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Viability of Developing Natural Gas Infrastructure from The Barents Sea

From field to market – a complete analysis of the value chain

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Abstract

This thesis assesses whether it is profitable to build a natural gas infrastructure solution in the Barents Sea, under reasonable assumptions about costs and revenues. In order to answer this question we have looked at the resource base in the Barents Sea and the probability of new discoveries, how the global market for natural gas will develop, at what cost the oil and gas companies will be able to recover the resources, and what type of infrastructure that suits the region best and how it could be financed.

Our findings indicate that a natural gas pipeline would be a profitable solution, while other solutions are either not technically viable or not profitable. The proven resource base alone is not sufficient to justify a pipeline development, but the likelihood of new discoveries is high if exploration activity is increased. We found that exploration has been limited as a consequence of lacking infrastructure, meaning that there is a timing paradox concerning development of the region. If there is no infrastructure solution in place, there will not be enough exploration, and if there is not enough exploration, there will not be enough discoveries to justify the infrastructure development.

We have found that a project finance approach could have solved the timing paradox, if oil and gas companies were willing to contractually commit to pay for transportation rights beyond what their current discoveries will justify. As a project finance approach allows for high level of risk allocation between project participants, it is possible to divide project risk within the capital structure so that the infrastructure investment offers an attractive opportunity for various investors. We have found that a pipeline could be financed by dividing the risk between debt holders, infrastructure funds and oil and gas companies, so that all parties are able to achieve a risk-reward profile that match their preferences. However, we found that oil and gas companies are not willing to make these kinds of contractual commitments. This means that the pipeline project will have to carry more risk, making high leverage, as suggested in our project finance model, challenging.

To solve the timing paradox we thus conclude that government intervention is necessary. We find that state financing of the infrastructure is a better solution then further incentivizing exploration. State financing might be viewed as selective business support and is consequently politically difficult.

Preface

This master thesis is written in the last semester of our master's degree in financial economics at the Norwegian School of Economics, spring 2015. As a result of our interest in the oil and gas industry, we wanted to study a topic within the area of future natural gas developments. Natural gas developments in the Barents Sea region has become a relevant topic as the resources in the more mature areas of the Norwegian Continental Shelf is diminishing.

First and foremost, we want to thank our thesis advisor, Associate Professor Tommy Stamland. We are thankful for his valuable comments and general guidance through the process. In addition to our advisor, we want to thank all the individuals that have provided us with insightful thoughts and information on the subject we wanted to cover.

Working with the thesis has been a demanding process, but at the same time very educational. We have enjoyed working with the topic and feel that we have developed a deep understanding of how the oil and gas industry evaluate investment opportunities regarding natural gas developments. We hope the thesis will be of interest for the reader.

June 16, 2015

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1 Introduction

In 2011, the Norwegian government presented a White Paper, titled "An Industry for the Future – About the Petroleum Industry". This paper outlined ambitious targets for the industry, and stated that the main target of the Norwegian petroleum policy should be "to facilitate a profitable production of oil- and gas resources in a long run perspective" (The Ministry of Petroleum and Energy, 2011, p.6). Increasing recovery rates from fields in production, developing proven resources, and finding more resources are critical challenges emphasized in this paper.

The first two challenges relate primarily to the mature and developed regions of the continental shelf, notably The North and Norwegian Sea. In contrast, when tackling the third challenge of finding more resources, the Norwegian government and the Ministry of Petroleum and Energy (MPE) envisage the Barents Sea as a key region (The Ministry of Petroleum and Energy, 2011). Although uncertain, assessments show that the Barents Sea, together with deep-water areas of the Norwegian Sea, has the greatest probability of new discoveries on the Norwegian Continental Shelf (NCS). It is expected that the majority of the undiscovered petroleum deposits in the Barents Sea contain natural gas (Norwegian Petroleum Directorate, 2015a)

The Barents Sea has experienced much attention in recent years due to the high expectations for the region. In the 22nd licensing round in 2012, 72 out of 86 blocks were in the Barents Sea. On January 20, 2015 Tord Lien, the Minister of Petroleum and Energy, announced the 23rd licensing round. This round had 54 of 57 blocks in the Barents Sea region. Particularly interesting in the 23rd round was the opening of the Barents Sea Southeast (and Jan Mayen-region) for mapping and exploration of potential petroleum deposits (Eriksen, 2015). To secure the exploration activity envisaged under the 22nd and 23rd licensing round, the commercial viability of the natural gas resources has to be evaluated.

