used immediately after production, and natural gas supply systems can be divided into four interrelated parts:

1. Exploration
2. Development & production
3. Transportation
4. Distribution

In this study the emphasis is on costs of production and transportation. Exploration is considered already carried out and thus viewed as sunk cost. Distribution from the landing point to the consumers is not part of the study. Production can take place either onshore or offshore, and the natural gas can be transported to the market either by pipeline or ship. The transportation costs are becoming more and more important as a consequence of increasing distances from the fields to the markets.

Natural gas projects have notoriously long lead times and large capital requirements. Therefore, new supplies will only materialise if there is confidence that demand for the gas exists, and at a price which supports a suitable return on investments. This also implies that natural gas is generally sold on long-term contracts.

The conclusion drawn is that economies of scale exist. The report also support the theories in that pipeline is the superior technology for high volumes. All else equal, pipeline can not compete for smaller volumes. Until present, the LNG technology has been the best alternative for transportation of such smaller volumes, but the report concludes that NGH fully competes.

However, it is not only volume that is important when choosing transportation mode. The distance to the market where the natural gas is to be transported is also crucial. Pipeline technology is sensitive to changes in distance with costs increasing almost proportionally, while the shipping modes are not. This implies that the shipping modes, all else equal, are superior for long transportation distances. This conclusion is not fully supported by the figure above, due to the fact that the economics of scale more than neutralise the disadvantages of Shtockmanovskaya being further from the market and further offshore. NGH is superior to LNG also with regards to distance.

Despite the fact that the two economic models used for the evaluation has provided very different absolute project values, they have provide the same conclusion about the ranking of the different technologies. On this basis then there is a clear indication that if NGH technology is developed further into a reliable and feasible alternative, LNG technology will practically always be inferior, while pipeline technology still remains very competitive, especially for large projects.

Unfortunately, the study has indicated that despite the superiority of NGH, marginal fields like Snøhvit are still unlikely to be developed under the present market conditions.

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1. INTRODUCTION

Natural gas is today an important source of energy world-wide. However, natural gas can rarely be used immediately after production, and natural gas supply systems can be divided into four interrelated parts:

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4. Distribution

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Natural gas projects have notoriously long lead times and large capital requirements. Therefore, new supplies will only materialise if there is confidence that demand for the gas exists, and at a price which supports a suitable return on investments. This also implies that natural gas is generally sold on long-term contracts.

1.1 Project description.

In Northern Norway, the Barents Sea, the Yamal peninsula and North-western Siberia there are fields containing huge amounts of natural gas and condensate. They all have in common that they are situated far north and distant from potential markets. This combined with the high transportation costs for natural gas, have resulted in these fields traditionally being looked upon as non-profitable.

Earlier studies are based upon the two existing transportation technologies:

1. Pipeline
2. Ships carrying liquefied natural gas (LNG)

In this study, however, transportation based on "gas-in-ice" technology is also considered. The idea is to transport natural gas as a solid material called natural gas hydrate (NGH). This is a new method for storing and transportation of natural gases at atmospheric pressure, a technology patented by Gudmundsson (1990)[1]. In this method NGH are refrigerated to about -15° C and then kept at near adiabatic conditions. The hydrates remain stable, making it possible to transport natural gas in an insulated bulk-carrier over long distances. This reduces vessel investment costs, and the NGH-chain is estimated to cost significantly less than the LNG-chain (Gudmundsson et al, 1995).

All three technologies are described in detail in chapter 2.

The purpose of the study is to evaluate and compare this new technology to LNG and pipeline. The evaluation is based upon cost estimates and analysis of the market situation for natural gas. Three fields with different characteristics have been chosen as case studies. The fields are:

1. Snøhvit, Barents Sea (Norway)
2. Shtockmanovskaya, Barents Sea (Russia)
3. Harasavey, Yamal Peninsula (Russia)

The geographical location of Snøhvit and Shtockmanovskaya fields, which are the two fields analysed in detail in this study, are shown on the map below. Harasavey is situated further east, and is only discussed briefly in chapter 8.

[1] Jon Steinar Gudmundsson, professor, University of Trondheim, NTH

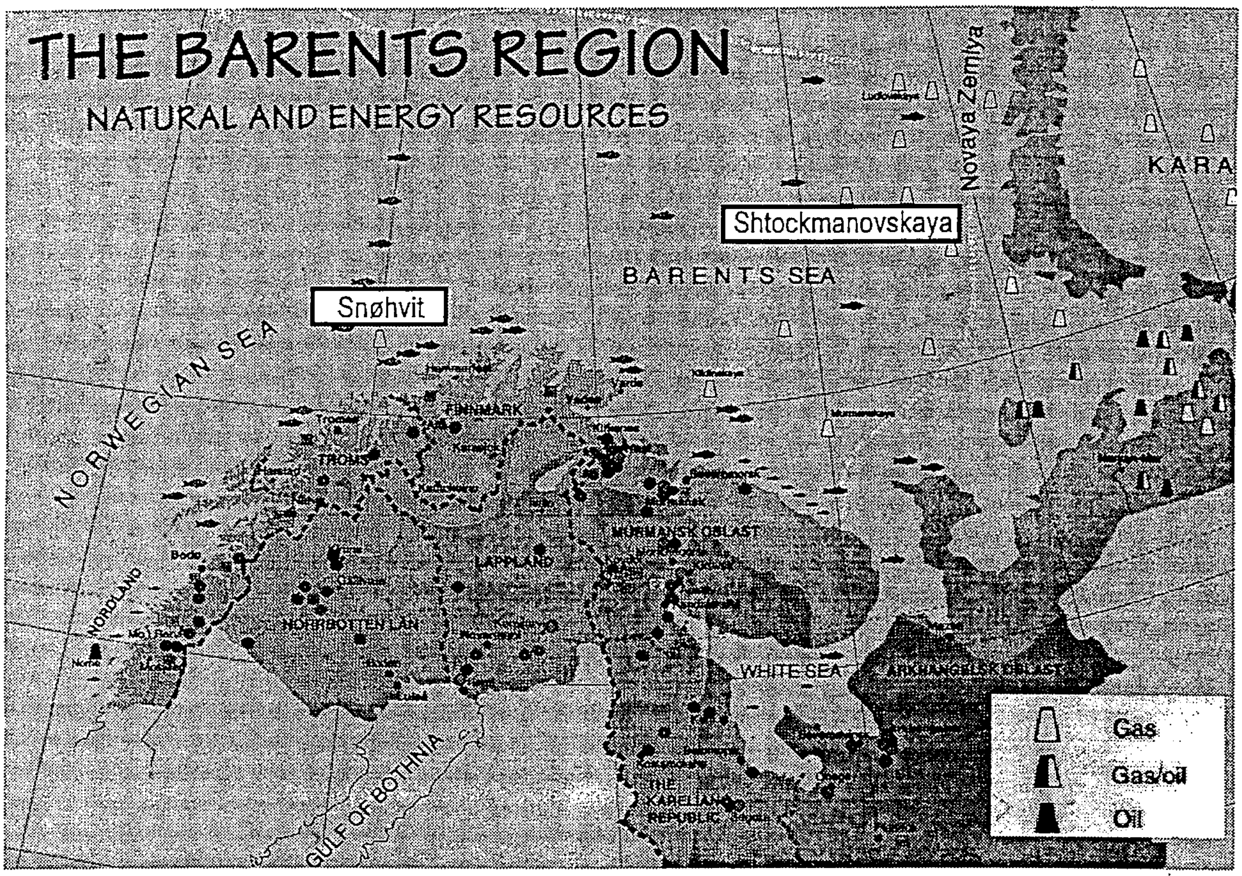

Figure 1-1 : Map of the Barents region

Potential markets for natural gas from these fields can theoretically be located any place in the world. In this study Europe, and specifically the Rotterdam area, has been chosen as a landing point for LNG and NGH shipments. Natural gas transported by pipeline is assumed delivered at the German border, while the associated condensate is sold at the onshore location at the prevailing market price. A more detailed discussion of potential buyers of natural gas from the mentioned areas is presented in chapter 3.

The main challenge of the study is to give a correct picture of the different costs and risks involved in the different types of technology and geographical areas. The three fields mentioned above are chosen to highlight a number of questions which are necessary to answer when comparing the different technologies:

1. What are the economies of scale with regards to investments, costs and income?
2. Have geographical location and conditions any significant impact on profitability?
3. What are the risks involved?

Snøhvit, Shtockmanovskaya and Harasavey differ in ways that can help us answer these questions.

1.2 General assumptions.

The evaluations of the fields and transportation technologies are carried out using investment analysis based on the net present value and CAPM methods described in chapter 5. As shown in figure 1.2, there are three important dimensions to consider when estimating a cash flow.

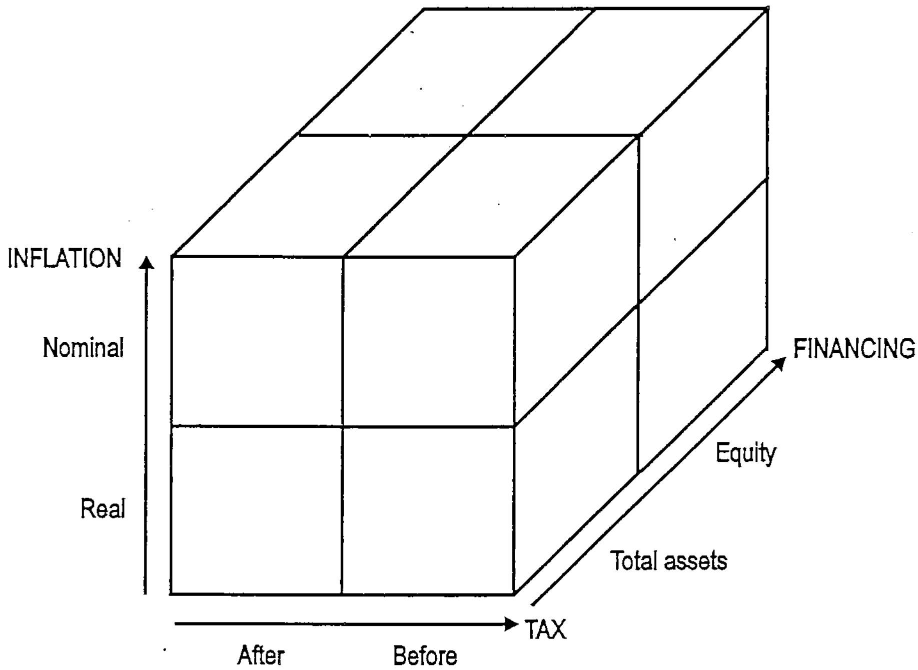

Figure 1-2 : Alternatives for budgeting cash flows

In this study, the cash flows will be presented in nominal (money-of-the-day) terms and taxes will be deducted. The evaluation of the projects will be based upon the return on total assets. It is very important to be consistent when making these choices. Thus, the discount rates estimated in chapter 6 and 7 will also have to be calculated for total assets, nominal values and on an after tax basis.

1.2.1 Licensing system and taxes

The rights to the natural resources belong to the state. The right to exploit these resources are awarded to private and public companies on terms and conditions established by law.

Production licenses[2] for each field are awarded to individual applicants which then are married into groups, and an operator is elected. The state plays a dominant role both through direct financial interests and through whole or part ownership of companies taking shares in most licenses. In this study it is assumed that a single private company has been awarded the entire license for each field, without any involvement from the state.

For the licensee, two important payments normally have to made to the state: the area fee and the CO_2 tax. In the analysis, it is assumed that all exploration has been carried out, and that the license has been prolonged to cover the lifetime of the project. For this entire period, the company will have to pay a fee per square kilometre according to the table below. The CO_2 tax is payable according to the amount of natural gas flared and used for power generation on platforms, and it is currently 0.13 USD per CM. Both of these taxes are regulated by the government and in this study they are assumed to remain constant in nominal terms.

License fee (1000 $ per km²)			
Year	Fee	Year	Fee
1-6	615	12	4385
7	1154	13	5615
8	1231	14	6923
9	1538	15	8154
10	1846	16	9385
11	3077	17→	18692

Table 1-1 : License fee

The taxation of the petroleum industry (offshore and onshore activities directly related to the production and transportation of petroleum products) is built upon the general corporation tax legislation (The contents of this chapter is only based on Norwegian taxation rules). Because of the extraordinary high profitability in the petroleum industry, a special tax has been added. The corporation tax is 28% and the special tax is 50%. For both taxes, profits chargeable are

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[2] Gives the exclusive rights to exploration and production of petroleum within the stipulated areas

calculated by deducting operating costs and depreciation from the revenues[3]. The production assets are depreciated on a straight line basis over six years from the year they are purchased. All investments (including ships and pipelines) are considered production assets in this study. In addition, an uplift allowance of 5% per year for six years on capital investments is deductible against special tax. Abandonment costs are not deductible against any of the taxes (Norwegian tax law, 1975). As mentioned later this chapter, the need for working capital will be included in the investment analysis. This can have a complicating effect on the tax calculation due to the inflation regulation of inventory values. This will not be taken into consideration in this analysis. Evaluating projects in Russia is more difficult due to a lack of regulations accompanied by an unclear and for most western companies a not acceptable tax legislation. A good example of this is the taxation of Conoco. The company pays more than 100% tax on any profits from exploiting oil fields in their operation "Northern Light" in the Pechora-area [4]. As a presumably good approximation, this study will evaluate the Shtockmanovskaya project using the Norwegian tax calculation as a basis.

1.2.2 Prices, inflation and exchange rates

It is assumed that all revenues are in USD and the costs are based on a western European price level and recalculated into USD, also in Russia. The exchange rate is assumed to be 6.5 NOK per USD for the whole period (Wood Mackenzie, 1995). In Russia some of the costs would normally accrue in the local currency, and thus be somewhat lower. This is not taken into consideration in the study, and the project values calculated might be higher for the Russian projects. The projects will have start up in year 2000. The investment period is set to 5 years, which implies start of sales in year 2005. All data will be inflation adjusted to a year 1996 level based on historical inflation rates (Statistics Norway, 1996). From 1996 and onwards all data will be adjusted at an estimated general nominal rate of inflation at 3.5% per year. (Wood Mackenzie, 1995). The price of natural gas is estimated using the GAS-model as described in chapter 3.

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[3] Note that the tax shield from debt interest will be incorporated in the discount rate, and thus not deducted

[4] Barents Perspektiv, aug 1995

1.2.3 Influence on other projects

The natural gas price estimations concludes that the price will drop if additional gas is introduced in the market (chapter 3). This implies a loss on existing sales, and should therefore be treated as a cost in the investment analysis. However, this is not taken into account in this study: each project is analysed on a "stand alone basis". This is a simplification that might have crucial effects on the profitability of the project if existing gas sales are significant.

1.2.4 Working capital

An investment project induces a need for working capital[5]. This need has to be included in the investment analyses. The need for working capital normally depends on the sales, and for oil and natural gas projects the need is generally low (Statistics Norway, 1992). In this study, it is assumed that the need for net working capital is about 5% of the sales, and when calculating the net present value, net working capital has to be deducted from the cash flow at the year the production commences. In the last year of the projects' expected lifetime, the total amount of working capital are added back to the cash flow of that year.

[5] Defined as current assets minus current liabilities

2. THREE DIFFERENT SOLUTIONS FOR NATURAL GAS EXPORT

As mentioned above, there are three different technological possibilities for transporting natural gas. This chapter will give a brief description of each technology, describing similarities and differences. The costs of natural gas production and transportation to the onshore terminals for each field are assumed to be the same for all technologies. These are described in more detail in each of the investment analysis. Both investments and operating costs exhibit varying economies of scale. Economies of scale are characterised by decreasing average costs when the scale of a project is increased.

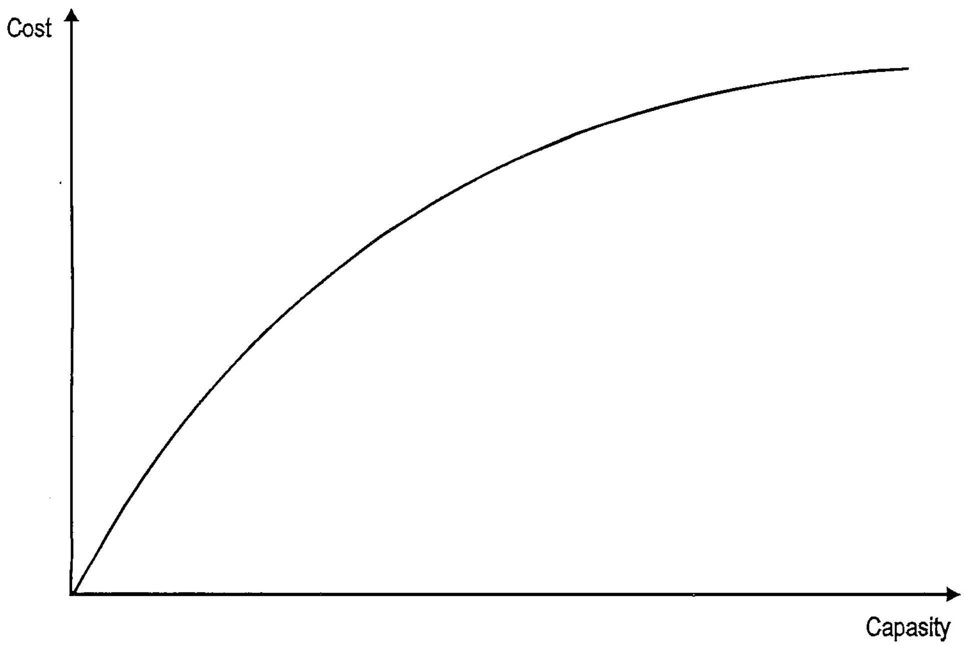


Figure 2-1 : Economies of scale

Economies of scale of an investment can be quantified using the following formula (presented graphically in figure 2.1): $I_1 = I_0 * (C_1 / C_0)^n$

where: C_0= capacity one unit

I_0 = investment cost for C_0

C_1= project capacity

I_1 = total investment cost for C_1

n = scale factor

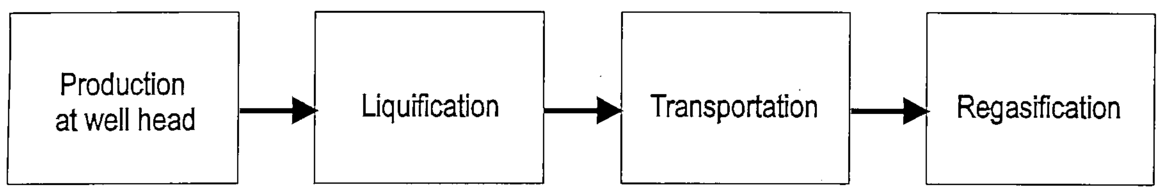
For large natural gas projects, n is normally well below 1, which implies considerable economies of scale. The formula will be used in calculating the costs for different plants with different capacities in the analysis. A similar formula exists for operating costs, but in this study operating costs for plants are expressed as a percentage of investment cost or based on empirical data which implies that economies of scale in operating costs are automatically included.

2.1 LNG-chain

An LNG export project consists of four distinct but interrelated stages:

1. Natural gas production and transportation to the liquefaction plant.
2. Liquefaction, storage and ship loading.
3. Shipping LNG in specially cooled tankers to the reception terminal.
4. Arrival at receiving terminal, unloading, LNG storage and regasification.

An LNG-chain might look like this:



If any one elements in the chain is not ready in time or fails for any reason, the whole project may be in jeopardy.

2.1.1 Liquefaction

Because this technology requires natural gas to be transported liquefied, the gas has to be brought ashore and undergo a process at a liquefaction plant before it can be shipped. In this process the natural gas is cooled to a point where it becomes a liquid rather than a gas. A liquefaction plant consists of one or several liquefaction units (trains) and infrastructure (utilities, storage, buildings, marine facilities etc.). The number and capacity of trains is determined by the volume of natural gas to be transported.
The liquefaction plant normally accounts for about 50% of the total investment costs of the LNG-chain (The Oil and Gas Journal - November 17, 1975). The infrastructure is built along

with the first train, and this implies that the cost of adding additional capacity/trains is considerably lower than for the first train. The cost of constructing such a plant will vary geographically depending on the cost of land, environmental and safety regulations and labour costs. Typical cost of a liquefaction plant is indicated below (IEA 1994):

Plant with a capacity of 5 BCM including infrastructure	: 1.4 - 2 billion USD
Construction of additional trains with capacity of 2.5 BCM each	: 0.3 - 0.5 billion USD

These indications implies considerable economies of scale, and industry experts generally scale up with an exponent n of 0.6-0.7 in any capacity increase over a wide range (Nagelvoort 1994).

Operating and maintenance costs normally amounts to about 4% of the total capital cost of a 5 BCM plant. In addition, about 12% of the natural gas intake is consumed as fuel during the liquefaction process (based on IEA 1994).

2.1.2 Transportation

LNG is transported using technically advanced ships, containing expensive materials and sophisticated cargo handling arrangements. In this study ships with a cargo carrying capacity of 135.000 CM is assumed.

Costs associated with acquiring and operating ships are typically broken down into three components: capital, operating and voyage costs.

Capital costs are high in relation to other types of commercial vessels. According to Lloyd's Shipping Economist (October 1995), the newbuilding price for a 135.000 CM vessel is about 275 million USD. Potential quantity discounts may be obtained, and this is considered when calculating the cost of a pool of ships. When the project comes to an end, the ships are assumed to scrapped at the inflation adjusted equivalent of the current scrapping price of about 200 USD per Mt. A 135.000 CM LNG-carrier has a light-weight of about 12.500 Mt. (Holte, 1978).

Operating costs (manning, insurance, repairs, maintenance, stores and administration) can be substantially higher than those of less technically advanced ships, due to the use of higher skilled personnel, stricter regulations etc. The costs are in the region 5-8 million USD per year per ship (IEA, 1994). In this study costs of 6 million USD per year is used (based on Drewry Shipping Consultants, 1992).

Voyage costs consist of fuel costs, port charges and canal dues (not applicable for the transportation routes in this study) and are closely linked with the distance between the producer and the market and the volume to be transported. As an approximation, in this study it is assumed that the LNG carriers are fuelled 100% using boil-off gases from the cargo. The energy produced using boil-off can be substituted completely using fuel oil. In practice this is not realistic because some boil-off is inevitable. If this boil-off is not sufficient to cover the energy requirements, it is necessary to deliberately increase the boil-off rate. The cost for this is indirectly accounted for by reducing income. In the analysis the boil-off rate is on average (ballast and laden) set to 0.25% per day (based on Drewry Shipping Consultants, 1992). Port charges are assumed to be 0.3 USD per GRT per call to Rotterdam (Andresen, 1995). A 135.000 CM LNG-carrier has a GRT of about 117.000.

2.1.3 Regasification

A receiving terminal is necessary to unload the ships and to regasificate the liquefied gas before distribution. This phase of the LNG-chain is the simplest and least expensive. It consists of a harbour with facilities for offloading tankers, LNG-storage, regasification and distribution of natural gas.

Construction costs can vary greatly from one project to another depending on the extent of port development, storage requirement and safety regulations. According to IEA investment costs are in the range of 400-700 million USD for regasification capacities of about 5 BCM. However, Gaz de France deviates significantly with costs in the range of 250-500 million USD for capacities of about 5-10 BCM. For plants with capacities exceeding 10 BCM economies of scale are limited (IEA, 1994).

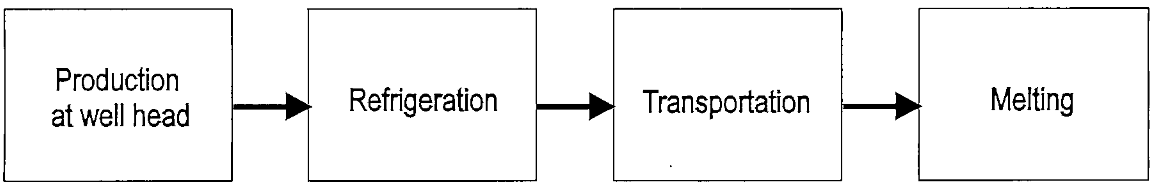
A survey among 28 receiving terminals (International Gas Union, 1994) has shown that it is difficult to estimate operating and maintenance costs, because of great variations from one terminal to another. In this study, operating costs are set to 2.5% of the total plant cost. In addition, about 1% of the natural gas intake is consumed as fuel during the regasification process (IEA 1994).

It should also be noted that LNG-technology is in essence mature, and it is unrealistic to expect dramatic cost reductions in the future (Nagelvoort, 1994).

2.2 NGH-chain

In essence, the stages of an NGH export project are similar to those of an LNG project listed in chapter 2.1. The liquefaction plant of an LNG project is substituted by a refrigeration plant, the LNG-carriers by NGH-carriers and the regasification plant by a melting plant.

An NGH-chain might look like this:



2.2.1 Refrigeration

In this technology natural gas is transported as solid hydrates. In this process the gas is transformed into hydrates and refrigerated to -15° C at an onshore plant. The plant consists of several technical components that will not be discussed in detail here[6]. In addition to the plant, storage and shipping facilities are also needed.
The investment cost of an NGH plant is assumed to be significantly lower than for a corresponding LNG plant. Typical cost of a refrigeration plant with a capacity of 4 BCM including infrastructure is indicated at 600 million USD (Gudmundsson et al, 1995).
In the data provided by professor Gudmundsson, all costs are adjusted upwards with "a 30% contingency". The contingency is interpreted as a risk adjustment, and in this study this

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[6] See Hveding, 1994 for details

adjustment is excluded to avoid taking risk into consideration twice. Risk will be taken into account by adjusting the discount rate (see chapter 5). Economies of scale are expected to be less than for LNG, because the need for infrastructure (especially port facilities) is assumed to increase more than for LNG with increases in volume. The scale factor is therefore set to n = 0.75 in this study as compared to 0.65 for LNG.

Operating costs are unknown, but in this study they are set to 4% of the total plant cost (same as for LNG). Of the total natural gas intake 7% is consumed during the NGH production process.

2.2.2 Transportation

NGH is transported using insulated bulk-carriers. These ships are technically less advanced and thus require a less skilled crew than LNG-carriers. Three different sizes of ships where initially considered in this study (small, medium, large). Preliminary results concludes that economies of scale are significant, and large ships are thus preferable. Increasing the size of the ships means reducing the number of vessels needed to transport a certain amount of cargo. This reduces both the capital, operating and voyage costs, e.g. crew and fuel costs.

An economic feasible and a realistic size for the NGH-carriers is 300.000 DWT. This corresponds to about half the capacity of an LNG-carrier, which means that two NGH-carriers are needed to transport the same amount of natural gas as one LNG-carrier. One problem with ships of this size is their draught which may restrict access to certain ports. Japan, a major importer of LNG, is an example (max. 250.000 DWT). Offshore facilities may be a solution to this problem.

A standard bulk-carrier of this size (300.000 DWT) is estimated to cost about 85 million USD (based on Lloyd's Shipping Economist, 1995). In addition, insulation of the tanks and special loading/unloading equipment is needed to transport NGH. These amount to a total of about 15 million USD (Hveding, 1994). Total capital costs are thus estimated to 100 million USD per ship, which is consistent with Gudmundsson. Quantity discounts may also be obtainable for such ships. A 300.000 DWT NGH carrier has a light-weight of about 48.750 Mt., and the ships are assumed to be scrapped at the end of the project at the price indicated above.

Total operating costs for the NGH-carriers are larger than for LNG, because of the larger number of ships needed. In this study costs of 5 million USD per year per ship is used (based on Drewry Shipping Consultants, 1992).

The NGH-carriers are fuelled using bunkers. A 300.000 DWT bulk-carrier uses about 50 Mt. of fuel-oil (380 cst) per day when steaming and 5 Mt. when in harbour (J. Grieg & Co.). Assuming a bunkers price of 100 USD/Mt. gives a daily fuel cost of 5000 and 500 USD respectively. Port charges are assumed to be the same as for LNG-carriers (0.3 USD per GRT). A 300.000 DWT bulk-carrier has a GRT of about 150.000 (Rederiforbundet, 1996).

LNG-carriers normally serve one specific route and one type of cargo (natural gas). A second-hand market for such carriers is almost non-existent. NGH-carriers are much more flexible because they are not as dependent upon one specific project or cargo, and can be sold in the second-hand market. This reduces the risk of the investment because the exit costs are lower.

2.2.3 Melting

The melting plant consists of the same infrastructure as the regasification plant for LNG. The construction cost is assumed to be about 240 million USD. The contingency adjustment is of course excluded here as well, and the economies of scale are assumed to be the same as for the refrigeration plant.

Operating costs are unknown, but in this study they are set to 2.5% of the total plant cost (same as for LNG). Of the total natural gas intake 1% is consumed during the NGH melting process.

2.2.4 Other aspects of the NGH technology

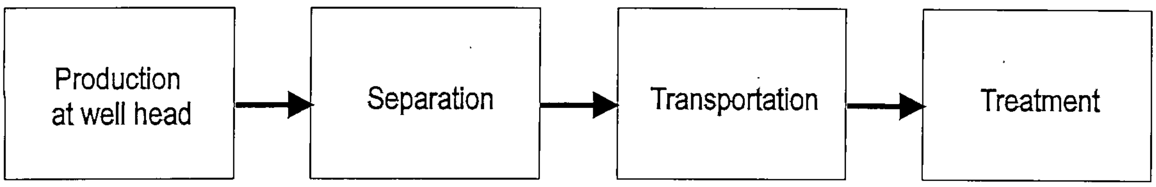
An important aspect of the NGH-chain is that is inherently much safer than the LNG-chain. An accident in the LNG-chain will have a greater negative impact on the surrounding infrastructure and life. This should be considered when comparing NGH to LNG. It should also be noted that the NGH-technology has never been tried out on a large scale, and the above cost estimates cannot be supported by any empirical data.