Despite the ambitions for the region, further developments of the gas resources might prove to be commercially challenging. So far, only a limited number of the proven gas discoveries have been developed. The lack of an infrastructure solution enabling transportation of natural gas to the markets is a key issue for making the gas resources commercial (Anker, 2013). There are no proven natural gas fields in the Barents Sea large enough to justify the necessary investments for an infrastructure solution single-handily (Gassco, 2014, p.36). Without relevant infrastructure in place, it is likely that future discoveries in the Barents Sea will also be left undeveloped, an issue which will be addressed later in the thesis.

In addition to the amount of recoverable resources, the viability of an infrastructure solution will depend on the market price and market conditions for natural gas. For the development of the gas resources to be profitable, it is important that the natural gas markets are attractive enough to justify the costs of both infrastructure and field developments. Consequently, to further discuss the economic viability of an infrastructure solution, a thorough analysis of the natural gas market is required.

Addressing the issues concerning the potential development of the natural gas resources in the Barents Sea will be crucial for a successfully achieving the targets of the petroleum policy. The remoteness of the Barents Sea and the changing market dynamics makes it appropriate to discuss various infrastructure solutions. All possible solutions will contain large capex-requirements in infrastructure, collaboration between several licenses to realize investments, and a large share of marginal resources. Alternative models to finance the gas infrastructure investments may be needed to maximize the value creation from the gas resources in the Barents Sea. (Gassco, 2014, s.36).

2 Research Question and Limitations

2.1 Research Question

The research question this thesis seeks to answer is:

Is it profitable to build an infrastructure solution in the Barents Sea under reasonable assumptions about costs and revenues?

The following four sub questions must be answered to thoroughly address this research question:

1. Resource base: *Is the resource base and probability of new discoveries in the Barents Sea sufficient to justify further developments in the area?*
2. Market conditions: *How will the market for natural gas develop, and will the price of natural gas be high enough to justify further developments in the Barents Sea?*
3. Cost of field development: *At what cost will the natural gas companies be able to recover the gas resources in the Barents Sea?*
4. Infrastructure: *What type of infrastructure solutions would be appropriate and how should the investment in infrastructure be financed?*

2.2 Limitations

To ensure independence in the assessments of the resource estimations and potential in the Barents Sea, it could be argued that we should have performed our own calculations of the resource potential in the region. However, we believe that NPD's analysis provides the necessary independence in their estimates. The NPD is a government specialist directorate with the objective of "creating the greatest possible values for society from the oil and gas activities by means of prudent resource management" (Norwegian Petroleum Directorate, u.d.). We believe that the NPD by no means have an incentive to provide inaccurate information concerning the resource potential.

Calculating the cost of field development is a challenging exercise, due to the complexity and unique characteristics of each field development. Consequently, the field development costs are generalized based on historical data from similar gas field projects.

With regard to the choice of infrastructure, the considerations are limited to technologies that have been proven on a commercial scale. This is primarily pipeline transport and sea transport of liquefied natural gas (LNG). Sea transportation in the form of compressed natural gas (CNG) and gas to liquids (GTL) is also discussed, although only a limited number similar of projects utilize these methods.

When assessing the potential revenues associated with developing natural gas resources in the Barents Sea, the analysis is limited to the revenues generated by the sale of dry gas. Thus, the potential extra revenue generated from production of natural gas liquids (NGL), which is a byproduct in some gas fields, is not included. In addition the thesis does not look at the potential increase in oil production, resulting from oil fields with associated gas having an easier evacuation solution for the gas that is mixed in the oil when it is taken out of the ground.

3 Historical Development of Norwegian Gas Resources

Throughout Norway's history as a natural gas exporter, expansions of the transportation network has been based on large discoveries, securing utilization of new infrastructure developments (Pedersen & Nygård, 2005). Consequently, the infrastructure has been developed in parallel with the resources to which it is connected. The management and governance of the transportation network, and the sales of natural gas, has however evolved over the course of Norwegian oil and gas history.