2.3 Pipeline-chain

A pipeline export project consists of three stages:

1. Natural gas production and transport to the onshore terminal.
2. Separation.
3. Transportation by pipeline to landing point.
4. Storage and treatment to comply with contractual requirements.

A pipeline-chain might look like this:



2.3.1 Separation

It is assumed that the natural gas produced at the fields is transported to an onshore terminal. Here the gas goes through a process of separation, e.g. outstripping of gas condensate and water. Investment and operating costs for such a terminal are difficult to estimate. An indication can be inferred from the Kollsnes facility in Norway. This terminal has a capacity of 27 BCM per year and construction costs amount to about 2.1 billion USD (Wood Mackenzie, 1995). This implies a unit cost of about 75 million USD per BCM. Because economics of scale are likely to exist for facilities of this size, the unit cost will be significantly higher for smaller plants. For larger plants, direct upscaling is feasible because economies of scale is exhausted at this level of production.

Based on estimates from Wood Mackenzie and IEA, operating costs are set to about 2% of investment cost.

2.3.2 Transportation

After leaving the onshore treatment facility the gas is transported to the import terminal by pipeline using compressor stations in order to increase the pressure. Construction costs for offshore pipelines with a diameter of 30-40" are in the range of 1.5-2.4 million USD per km. (IEA, 1994). As a rule of thumb, construction costs for onshore pipelines are about one third those of offshore. This rule implies that the construction costs for an onshore pipeline are in the range of 0.5-0.8 million USD per km. A pipeline with these measurements has a capacity of 12-15 BCM per year, depending on the number and power of compressor stations. In the Shtockmanovskaya analysis, we have assumed the use of two pipelines with this capacity instead of one large. It might be more cost-efficient to build one large, because of the relationship between volume and surface area. The volume of the pipe (volume through-put) is $\pi r^2 l$ where r is the pipeline's radius and l the length of the pipeline. The cost of the pipeline depends on how much steel it takes to make it. That cost is related not to volume, but to the surface area of the pipeline, which equals $2\pi r l$. Doubling the radius raises volume (and output) by a factor of 4, but raises surface area by only a factor of 2. Thus, by reducing the number of pipelines from two to one it is possible to maintain the same through-put with a less amount of steel. However, two or more pipes increases flexibility and redundancy in the system. Other issues as capacity of offshore pipelaying vessel, critical length - diameter relationships for pipes, number of weldings etc. will also influence costs.

Based on estimates from Wood Mackenzie and IEA, operating and maintenance costs for offshore and onshore pipelines are set to 2 and 4% of investment costs respectively.

2.3.3 Treatment

The main function of the import terminal is to remove any liquid and solid components and heat the gas if needed. In addition gas metering and quality control will be performed. There are few cost estimates available for such facilities, but data from the relatively new Zeebrugge terminal in Belgium can indicate a cost level. Estimated construction costs for the terminal is 185 million USD. With a capacity of about 23 BCM per year this implies a unit cost of about 8 million USD per BCM. The nature of the economies of scale for such facilities is assumed to be the same as for separation plants (see 2.3.1). Operating costs as an annual proportion of construction costs are in the region of 2% (Wood Mackenzie, 1995).

2.3.4 Pipeline vs. transportation by ships

The choice between transporting natural gas either by pipeline or ship depends crucially upon two factors:

1. The transportation distance
2. The volume to be transported

At any given volume, increasing the distance will eventually lead to ships being the most cost efficient solution. The reason is that the ship technologies have a relatively high proportion of investment costs unrelated to the transportation distance, and hence related to the onshore plants. When using pipeline technology there is a strong relationship between distance and costs. On the other hand, the critical distance where the transportation technologies become equally cost efficient, increases with volume. Offshore pipelines are more expensive than onshore, and the critical distance will be shorter (Bjerkholt, Olsen and Strøm, 1990). These relations are presented graphically in figure 2.2.

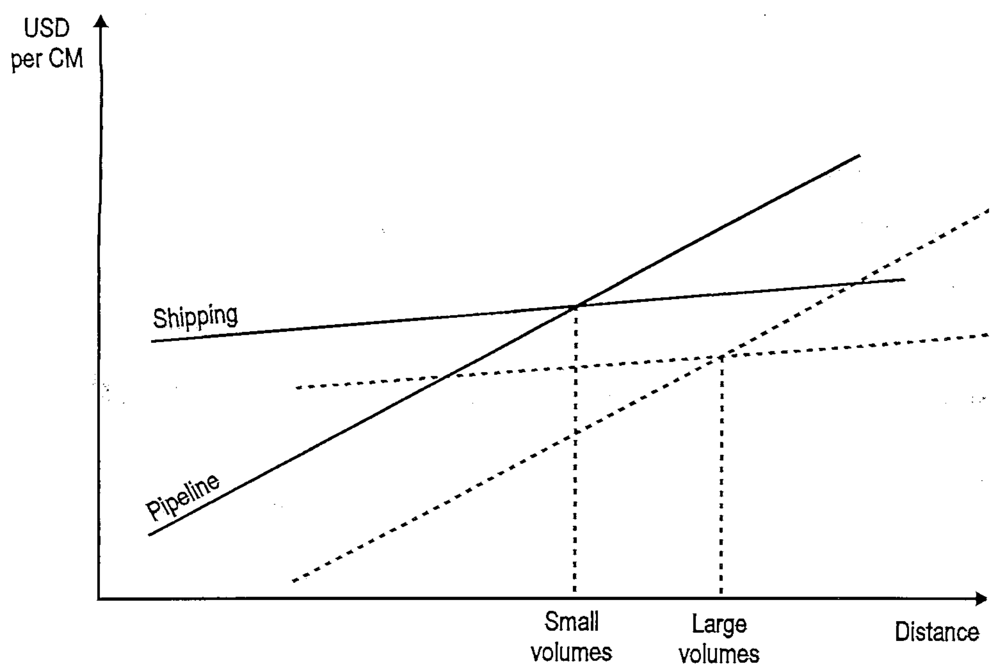


Figure 2-2 : Critical distance

Constructing a pipeline is an irreversible investment decision involving institutional and practical difficulties like crossing mountain ranges and international borders. Pipelines are also less flexible with regards to capacity and transport routes than the shipping modes of transportation, and the market risk is thus higher. This implies that ship transportation can be desirable even within the range of the critical distance.

3. THE NATURAL GAS MARKET IN EUROPE

Performing an investment analysis of natural gas projects requires information about present and future natural gas prices. The price of natural gas obtained will generally be a function of supply, demand and international politics, e.g. the degree of counter trade.

3.1 Ownership and organisation of the natural gas industry

Natural gas delivered as LNG will not obtain the same price as natural gas delivered by pipeline, because the LNG still has to go through a process before it can be utilised. In Europe, the LNG is delivered f.o.b. (at liquefaction site), which means that the LNG still has to be transported as well as regasified before it is delivered to the final user. Pipeline is delivered c.i.f., which in Europe generally means at the border. Despite of this, there is no problem in comparing the two options, because there exists empirical data on prices for both commodities. This however, is not the case for NGH. The f.o.b. price for NGH will most certainly differ substantially from the LNG price, due to differences in downstream capital and operating costs. Thus all the activities (as described in chapters 2.1 and 2.2) have to be incorporated in the investment analysis to make all three technologies comparable. It is assumed that the price of natural gas after regasification/melting is the same as for gas delivered by pipeline at the border.

To simplify the investment analysis, it is also assumed that the whole chain is owned and operated by a single company, which means that each project is viewed as an entity. In reality the organisational structure is far more complex due to the large capital requirements, risks involved, legislation and specialisation. Normally, each part of the chain is organised as a separate joint venture. However, a degree of participation and alliance along the whole chain is necessary to secure the long term contracts.

3.2 Present market situation

The European natural gas market is supplied by relatively few producing nations, of which the most significant are the exporting countries of Russia, the Netherlands, Norway (pipeline) and Algeria (LNG and pipeline). The UK is also a major producer, but the gas is supplied domestically. It also has the possibility to export through the Interconnector. Table 3.1 shows the production volume in BCM per year of the five major producers (BP, 1995).

Supply to and consumption in Europe			
Country	Supply	Consumption	
Algeria	29	-	BCM
Russia	99	-	BCM
Netherlands	66	38	BCM
UK	66	68	BCM
Norway	31	-	BCM
Germany	16	68	BCM
Italy	20	46	BCM
France	3	31	BCM
Others (excl. loss)	36	115	BCM
Total	*366*	*366*	*BCM*

Table 3-1 : Supply to and consumption of gas in Europe

The supply of natural gas is carried out by both private and public companies. However, the relatively high degree of state involvement often leads to the respective governments being viewed as the actual negotiating party. This concentration of suppliers may be described as an oligopolistic situation between all of these countries.

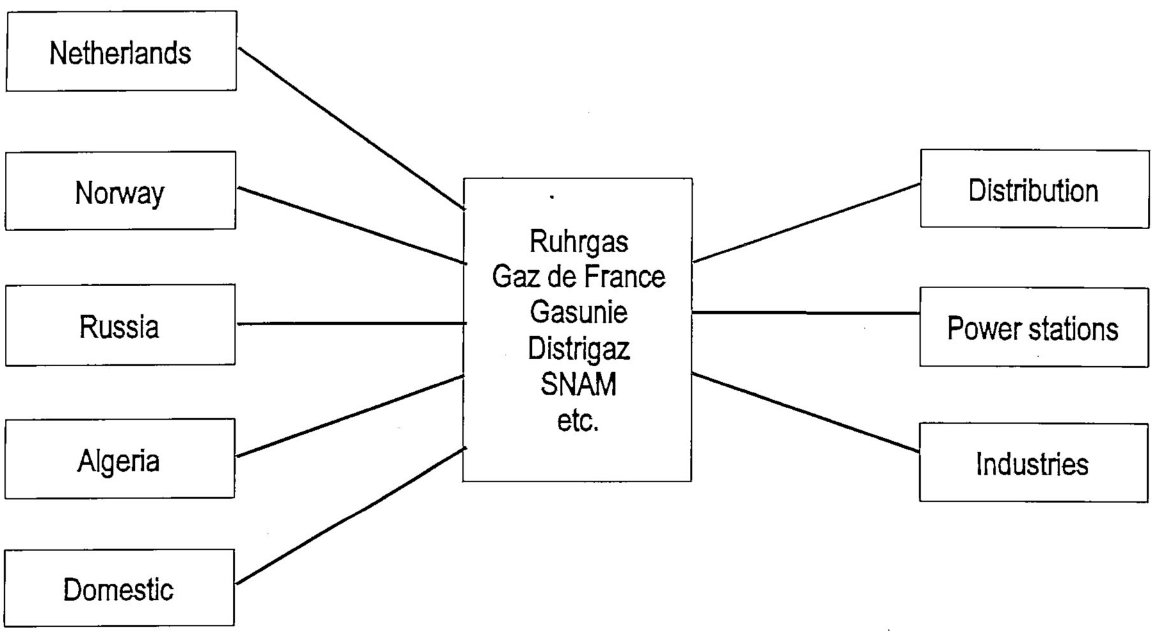


Figure 3-1 : Market structure Europe

The major importers of natural gas are Germany, France and Italy. Major domestic consumers are Russia, UK and the Netherlands. Generally, in each of these countries major national transmission companies are responsible for buying and distributing the imported and /or domestically produced natural gas to the end users (figure 3.1). This implies a virtual monopolistic situation in distributing natural gas in these markets.

In the European market described above, most transactions have the form of large, long-term bilateral contracts. For each contract, an individual price is negotiated between the producer and the national transmission company. The base price and indexing regulations of natural gas in these contracts, are closely linked to the prices of competing fuels, mainly oil and oil products. Information about prices and price indexing formulas for individual contracts is limited, because none of the major producers want to weaken their market position. Each buyer and producer will normally hold a portfolio of contracts which in general eliminates the risk of being exploited in a monopolistic or monopsonistic situation. Holding a portfolio also secures safe and continuous deliveries, e.g. the Czech Republic's bid for Norwegian natural gas in order to reduce the current dependence on Russia.

3.3 Future market situation

3.3.1 Potential for future demand and supply

Political, social and economical conditions in Europe are evolving towards new equilibria that are likely to affect the demand for energy, and natural gas in particular. The total demand for energy depends upon several factors such as costs, population growth, economic development etc. The total demand is expected to grow, but because all of these factors are difficult to assess, the magnitude of the increase is a matter of discussion among experts. Some are even expecting a stagnation of energy demand (Cofala, 1994). The market share of natural gas relative to competing fuels such as oil and coal, is expected to increase significantly as a result of growing concern for the environment. Natural gas is cleaner burning and lower in CO_2 emissions than other fossil fuels. Thus, it is generally accepted that substituting natural gas for other fossil fuels will reduce the greenhouse effect. The substitution is speeded up by governments using heavier taxation on industries utilising oil and coal, and encouraging the use of natural gas[7]. After the Chernobyl accident and several other incidents, natural gas is now also viewed by many as a better option than nuclear power generation. Technological developments and improved infrastructure may also have a positive effect on demand for natural gas.

200 BCM or more of additional natural gas supply is potentially available to Europe within the next decade or two. It would come mainly from non-OECD countries. Algeria has a potential to expand exports by refurbishing production and transportation facilities. Russia could export major volumes of natural gas at somewhat higher costs than Algeria, while Norway's potential supply is at the high end of the cost range. Natural gas could also be imported from Nigeria and Iran. In figure 3.2 the relative cost ranges of potential deliveries are presented (Arthur D. Little, 1992).

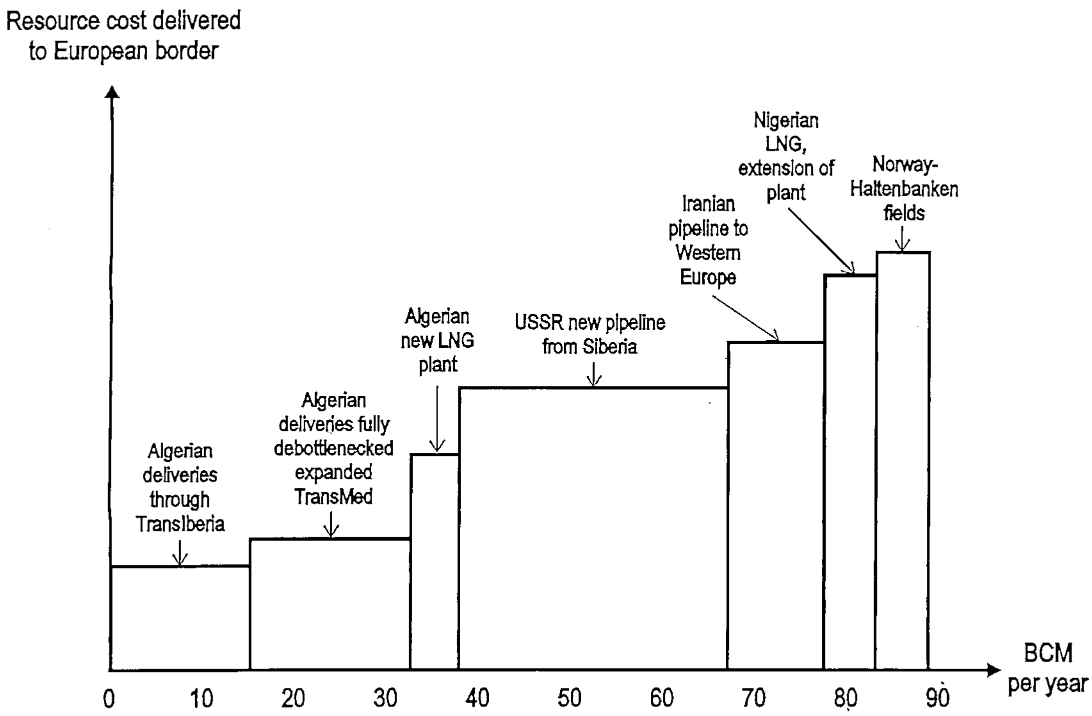


Figure 3-2 : Potential Supply

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[7] Some countries, like Germany for instance, tax coal less than other fossil fuels to protect the domestic coal industry

3.3.2 The GAS-model

In this study it is assumed that natural gas sales and condensate from the potential Norwegian and Russian fields will start in 2005. The trends of future supply and demand have been quantified as future price estimates by several sources. The most recent market evaluation has been conducted by SNF (Eldegard, 1995). The model used, GAS, divides the European market into 13 market regions and 5 producing nations. Based on assumptions about market demand composition and growth, production capacities, costs, changes to network structure and capacities as well as the behaviour of producers and consumers in the European market future demand, supply and prices for three different scenarios are estimated.

First, the model estimates future prices in 2005 at each of the landing points (base case). Then, new natural gas supplies from North Russia[8] (10 and 30 BCM) is introduced and the model estimates the new market solution. After the introduction, prices drops in all of the market regions. The prices are given at two different stages of the chain, none of which can be directly used in the investment analysis in this study. However, the results can be adjusted to fit the analysis by taking an average of the two price estimates. After adjusting the figures estimated by Eldegard, the resulting price in the core area of supply (includes Rotterdam area) drops 3.5% and 9% for additional supplies of 10 and 30 BCM respectively. In the base case, the price was estimated at 165 USD per 1000 CM natural gas. This price is based upon a given calorific value[9] which is assumed to be the same as for the natural gas from the projects in this study.

The model will only provide a simplified picture of the complicated structure of the European natural gas market. The main determinant of the model is future estimates of oil prices[10]. In the model, prices of 65 and 85 USD per Mt. are assumed for light and heavy fuel oils

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[8] The gas is delivered as LNG, but in this study the effect is assumed to be the same for pipeline gas

[9] Measures the energy content of each CM natural gas

[10] Estimates of exchange rates are also crucial factors in the GAS-model, but no information on these are available

respectively. These figures are somewhat low compared to those quoted in the press, but these are believed to be incidentally high due to an extraordinary demand for fuel oils. As described above, the European natural gas market is based on long term contracts. This is not reflected in the model. Therefore, the market potential for new suppliers might be overestimated. However, the solution will also be more efficient (closer to a market equilibrium) when excluding long term contracts, and thus underestimating the price obtainable.

The GAS model does not provide any estimate of the condensate price. The current price of condensate is about 160 USD per Mt. c.i.f. Rotterdam (Andresen, 1995). The transportation cost at the current market timecharter rates is about 15 USD per Mt. (Ramsland, 1995) from the Barents Sea area. The 2005 condensate price will be estimated by adjusting the current price for general inflation, which might not be very realistic.

3.3.3 Liberalisation and deregulation

The European natural gas industry is facing significant and apparently inevitable change, driven by market forces and the European Commission (EC). The pattern will be familiar to natural gas companies in the USA and UK. Shifting market expectations, the involvement of non-regulated private companies and legislations are challenging the premises both of natural monopolies and of regulated competition. The deregulation of the UK market resulted in prices plunging by almost 50% (Dagens Næringsliv, 1995). For the time being, energy liberalisation continues to be focused on the electricity market with a council working group trying to hammer out a compromise between the third party access system (TPA) and the single buyer system (SBS)[11]. The outcome of this compromise will most certainly set a precedent for the natural gas industry. The degree of the resulting liberalisation in the natural

[11] TPA allows direct contracts between producers and consumers while an independent third party is responsible for running and maintaining the means for transport and charges a tariff for use of capacity.

SBS allows only one company to be seller of the commodity and owner of the means of transport. Producers are enforced to sell to the SBS or the SBS may even itself be a producer (Eldegard, 1995).

gas market and at what time it will take effect is not yet known. Most analysts expect the reform to come at some time early in the 21st century. However, if a directive had been adopted immediately it would not have been fully effective before 2005.

TPA has been assumed in the GAS-modelling, and the solution is therefore closer to a market equilibrium than the current market situation implies.

4. PROJECT FINANCING

There are different opinions on what effect the financial structure of a project has on its value. In an ideal world as described by Miller and Modigliani (1958) the value of a company is not related at all to the financial structure of the company. An ideal world is a world in which:

1. There are no bankruptcy cost
2. Tax on total return on assets not influenced by leverage
3. The shareholders are able to copy any debt ratio and at the same financial terms as the company
4. There are no transaction costs
5. There are no agency costs

However, it is a generally accepted view that the ideal assumptions are not fulfilled in the real world, where leverage may have both benefits and costs. As leverage increases, the agency costs normally decreases and bankruptcy costs of debt rise. The optimal debt equity ratio is at the point at which company value is maximised, the point where the marginal costs of debt just offset the marginal benefits. The effects of taxation on financial structure is a more controversial subject. There are three main views. The first is the corrected Miller and Modigliani hypothesis which implies an optimal debt ratio of 100% due to the deductibility of interest when calculating taxes. Miller and Modigliani does not take into account the effect that increased leverage has on the debt interest rate. When the leverage increases the tax advantage increases, but at the same time the cost of debt increases, and thus 100% debt financing is no longer optimal. In Miller's article "Debt and taxes" taxes are argued to be totally irrelevant when choosing financial structure when both corporate and personal taxes are incorporated. When relaxing some of Miller's rather strict assumptions and looking at empirical data, Miller's results break down and the leverage is proved to be advantageous at least up to a given point. The critique against both views discussed has lead to a third view which is a compromise in which taxes are assumed to have an impact, but do not lead to a 100% debt ratio. The latter view is shown graphically in figure 4.1 below.

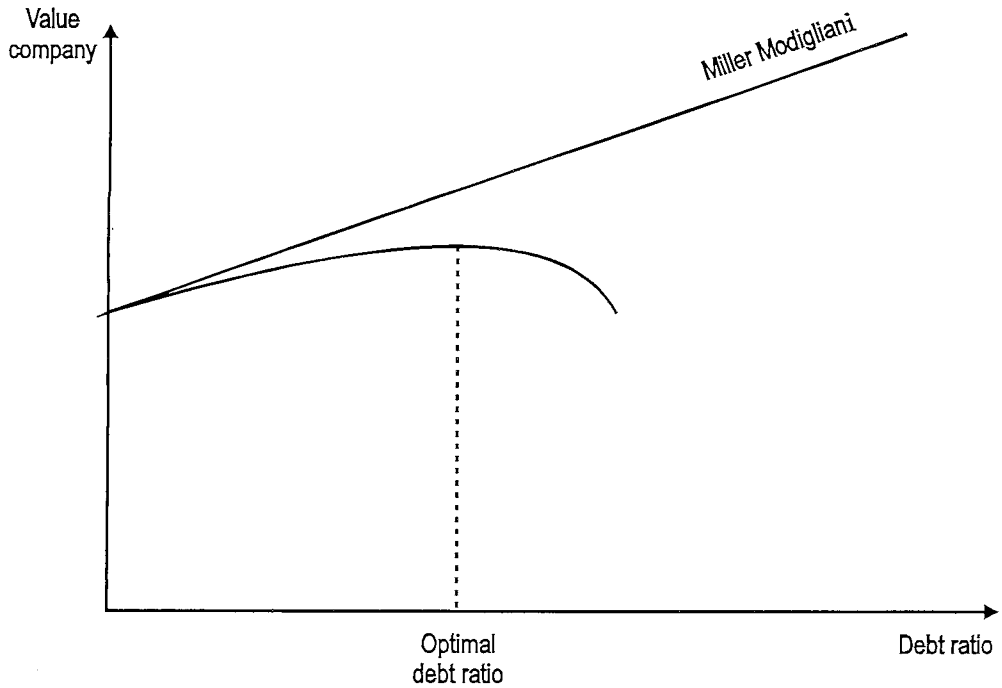

Figure 4-1 : Optimal debt ratio

The discussion above indicates that there exists a optimal debt ratio for all projects. It is a difficult task trying to find a project's optimal debt ratio. Thus, in this study, the debt ratio of a company involved in similar petroleum activities as the projects analysed, will be used and assumed to be the optimal. The Norwegian company Saga Petroleum has a debt ratio of about 40% (based on market values 1992), and this is the debt ratio that will be used in this study.

The above debt ratio implies that 40% of the project's value (initial investment + present value) will have to be financed by external liabilities. In this study it is assumed that these funds are obtained by issuing debenture bonds. These bonds will have to yield a coupon rate of about 7.6% p.a. according to DnB Securities. In order for the discount rate calculated using the weighted average cost of capital in chapter 5, the projects debt ratio will have to be constant. Bonds thus have to be redeemed or new ones issued in step with the project's market value.

5. METHODS USED IN THE INVESTMENT ANALYSIS

The analysis will build on the principles of business economics. This implies that the goal of the company is to maximise the shareholders' wealth, which means that both profits and risks will have to be taken into consideration when analysing the projects. Normally, because of the high participation from the state as described in chapter 1, the principles of political economics will also be taken into account, e.g. emphasis will be put on environmental, employment and regional development issues.

5.1 Net present value method

An investment project's net present value (NPV) is derived by discounting the future net cash receipts (the difference between the cash inflows and outflows induced by the investment) at a rate which reflects the value of the alternative use of the capital, summing them up over the life of the project and deducting the initial outlay. Before we can apply the NPV method of project evaluation as a decision rule, the goal for the company must be defined. Under the assumption of wealth maximisation mentioned in chapter 1, the following decision rules should be adopted:

If the NPV > 0, accept the project

If the NPV < 0, reject the project

Mathematically, the NPV method for natural gas projects can be defined as follows:

$$(5.1) \quad NPV = -I_0 - W_0 + \sum_{y=1}^{n} \frac{S_y(1-t) + td_y - I_y + \Delta W_y}{(1+k)^y} + \frac{SV(1-t) - A}{(1+k)^n}$$

where

where	I_y	= investment outlay year y
	W_y	= net working capital year y
	S_y	= the expected net cash receipt in year y
	A	= abandonment costs
	SV	= salvage value of the investments
	d_y	= depreciation in year y
	t	= corporate tax rate
	n	= the project duration in years
	k	= the cost of capital (discount rate)

Note that the tax shield from interest payments is not deducted. The reason is that the tax advantage of the debt will be accounted for in the discount rate k.

This formula is general, and does not take into account complicating tax issues. These will however be incorporated in the analysis.

The theory does not take into account the value of options that occur as the project goes along, e.g. the possibilities of closing down etc. The effect of this on the NPV is discussed further later in this chapter.

5.2 Riskless interest rate

As discussed in chapter 5.1, the cash flows should be discounted at a rate which reflects the value of the alternative use of the capital. Under full certainty this rate is equivalent with a riskless interest rate. It is assumed that all investors have access to a financial market where they may borrow and place money at a riskless interest rate. A good approximation for such a riskless financial object is a government bond. Natural gas projects have a duration of several decades and thus the most correct discount rate will be the yield of a long term government bond. In this study the yield of a Norwegian government bond with a 10-year term is used as a riskless interest rate. The current yield is 6.75% (Dagens Næringsliv, 25.01.96).

5.3 Incorporation of risk and uncertainty in investment projects

The riskless interest rate as a discount factor as described in chapter 5.2, is applicable only in the unrealistic case in which the results of all decisions are known in advance with certainty. When uncertainty prevails, the company must consider risk as well as profit which implies choosing that combination of the two which maximises the market value of its stock, as illustrated in figure 5.1.
Uncertainty generally prevails in the real world and this is also true for natural gas projects. Such projects demand large investments, which are virtually irreversible. They are also long-lasting (up to 15-25 years) and thus reliable upon predictions far into the future, which of course increases the uncertainty of the cash flow calculations.

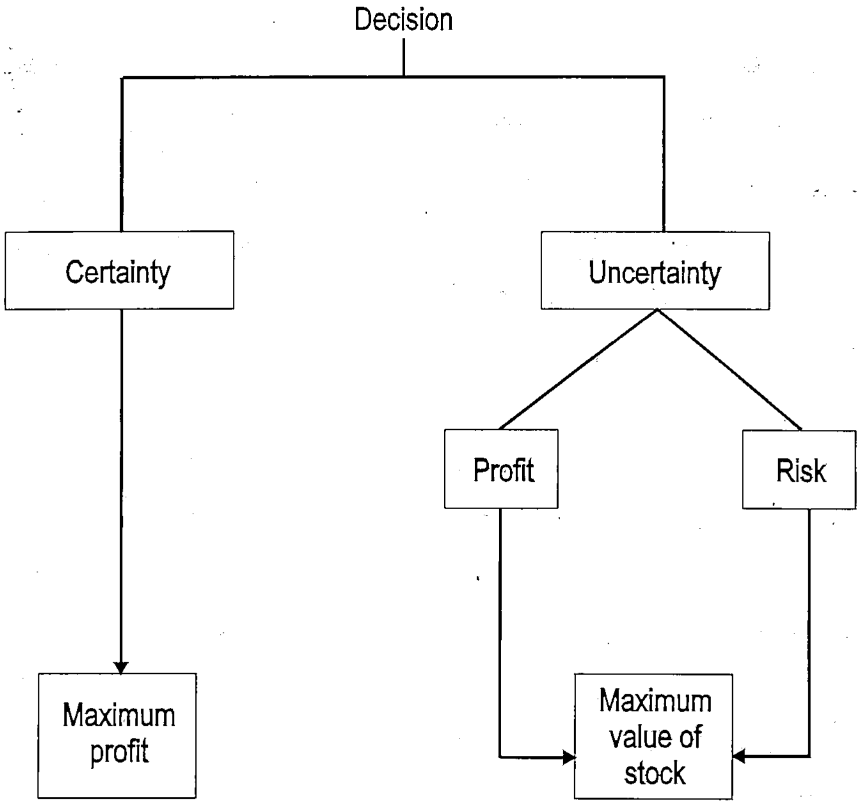

Figure 5-1 : Uncertainty versus certainty

During the lifetime of a natural gas field a number of risks occur (Bøhren & Ekern, 1987):

1. Reservoir risk (volume of natural gas reserves)
2. Development risk (technology, magnitude of investment, start-up)
3. Production risk (production profile, operating costs, production/reserves ratio)
4. Income risk (prices, exchange rates)
5. Political risk (taxes, direction)

A critical point in any project analysis is to reveal which of these risk categories should be regarded as relevant. Before the investment decision is made, the owners have a portfolio of investment objects which is called the initial portfolio or the reference portfolio. After adding the project, the owners have a new portfolio which is called the end portfolio. Relevant risk for a project is the project's contribution of risk to the owners' portfolio. Relevant risk is discussed according to six different levels. Each level has a corresponding reference portfolio. The levels are, from low to high:

1. The project (no reference portfolio)
2. The company (reference portfolio = all projects within the company)
3. The natural gas industry (reference portfolio = all projects within the industry)
4. All companies listed on the stock exchange (reference portfolio = all shares)
5. National economic community portfolio (reference portfolio = domestic part of GDP)
6. International economic community portfolio (reference portfolio = GDP)

The relevant risk of a project can be decomposed into project specific risk and correlation risk. It can be shown mathematically that the project specific risk can be almost eliminated by holding a well diversified portfolio of projects. The elimination is obtained because the implications of project specific incidents will neutralise each other. Because the reference portfolio is increased going from a lower to higher level of analysis, the project specific risk as a whole is relevant at level 1 and almost eliminated at level 6.

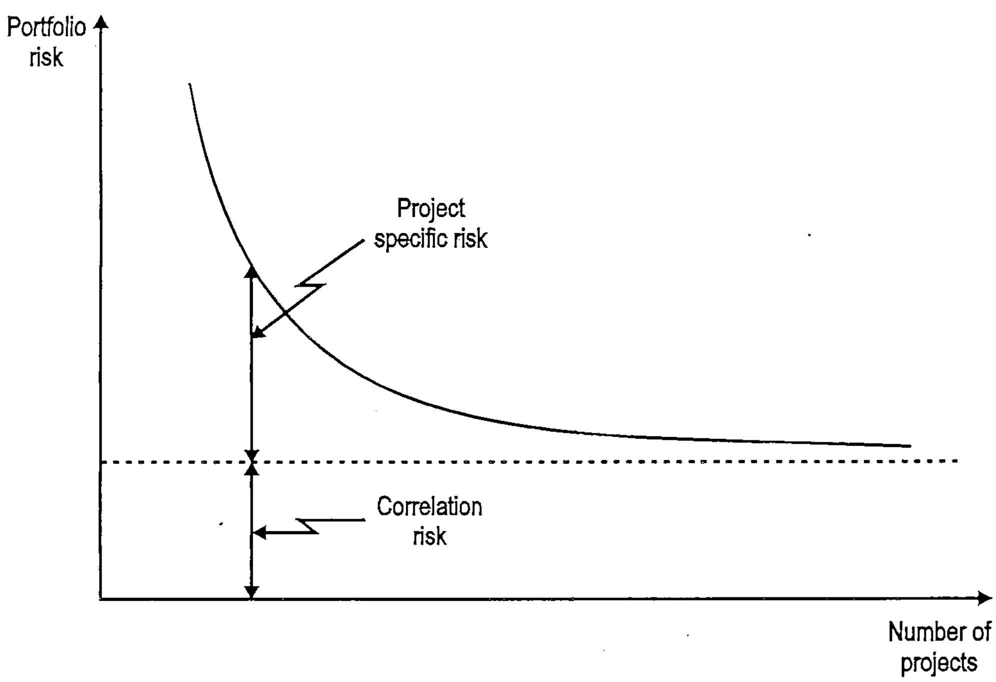

Figure 5-2 : Relationship between the number of projects and the total portfolio risk

When the project specific risk can be eliminated, the relevant risk is only determined by the covariation between the project and the reference portfolio (correlation risk). Figure 5.2 gives a graphical presentation of the relationship between the number of projects and the total portfolio risk.

However, if the project is large compared to the reference portfolio, which might be the case for large natural gas projects, the project specific risk can be non-diversifiable, even at the higher levels.

The relevant level for analysing a project depends on which interest group the project is meant to serve and what reference portfolio this group has. As noted above, in this study it is assumed that the goal of the company is to maximise the wealth of the shareholders, which is equivalent to maximising the share price. The relevant reference portfolio for the shareholders are all shares listed on the stock exchange. From this it can be concluded that level 4 is the correct level for analysing the risk for natural gas projects in this study. At this level the Capital Asset Pricing Model discussed in the next chapter can provide a suitable risk adjusted discount rate.

5.3.1 Capital Asset Pricing Model (CAPM)

Traditionally, there are two main methods for incorporating risk into investment analysis. In the first method called RADR (Risk Adjusted Interest Rate) it is done by using a higher discount rate than for investments under certainty. The alternative method called CE (Certainty Equivalent) uses more conservative and restrictive estimates for the future cash flows and the riskless interest rate as a discount rate. The two methods are equivalent in the sense that they provide the same net present value if the respective risk adjustments are carried out in an appropriate manner. In this study, the RADR-method will be used.

5.3.2 The theory of CAPM

The CAPM was originally developed for the security market, but the model also provides some important insights into the capital budgeting process. First, applied to individual securities, the expected rate of return is given by the riskless interest rate plus a premium which is determined only by the security's contribution to the overall risk of the market portfolio (systematic risk). This implies that the investor is only expected to get paid for systematic risk and thus assumes that the security-specific (non-systematic) risk can be completely eliminated using portfolio diversification as described above.

The model is built on the assumption of a capital market in which:

1. There are no transaction costs or taxes
2. All relevant information regarding securities is freely available to all investors simultaneously
3. All investors can borrow or lend any amount in the relevant range without effecting the interest rate, and there is no risk of bankruptcy
4. There is a given uniform investment period for all investors
5. Investors are risk averse and reach their decisions using the mean-variance rule[12]

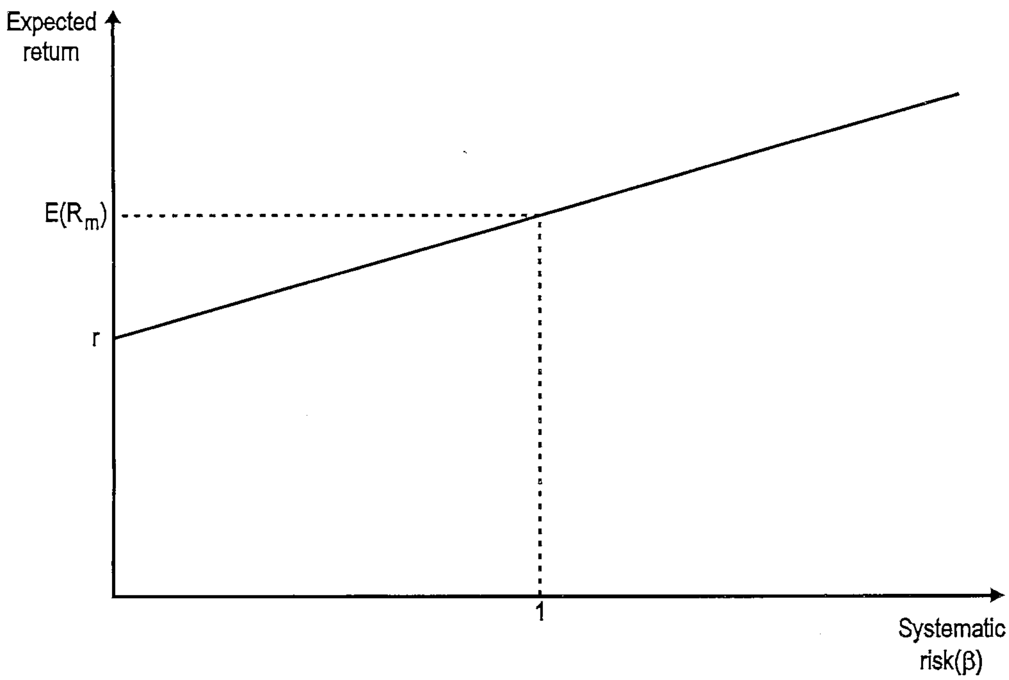

Figure 5-3 : Relationship between risk and expected return

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[12] The mean-variance rule implies that an investor will prefer project A to project B if either:

1. $E(A) \geq E(B)$ and $Var(A) < Var(B)$ or

2. $E(A) > E(B)$ and $Var(A) \leq Var(B)$

Thus, the model provides the equilibrium relationship between systematic risk and expected return in such a market, as shown in figure 5.3.
According to CAPM, expected return can be interpreted as an investor's required rate of return when calculating the net present value of investments.

Given the assumptions above it can be shown that with a one-period horizon, the next period expected rate of return E(R) of a security is:

(5.2) $E(R) = r + [E(R_m) - r]\ \beta$

where: $E(R)$ = expected return on security

r = riskless interest rate

$E(R_m)$ = expected return on the market portfolio

β = measurement of systematic risk of security

$E(R_m) - r$ = the market risk premium

$[E(R_m) - r]\ \beta$ = the risk premium for security

The market portfolio m in a perfect market, will consist of an weighted average of every investment available in the market. In practice, a broadly composed index of a stock exchange can be used as a substitute for the hypothetical market portfolio. In this study, the index of Oslo stock exchange will be used. Using historical data from the period 1987-94, the expected return on the market portfolio $E(R_m)$ is estimated at 14.9% in nominal terms (Limperopoulos, 1995).

β is defined as $Cov(R,R_m) / Var(R_m)$ which expresses the expected relationship between the return on the market portfolio and the return on the security. Thus, it is the security's covariation with the market which is the relevant measurement of risk. When $\beta = 1$ the systematic risk of the security is equivalent with the average systematic risk in the market. This implies that securities with $\beta > 1$ have a higher degree of risk than the market portfolio, and thus demands a higher risk premium and required rate of return than the market portfolio (vice versa for $\beta < 1$).

5.3.2.1 The CAPM applied to real investment projects

Each of the shares in the market portfolio used in the previous described theory, can be regarded as consisting of one or several projects. This implies that the CAPM can be used not only for evaluating securities and shares, but also for evaluating real investment projects. Thus, the term "security" in formula 5.2 above, can be substituted by the term "project". If a project does not imply an expansion of the existing activities (non-diversifying) of a company, the project β is equivalent with the share's β. If the project represents an expansion of the activities or a "stand-alone" project, finding the correct β for a project in practice can be done by comparing the project's return and risk characteristics with similar activities (a company, an industry etc.) for which the β is already known or can be estimated. For example, the stock exchange provides a broad range of companies for which the β can be calculated using historical data. If no single comparable activity exists, a weighted average of β's from different activities can be used as an approximation of the project's β. In this study, the projects are composed of several different activities ranging from natural gas exploration to transportation and onshore facilities. Activity is a broad term in this sense, also including geographical location and the technology used. This implies that the β for similar types of projects can differ substantially from one geographical area/technology to the other. Thus, the Shtockmanovskaya project's β may differ from that of Snøhvit (e.g. due to differences in political stability), and the β of a project using one type of natural gas transportation mode may differ from a project using another (e.g. due to the fact that the cost estimates for NGH-technology is not based on empirical data, and thus may have a higher variance). This implies that a separate β for each alternative will have to be estimated in the analysis part of the study.

Earlier in this chapter, five risk factors were mentioned. At analysis level 4 (all companies listed on the stock exchange) all project specific risks can be regarded as completely diversifiable for practical purposes. This implies that the first three risk factors listed are not relevant at this level. Because CAPM also refers to the stock exchange, only income risk and the general part of political risk will influence the β. The income risk is closely related to the fluctuations of the oil price and changes in the exchange rates. The latter can almost be regarded as irrelevant, because most companies in the oil and natural gas industry have adjusted by paying their costs in USD, so that changes in the USD is reflected both in the income and cost elements of the cash flow. As mentioned in chapter 3.2 there is a strong covariance between the oil price and the price of both natural gas and condensate. The general part of political risk is related to changes the authorities might carry out in regards to taxation, subsidies, regulations, stock exchange policy etc. For projects of the Shtockmanovskaya size, also the three first listed factors become partly non-diversifiable. This is especially true for Norway, because the Norwegian onshore industries depend strongly on the activities offshore (the "Kuwait-effect").

The use of historical stock exchange data (share prices) for estimating the required rate of return of a project as described above, assumes that the company is 100% equity financed. If the company is financed by debt as well as equity as the case is for large natural gas projects (see chapter 4), the project will have to yield a return which is consistent not only with the cost of equity as provided by CAPM, but also the cost of debt. It can be shown that the required rate of return (the discount rate) of the project must be the weighted average of the cost of equity and the cost of debt. As noted in chapter 1, the discount rate must also be consistent with the cash flow calculations. Because the cash flows in this study will be calculated on an after tax basis, the cost of capital k can be calculated as follows:

(5.3) $k = (1-t)ak_e + (1-t)(1-a)i$

where: k = cost of capital

k_e= cost of equity

i = cost of debt (the debt interest rate)

a = equity to total capital ratio

t = corporate tax rate

If we assume that CAPM holds, we know from the above discussion that :
$k_e = E(R) = r + [E(R_m) - r]\ \beta]$. Thus, formula 5.2 can be written as (Boye, 1992):

(5.4) $k = a(r(1-t) + [E(R_m) - r(1-t)]\ \beta) + (1-a)(1-t)i$

Note that in the cost of equity formula $E(R_m)$ should not be tax adjusted to be consistent with Norwegian tax law.

The cost of capital k calculated according to this formula will represent the correct discount rate for calculating the NPV of the projects as described in chapter 5.1. The β of the project is estimated using historical stock exchange data as described above. Two important assumptions have to be made in order to justify this formula:

1. The project's debt ratio is the same as the debt ratio for the company (based on the market values of both debt and equity) which the calculation is based upon.
2. The project has the same systematic risk as the shares of the company which the calculation is based upon.

The debt ratio of the company which the calculation is based upon is also assumed to be the optimal one. Issues regarding the cost of debt and the optimal debt ratio is discussed in chapter 4 above.

Using the principles above, the CAPM can provide a suitable risk adjusted discount rate for calculating the net present value of the different projects in this study. However, some warnings about the applicability of CAPM must be mentioned. The five underlying assumptions of the model listed above are strict and some of them are not realistic.
A serious problem is that the model assumes a one period project and that investors have a one period planning horizon, which of course is not the case for large natural gas projects. A constant risk premium in the discount rate implies that the risk connected to the future cash flows increases exponentially over time. In reality the risk is gradually dissolved over time. Obviously many of the other assumptions made are neither fulfilled in practice. However, all of this does not implicate that the model is unfit for use. Empirical surveys have shown that there is in fact a linear relationship between return and systematic risk. Furthermore, under certain conditions the use of the one period model can be justified also for multiperiod projects.

5.3.3 **Option pricing theory**

This chapter refines the theory of investment analysis described above by introducing the concepts and methods from option pricing theory to evaluate natural gas projects. In financial option theory two types of options exist. A call (put) option is a right, but not an obligation, to buy (sell) a given number of shares of the underlying stock at a given price on or before a specific date. Also real investments have some of the characteristics of options. Such options are called real options, and they are normally longer lasting and more complicated than the options related to financial objects. A project evaluation of a natural gas field can be undertaken as if the project consists of a series of sequential options (Bøhren & Ekern, 1984):

1. Exploration option (the right to explore)
2. Development option (the right to develop)
3. Production option (the right to produce)
4. Abandonment option (the right to shut down)

In the petroleum industry where prices are highly volatile, these options can have great value. The flexibility of an investment decision is not taken into account, which implies that traditional investment analysis does not describe the whole truth. The reason for this is that flexibility has a value of its own. From interpreting a real investment opportunity as an option, the investment may be worthwhile (the option value is positive) even if its expected cash flow is worth less then the investment cost. Similarly, if making the investment is interpreted as exercising that option, a positive net present value is not a clear-cut go signal. Thus, a positive net present value is neither a necessary nor a sufficient condition for a project to be profitable.

Compared to traditional discounted cash flow methods, the option framework relies more heavily on market-based input data and yields improved estimates of the expected cash flow elements. Moreover, the approach avoids the need to specify appropriate risk-adjusted discount rates. Using option pricing theory, the problems of estimating or even guessing the future price development and risk adjusted discount rate is reduced, because observable data can used evaluating the natural gas projects.

The two major features provided by this theory can be summarised like this:

1) Sequential access of information

As time goes by, new information will become available that may influence the evaluation of a project's profitability in several ways. Particularly, the value may be increased if the new information available results in better decision making. An important distinction has to be made between project external and internal uncertainty. Under project external uncertainty new information will be continuously available, independent of whether the project is carried out or not. Under project internal uncertainty however, new information will only be available if certain activities directly connected to the project itself are carried out (e.g. research & development).

2) Flexibility

The introduction of the options listed above provides the decision maker with an increased number of alternatives. This increased flexibility in combination with the sequential access of information may yield substantially increased project value. With flexibility the possibility to take advantage of a favourable outcome combined with a reduced height of fall in the case of an unfavourable outcome is strengthened. The value of such flexibility is seldom reflected in a traditional investment analysis.

In this study the effect of the real options available in natural gas projects will be examined by evaluating the projects under the assumptions that the decision maker has the option to postpone the investment to a later point in time (development option). This possibility is important due to the fact that investments in oil and natural gas projects are mainly irreversible (sunk costs). In addition, it is assumed that the future natural gas price is the only uncertain variable and taxes are not incorporated. Thus, the calculations are not to be viewed as an attempt to provide an exact evaluation of the project, but merely as an indication of the value increasing effects of real options. Normally, other additional options and other uncertain variables (e.g. costs) will be present.

5.3.3.1 The option model

The option model that will be applied for evaluating the introduction of a development option will be based on theory provided by Bjerksund and Ekern (1990). The assumptions are as follows:

1. The price of natural gas is directly linked to the price of oil
2. The price of oil follows geometric Brownian motion[13]
3. All costs (including investment costs) are known with certainty and there are no taxes
4. The convenience yield (the benefit of having an inventory in hand) of gas is positive
5. The riskless interest rate is constant and known over time
6. The project can be initiated at any time, corresponding to a perpetual American call option
7. The usual assumptions of a perfect market are fulfilled

Ignoring taxes and assuming constant costs will draw the project value in opposite directions, thus decreasing the effect of these errors.

Under these assumptions the expected price of natural gas in t periods is

(5.5) $$E_0(S(t)) = S(0)e^{\mu t}$$

where μ = growth rate expected price

t = year

$S(t)$ = price at year t

This expected future price has to be discounted at a suitable required rate of return to calculate the present value of one future unit of natural gas:

(5.6) $$\mu^* = \mu + \delta$$

where δ = convenience yield

μ^* = required rate of return

This yields the following present value of a future unit of natural gas:

[13] This is a "standard" assumption of a price process in economic literature for a good like crude oil. It implies constant volatility and thus exponentially increasing uncertainty.

(5.7) $$e^{-\delta t}S(0)$$

This is simply today's price discounted by the convenience yield.

The net present value of an immediate development and subsequent production of the field is

(5.8) $$A(\delta)S(0) - K$$

where $A(\delta)$ = equivalent time adjusted reservoir volume

K = present value of all costs

and the equivalent time adjusted reservoir volume

(5.9) $$A(\delta) \equiv \int_t e^{-\delta t} q(t)dt$$

where

$q(t)$ = yearly production rate

$A(\delta)$ is the volume of immediate available gas equivalent to the total reservoir volume received over the entire production period.

When performing a "now or never" analysis the break-even price is

(5.10) $$S_{BE} \equiv K/A(\delta)$$

derived from equating $A(\delta)S(0) - K$ to zero.

Without flexibility the field value equals the time adjusted reservoir volume multiplied by the difference between today's price and the break-even price. Thus the net present value rule can be transformed into a decision rule: develop only if today's price exceeds the break even price.

With flexibility the possibility to develop can be considered as A(δ) call options on a unit of natural gas with the break-even price S_{BE} as the exercise price. Consequently, the possibility to develop appears as a real option. The value of this real options depends upon the terms for exercising, i.e. the development decision. As mentioned in assumption number 6 above, the terms for exercising will be those corresponding to a perpetual American call option, i.e. the exercising can take place at any point in time.

It can be shown that under this assumption, the critical natural gas exercise price is

$$(5.11)\quad S_{AP} = \frac{\varepsilon}{\varepsilon - 1} S_{BE}$$

where: $\varepsilon \equiv [0.5 - \frac{b}{\sigma^2}] + \sqrt{[\frac{b}{\sigma^2} - 0.5]^2 + 2\frac{r}{\sigma^2}}$

where: r = real riskless interest rate

b= r-δ

S_{AP} will always exceed S_{BE} because the fraction ε/(ε-1) always exceeds 1.

The value of this real option can be expressed

$$(5.12)\quad W_{AP} = A(\delta)[\frac{S_{AP} - S_{BE}}{S_{AP}^{\ \varepsilon}}]S^{\varepsilon}.$$

This project value can be compared to the value calculated using traditional investment analysis. However, the two models presented are fundamentally different both in assumptions and methodology and comparisons should be carried out with great caution.

Note that in the CAPM framework the future price estimates were based on the GAS-model, whereas in this framework the future prices follow a geometric Brownian motion. The method of discounting also differs: in the CAPM framework discrete cash-flows were discounted yearly, here they are continuous and discounted continuously.

5.3.4 Sensitivity analysis

Probably the most common method of evaluating a project's risk in practice is sensitivity analysis, in which the company makes its best estimate of the revenues and costs involved in a project (expected values), calculates the projects NPV and then checks the sensitivity of the NPV to possible fluctuations around the expect values of revenue, cost items and other variables. If small fluctuations prove critical in the sense that the NPV becomes negative, the project is considered very risky since if small fluctuations are likely to occur. When calculating the NPV and checking a projects risk using sensitivity analysis, the riskless and not the risk adjusted interest rate should be used as the discount factor. When the discount rate is risk adjusted, the risk has already been taken into account and there is thus no need to consider it again using sensitivity analysis. In this study sensitivity analysis will be used to test different estimates of input data, and thus not as a way of checking risk per se.

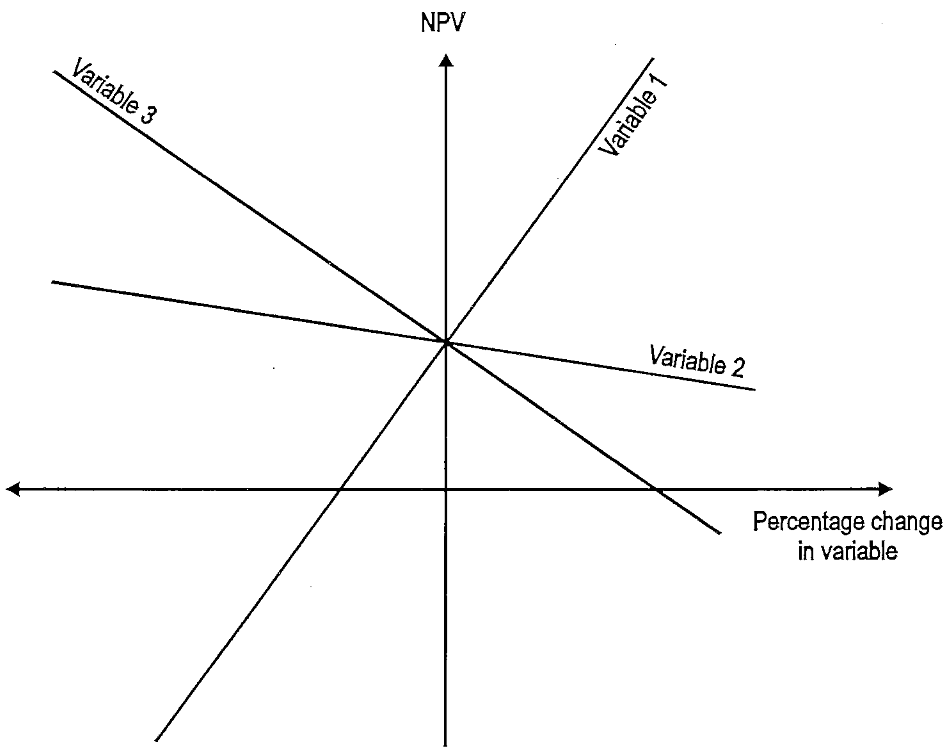

Figure 5-4 : Sensitivity analysis

As a basis for further sensitivity analysis, the effects of changes in different input data can be presented in a simple star diagram as shown in figure 5.4.

Some variables (like variable 1 in the figure) will prove to be more critical than others, and these variables will be analysed in more detail using different types of sensitivity analysis. The different technologies will be compared along with estimates of how much the variables must change in order to disturb the initial ranking of the projects.

It should be noted that looking at each variable in turn as in figure 5.4 may not give a very realistic picture of the resulting effects due to the possible correlations between variables. As an example, the bunker price will be highly correlated to the price of oil. For some variables this possibility will be taken into consideration (like the correlation between the price of natural gas and the condensate price), for others that are non-significant variables (like the bunker price) it will be ignored.

6. INVESTMENT ANALYSIS OF THE SNØHVIT PROJECT

6.1 Characteristics and main results[14]

Snøhvit is likely to be the first natural gas field to be developed in the Tromsøflaket area of the Barents Sea. However, it should be stressed that no development of the Snøhvit field will occur before an agreement on the sale of the natural gas is reach. The results of the exploration activities have been disappointing and the oil and gas companies' interest in the area has been correspondingly decreasing. As mentioned in chapter 5, political economics will be taken into account by the state. This has resulted in an effort to adjust the economic conditions for companies willing to operate in this area, e.g. by granting tax shields etc. (Stortingsmelding no. 26, 1993/94). Thus, despite the constraints on the profit available to the operators, two potential buyers have started negotiations for natural gas deliveries (ENEL and ENRON).

Moreover, the Snøhvit field is surrounded by several satellite fields. The most important of these are the Askeladden and Albatross fields which contain recoverable reserves totalling approximately the size of the Snøhvit field itself. These fields can increase the Snøhvit project if phased in at a later stage, and viewed as real options for further development this value can be significant. In this study Snøhvit is evaluated on a stand-alone basis, thereby ignoring this additional potential.

Based on figures from Wood Mackenzie the investment costs for the offshore facilities and pipeline for transportation to the onshore terminal totals 1230 million USD (equally distributed among facilities and pipeline). There is a need for 2 LNG carriers and 4 NGH carriers to transport the yearly volume to the market.

The main characteristics of the field are presented in table 6.1.

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[14] All figures are presented in nominal terms and present values are calculated for year 2000 (project start-up).

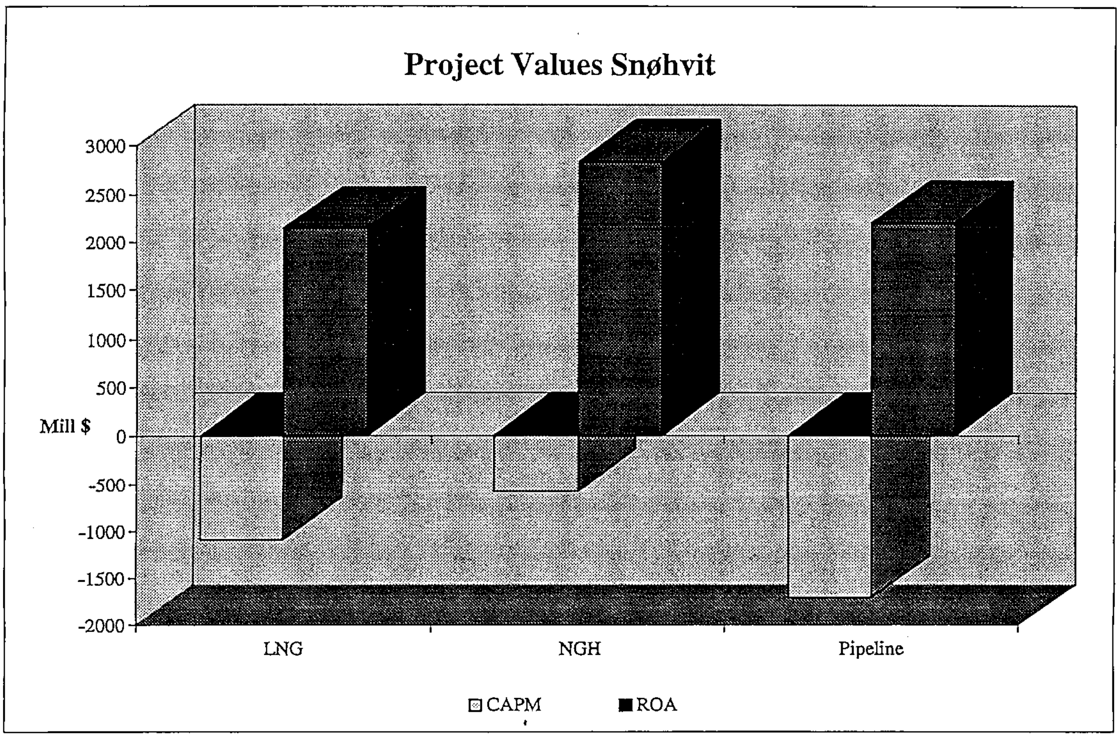
Total reserves natural gas	80 BCM
Total reserves condensate	6.6 Mill Mt.
Production rate natural gas	4 BCM/Year
Production rate condensate	0.33 Mill Mt./Year
Location of field	130 KM offshore
Location of onshore facilities	Sørøya
Operator	Norsk Hydro Production/Statoil
Expected price natural gas (2005)	165 USD per 1000 CM
Expected price natural gas (2000)	134 USD per 1000 CM

Table 6-1 : Main characteristics of the Snøhvit Field

The main results of the analysis for the Snøhvit field is presented below. The calculations have been carried out using both the CAPM and real options approach (ROA) presented in chapter 5.