3.1 1973 - 2001

The first transportation of natural gas from the Norwegian Continental Shelf took place in 1977. The gas was transported from the Ekofisk-field via the pipeline Norpipe to a receiving terminal in Emden, Germany. The Phillips Group initiated the construction in 1973, after selling the Ekofisk-gas on long-term contracts to buyers on the European Continent. The price-mechanisms, under which the contracts were negotiated, were based on indexing the price of gas to the price of heating oil for a period between 20-30 years. In addition to the price following movements in the oil prices, the contracts had standardized take-or-pay clauses[1]. (Norsk Oljemuseum, 2010)

[1] Take-or-pay clauses require a purchaser to pay for a minimum quantity of goods or services, whether or not those goods or services are taken. (Holland & Ashley, 2013)

Figure 1 - Timeline of the historical development of Norwegian Gas Resources

As more fields were discovered in the early developments of the NCS, more pipelines were constructed. This provided the necessary link for the natural gas to reach the European markets. In these early stages, the license holders of the fields sold the natural gas on field depletion contracts. Considering the relative modest size of the natural gas resources of these fields, selling all the gas in one chunk posed few problems. (Pedersen & Nygård, 2005)

This changed in 1979, when the Troll field was discovered. Today, Troll is the cornerstone of Norwegian gas production and the largest gas discovery in Norwegian oil and gas history. The field holds roughly 40 per cent of the proven gas resources on the continental shelf (Norwegian Petroleum Directorate, 2014). Although enormous, it was difficult to make Troll commercially interesting when discovered, as it was considered only marginally profitable. The vast resource size and the complexity concerning field development, called for a new approach related to the sale of the gas. Unlike the early discoveries, the Troll gas was sold in portions to large European utilities. The emergence of European gas markets, The Cold War, and the desire for independence from Soviet gas deliveries made the contracts lucrative for the license holders (Pedersen & Nygård, 2005).

After finalizing the sale of the Troll gas in the mid-1980s, the Norwegian government established two committees: *Gassforhandlingsutvalget (GFU)* and *Det Norske Gassforsyningsutvalget* (FU). The GFU was established to create a monopoly in the sale and marketing of the Norwegian natural gas resources. GFU consisted of representatives from Statoil, Norsk Hydro and Saga Petroleum (acquired by Norsk Hydro in 1999). After the establishment of the GFU it was no longer allowed for the various field licenses-holders to market and sell their own gas. The GFU negotiated "field-neutral" sale contracts, meaning that neither the GFU nor the buyer of the gas knew which field the gas was coming from. The Ministry of Petroleum and Energy assigned which fields that should fulfil the delivery of the gas. The allocation of the gas deliveries was performed regularly through allocation rounds, based on recommendations from the FU. The intention of the GFU was to optimize the resource management by ensuring that the most profitable reserves were developed first, and that the corresponding pipelines and receiving terminals were built in the most cost efficient way. (Pedersen & Nygård, 2005)

While the GFU were in charge of sales and marketing, the FU worked on the exploration, development, and exploitation of the gas fields and the connected pipeline system. The GFU/FU-system secured a coordinated development of the Norwegian gas resources and the necessary infrastructure needed to transport and refine the gas.

3.2 2001 – 2015

The GFU proved to be a successful establishment, and negotiated on behalf of the license-holders and the Norwegian Government, very lucrative prices of Norwegian natural gas. However, since the GFU was a monopoly it experienced much scrutiny from both the buyers and the European Union. The European Parliament began to form a new directive as a result of what the EU and gas buyers perceived as unreasonable prices. The Gas Market Directive, ratified on 12.august 2000, involved a liberalization (devolution) of the European gas market and a gradual dissolving of the gas-monopolies spread across Europe. In Norway, the directive was implemented in September 2001 and the GFU and FU were consequently terminated. The license-holders were again on their own in terms of selling and marketing their own gas.

To ensure operational efficiency after the GFU/FU system was terminated, the Norwegian Ministry of Petroleum and Energy established a new company, Gassco AS, to manage operations of the pipeline system on May 14 2001 (The Ministry of Petroleum and Energy, 2001). The idea when forming Gassco was to secure neutrality in the transportation system, fair treatment of the shippers in the transport- and processing facilities, and facilitate further developments of the gas transport system (Gassco, 2014b).