Project Values	*CAPM*	*ROA*	
LNG	-1090	2144	Mill. USD
NGH	-575	2839	Mill. USD
Pipeline	-1695	2212	Mill. USD

Table 6-2 : Main results of the Snøhvit investment analyses



Graphic Results 6-1 (Project Values Snøhvit)

From the table and graphics above it can been seen that the CAPM approach has resulted in negative project values for all three transportation technologies. A decision maker will thus not have an incentive to develop the Snøhvit field given the underlying assumptions. As expected, the real options model indicates positive project values for all technologies. However, to realise this value it is required to wait until the natural gas price reaches a critical price. This price has proved to be very high for all technologies, and this implies that the decision maker must consider thoroughly whether the project should be initiated or not. The following sections contain a more detailed presentation and explanation of the results and calculations. In addition, the impact of changes in critical input data will be presented using a wide variety of sensitivity analyses. For verification, the LNG calculations will be carried out in full, while the corresponding figures for NGH and pipeline is presented without detailed calculations.

6.2 Cash flows

Based on the data in chapter 2, the tables 6.3 through 6.5 present the cash flows for the three different transportation alternatives.[15]

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[15] In addition to the data in chapter 2, other main assumptions for calculating the cash flow is presented in appendix xx

Cash flow Snøhvit LNG-alternative (All figures in mill. $)															
Year	Revenue		Capital costs					Licence		Operating costs					
	Conden-sate	Gas	Offshore	Liquifi-cation	Ships	Regasifi-cation	Working capital	Area fee	CO2-fee	Offshore	Liquifi-cation	Ships	Regasifi-cation	Taxes	Cash flow
2000			-292.4	-251.8				-0.8							-545.0
2001			-302.6	-260.6				-0.8							-564.0
2002			-313.2	-269.7				-0.8							-583.7
2003			-324.1	-279.2	-362.1	-229.0		-0.8							-1195.3
2004			-335.5	-288.9	-374.8	-237.0		-0.8							-1237.1
2005	68.2	577.5					-32.3	-0.8	-68.8	-149.7	-59.8	-19.2	-12.3		302.8
2006	70.6	597.8						-1.6	-68.8	-155.0	-61.9	-19.8	-12.7		348.5
2007	73.0	618.7						-1.7	-68.8	-160.4	-64.1	-20.5	-13.1		363.1
2008	75.6	640.3						-2.1	-68.8	-166.0	-66.3	-21.3	-13.6		377.8
2009	78.2	662.7						-2.5	-68.8	-171.8	-68.6	-22.0	-14.1		393.1
2010	81.0	685.9						-4.2	-68.8	-177.8	-71.0	-22.8	-14.6		407.7
2011	83.8	710.0						-6.0	-68.8	-184.1	-73.5	-23.6	-15.1		422.7
2012	86.7	734.8						-7.6	-68.8	-190.5	-76.1	-24.4	-15.6		438.5
2013	89.8	760.5						-9.4	-68.8	-197.2	-78.8	-25.2	-16.2		454.7
2014	92.9	787.1						-11.1	-68.8	-204.1	-81.5	-26.1	-16.7		471.7
2015	96.2	814.7						-12.8	-68.8	-211.2	-84.4	-27.0	-17.3		489.3
2016	99.5	843.2						-25.4	-68.8	-218.6	-87.3	-28.0	-17.9		496.7
2017	103.0	872.7						-25.4	-68.8	-226.3	-90.4	-29.0	-18.5	-222.3	295.0
2018	106.6	903.3						-25.4	-68.8	-234.2	-93.5	-30.0	-19.2	-420.2	118.5
2019	110.4	934.9						-25.4	-68.8	-242.4	-96.8	-31.0	-19.9	-437.5	123.4
2020	114.2	967.6						-25.4	-68.8	-250.9	-100.2	-32.1	-20.5	-455.4	128.4
2021	118.2	1001.5						-25.4	-68.8	-259.6	-103.7	-33.2	-21.3	-473.9	133.7
2022	122.4	1036.5						-25.4	-68.8	-268.7	-107.3	-34.4	-22.0	-493.1	139.1
2023	126.6	1072.8						-25.4	-68.8	-278.1	-111.1	-35.6	-22.8	-512.9	144.7
2024	131.1	1110.3			13.6		87.6	-25.4	-68.8	-287.9	-115.0	-36.9	-23.6	-544.0	241.0

Table 6-3 : Cash Flow Snøhvit LNG alternative

Cash flow Snøhvit NGH-alternative (All figures in mill. $)																
Year	Revenue		Capital costs					Licence		Operating costs						
	Conden-sate	Gas	Offshore	Refrige-ration	Ships	Melting	Working capital	Area fee	CO2-fee	Offshore	Refrige-ration	Ships	Regasifi-cation	Taxes	Cash flow
2000			-292.4	-142.5				-0.8						0.0	-435.7
2001			-302.6	-147.5				-0.8						0.0	-450.9
2002			-313.2	-152.7				-0.8						0.0	-466.7
2003			-324.1	-158.0	-263.4	-158.0		-0.8						0.0	-904.4
2004			-335.5	-163.5	-272.6	-163.5		-0.8						0.0	-936.0
2005	68.2	619.5					-34.4	-0.8	-35.8	-149.7	-33.9	-38.9	-8.5	0.0	385.7
2006	70.6	641.2						-1.6	-35.8	-155.0	-35.0	-40.3	-8.8	0.0	435.4
2007	73.0	663.6						-1.7	-35.8	-160.4	-36.3	-41.7	-9.1	0.0	451.8
2008	75.6	686.8						-2.1	-35.8	-166.0	-37.5	-43.1	-9.4	0.0	468.5
2009	78.2	710.9						-2.5	-35.8	-171.8	-38.8	-44.7	-9.7	0.0	485.8
2010	81.0	735.8						-4.2	-35.8	-177.8	-40.2	-46.2	-10.1	0.0	502.5
2011	83.8	761.5						-6.0	-35.8	-184.1	-41.6	-47.8	-10.4	0.0	519.7
2012	86.7	788.2						-7.6	-35.8	-190.5	-43.1	-49.5	-10.8	0.0	537.7
2013	89.8	815.8						-9.4	-35.8	-197.2	-44.6	-51.2	-11.1	-269.3	286.9
2014	92.9	844.3						-11.1	-35.8	-204.1	-46.1	-53.0	-11.5	-449.0	126.6
2015	96.2	873.9						-12.8	-35.8	-211.2	-47.8	-54.9	-11.9	-464.6	131.1
2016	99.5	904.4						-25.4	-35.8	-218.6	-49.4	-56.8	-12.4	-472.4	133.2
2017	103.0	936.1						-25.4	-35.8	-226.3	-51.2	-58.8	-12.8	-490.6	138.4
2018	106.6	968.9						-25.4	-35.8	-234.2	-52.9	-60.9	-13.2	-509.4	143.7
2019	110.4	1002.8						-25.4	-35.8	-242.4	-54.8	-63.0	-13.7	-528.9	149.2
2020	114.2	1037.9						-25.4	-35.8	-250.9	-56.7	-65.2	-14.2	-549.1	154.9
2021	118.2	1074.2						-25.4	-35.8	-259.6	-58.7	-67.5	-14.7	-570.0	160.8
2022	122.4	1111.8						-25.4	-35.8	-268.7	-60.8	-69.8	-15.2	-591.6	166.9
2023	126.6	1150.7						-25.4	-35.8	-278.1	-62.9	-72.3	-15.7	-614.0	173.2
2024	131.1	1191.0			105.8		93.2	-25.4	-35.8	-287.9	-65.1	-74.8	-16.3	-719.6	296.2

Table 6-4 : Cash Flow Snøhvit NGH alternative

Cash flow Snøhvit Pipeline-alternative (All figures in mill. $)																
Year	Revenue		Capital costs					Licence		Operating costs						
	Condensate	Gas	Offshore	Separation	Pipeline	Treatment	Working capital	Area fee	CO2-fee	Offshore	Separation	Pipeline	Treatment	Taxes	Cash flow
2000			-292.4	-144.2	-576.7			-0.8						0.0	-1014.1
2001			-302.6	-149.2	-596.9			-0.8						0.0	-1049.6
2002			-313.2	-154.4	-617.8			-0.8						0.0	-1086.3
2003			-324.1	-159.9	-639.4	-39.1		-0.8						0.0	-1163.3
2004			-335.5	-165.4	-661.8	-40.4		-0.8						0.0	-1204.0
2005	68.2	629.9					-34.9	-0.8	-30.6	-149.7	-17.1	-68.5	-0.4	0.0	395.9
2006	70.6	651.9						-1.6	-30.6	-155.0	-17.7	-70.9	-0.4	0.0	446.2
2007	73.0	674.7						-1.7	-30.6	-160.4	-18.3	-73.4	-0.4	0.0	462.9
2008	75.6	698.3						-2.1	-30.6	-166.0	-19.0	-75.9	-0.5	0.0	479.8
2009	78.2	722.8						-2.5	-30.6	-171.8	-19.7	-78.6	-0.5	0.0	497.3
2010	81.0	748.1						-4.2	-30.6	-177.8	-20.3	-81.4	-0.5	0.0	514.2
2011	83.8	774.3						-6.0	-30.6	-184.1	-21.0	-84.2	-0.5	0.0	531.6
2012	86.7	801.4						-7.6	-30.6	-190.5	-21.8	-87.1	-0.5	0.0	549.8
2013	89.8	829.4						-9.4	-30.6	-197.2	-22.5	-90.2	-0.6	0.0	568.6
2014	92.9	858.4						-11.1	-30.6	-204.1	-23.3	-93.4	-0.6	0.0	588.3
2015	96.2	888.5						-12.8	-30.6	-211.2	-24.2	-96.6	-0.6	0.0	608.6
2016	99.5	919.6						-25.4	-30.6	-218.6	-25.0	-100.0	-0.6	0.0	618.8
2017	103.0	951.8						-25.4	-30.6	-226.3	-25.9	-103.5	-0.6	-63.9	578.5
2018	106.6	985.1						-25.4	-30.6	-234.2	-26.8	-107.1	-0.7	-404.2	262.7
2019	110.4	1019.5						-25.4	-30.6	-242.4	-27.7	-110.9	-0.7	-539.9	152.3
2020	114.2	1055.2						-25.4	-30.6	-250.9	-28.7	-114.8	-0.7	-560.3	158.0
2021	118.2	1092.2						-25.4	-30.6	-259.6	-29.7	-118.8	-0.7	-581.5	164.0
2022	122.4	1130.4						-25.4	-30.6	-268.7	-30.7	-122.9	-0.8	-603.4	170.2
2023	126.6	1169.9						-25.4	-30.6	-278.1	-31.8	-127.2	-0.8	-626.0	176.6
2024	131.1	1210.9					94.6	-25.4	-30.6	-287.9	-32.9	-131.7	-0.8	-649.4	277.8

Table 6-5 : Cash Flow Snøhvit Pipeline alternative

6.3 Evaluation using the CAPM approach

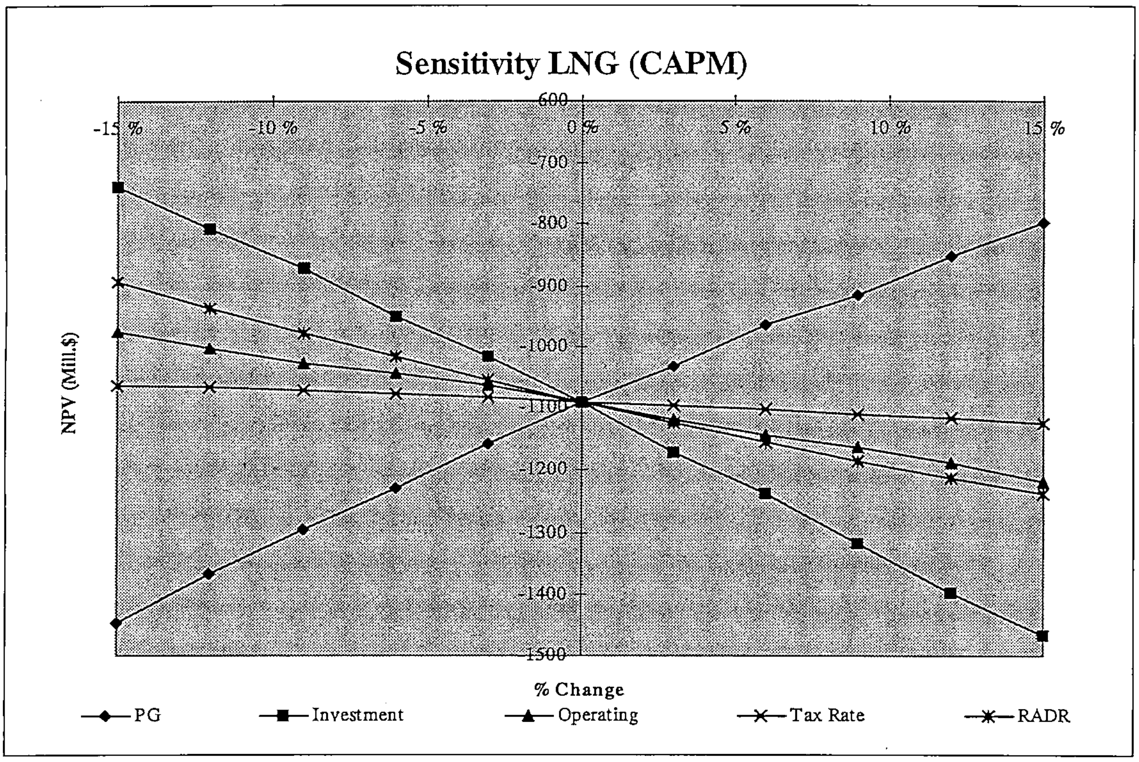
The correct discount rates for the different alternatives is calculated using formula 5.4. All the inputs to this formula have already been presented, except for the systematic risk factor β. This factor must be calculated separately for each technology and geographic area. As mentioned in chapter 5.3.1.2 one method for finding a suitable β is to identify a company undertaking similar activities for which the β is already known or can easily be calculated using historical stock-exchange data. Thus, for known technologies (LNG and pipeline) there are several large oil and natural gas companies world-wide which can provide such information. For the Snøhvit field, a Norwegian company like Saga Petroleum is the most appropriate comparison. A minor drawback with this company is that shipping is not a major part of their activities. Using the published β for Saga equal to about 1 (Dagens Næringsliv, 15/5-96), and assuming that the project and Saga have the same equity ratio of 60%, the required rate of return for the LNG alternative is calculated as:

$$k_{LNG} = 0.6[0.0675(1\text{-}0.78)+(0.149\text{-}0.0675(1\text{-}0.78))1] + (1\text{-}0.6)(1\text{-}0.78)0.076 \approx 9.6\%$$

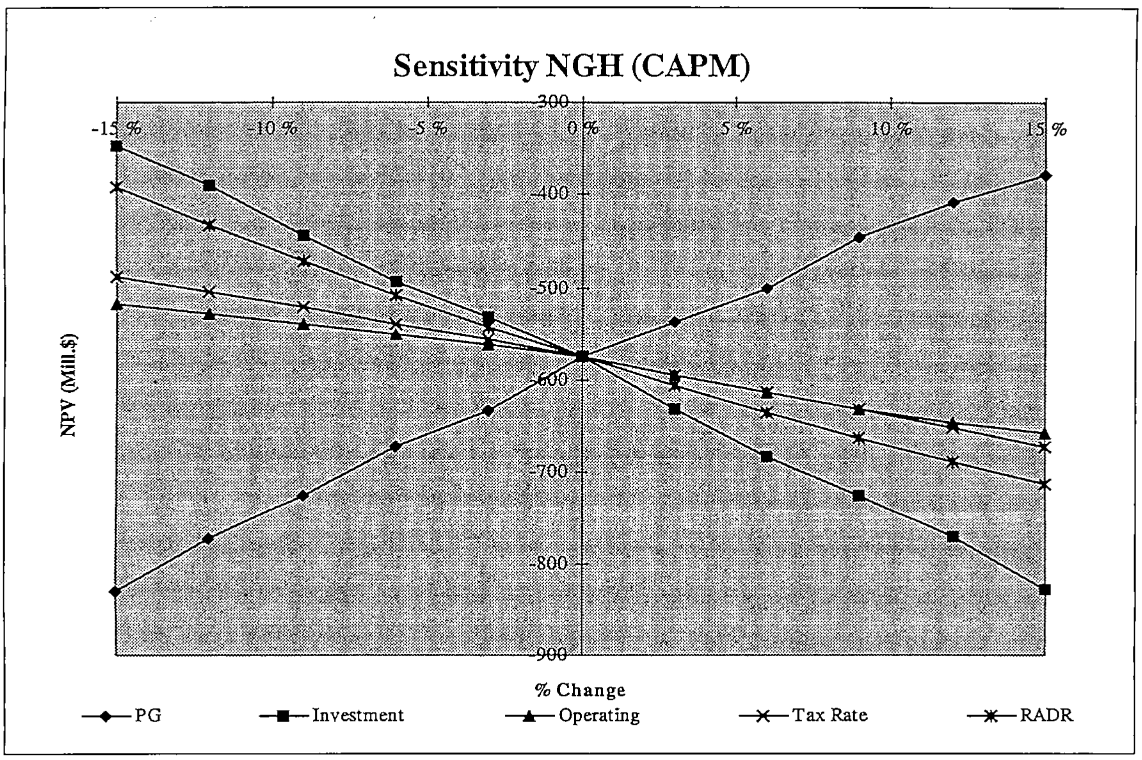
Since pipeline is also a well known technology, it is assumed that the systematic risk factor and thus the required rate of return for the pipeline alternative is equal to the one for the LNG alternative ($k_{LNG} = k_{PIPE}$). The NGH alternative is somewhat different due to the experimental nature of its technology, and as mentioned in chapter 5.3.1.2 this implies a different β than for the other technologies. According to Mossin (1982) companies utilising new and experimental technology will normally have a higher systematic risk than others, all else equal. In this study a weighted average of the β of 1 for oil and natural gas companies (2/3 weight) and a β of 1.6 for high-tech companies (1/3 weight) is used. This yields a $\beta_{NGH} = 1.2$ implying a required rate of return $k_{NGH} \approx 11.2\%$ (still using formula 5.4). Discounting the respective cash flows using these risk adjusted discount rates, results in the negative net present values shown in table 6.2.

6.3.1 Sensitivity analysis

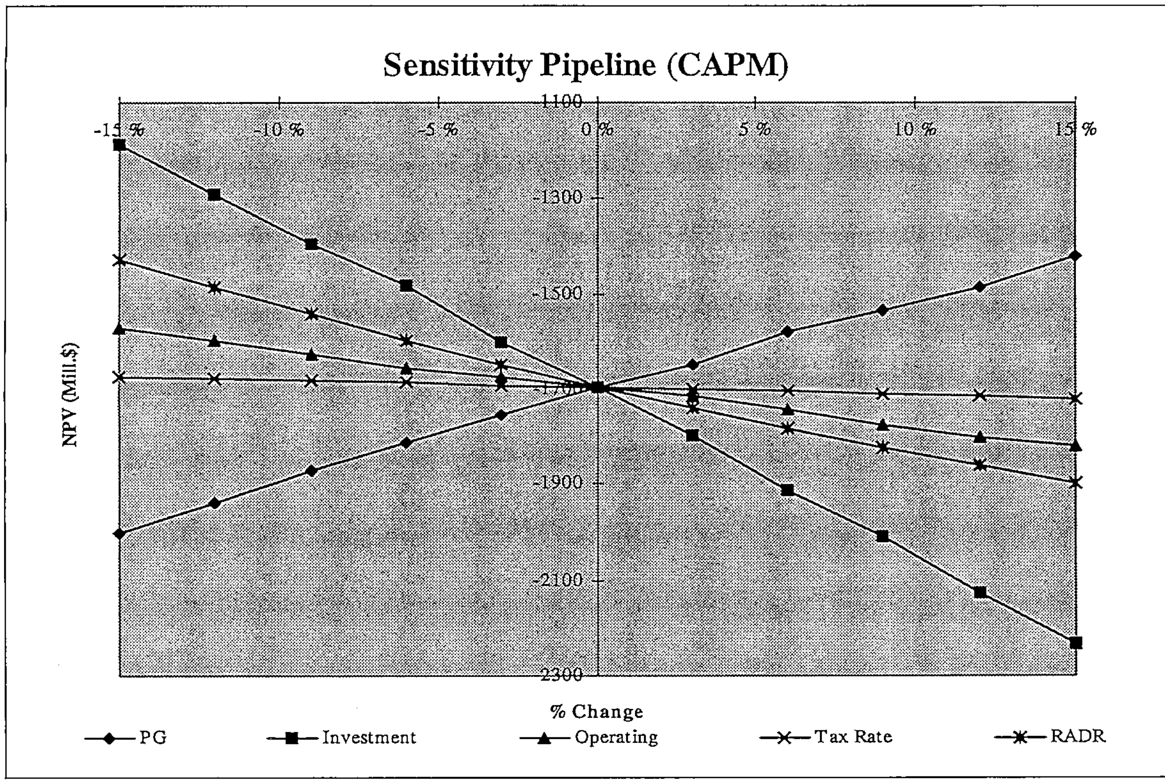
In this chapter a wide variety of sensitivity analyses will be presented for the CAPM approach. The net present values above provided by the CAPM are now correctly risk adjusted. It is however interesting to evaluate the project using both higher and lower estimates for the most important input data. In the graphics 6.2 through 6.4 the main results are presented in a graphical form.



Graphic Results 6-2 : Sensitivity LNG (CAPM)



Graphic Results 6-3 : Sensitivity NGH (CAPM)



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aGraphic Results 6-4 : Sensitivity Pipeline (CAPM)

The net present value is most sensitive to changes in variables which lines have the highest slope[16]. Thus, as can be seen in the diagrams, changes in the two variables price of gas and investment costs are the most significant. Changes in the tax rate leads to a corresponding and offsetting effect in the discount rate, resulting in little sensitivity for this variable. The tax rate None of the alternatives provides a positive project value for any input data ranging from -15% to +15% of the original estimates, all else equal. In the three following figures the sensitivity of the net present value for changes in the natural gas price (PG), systematic risk (β) and investment costs are presented. The systematic risk is interesting because the estimate for this variable is highly uncertain; it may vary over a wide range. In the figures a wider range for the input data is used, in order to provide break even values for all of these three variables.

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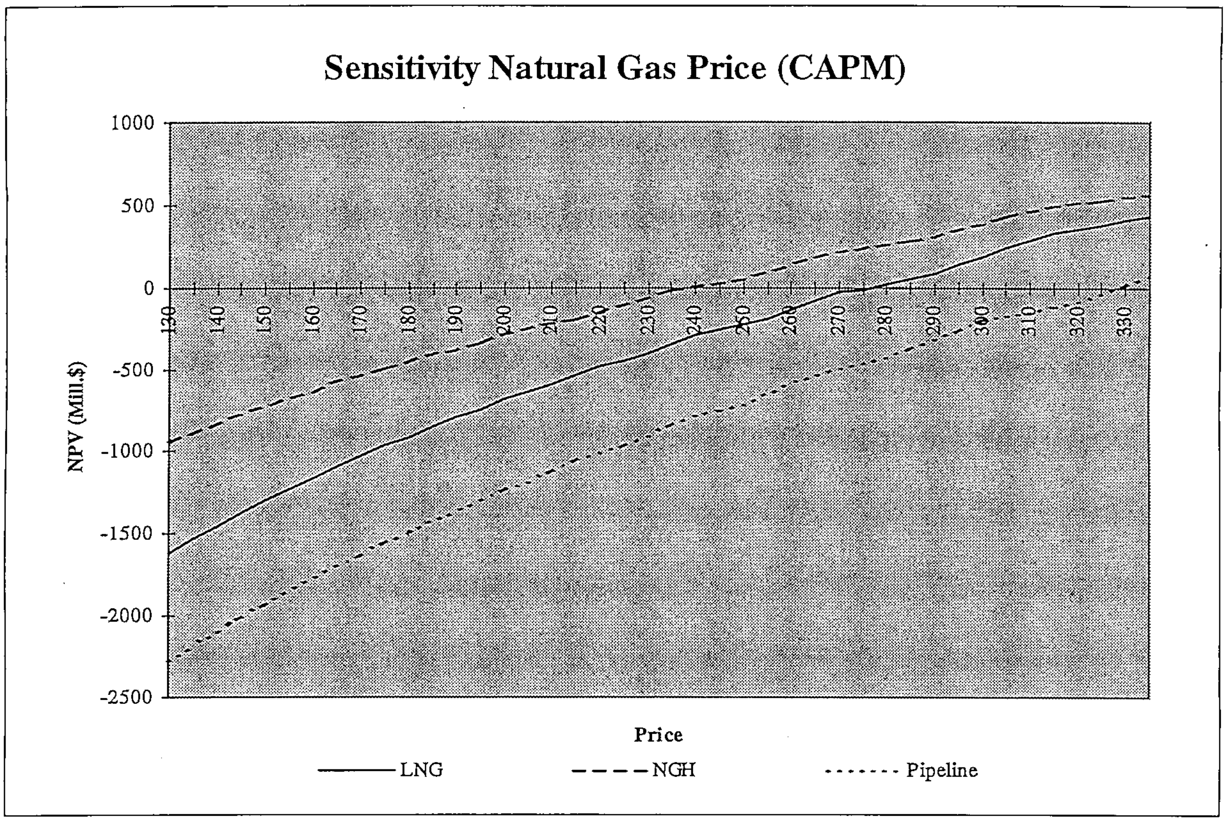
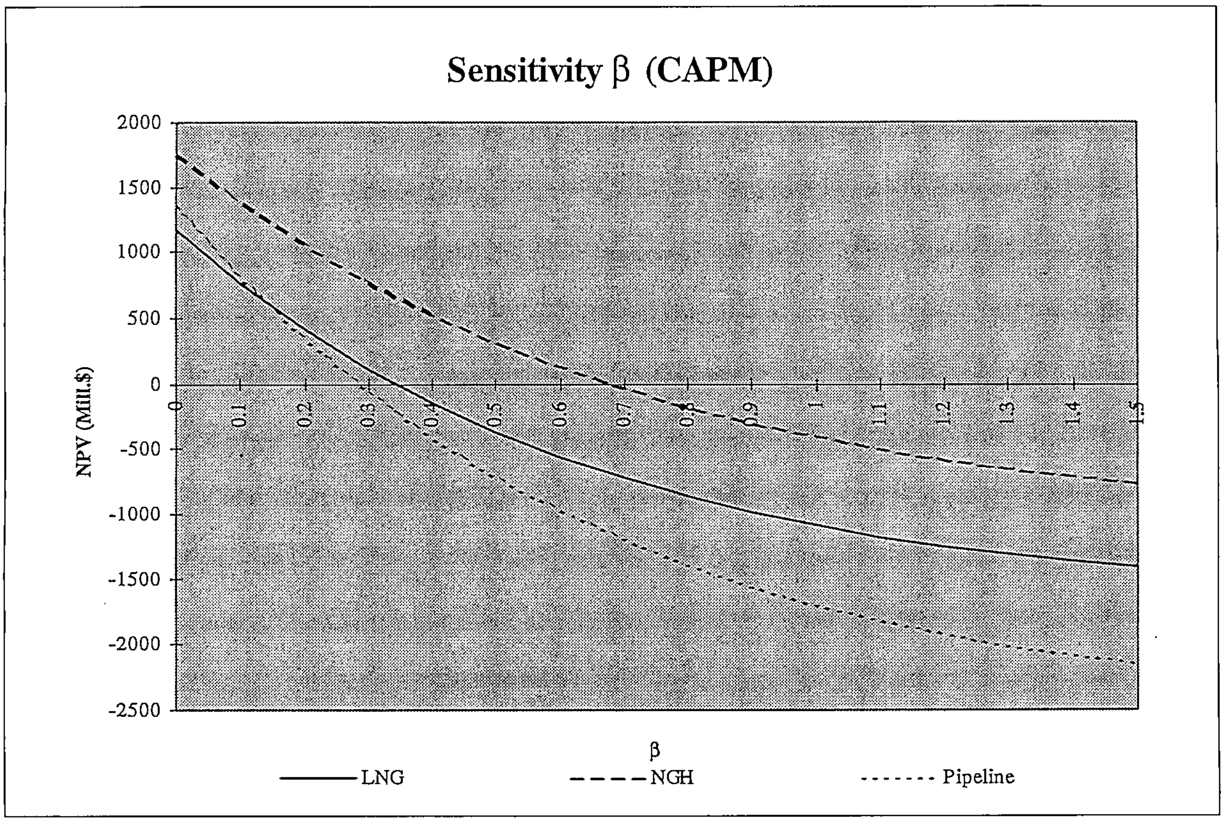
[16] Note that here the relationship between the price of natural gas and condensate has been taken into account, under the assumption of perfect correlation.



Graphic Results 6-5 (Sensitivity Natural Gas Price (CAPM)

As expected, in graphic result 6.5 the net present value of the projects increases as the natural gas price rise. The break even prices are found where the curves cross the x-axis at about 240, 275 and 328 USD per 1000 CM for the NGH, LNG and pipeline alternatives respectively. The break even prices all exceed by far the estimated price of 165 USD, which has the implication that the actual price must exceed the estimated one by 45%, 67% and 99% respectively for the projects to be profitable. It is regarded as highly unrealistic that the price will reach such a level, unless something unexpected (e.g. war) happens that dramatically alters any of the factors that influences the natural gas price. These high break even prices are a clear indication that none of the alternatives will make the Snøhvit field worth developing unless any of the other input data also changes the projects in a positive direction (e.g. cost reductions). Nevertheless, the analysis indicates that using the new NGH technology has the best chance for making such a marginal natural gas field profitable.