From 2001 to 2003, the transportation system was organized as partnerships/joint-ventures where each individual pipeline or terminal was a separate entity. The shippers who transported the gas negotiated conditions of carriage with each individual partnership in order to bring the gas to the markets. To ensure a more effective management of the transportation network, the different partnerships established on January 1, 2003 a collective partnership called Gassled (Pedersen & Nygård, 2005). Gassled became a consortium of larger oil- and gas-companies that now owned the transportation system. The idea behind creating a single owner was a simpler transportation system that facilitated a better exploitation of the petroleum resources. Gassco, who started the operations of the pipelines in 2001, continued as sole operational manager of the pipelines, processing facilities, and receiving terminals.

Today, the transportation system covers 7980 kilometer of pipelines, three processing facilities and six receiving terminals. At the processing facilities the rich gas from the offshore reserves is refined into natural gas liquids (NGL) and dry-gas. Ships transport the NGL while the dry-gas is transported through the pipeline-system to receiving terminals in Europe. The six receiving terminals consist of two in Germany, one in Belgium, one in France and two in the UK (Gassco, 2014b).

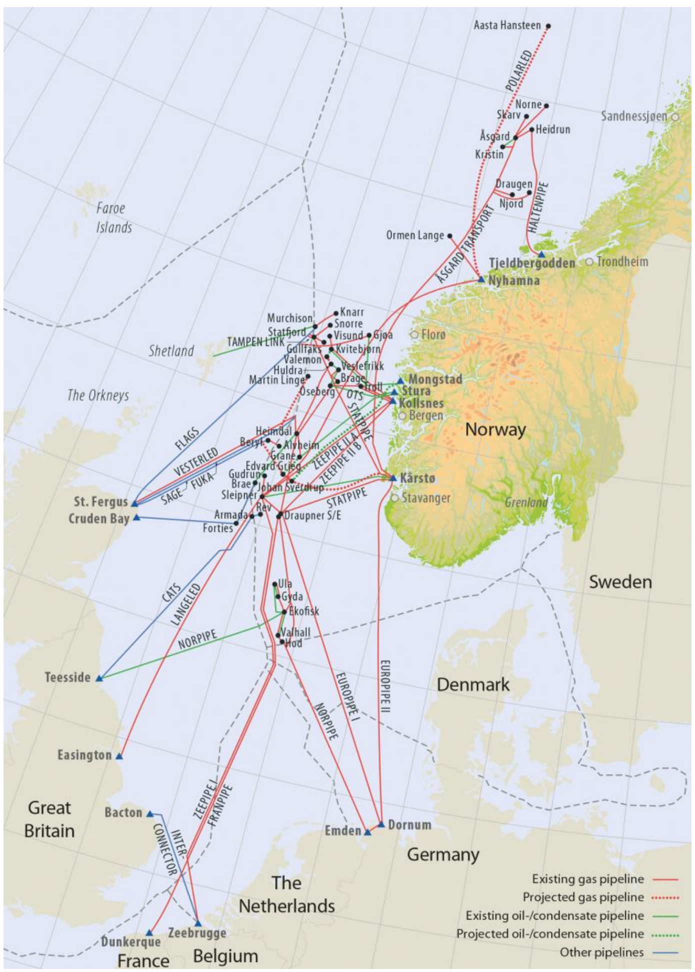

Figure 2 - Current pipeline infrastructure on the NCS (Norwegian Petroleum Directorate, 2015f)

From 2003 until 2010, large oil and gas (O&G) companies with operational licenses on the NCS owned Gassled. However, due to low returns associated with owning shares in the transportation network, the O&G companies initiated in 2010 a process that involved selling their stakes in Gassled. The Gassled stakes were sold to reputable international infrastructure funds with return preferences consistent with owning regulated infrastructure assets (Gammons, Hern, Haug, Grayburn, & Pu, 2013). The O&G companies sold their stakes to free capital for projects with higher expected returns, which were more closely related to their core business.