Graphic Results 6-6 (Sensitivity β)

As noted above the estimate of the systematic risk factor for any new project will always be difficult because each project will be unique in the sense that no project is an exact copy of a known existing project. It is therefore interesting to plot the net present values against a variety of β's as shown in graphic result 6.6. The graphs indicate a decreasing net present value for the project as the expected systematic risk increases within a reasonable limit[17]: the higher the project's risk, the higher the required rate of return and the lower the project's value. From the curves' crossing of the x-axis, it can be seen that if β is expected to be lower than approximately 0.67, 0.35 and 0.28 for the NGH, LNG and pipeline alternatives respectively, the project values are positive. Looking at β's for similar activities (e.g. oil and gas companies) does not indicate any possibility for such a low β, which again underlines the poor profitability of this project.

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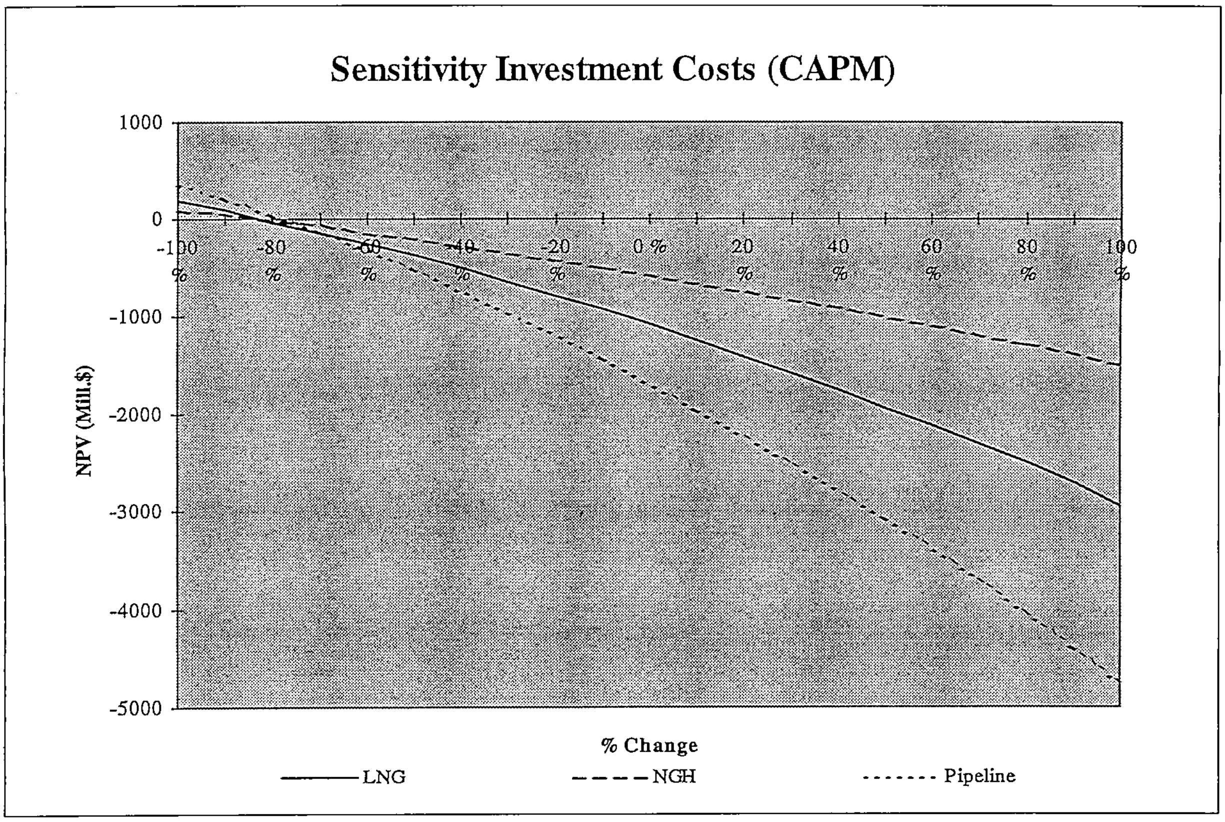
[17] For high values of β the NPV will eventually start to increase. In the extreme case, $\lim_{\beta \to \infty}$ (RADR) = $\infty \Rightarrow$ NPV $\to$ 0.

The figure also indicates how much the systematic risk of one project must change in order to overtake any of the other projects. β_{NGH} is the most uncertain of the estimated β's, but goal seeking calculations indicate that for this field, no matter how high β_{NGH} is ($\beta_{NGH} \rightarrow \infty$), the net present values of neither the LNG nor the pipeline alternative will ever exceed that of the NGH alternative. This is not a general result, but is caused in this special case by the structure of the investment costs and cash flows. As another example, β_{LNG} must decrease from 1 to about 0.65 for the LNG alternative to become more profitable than the NGH alternative (β_{NGH} = 1.2).

The investment costs are one of the main characteristics for each of the technologies, and it is thus interesting to compare the different alternatives for different values for this input as in graphic result 6.7 [18].



Graphic Results 6-7 Sensitivity Investment Costs (CAPM)

[18] Note that for both the Snøhvit and Shtokmanovskoya projects the investments in field facilities are not included in this analysis because they are not technology specific.

The figure indicates that even though much research still has to be carried out before the investment costs for the NGH technology is more certain than at present, the estimated costs can increase by as much as approximately 70% before the LNG technology becomes superior. Alternatively, the LNG technology must be improved to lower investment costs by approximately 40% before it can compete with NGH, but as noted in chapter 2.1.3 the LNG technology is believed to be rather matured and such large reductions in costs are therefore unrealistic. On the contrary, NGH could prove to be much more expensive than first expected.

The conclusion using CAPM is that the Snøhvit project should not be initiated using any technology under the present circumstances. It can also be concluded that the traditional pipeline technology is the least favourable due the combination of small volumes and large distances (see figure 2.3). These conclusions could have been drawn on an earlier stage in the analysis, but the main lesson from stems from the comparison of the technologies which has value in itself, independent of the project's negative profitability.

6.4 Evaluation using the ROA approach

Using the model described in chapter 5.3.2.1 including the development option which incorporates flexibility, the project value of the Snøhvit field can be calculated.

In order to calculate the equivalent time adjusted reservoir volume $A(\delta)$, the convenience yield in year 2000 has to be estimated. Assuming a convenience yield of 4% per year for natural gas (Ekern & Stensland, 1993) this yields (for a production period of 20 years and a yearly production ratio of 3.8, 4.1 and 4.2 BCM[19] for LNG, NGH and pipeline respectively):

$$A(\delta)_{LNG} = \int_t e^{-\delta t}\, q(t)dt = (1-e^{-0.04*20}/0.04)*3.8 \approx 53.0 \text{ BCM}$$

Thus, having 53 BCM available today is equivalent with having 3.8*20 = 76 BCM available equally distributed over the next 20 years. The corresponding estimates for $A(\delta)_{NGH}$ and $A(\delta)_{PIPE}$ are approximately 56.4 and 57.2 BCM.

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[19] Including both natural gas and condensate in natural gas equivalents

Discounting the cash flow of costs (excluding taxes) in table 6.3 through 6.5 with the riskless interest rate of 6.75%, yields present values of costs $K_{LNG} \approx 6269$, $K_{NGH} \approx 5169$ and $K_{PIPE} \approx 7157$ million USD. The traditional break even price for LNG can now easily be calculated as:

$$S_{BE} = K_{LNG}/A(\delta)_{LNG} \approx 6269/53 \approx 118 \text{ USD per } 1000 \text{ CM}$$

This implies that the project should not be initiated unless the price is at least 118 USD[20]. Using the same calculations for NGH and pipeline yields 92 and 125 USD per 1000 CM. Compared to the assumed natural gas price in year 2000 of about 134 USD per CM, all of the alternatives yield positive values. This is in stark contrast to the results just presented using the CAPM approach above. The differences can be explained by several factors. The main factor is that taxes are not included in the real option approach. Other factors are the differences in the discount used rates when calculating the present values of costs and income. In the CAPM approach both costs and income are discounted using a common required rate of return, while in the real option approach a differentiated discount rate is used. Again it should be emphasised that these two models are fundamentally different and that direct comparisons should be undertaken with great caution.

In order to calculate the critical exercise price for the option to develop, the parameter ε must be calculated first. This parameter is calculated using only parameters provided by the market and thus the same for all three technologies. Based on the nominal riskless interest rate of 6.75%, the real riskless interest rate is $r_r \approx 3.15\%$ and the formula yields

$$\varepsilon = [0.5 - \frac{0.0315 - 0.04}{0.245^2}] + \sqrt{[\frac{0.0315 - 0.04}{0.245^2} - 0.5]^2 + 2\frac{0.0315}{0.245^2}} \approx 1.9$$

The critical exercise price for the LNG alternative can then be calculated as follows:

[20] Note that the exercise price should be compared to the current price less 1.5% which is the drop in price due to introduction of additional natural gas from the Snøhvit field into the market (i.e. 134*0.985 = 132).

$$S_{AP} = \frac{1.9}{1.9 - 1} 118 \approx 257 \text{ USD per 1000 CM}$$

This implies that the project should not be initiated unless the price is at least 257 USD. This is a very unrealistic price in the near future, unless something unexpected happens. The same applies for the corresponding exercise prices of 199 and 272 for NGH and pipeline. Thus, the option pricing theory motivates a great deal of caution in initiating such a marginal project. The value of the LNG project can now be calculated as:

$$W_{AP} = 53 \cdot [\frac{257 - 118}{257^{1.9}}] \cdot 132^{1.9} \approx 2144 \text{ million USD}$$

The figures for NGH and pipeline are 2286 and 2212 million USD respectively. Thus, as expected, the value of the projects viewed as real options exceed the value of the projects with immediate development. The main results are presented in table 6.4 below.

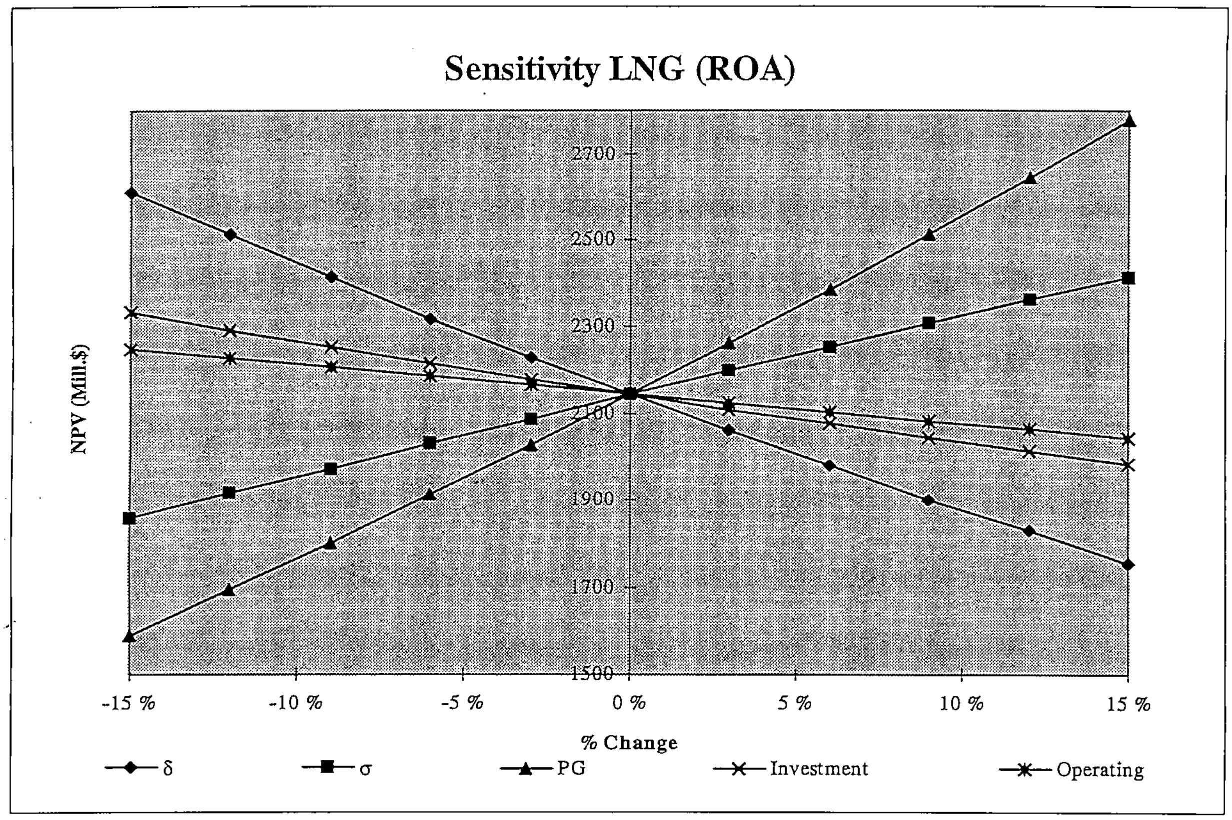
Summary Option Valuatio	*LNG*	*NGH*	*Pipeline*	
Break even price	118	92	125	USD
Project value excl. option	732	2286	411	Mill. USD
Critical exercise price	257	199	272	USD
Project value incl. option	2144	2839	2212	Mill. USD

Table 6-6 : Summary Option Valuation, Snøhvit

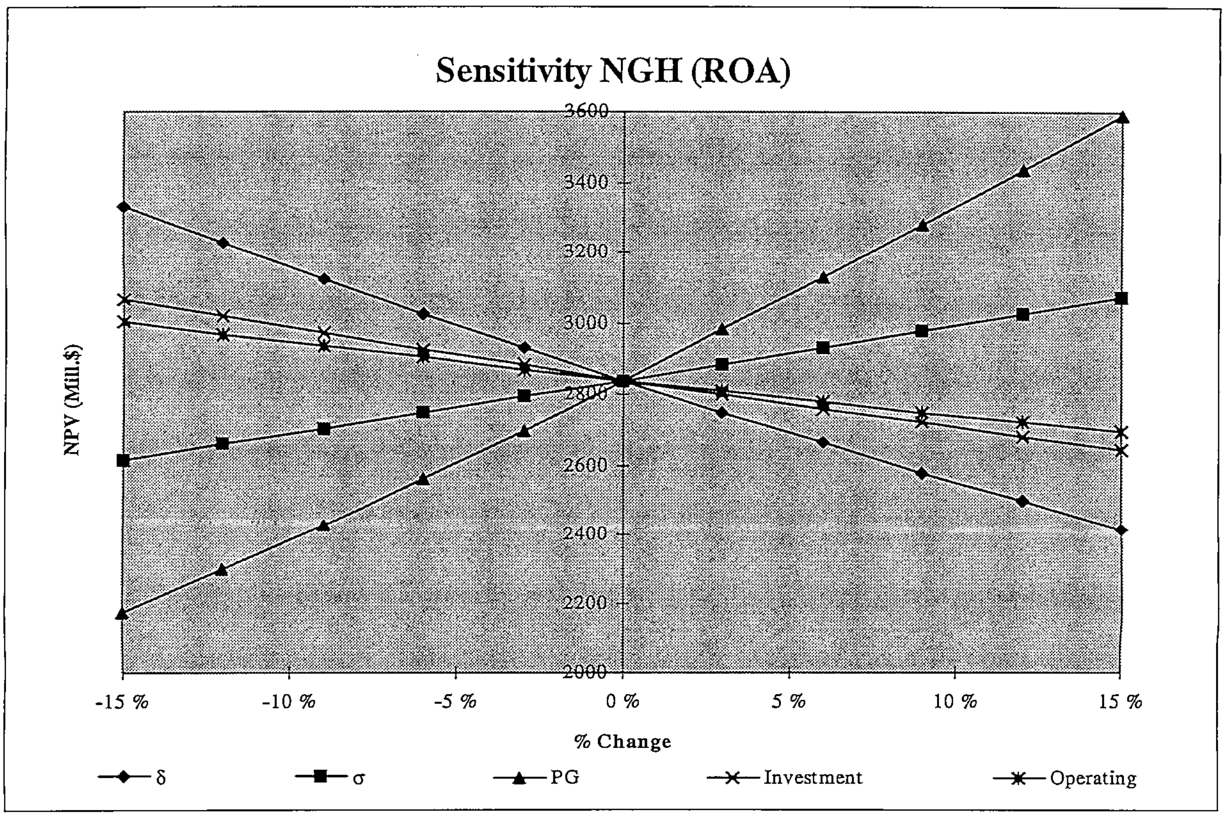
Note the puzzling fact that the pipeline value is superior to the LNG value when the real option is included. This can be explained by the relative importance of investment costs versus income. As the projects are deferred when the option to do so is introduced, price increases and investment costs thus become less important compared to income. Because income with the pipeline alternative is higher (less loss of gas in the chain), as income becomes more important relative to investment costs (higher for pipeline), the pipeline alternative will eventually become more profitable.

6.4.1 Sensitivity analysis

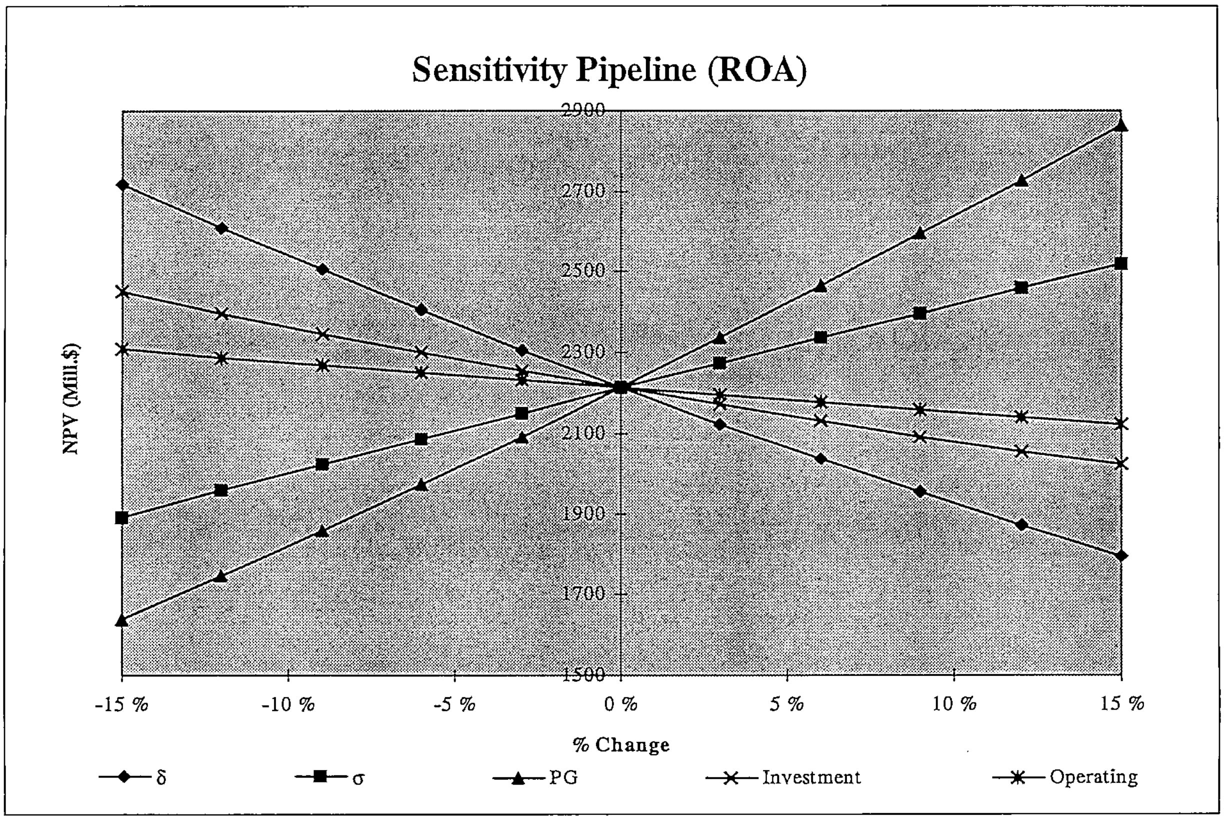
Similar diagrams as the ones for CAPM in graphic result 6.2 through 6.4 can be produced also for the real option approach. Diagrams are presented in graphic result 6.8 through 6.10.



Graphic Results 6-8 : Sensitivity LNG (ROA)

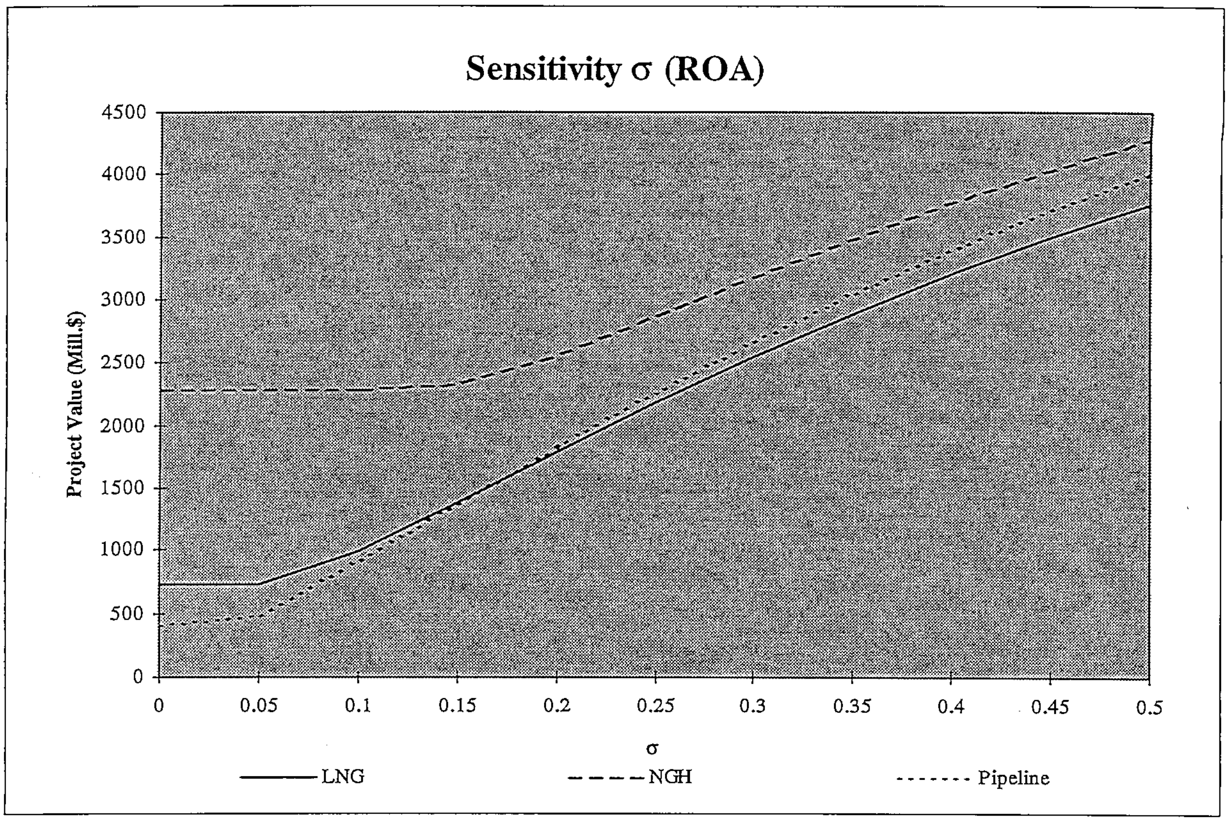


Graphic Results 6-9 : Sensitivity NGH (ROA)



Graphic Results 6-10 : Sensitivity Pipeline (ROA)

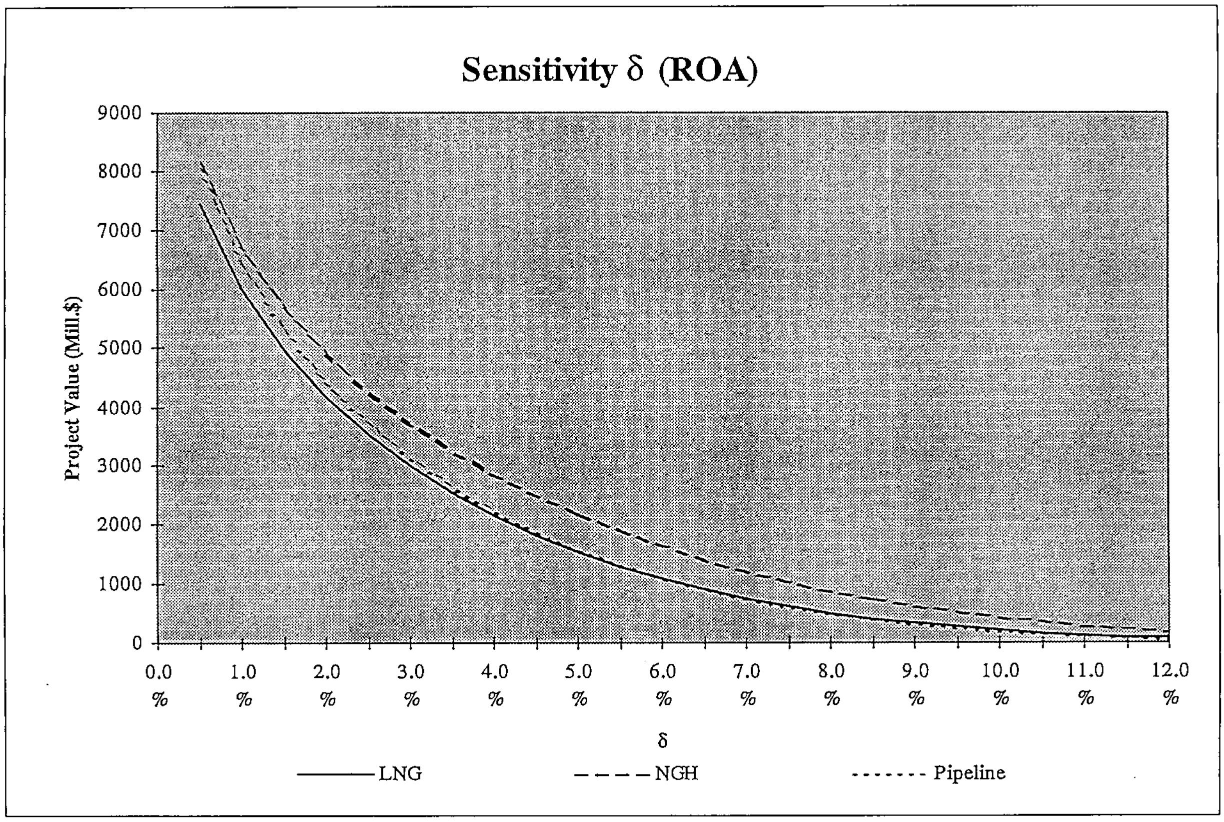
The first thing to notice is that the centres of the asterisks are now on the positive part of the y-axis, implying positive project values as indicated in chapter 6.1. Using the same reasoning as for the CAPM approach it can be seen that the most important input variables are the oil price volatility (σ), the convenience yield (δ), and the price of natural gas (PG). These are analysed further in the three figures below. The investment costs are also analysed, even though their relative importance has decreased for the reasons indicated above.



Graphic Results 6-11: Sensitivity σ (OA)

As shown in graphic result 6.11, the project values increase as the volatility of the oil price, measured by the standard deviation σ for relative price changes, increases. This may not seem very intuitive considering the CAPM approach where increased uncertainty implies a reduced project value. This effect is caused by the possibility to take advantage of a future increase in prices while the project will not be initiated following sufficient price decrease. The project value including the option will never fall below the value excluding the option. Also, if S_{AP} due to low volatility gets lower than the current price of natural gas, the project should be initiated immediately and the project value is the same as the value excluding the option. This explains the horizontal parts of the curves for low values of σ in 6.11.

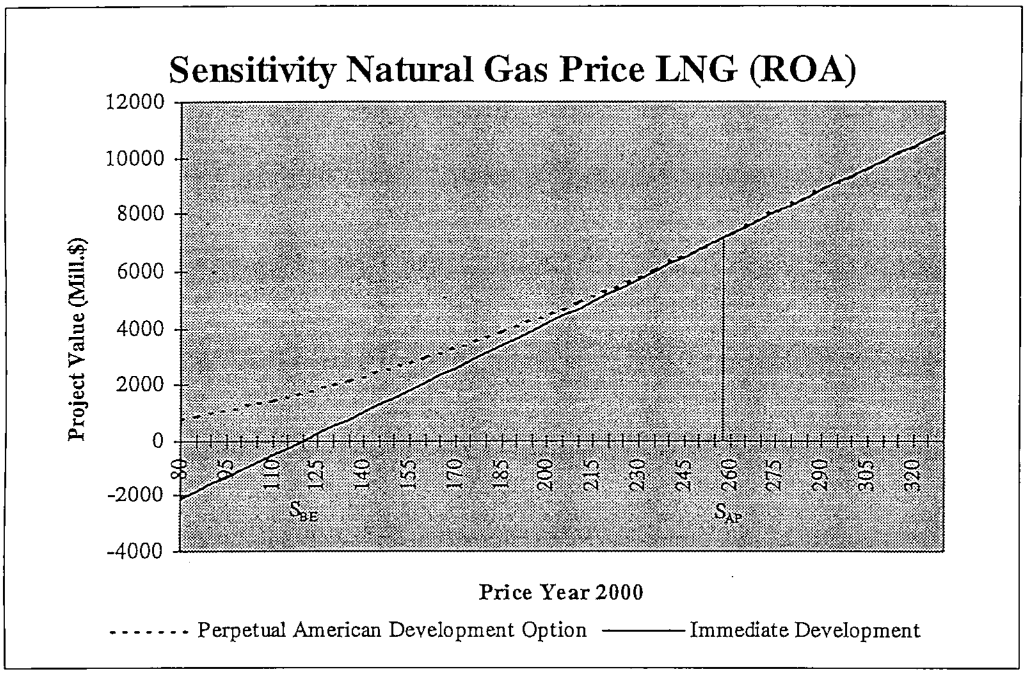
As can be seen in the figure, as the volatility changes, the ranking of the three alternatives may also change. This is a similar effect as noted above: as the volatility increases, the real option value of the income also increases and becomes more important than investment costs. As the volatility gets high, the parameter ε approaches 1, S_{AP} infinity and W_{AP} gets equal to $A(\delta)S(0)$. This implies that with a very high volatility income is the only factor that may differentiate the projects' values and the alternative with the lowest loss of gas through the chain becomes the most profitable (pipeline). However, for this field, volatilities that would rank pipeline above NGH are highly unlikely.



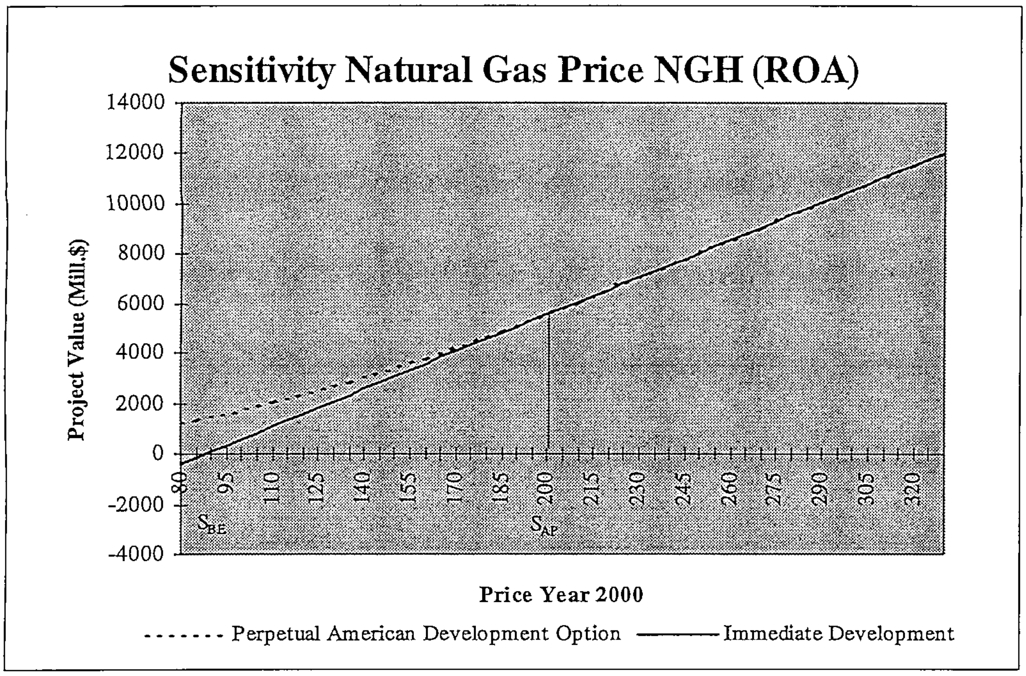
Graphic Results 6-12 : Sensitivity δ (POA)

As 6.12 shows, the project values are very sensitive to the convenience yield. The higher the convenience yield, the lower the project value, due to the fact that the opportunity cost of postponing the project increases. In this study the convenience yield for oil has been set somewhat arbitrarily to 4% and may thus vary in a wide range. If the convenience approaches zero, the project values will approach the total reservoir volume times the current price of natural gas. Thus, pipeline with the least loss of gas in its chain again becomes superior. The figure indicates that within a reasonable range for, NGH is the best alternative. If δ exceeds about 6% the LNG alternative is superior to pipeline, due to fact that the higher discounting of income has relatively more impact on the pipeline alternative.

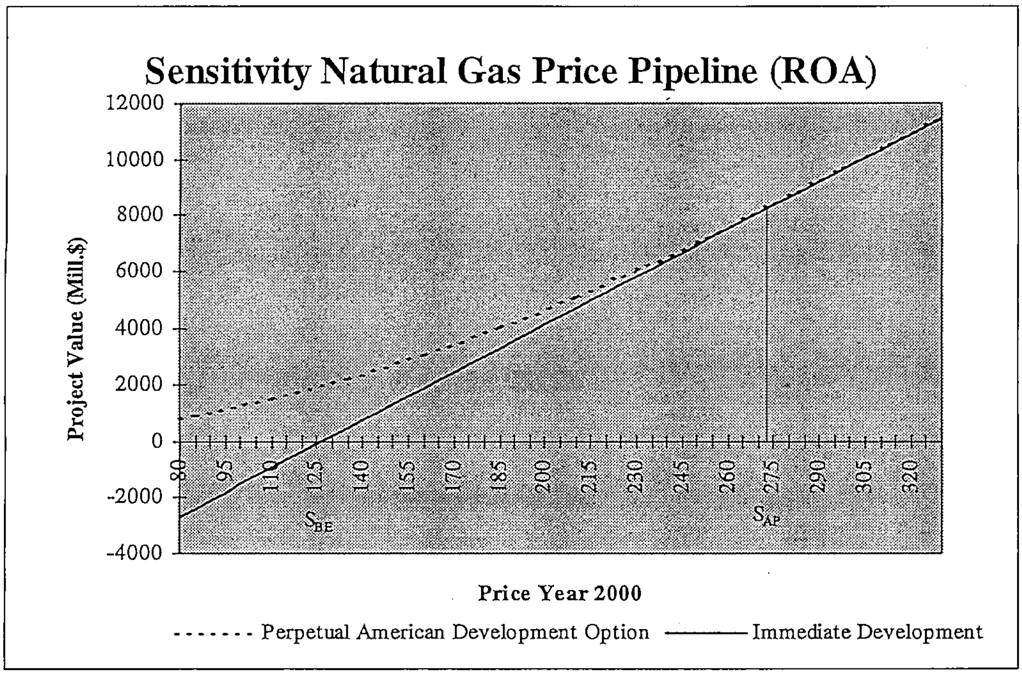
In graphic result 6.13 below, the project values are indicated for a wide variety of prices. Note that the project values with immediate development is not the same as the CAPM values due to the fundamentally different methodology and assumptions.



Graphic Results 6-13 Sensitivity of Natural Gas Price LNG (ROA)

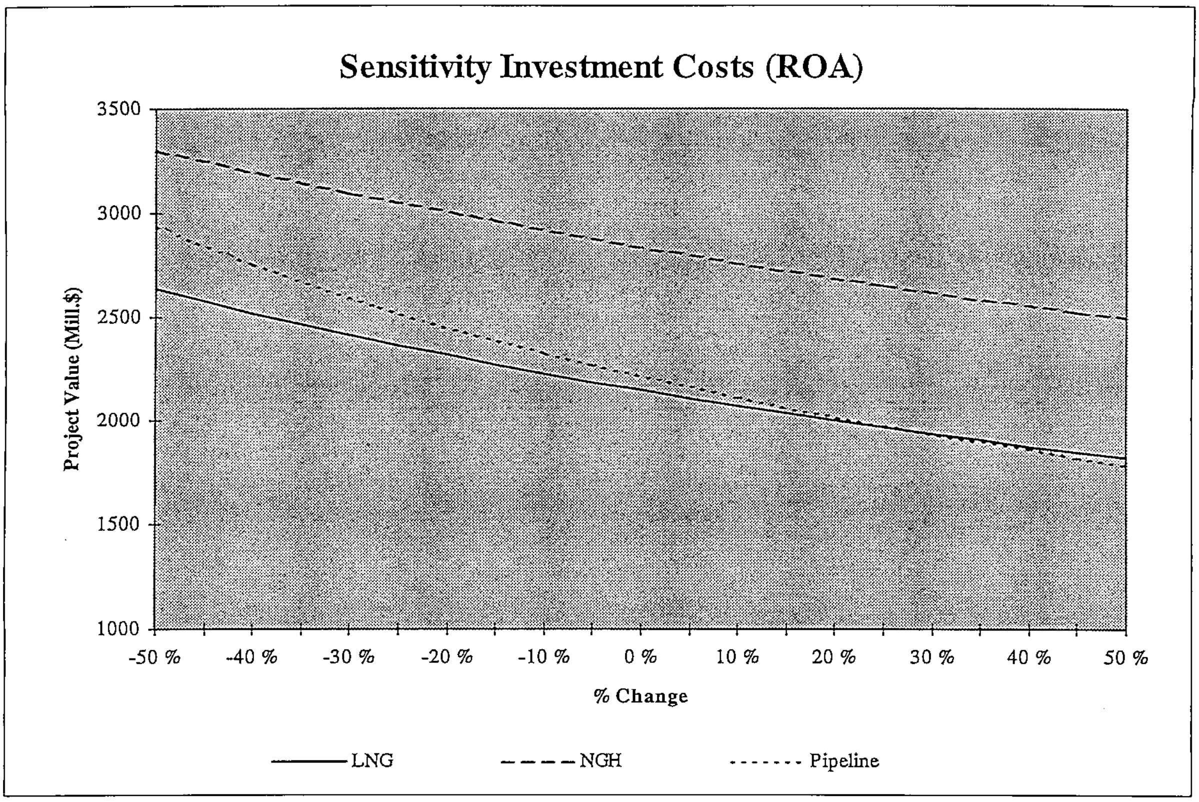


Graphic Results 6-14 : Sensitivity of Natural Gas Price NGH (ROA)



Graphic Results 6-15 : Sensitivity of Natural Gas Price Pipeline (ROA)

It can be observed from the graphic results that for all prices the value with the perpetual American development option is always higher or equal to the project value with immediate development. From the figure the break even price of immediate development is found where the curve for this alternative crosses the x-axis. Correspondingly, the exercise price with the development option is found at the point where the two curves merge. The reason that the curves merge is that for $S_{AP} \leq S(0)$ the project would be initiated immediately implying no value of the development option itself.



Graphic Results 6-16 : Sensitivity Investment Cost (ROA).

As the corresponding figure for the CAPM approach indicated, large unrealistic changes in investment costs are necessary to change the ranking of the two shipping technologies. This figure indicates an even more extreme result, which again can be attributed to the decreased importance of investment costs when the option is included.

The conclusion using ROA is that the value of the Snøhvit project is positive for all technologies, with NGH ranking highest. However, the project should not be initiated unless the price exceeds a certain level. This level is rather high, and the ROA thus concludes that waiting, and not initiating this project immediately, is the optimal strategy.

7. INVESTMENT ANALYSIS OF THE SHTOKMANOVSKOYE PROJECT

7.1 Characteristics and main results[21]

The supergiant natural gas field Shtokmanovskoye is close to the disputed border between Norway and Russia in the Barents Sea, and so it is probable that the field development will take place with the co-operation of the Norwegian entities. The field is located Northeast of Murmansk, which is below the southern limit for pack ice. It is also a long way from an export point. Development is said to be dependent on the establishment of new natural gas markets, and will require considerable investment before it is ready to produce, since a pipeline would have to be built to the Murmansk area. Most of the natural gas is likely to be sold to customers in Europe. Total reserves are in the order of 3000 BCM, but in this study it is assumed that no more than 600 BCM will be extracted over a period of 20 years. Based on figures from Norsk Hydro, the investment costs for the offshore facilities and pipeline for transportation to the onshore terminal totals about 6800 million USD (approximately 60% pipeline investment). There is a need for 13 LNG carriers and 32 NGH carriers to transport the yearly volume to the market.

The main characteristics of the field is presented in table 7.1. The main results of the analysis for the Shtokmanovskoye field is presented below.

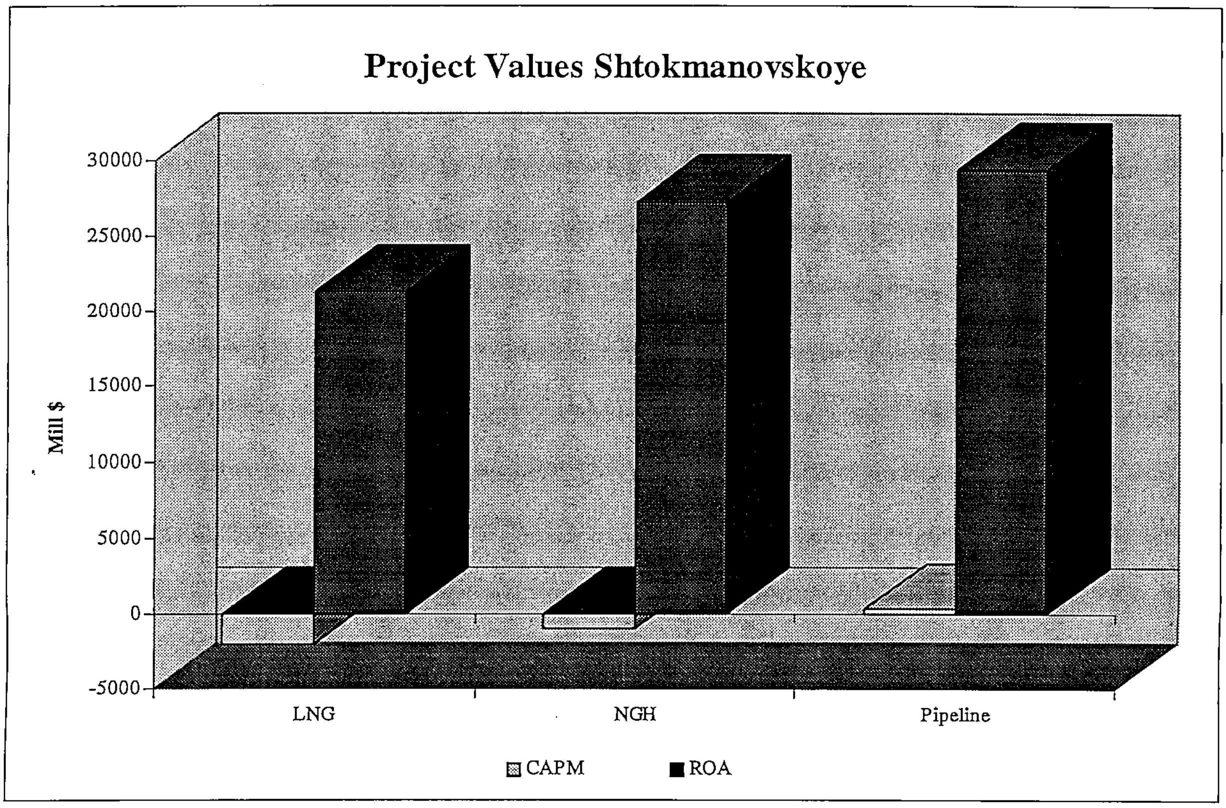
Total reserves natural gas	3000 BCM
Total reserves condensate	40 Mill Mt.
Production rate natural gas	30 BCM/Year
Production rate condensate	2 Mill Mt./Year
Location of field	600 KM offshore
Location of onshore facilities	Murmansk area
Operator	Rosshelf
Expected price natural gas (2005)	165 USD per 1000 CM
Expected price natural gas (2000)	134 USD per 1000 CM

Table 7-1: Main characteristics of the Shtokmanovskoye field

[21] All figures are presented in nominal terms and present values are calculated for year 2000 (project start-up).

Project Values	*CAPM*	*ROA*	
LNG	-2073	21296	Mill. USD
NGH	-1042	27271	Mill. USD
Pipeline	262	29408	Mill. USD

Table 7-2 : Main results of the Shtokmanovskoye investment analyses



Graphic Results 7-1 : Project Values Shtokmanovskoye

From the table and graphics above it can been seen that the CAPM approach has resulted in negative project values for both of the shipping modes, but slightly positive for the pipeline alternative. A decision maker should thus initiate the project using pipeline technology. The real options model indicates high positive project values for all technologies. It is still important to keep in mind the exclusion of taxes in the real options approach when comparing the models. To realise this value it is required to wait until the natural gas price reach a critical price. For this project, these prices are realistic compared to the current price of natural gas. The following sections contain a more detailed presentation and explanation of the results and calculations. In addition, the impact of changes in critical input data will be presented using a wide variety of sensitivity analyses.

7.2 Cash flows

Based on the data in chapter 2, the tables 7.3 through 7.5 present the cash flows for the three different transportation alternatives.[22]

[22] In addition to the data in chapter 2, other main assumptions for calculating the cash flow is presented in appendix xx

Cash flow Shtockmanovskaya LNG-alternative

(All figures in mill. $)

Year	Revenue		Capital costs					Licence		Operating costs					
	Condensate	Gas	Offshore	Liquification	Ships	Regasification	Working capital	Area fee	CO2-fee	Offshore	Liquification	Ships	Regasification	Taxes	Cash flow
2000			-1612.6	-932.9				-1.4							-2546.9
2001			-1669.1	-965.5				-1.4							-2636.0
2002			-1727.5	-999.3				-1.4							-2728.2
2003			-1788.0	-1034.3	-2353.8	-1246.3		-1.4							-6423.7
2004			-1850.5	-1070.5	-2436.2	-1290.0		-1.4							-6648.5
2005	409.1	3989.2					-219.9	-1.4	-528.0	-217.0	-221.6	-126.9	-66.8		3016.7
2006	423.4	4128.8						-2.5	-528.0	-224.6	-229.4	-131.3	-69.1		3367.3
2007	438.2	4273.3						-2.7	-528.0	-232.5	-237.4	-135.9	-71.5		3503.5
2008	453.5	4422.9						-3.4	-528.0	-240.6	-245.7	-140.6	-74.0		3644.1
2009	469.4	4577.7						-4.1	-528.0	-249.0	-254.3	-145.6	-76.6		3789.5
2010	485.9	4737.9						-6.8	-528.0	-257.7	-263.2	-150.7	-79.3		3938.1
2011	502.9	4903.7						-9.6	-528.0	-266.8	-272.4	-155.9	-82.1	-442.7	3649.0
2012	520.5	5075.4						-12.4	-528.0	-276.1	-281.9	-161.4	-84.9	-2655.4	1595.7
2013	538.7	5253.0						-15.2	-528.0	-285.8	-291.8	-167.0	-87.9	-3488.4	927.5
2014	557.5	5436.9						-17.9	-528.0	-295.8	-302.0	-172.9	-91.0	-3623.2	963.6
2015	577.0	5627.2						-20.6	-528.0	-306.1	-312.6	-178.9	-94.2	-3762.8	1000.9
2016	597.2	5824.1						-41.1	-528.0	-316.8	-323.5	-185.2	-97.5	-3893.5	1035.7
2017	618.1	6028.0						-41.1	-528.0	-327.9	-334.8	-191.7	-100.9	-4045.3	1076.3
2018	639.8	6238.9						-41.1	-528.0	-339.4	-346.6	-198.4	-104.4	-4202.4	1118.4
2019	662.2	6457.3						-41.1	-528.0	-351.3	-358.7	-205.3	-108.1	-4365.0	1161.9
2020	685.3	6683.3						-41.1	-528.0	-363.6	-371.2	-212.5	-111.8	-4533.3	1206.9
2021	709.3	6917.2						-41.1	-528.0	-376.3	-384.2	-220.0	-115.8	-4707.6	1253.6
2022	734.2	7159.3						-41.1	-528.0	-389.5	-397.7	-227.7	-119.8	-4887.9	1301.8
2023	759.8	7409.9						-41.1	-528.0	-403.1	-411.6	-235.6	-124.0	-5074.5	1351.8
2024	786.4	7669.2			88.1		596.4	-41.1	-528.0	-417.2	-426.0	-243.9	-128.3	-5272.2	2083.4

Cash flow Shtockmanovskoya NGH-alternative

(All figures in mill. $)

Year	Revenue		Capital costs					Licence		Operating costs					
	Conden-sate	Gas	Offshore	Refrige-ration	Ships	Melting	Working capital	Area fee	CO2-fee	Offshore	Refrige-ration	Ships	Regasifi-cation	Taxes	Cash flow
2000			-1612.6	-645.9				-1.4							-2259.9
2001			-1669.1	-668.5				-1.4							-2339.0
2002			-1727.5	-691.9				-1.4							-2420.8
2003			-1788.0	-716.1	-2106.9	-716.1		-1.4							-5328.5
2004			-1850.5	-741.2	-2180.6	-741.2		-1.4							-5514.9
2005	409.1	4292.4					-235.1	-1.4	-268.2	-217.0	-153.4	-313.7	-38.4		3474.5
2006	423.4	4442.7						-2.5	-268.2	-224.6	-158.8	-324.7	-39.7		3847.6
2007	438.2	4598.2						-2.7	-268.2	-232.5	-164.4	-336.0	-41.1		3991.6
2008	453.5	4759.1						-3.4	-268.2	-240.6	-170.1	-347.8	-42.5		4140.1
2009	469.4	4925.7						-4.1	-268.2	-249.0	-176.1	-360.0	-44.0		4293.8
2010	485.9	5098.1						-6.8	-268.2	-257.7	-182.2	-372.6	-45.6	-1853.1	2597.9
2011	502.9	5276.5						-9.6	-268.2	-266.8	-188.6	-385.6	-47.2	-3598.5	1015.0
2012	520.5	5461.2						-12.4	-268.2	-276.1	-195.2	-399.1	-48.8	-3729.9	1052.0
2013	538.7	5652.3						-15.2	-268.2	-285.8	-202.0	-413.1	-50.5	-3865.9	1090.4
2014	557.5	5850.2						-17.9	-268.2	-295.8	-209.1	-427.5	-52.3	-4006.8	1130.1
2015	577.0	6054.9						-20.6	-268.2	-306.1	-216.4	-442.5	-54.1	-4152.7	1171.3
2016	597.2	6266.8						-41.1	-268.2	-316.8	-224.0	-458.0	-56.0	-4290.0	1210.0
2017	618.1	6486.2						-41.1	-268.2	-327.9	-231.8	-474.0	-58.0	-4448.6	1254.7
2018	639.8	6713.2						-41.1	-268.2	-339.4	-240.0	-490.6	-60.0	-4612.7	1301.0
2019	662.2	6948.2						-41.1	-268.2	-351.3	-248.4	-507.8	-62.1	-4782.6	1348.9
2020	685.3	7191.3						-41.1	-268.2	-363.6	-257.0	-525.5	-64.3	-4958.5	1398.5
2021	709.3	7443.0						-41.1	-268.2	-376.3	-266.0	-543.9	-66.5	-5140.5	1449.9
2022	734.2	7703.6						-41.1	-268.2	-389.5	-275.4	-563.0	-68.8	-5328.8	1503.0
2023	759.8	7973.2						-41.1	-268.2	-403.1	-285.0	-582.7	-71.2	-5523.8	1558.0
2024	786.4	8252.2			846.1		637.5	-41.1	-268.2	-417.2	-295.0	-603.1	-73.7	-6385.5	2438.5

Cash flow Shtockmanovskaya Pipeline-alternative

(All figures in mill. $)

Year	Revenue		Capital costs					Licence		Operating costs					
	Condensate	Gas	Offshore	Separation	Pipeline	Treatment	Working capital	Area fee	CO2-fee	Offshore	Separation	Pipeline	Treatment	Taxes	Cash flow
2000			-1612.6	-554.3	-950.1			-1.4							-3118.4
2001			-1669.1	-573.7	-983.4			-1.4							-3227.5
2002			-1727.5	-593.7	-1017.8			-1.4							-3340.4
2003			-1788.0	-614.5	-1053.4	-158.9		-1.4							-3616.1
2004			-1850.5	-636.0	-1090.3	-164.4		-1.4							-3742.7
2005	409.1	4364.2					-238.7	-1.4	-229.8	-217.0	-65.8	-338.5	-1.7		3680.3
2006	423.4	4517.0						-2.5	-229.8	-224.6	-68.1	-350.4	-1.8		4063.1
2007	438.2	4675.1						-2.7	-229.8	-232.5	-70.5	-362.7	-1.8		4213.3
2008	453.5	4838.7						-3.4	-229.8	-240.6	-73.0	-375.3	-1.9		4368.2
2009	469.4	5008.1						-4.1	-229.8	-249.0	-75.5	-388.5	-2.0	-561.2	3967.4
2010	485.9	5183.3						-6.8	-229.8	-257.7	-78.2	-402.1	-2.0	-3127.9	1564.6
2011	502.9	5364.7						-9.6	-229.8	-266.8	-80.9	-416.2	-2.1	-3792.5	1069.7
2012	520.5	5552.5						-12.4	-229.8	-276.1	-83.8	-430.7	-2.2	-3929.7	1108.4
2013	538.7	5746.9						-15.2	-229.8	-285.8	-86.7	-445.8	-2.2	-4071.6	1148.4
2014	557.5	5948.0						-17.9	-229.8	-295.8	-89.7	-461.4	-2.3	-4218.7	1189.9
2015	577.0	6156.2						-20.6	-229.8	-306.1	-92.9	-477.5	-2.4	-4371.0	1232.8
2016	597.2	6371.6						-41.1	-229.8	-316.8	-96.1	-494.3	-2.5	-4514.8	1273.4
2017	618.1	6594.6						-41.1	-229.8	-327.9	-99.5	-511.6	-2.6	-4680.2	1320.1
2018	639.8	6825.5						-41.1	-229.8	-339.4	-103.0	-529.5	-2.7	-4851.4	1368.4
2019	662.2	7064.4						-41.1	-229.8	-351.3	-106.6	-548.0	-2.8	-5028.6	1418.3
2020	685.3	7311.6						-41.1	-229.8	-363.6	-110.3	-567.2	-2.9	-5212.0	1470.1
2021	709.3	7567.5						-41.1	-229.8	-376.3	-114.1	-587.0	-3.0	-5401.8	1523.6
2022	734.2	7832.4						-41.1	-229.8	-389.5	-118.1	-607.6	-3.1	-5598.3	1579.0
2023	759.8	8106.5						-41.1	-229.8	-403.1	-122.3	-628.8	-3.2	-5801.6	1636.4
2024	786.4	8390.2					647.2	-41.1	-229.8	-417.2	-126.6	-650.9	-3.3	-6012.1	2343.0

7.3 Evaluation using the CAPM approach

As for the Snøhvit field, the systematic risk factor for each technology has to be calculated. The other input data to formula 5.4 are assumed to be identical to the ones of the Snøhvit project. The β's for the Snøhvit project can be used as a basis also for the Shtokmanovskoye project, but due to geographical, political and other risk relevant differences between Norway and Russia, they have to be adjusted upwards somewhat. This also seems to a generally accepted rule for investors. Table 7.6 below indicates an empirical survey among American companies, where the required rate of return (ROR) is the total of the riskless interest rate and several risk factors (Oil & Gas Journal, 1993). As can be seen, the risk factors are consequently assumed to be higher in Russia than in Western Europe.

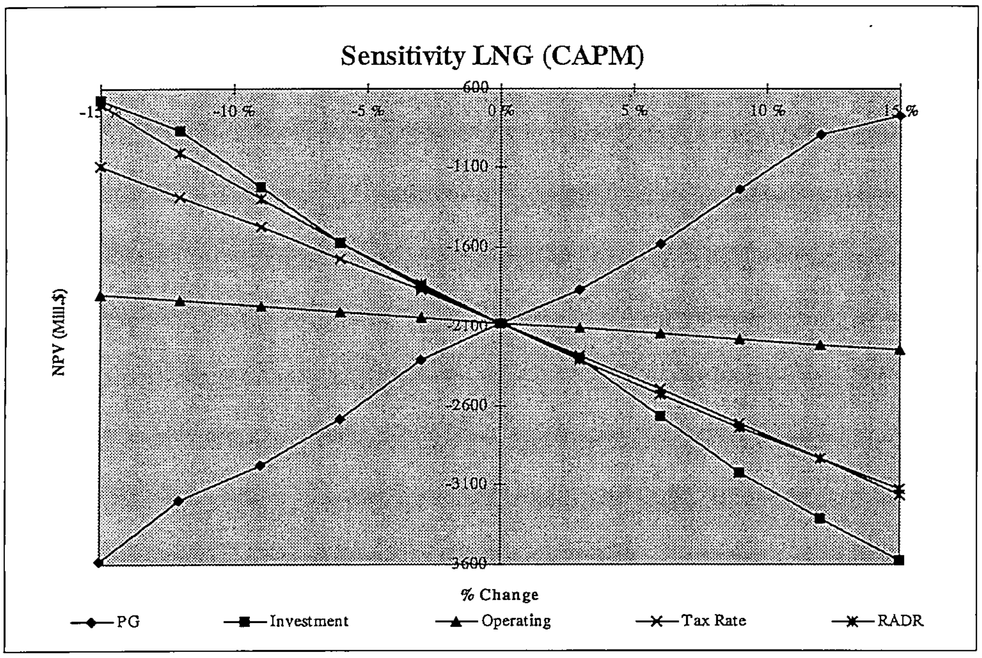
Required ROR	Western Europe	Russia
Political risk	3%	>3%
Geographical risk	2%	>3%
Currency risk	2%	>3%
Commercial risk	4-5%	>6%
Financing risk	2-3%	>3%
Investment risk	2-3%	>3%
Long term inflatior	4-5%	>4%
Real ROR	3-4%	>3-4%
Total	22-27%	>28%

Table 7-6 : Required ROR

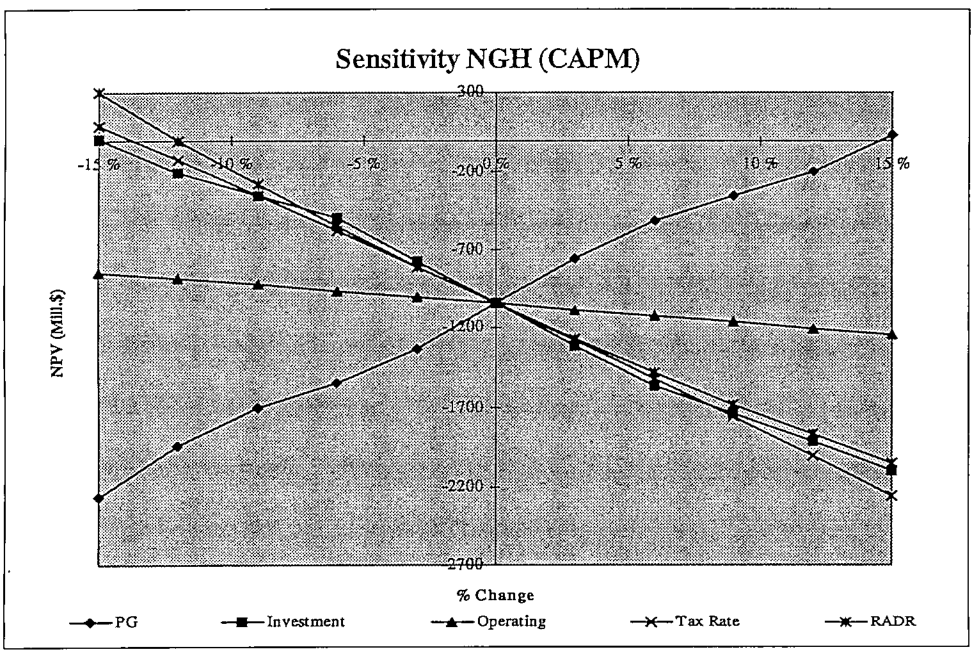
In this study the systematic risk factors for Shtokmanovskoye are assumed to be 1.1, 1.3 and 1.1 for the LNG, NGH and pipeline technologies respectively. This yields risk adjusted discount rates of 10.4, 12.0 and 10.4%. Compared to the empirical study referred to above, these may seem rather low, even though the relative difference between these RADRs and the ones for Snøhvit are of the same magnitude as in the table. The RORs in the table seems rather high, and when compared to the standard discount rate of 7% used on public projects in Norway, the rates calculated in this study seems more feasible.

7.3.1 Sensitivity analysis

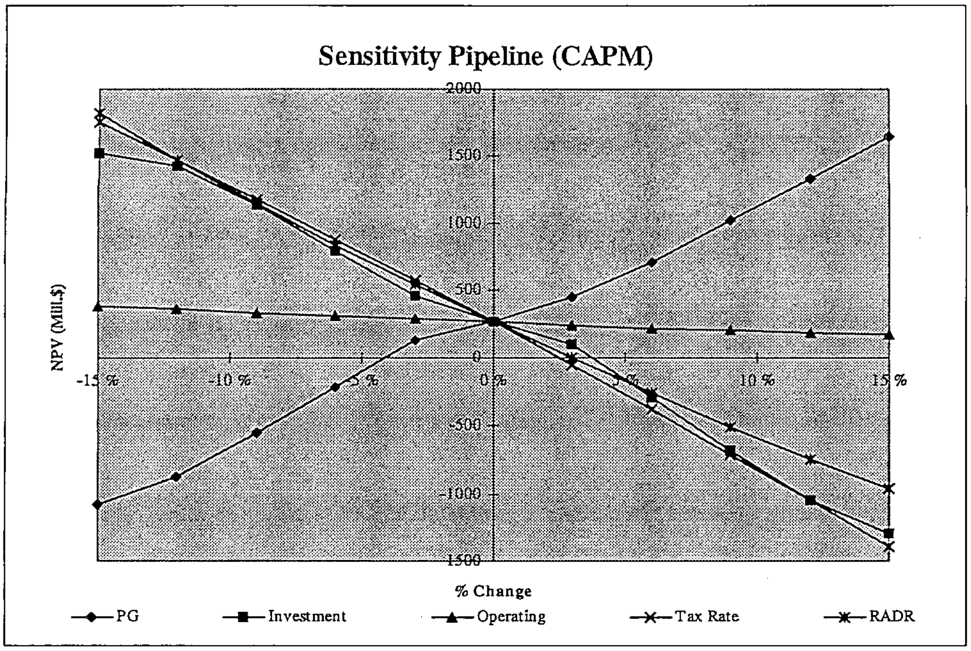
In this chapter similar sensitivity analysis as for the Snøhvit project will be presented. This is particularly interesting in order to check the influence of size (economies of scale) of natural gas projects, transportation distance and differences in economical conditions. In the graphics 7.2 through 7.4 the main results are presented.



Graphic Results 7-2 : Sensitivity LNG (CAPM)

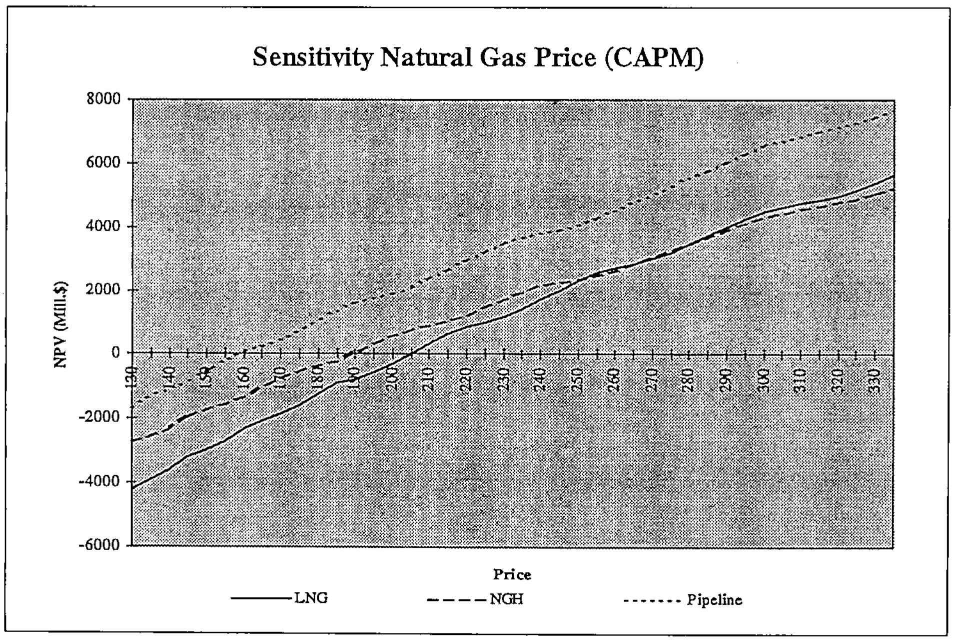


Graphic Results 7-3 : Sensitivity NGH (CAPM)



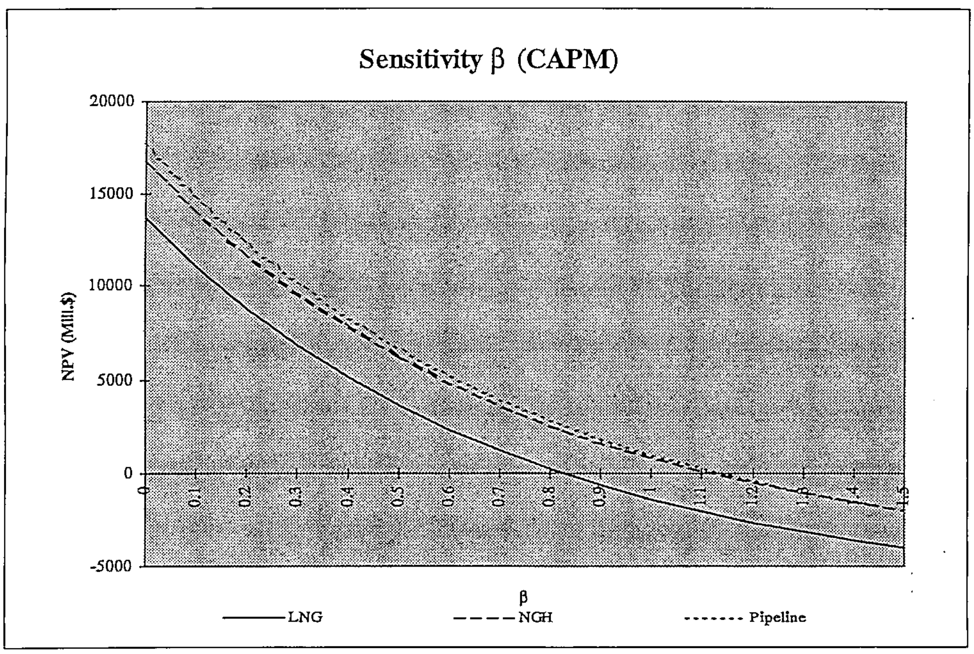
Graphic Results 7-4 : Sensitivity Pipeline (CAPM)

As can be seen, the same input data as for the Snøhvit field are the most important. However, some differences have appeared for this much larger project. The net present values are clearly more sensitive to changes in the tax rate. This can be explained by the economies of scale whereby costs are of less importance relative to income than for the Snøhvit project



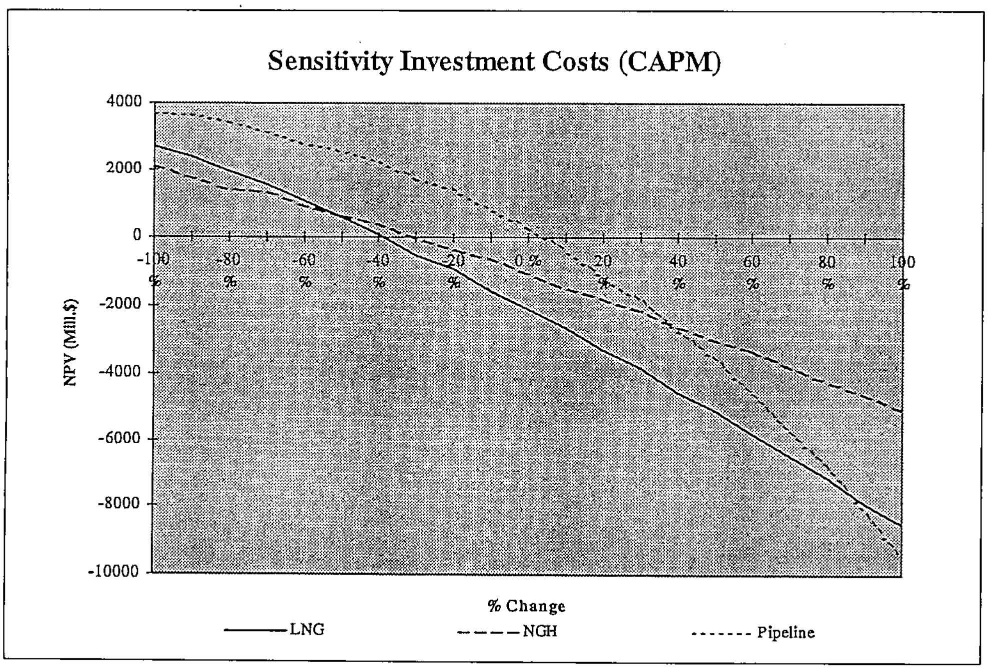
Graphic Results 7-5 Sensitivity Natural Gas Price (CAPM)

This results (7.4) in a relative increase in taxable income, and increased influence of taxes. Political economics, e.g. granting tax shields, will thus have a greater effect on the willingness to participate in this project than it would have had in the Snøhvit case.
From comparing graphic result 7.5 and 6.5 it can be seen that the break even prices for the Shtokmanovskoye projects are much lower than for the Snøhvit field. For this project the pipeline technology is the most profitable one, and thus also the one with the lowest break even price at 157 which makes it slightly profitable. The corresponding figures for NGH and LNG are still outside the reasonable range of prices. Going from Snøhvit to Shtokmanovskoye has the result that pipeline is superior to both shipping modes, which can be attributed to the increased volume. The curves of the NGH and LNG alternatives intersects at a high price. Normally, NGH would be the most favourable shipping mode the higher the prices due to less loss of natural gas in the chain (see chapter 6.4.1), but the higher risk adjusted discount rate for NGH offsets this effect. The curves of the pipeline and LNG alternative does not intersect in the diagram due to their equal discount rates.



Graphic Results 7-6 : Sensitivity β (CAPM)

As graphic result 7.6 indicates only small reductions in risk for the NGH alternative relative to pipeline will make NGH a better solution for Shtokmanovskoye. Relative reductions of this kind can occur in two ways. Firstly, further research and development on NGH may reduce the technology specific uncertainty of this alternative. However, this will normally only result in a $\beta_{NGH} \geq \beta_{PIPE}$. Secondly, a further reduction in β_{NGH} relative to β_{PIPE} can occur if the systematic risk of the geographical areas in which the two technologies operates differs. Such a difference may occur because NGH operates in a rather homogenous environment offshore, while pipelines will have to cross several borders in the former Soviet Union and is thus more vulnerable to political turmoil. Another important issue that has to be considered in this context, is the fact that Russia already depends a 100% on their pipeline infrastructure to deliver natural gas to their customers. Including shipping transportation will create more differentiated, flexible and reliable delivery strategy. Because the pipeline and NGH alternatives are relatively equal in profitability, a small incentive from the state could induce the natural gas companies to chose NGH as their transportation mode. LNG can not compete with either of the technologies, unless the technology specific uncertainty of NGH increases significantly.



Graphic Results 7-7 : Sensitivity Investment Cost (CAPM)

As mentioned above, the project values for this project are less sensitive to changes in investment costs. However, the ranking of the alternative technologies are somewhat more sensitive for this field size. Graphic result 7.7 presents the changes in investment costs. It can be seen that a simultaneous percentage reduction of all investment costs of about 55 % will make LNG a better alternative than NGH. Pipeline however, will remain the superior technology for all simultaneous decreases in investment costs, and is overtaken by NGH with an increase of about 35 %. These results are due to the differences in the magnitude of the initial investment costs: pipeline has the highest investment costs, and will thus profit the most from an overall percentage decrease in investment costs and vice versa. When evaluating the NGH technology it is perhaps more interesting to study how changes in the relative magnitude of investment costs between the technologies will effect the ranking. A drop in the LNG investment costs of about 20 % or an increase in the NGH investment costs of about 30 % will make LNG a better alternative than NGH. Correspondingly, a drop of 35% in the NGH investment costs or an increase in the pipeline investment costs of about 20% will make NGH the better alternative.

The conclusion using CAPM is that the Shtokmanovskoye project should be initiated using pipeline technology under the current assumptions. However, small changes in input data could make the NGH alternative profitable, and if this is the case, political and strategic considerations should influence the choice of technology. Under certain circumstances this would imply that NGH is the most feasible alternative.

7.4 Evaluation using the ROA approach

Using the exact same calculations as performed on the Snøhvit project above, table 7.3 presents the main results of the real options approach used on the Shtokmanovskoye project.

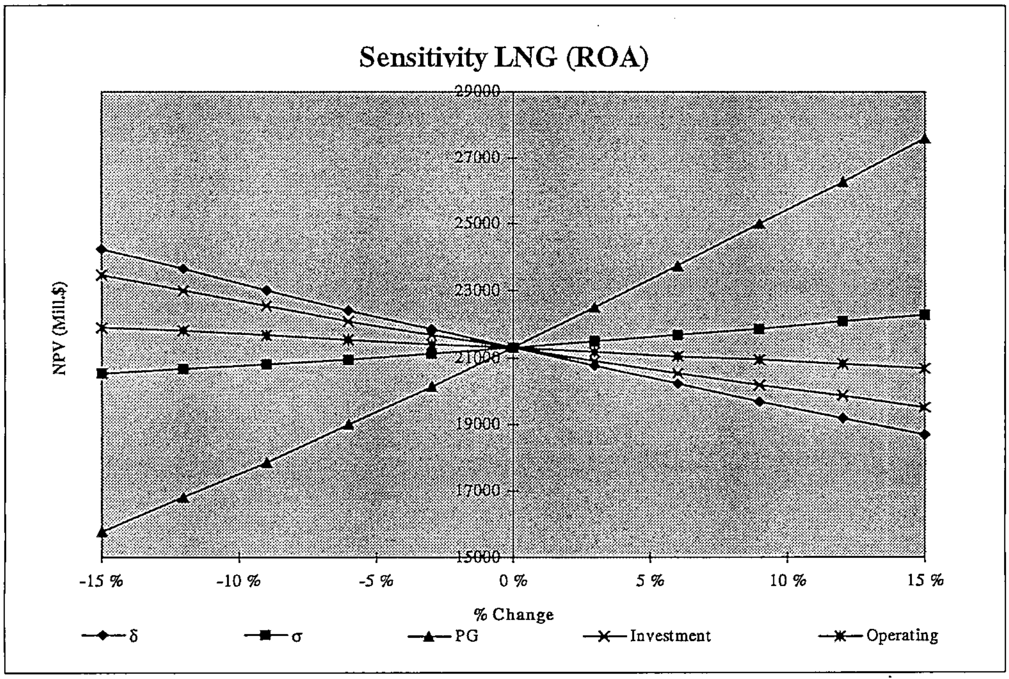
Summary Option Valuatio	*LNG*	*NGH*	*Pipeline*	
Break even price	70	56	52	USD
Project value excl. option	20356	27270	29408	Mill. USD
Critical exercise price	151	122	114	USD
Project value incl. option	21296	27271	29408	Mill. USD

Table 7-3 : Summary Option Valuation

First, notice that the break even price for all alternatives is below the current price of natural gas. This implies that a choice between no development and immediate development would result in a decision to initiate the project. The projects are ranked the same way as with the CAPM approach, but here it becomes even clearer that the values are not directly comparable, due to the exclusion of taxes and fundamentally differences in methodology. Moreover, notice that the critical exercise price for the pipeline alternative is below the current price of natural gas, and that this project thus should be initiated immediately even when the option to develop is taken into consideration. This also implies that the project value including the option is equal to the value excluding the option. Consequently, the option itself has no value. The NGH and LNG alternatives have also critical exercise prices close to the current price, but for these it would be optimal to wait for a short time before initiating[23].

Sensitivity analysis

The main sensitivities for this approach are presented in graphics 7.8 through 7.10.



Graphic Results 7-8 : Sensitivity LNG (ROA)

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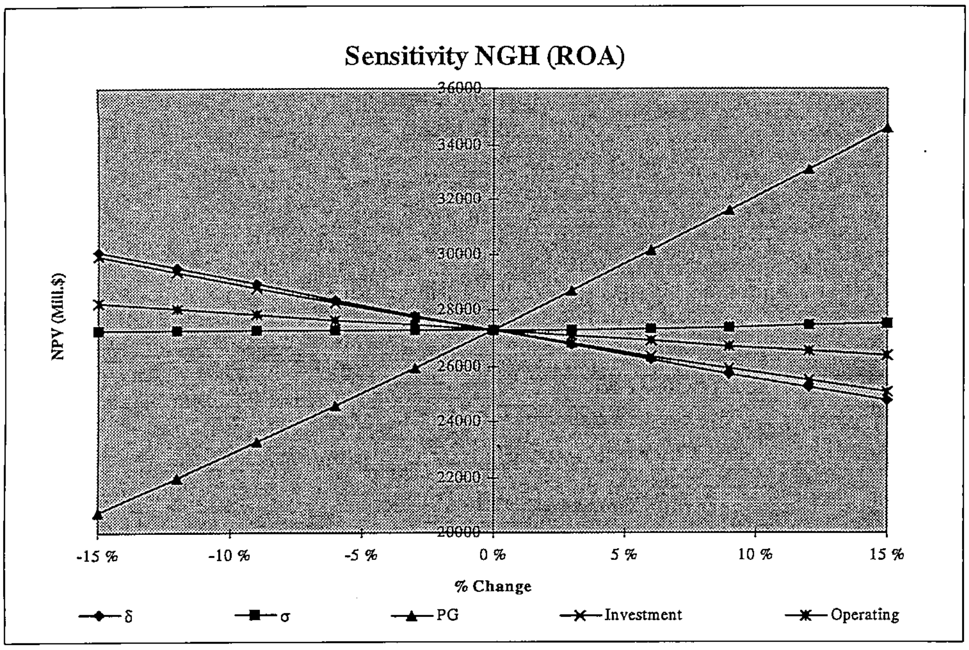
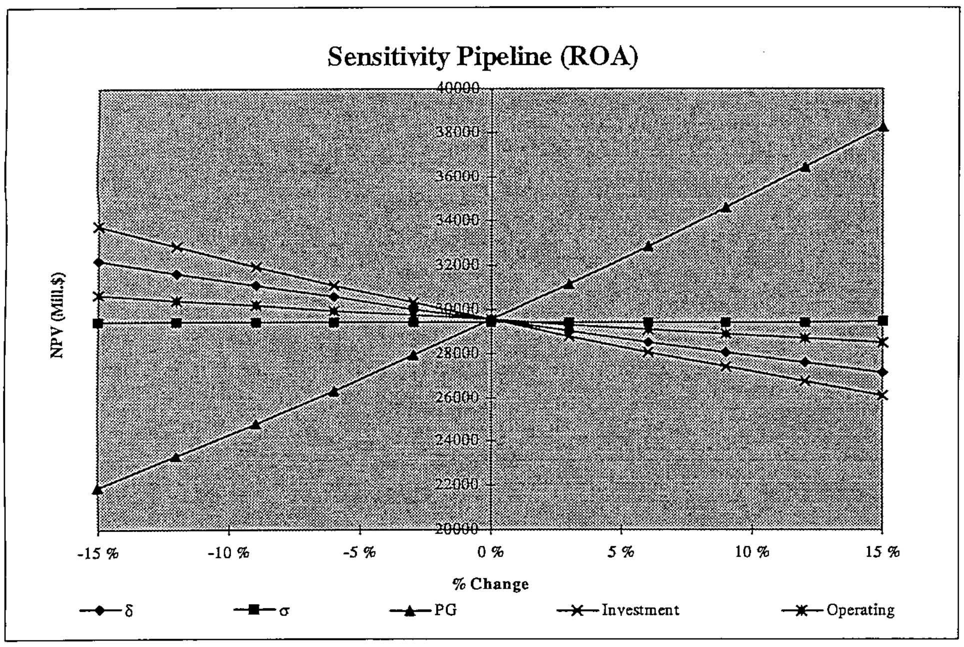
[23] Note that the exercise prices should be compared to the current price less 9% which is the drop in price due to introduction of additional natural gas from the Shtokmanovskoye field into the market (i.e. 134*0.91 = 121.9).

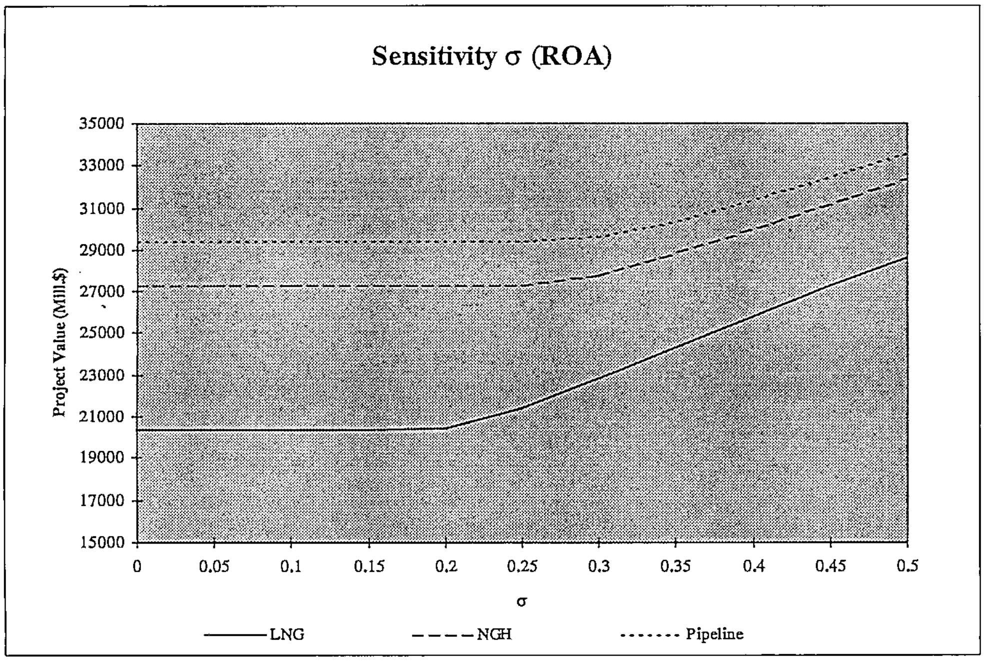


Graphic Results 7-9 : Sensitivity NGH (ROA)



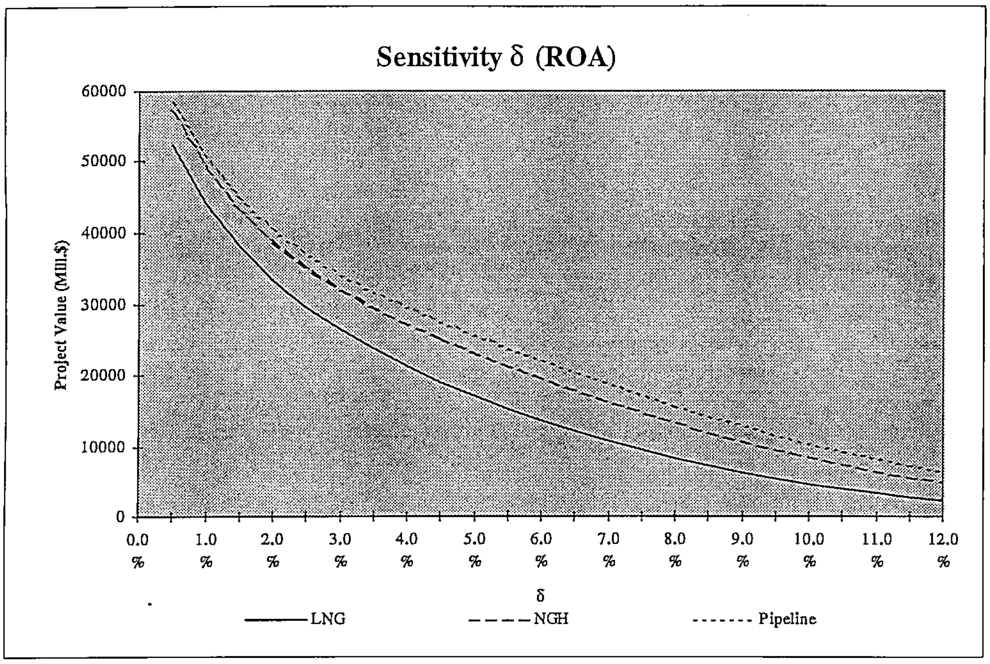
Graphic Results 7-10 : Sensitivity Pipeline (ROA)

Using the same reasoning as for the CAPM approach it can be seen that the most important input variables are the convenience yield (δ) and first and foremost the price of natural gas (PG). Small changes in the volatility has now very little influence on the project values. All three factors are analysed further in the three figures below. The sensitivity for changes in investment costs seems lower than in the Snøhvit project, and will be analysed for comparison.



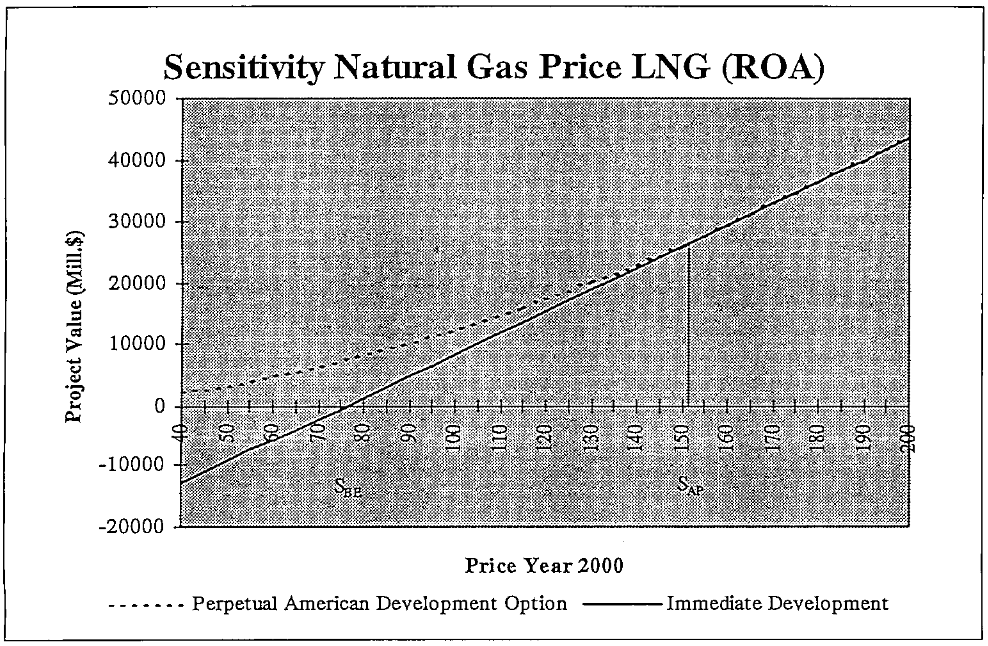
Graphic Results 7-11 : Sensitivity of volatility (ROA)

As shown in graphics 7.11 the same relationship between the volatility of the natural gas price and project values exists as in the Snøhvit case. Compared to the low sensitivity indicated above, it can be observed that when the range for which the volatility is allowed to change is increased the project value is more sensitive to upward changes. The differences in project values are diminishing as the volatility increases. This can be explained by the fact that an originally lowest ranking project will benefit the most from an introduction of a development option. Where the curves are horizontal, the value of the option itself is zero. This means that it is only for rather high volatilities that the option to wait will be exercised. Volatilities not shown in the diagram are believed to be unrealistic.

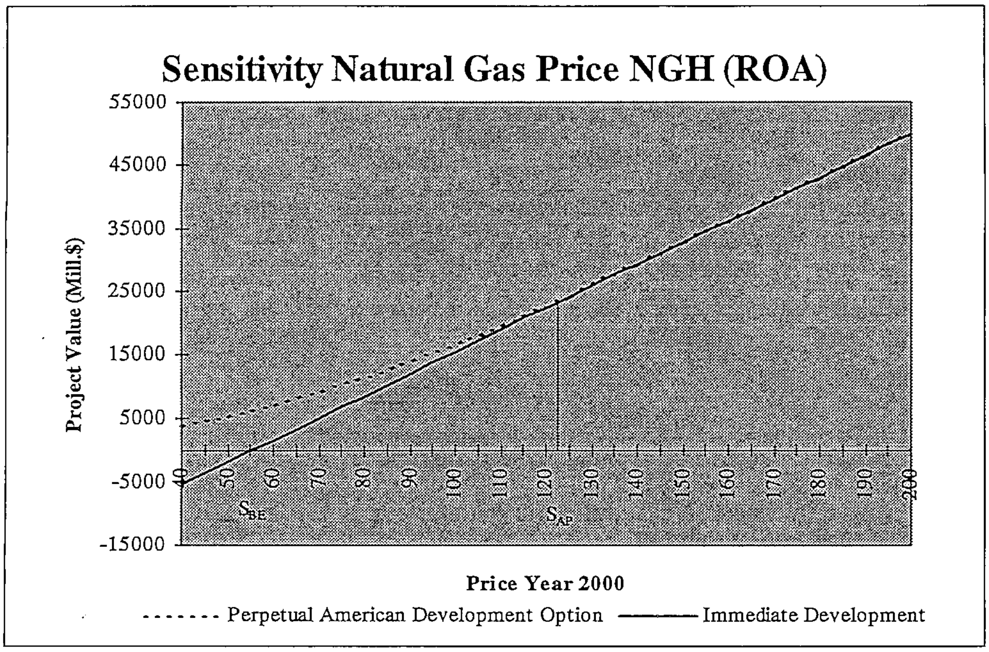


Graphic Results 7-12 : Sensitivity to convenience yield

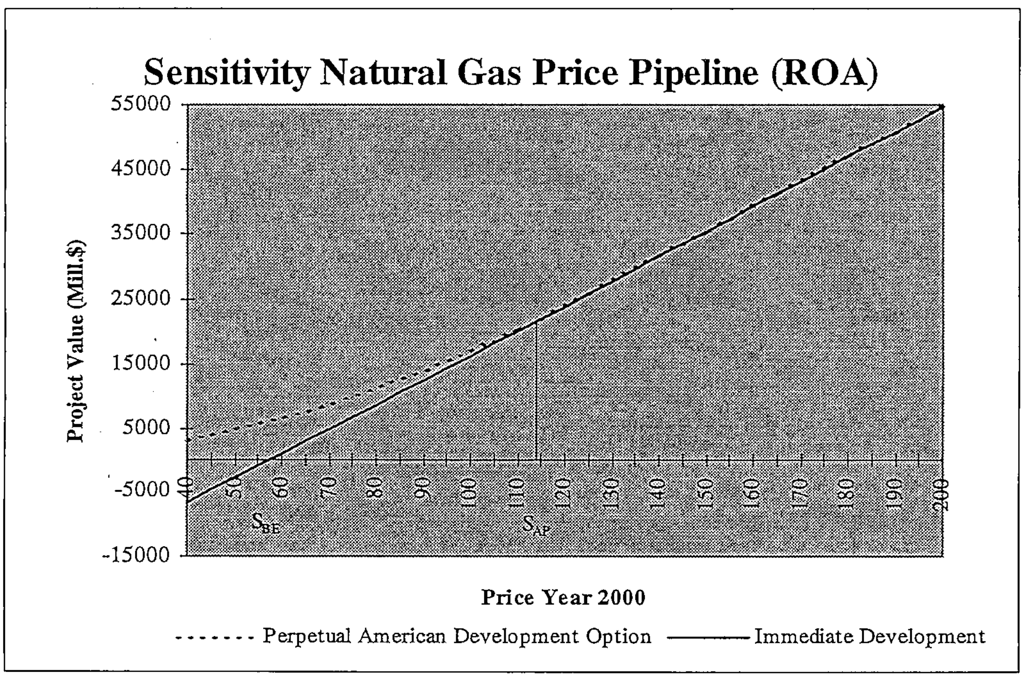
Graphic 7.12 shows the projects' sensitivity to changes in convenience yield. The figure indicates that pipeline is the superior technology for all reasonable values of δ, as opposed to graphic 6.12 for the Snøhvit field. In graphics 7.13 through 7.15 below, the project values are indicated for a wide variety of prices.



Graphic Results 7-13 : Sensitivity of Natural Gas price LNG (ROA)

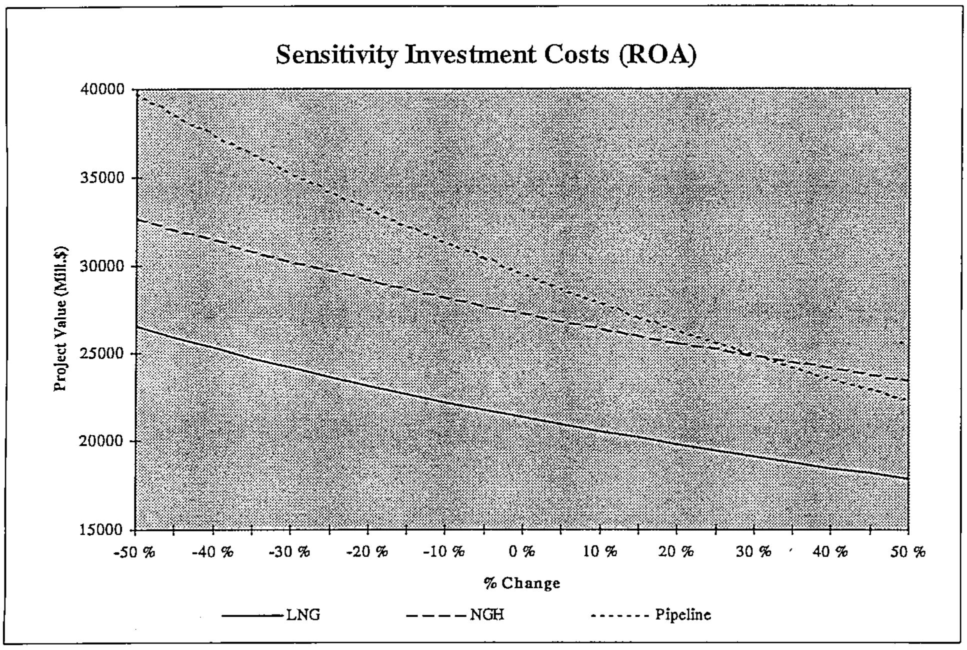


Graphic Results 7-14 : Sensitivity of Natural Gas price NGH (ROA)



Graphic Results 7-15 : Sensitivity of Natural Gas price Pipeline (ROA)

The curves of the perpetual American development option and immediate development merge at an earlier price than in the Snøhvit case. This is due the fact that the Shtokmanovskoye project is far more profitable and thus can be initiated at a lower price and earlier point in time.



Graphic Results 7-16 : Sensitivity investment costs (ROA)

The analysis of investment cost in graphic 7.16 shows that efforts to change the investment costs for the technologies can now change the ranking of the pipeline and NGH technologies. If the NGH investment costs can be reduced by about 25%, it will be the leading technology also for this field size. Such a reduction may well be obtainable because NGH is such a young and unexplored technology. It is also possible that the pipeline technology proves to be the necessary 15% more expensive in order for NGH to take its place as the most favourable alternative. Within reasonable changes in investment costs, the LNG technology is far from a competitive alternative to pipeline and NGH.

The conclusion using ROA is that the value of the Shtokmanovskoye project is high for all technologies, with pipeline ranking highest. The exercise prices are all within reachable levels, and the project should be initiated as soon as possible using pipeline technology.

8. COMMENTS TO THE HARASAVEY PROJECT

Preliminary analysis of the three projects originally chosen for the study, indicated that the two shipping modes of transporting natural gas most probably would have yielded significant negative net present values for this project, which resulted in a decision not to pursue these alternatives further for this field. These indications are verified by the results presented for the Shtockmanovskaya project. This project shows negative NPV's for the NGH and LNG alternatives. Due to

- longer transportation routes
- ice conditions in the Kara Sea and other more difficult geographical conditions
- shallower waters

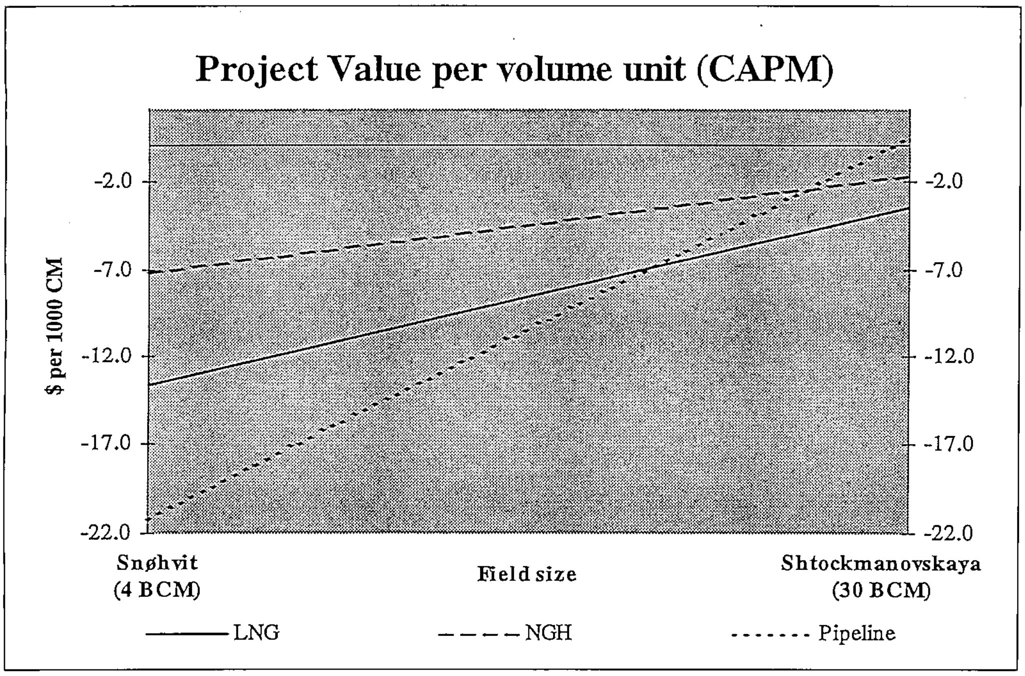
the costs of the LNG and NGH alternatives would have to increase due to the need for smaller, additional and more expensive ships than for the Shtockmanovskaya field.

As the Shtockmanovskaya field indicates, it is also doubtful that pipeline might be profitable for the Harasavey field. The Shtockmanovskaya project would be most favourable, due to its relative closeness to the markets. A simultaneous introduction of natural gas from both these fields, would as the GAS-model has indicated, imply a substantial price reduction which probably would be devastating for both projects.

9. CONCLUSIONS

In this study two different natural gas fields have been studied for three different technological solutions, using two different economic theories. The goal of the analysis was to examine whether a new technology for transporting natural gas, NGH, can compete with the existing technologies pipeline and LNG.

The first important issue regarding economies of scale in natural gas projects, is best illustrated in the figure below.



Graphic Results 9-1 : Project value per volume unit (CAPM)

The conclusion drawn from the figure is that economies of scale exist[24]. The figure also support the above mentioned theories in that pipeline is the superior technology for high volumes. All else equal, pipeline can not compete for smaller volumes. Until present, the

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[24] CAPM is here used as the example; similar conclusions are drawn using the ROA.

LNG technology has been the best alternative for transportation of such smaller volumes, but as the figure illustrates, NGH fully competes.

However, it is not only volume that is important when choosing transportation mode. The distance to the market where the natural gas is to be transported is also crucial. Pipeline technology is sensitive to changes in distance with costs increasing almost proportionally, while the shipping modes are not. This implies that the shipping modes, all else equal, are superior for long transportation distances. This conclusion is not fully supported by the figure above, due to the fact that the economics of scale more than neutralise the disadvantages of Shtockmanovskaya being further from the market and further offshore. NGH is superior to LNG also with regards to distance.

Despite the fact that the two economic models used for the evaluation has provided very different absolute project values, they have provide the same conclusion about the ranking of the different technologies.

On this basis then there is a clear indication that if NGH technology is developed further into a reliable and feasible alternative, LNG technology will practically always be inferior, while pipeline technology still remains very competitive, especially for large projects.

Unfortunately, the study has indicated that despite the superiority of NGH, marginal fields like Snøhvit are still unlikely to be developed under the present market conditions.

APPENDIX A: GENERAL ASSUMPTIONS

A.1 Approximate conversion factors

			Source
Density LNG	420.0	Kg/CM	Gudmundsson
Density NGH	928.5	Kg/CM	Gudmundsson
1 CM LNG equals	4.0	CM NGH	Gudmundsson
1 BCM NG equals	0.73	Mt. LNG	BP
1 mmBTU equals	28.0	CM NG	BP

A.2 LNG-chain

A.2.1 LNG-plant

Operating and maintenance costs	4%	of investment	IEA
Gas consumed at plant	12%	of gas intake	IEA

A.2.2 LNG-carrier

Investment cost	275	Mill.$/carrier	Lloyd Shipping Ec.
Size	135000	CM	
Gross tonnage	117000	Mt.	Kværner
Light-weight	12500	Mt.	Holte
Speed	19.5	Knots	Kværner
Consumption	0.25%	of cargo/day	IEA
Time in port loading	3.0	days/roundtrip	Drewry
Time in port discharging	3.0	days/roundtrip	Drewry
Operating and maintenance costs	6	Mill. $/year	Drewry

A.2.3 LNG regasification

Operating and maintenance costs	2.5%	of investment	IEA
Gas consumed at plant	1%	of gas intake	IEA

A.3 NGH-chain

A.3.1 NGH-plant

Operating and maintenance costs	4%	of investment	Same as LNG
Gas consumed at plant	7%	of gas intake	Gudmundsson

A.3.2 NGH-carrier

Investment cost	100	Mill.$/carrier	Gudmundsson

Size	300000	DWT	Gudmundsson
Gross tonnage	150000	Mt.	Rederiforbundet
Light-weight	48750	Mt.	Holte
Speed	14	Knots	Grieg
Load factor	95%		Wergeland
Bunker consumption at sea	50	Mt./day	Grieg
Bunker consumption in harbour	5	Mt./day	Grieg
Time in port loading	4	days/roundtrip	Veerhaven
Time in port discharging	4	days/roundtrip	Veerhaven
Operating and maintenance costs	5	Mill. $/year	Drewry

A.3.3 NGH melting

Operating and maintenance costs	2.5%	of investment	Same as LNG
Gas consumed at plant	1%	of gas intake	Gudmundsson

A.4 Pipeline chain

A.4.1 Separation plant

Operating and maintenance costs	2%	of investment	Wood Mackenzie
Gas consumed at plant	4%	of gas intake	

A.4.2 Pipeline

Maintenance costs offshore	2%	of investment	Wood Mackenzie
Maintenance costs onshore	4%	of investment	Wood Mackenzie
Loss/consumption of gas	2%	of gas intake	

A.4.3 Treatment plant

Operating and maintenance costs	2%	of investment	Wood Mackenzie
Gas consumed at plant	0.5%	of gas intake	

A.5 Miscellaneous

Bunker price Rotterdam	100	$/Mt.	Trade Winds
Port charges Rotterdam	0.3	$/GRT	Andresen
Scrapping price	200	$/Mt.	
Border price gas base case	165	$/1000 CM	Eldegard
F.o.b. price condensate	145	$/Mt.	Ramsland
Start up	2005		
Number of production periods	20	years	
General inflation	3.5%	per year	Wood Mackenzie
Nominal riskless interest rate	6.75%	per year	Dagens Næringsliv

Real riskless interest rate	3.15%	per year	Estimated
Return on market portfolio	14.9%	per year	Limperopoulos
Cost of debt	7.6%	per year	DnB
Marginal tax rate	78%		
Equity ratio	60%		
Working capital need	5%	of sales	
Convenience yield oil	4%		Ekern/Stensland
Price volatility oil	0.245		Ekern/Stensland
Exchange rate NOK/$	6.5	NOK	Wood Mackenzie

APPENDIX B: ASSUMPTIONS SNØHVIT

B.1 Production

			Source
Natural gas	4000	Mill. CM/year	Gudmundsson
Condensate	0.33	Mill. Mt./year	Wood Mackenzie
Operating and maintenance costs	106.2	Mill.$/year	Wood Mackenzie
Investment cost field facilities	615.4	Mill.$	Wood Mackenzie
Investment cost of pipeline	615.4	Mill.$	Wood Mackenzie

B.2 LNG-chain

B.2.1 LNG-plant

Investment cost	1060	Mill.$	Gudmundsson

B.2.2 LNG-carrier

Theoretical number needed	1.5	carriers	Estimated
Actual number needed	2	carriers	Estimated
Max. number of trips	30.3	per carrier	Estimated
Actual number of trips	23	per carrier	Estimated
Time at sea	5.9	days/roundtrip	Estimated

B.2.3 LNG regasification

Investment cost	348	Mill.$	Gudmundsson

B.3 NGH-chain

B.3.1 NGH-plant

Investment cost	600	Mill.$	Gudmundsson

B.3.2 NGH-carrier

Theoretical number needed	3.8	carriers	Estimated
Actual number needed	4	carriers	Estimated
Max. number of trips	22.2	per carrier	Estimated
Actual number of trips	21	per carrier	Estimated
Time at sea	8.2	days/roundtrip	Estimated

B.3.3 NGH melting

Investment cost	240 Mill.$	Gudmundsson

B.4 Pipeline chain

B.4.1 Separation plant

Investment cost	607 Mill.$	Scale down Kollsnes

B.4.2 Pipeline

Investment cost offshore	1.5 Mill.$/km.	IEA
Investment cost onshore	0.5 Mill.$/km.	IEA

B.4.2 Treatment plant

Investment cost	59 Mill.$	Scale down Zeebrugge

B.5 Miscellaneous

Distance Hammerfest-Rotterdam	1380 Nm.	Dataloy distance table
Distance Hammerfest-Sleipner	1619 Km.	
Areal of field	1360 Km^2	Wood Mackenzie
Decrease in border price due to introduction of additional gas	1.5%	Eldegard
β_{LNG}	1.0	
β_{NGH}	1.2	
β_{PIPE}	1.0	

APPENDIX C: ASSUMPTIONS SHTOCKMANOVSKAYA

C.1 Production

			Source
Natural gas	30000	Mill. CM/year	
Condensate	2.0	Mill. Mt./year	Scale up Snøhvit
Operating and maintenance costs	153.8	Mill.$/year	Based on Troll
Investment cost field facilities	2789.0	Mill.$	Scale up Snøhvit
Investment cost of pipeline	4000.0	Mill.$	Scale up of Troll

C.2 LNG-chain

C.2.1 LNG-plant

Investment cost	3927	Mill.$	Scale up Snøhvit

C.2.2 LNG-carrier

Theoretical number needed	12.4	carriers	Estimated
Actual number needed	13.0	carriers	Estimated
Max. number of trips	27.4	per carrier	Estimated
Actual number of trips	26	per carrier	Estimated
Time at sea	7.1	days/roundtrip	Estimated

C.2.3 LNG regasification

Investment cost	1893	Mill.$	Scale up Snøhvit

C.3 NGH-chain

C.3.1 NGH-plant

Investment cost	2719	Mill.$	Scale up Snøhvit

C.3.2 NGH-carrier

Theoretical number needed	31.5	carriers	Estimated
Actual number needed	32	carriers	Estimated
Max. number of trips	20.1	per carrier	Estimated
Actual number of trips	20	per carrier	Estimated
Time at sea	9.9	days/roundtrip	Estimated

C.3.3 NGH melting

Investment cost	1088 Mill.$	Scale up of Snøhvit

C.4 Pipeline chain

C.4.1 Separation plant

Investment cost	2333 Mill.$	Scale up Kollsnes

C.4.2 Pipeline

Investment cost offshore	4.8 Mill.$/km.	IEA
Investment cost onshore	1.6 Mill.$/km.	IEA

C.4.2 Treatment plant

Investment cost	241 Mill.$	Scale up Zeebrugge

C.5 Miscellaneous

Distance Murmansk-Rotterdam	1670 Nm.	Dataloy distance table
Distance Murmansk-German b.	2500 Km.	
Areal of field	2200 Km^2.	Scale up Snøhvit
Decrease in border price due to introduction of additional gas	9%	Eldegard
β_{LNG}	1.1	
β_{NGH}	1.3	
β_{PIPE}	1.1	

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Review of INSROP Discussion paper:

Sub-programme III, Project 07.4

Title: Northern Gas Fields and NGH Technology. A feasibility study to develop natural gas hydrate technology to supply international gas markets from year 2000.

By: Trond Ramsland, Erik F. Loy, and Sturle Døsen.

This project is indeed a very thorough treatment of the feasibility of using NGH technology to substitute pipeline and LNG exports for Russia.

The project has been carefully structured and each section is discussed in depth. The language is very straightforward and the concepts are adequately explained, so that the paper can be read by experts and laymen, alike.

I felt that Chapter 5 could appear as an appendix if the paper is going to address an audience already familiar with project appraisal theory. Having said that, however, if the paper addresses a more general audience, Chapter 5 is well-placed.

One more general point: although the analysis is excellent I see one severe limitation: the inputs regarding the NGH option. There only seems to be one source of information about the costs of NGH and if these are wrongly estimated the whole analysis is becomes of little value.

My suggestions/criticisms are only a handful and I am listing them as follows:

1. Executive summary: although valid as an "abstract", this part does not qualify as an executive summary. An executive summary needs to be perhaps 2-3 pages long, summarize the main assumptions and findings of the paper, and make proper cross-references to the parts of the paper that contain relevant details.

2. Page 2: replace "(Gudmundsson, 1995)" with "(Gudmundsson et al, 1995)".

3. Page 5: replace "...For the licensee, two important payments normally has to made..." with "...two important payments normally have to be made..."

4. Page 5: replace "...the license has been prolonged cover..." with "...the licence has been prolonged to cover..."

5. Page 6: "(Barents Perspektiv, 1995)" - this does not appear in the list of references.

6. Page 7: "(Statistics Norway, 1992)" - this should appear in full in the list of references.

7. Page 8: on the X-axis of the graph, "Capasity" should read "Capacity".

8. Page 13: replace "(Gudmundsson, 1995)" with "(Gudmundsson et al, 1995)"

9. Page 20: replace "...Despite of this, there is no..." with "...Despite this, there is no..."

10. Page 21: replace "oligopolic" with "oligopolistic"

11. Page 22: replace "monopsonic" with "monopsonistic"

12. Page 22: replace "continuos" with "continuous"

13. Page 25: replace "determinator" with "determinant"

14. Page 25: "(Dagens Naeringsliv, 1995)" - give a more detailed reference.

15. Page 27: replace "Millers" with "Miller's" (it appears 3 times).

16. Page 27: replace "critics" with "critique".

17. Page 29: replace "...as described chapter 1..." with "...as described in chapter 1..."

18. Page 41: replace "...the introduction of an development option..." with "...the introduction of a development option..."

19. Page 41: replace "...natural gas is directly link to the..." with "natural gas is directly linked to the..."

20. Page 41: replace "All costs (including investment costs) and are known..." with "All costs)including investment costs) are known..."

21. Page 41: replace "...an inventory on hand..." with "...an inventory in hand..."

22. Page 44: replace "continuos" with "continuous"

23. Page 44: replace "If small fluctuations proves critical..." with "If small fluctuations prove critical..."

24. Page 44: replace "...very risky since if small..." with "... very risky since small..."

25. Page 44: replace "...In study sensitivity analysis..." with "...In this study sensitivity analysis..."

26. Page 46: replace "...despite of the constraints..." with "...despite the constraints..."

27. Page 47: replace "...The calculations has been..." with "...The calculations have been..."

28. Page 48: replace "...natural gas price reach a critical..." with "...natural gas price reaches a critical..."

29. Page 48: replace "...wide variety of sensitivity analysis..." with "...wide variety of sensitivity analyses..."

30. Page 52: replace "...inputs to this formula has already..." with "...inputs to this formula have already..."

31. Page 58: (Ekern & Stensland, 1993) - include this in the list of references.

32. Page 68: replace "...The following sub-chapters..." with "...The following sections"

33. Chapter 7: the verb "bypass" is often used in this chapter to indicate that one project has a better value than another; the authors might wish to consider using "ovetake" or "is superior to" instead.

34. Page 88: replace "On this basis the there is..." with "On this basis then there is..."

Overall, I would to reiterate that this is an excellent piece of work, which could also have practical applications, provided that more information on NGH technology becomes available.

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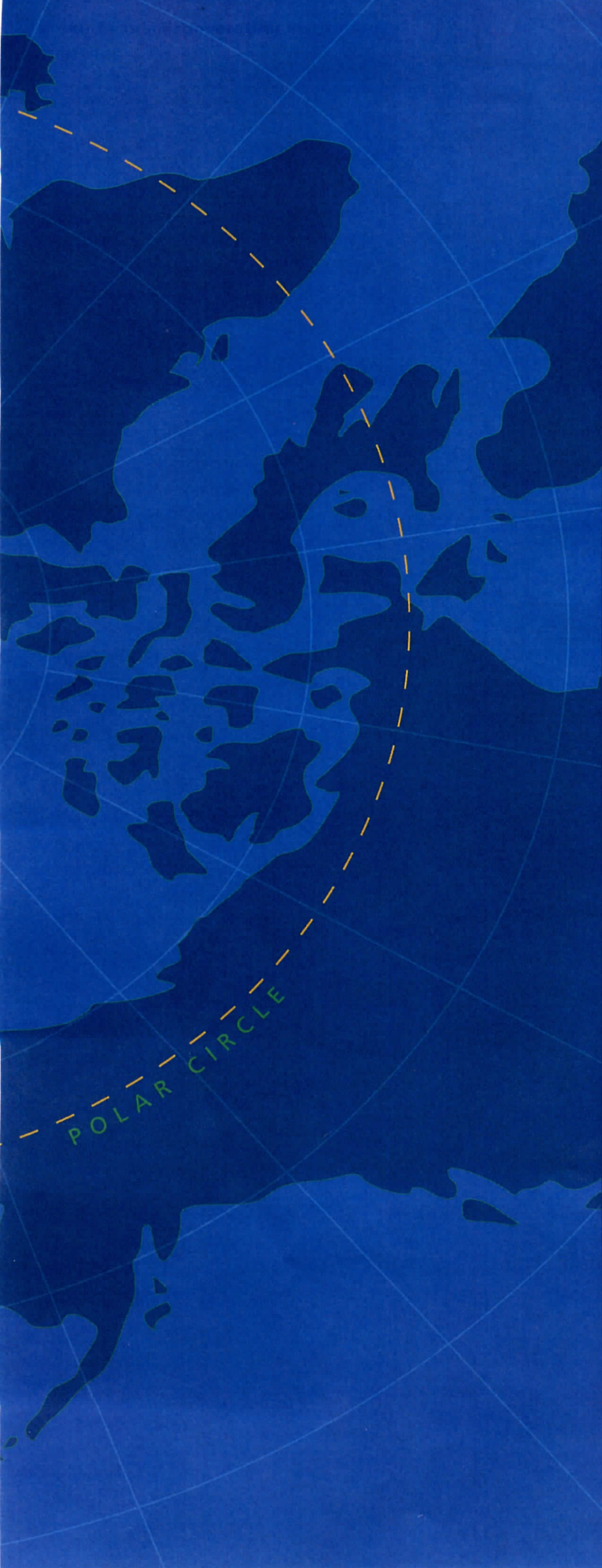
Best regards

Michael Tamvakis

27 October 1996



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SOF was established in 1975 as a non-profit organization to advance modernization and rationalization of Japan's shipbuilding and related industries, and to give assistance to non-profit organizations associated with these industries. SOF is provided with operation funds by the Sasakawa Foundation, the world's largest foundation operated with revenue from motorboat racing. An integral part of SOF, the Tsukuba Institute, carries out experimental research into ocean environment protection and ocean development.

Central Marine Research & Design Institute (CNIIMF), St. Petersburg, Russia.
CNIIMF was founded in 1929. The institute's research focus is applied and technological with four main goals: the improvment of merchant fleet efficiency; shipping safety; technical development of the merchant fleet; and design support for future fleet development. CNIIMF was a Russian state institution up to 1993, when it was converted into a stockholding company.

The Fridtjof Nansen Institute (FNI), Lysaker, Norway.
FNI was founded in 1958 and is based at Polhøgda, the home of Fridtjof Nansen, famous Norwegian polar explorer, scientist, humanist and statesman. The institute spesializes in applied social science research, with special focus on international resource and environmental management. In addition to INSROP, the research is organized in six integrated programmes. Typical of FNI research is a multidisciplinary approach, entailing extensive cooperation with other research institutions both at home and abroad. The INSROP Secretariat is located at FNI.