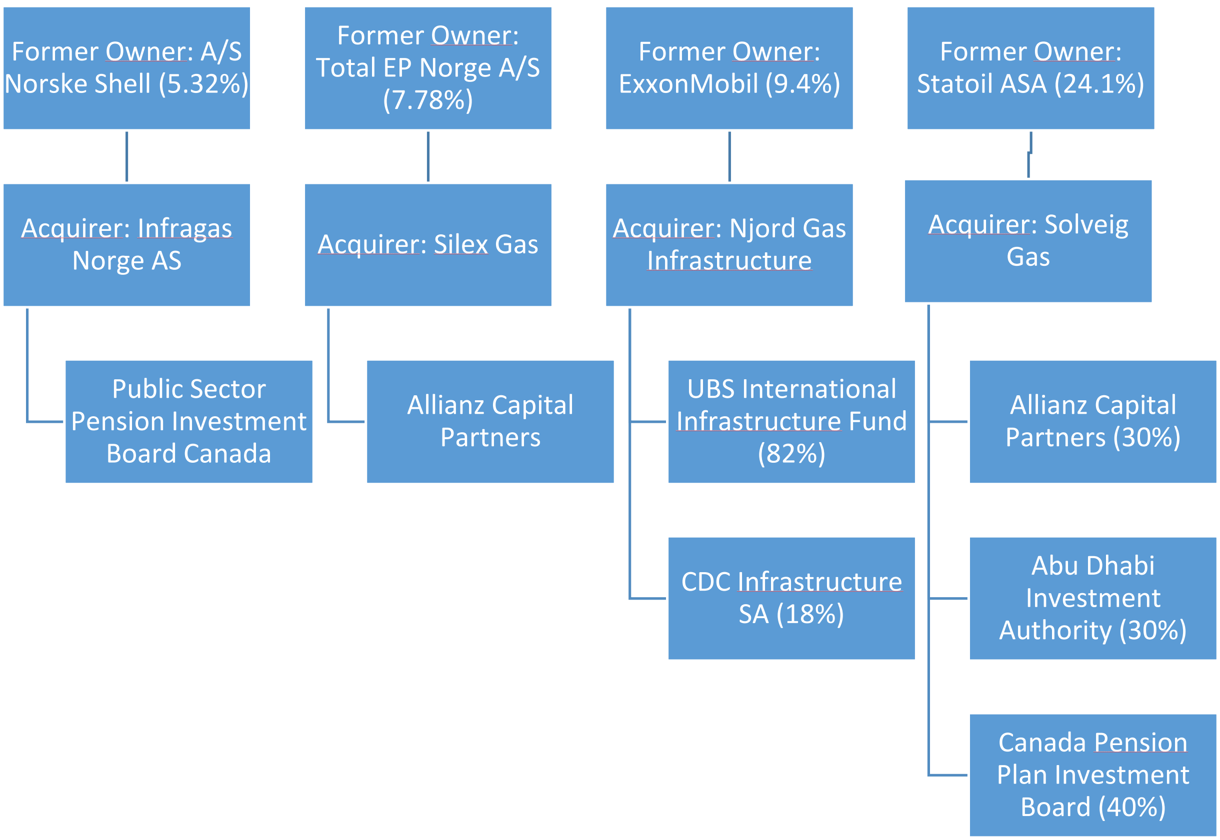

Figure 3 - Overview of the 2010 Gassled transaction

3.3 Commercial Difficulties Regarding Further Developments

3.3.1 The Timing Paradox

Although the natural gas potential in the Barents Sea looks promising, some O&G companies are hesitant to explore pure natural gas prospects the region (Rummelhoff, interview, 03.02.15). The reason being high development costs and a fear that the resources found can be left stranded due to a lack of infrastructure. A small or medium sized gas field does not generate enough revenue to justify the cost of developing the necessary infrastructure to bring the resources to the market (Torvund, interview, 04.04.15). Total EP's Norvarg field is an example this. Found in 2011, the field, expected to contain 30 BCM, was returned to the Norwegian government in 2014. Total commented that the lack of infrastructure was a key reason for why they choose to not further pursue the license (Taraldsen, 2013).

This shows that future developments of natural gas fields are likely to depend on collaboration with several other licenses in order to share the costs of a common infrastructure solution. However, this creates a first mover disadvantage in exploring pure natural gas prospects, as O&G companies have an incentive to postpone exploration until the proven resource base is higher and the likelihood of a shared infrastructure is greater.

Starting to develop infrastructure when there still is uncertainty concerning whether it is enough commercial resources to support the investment, has proven to be a risky exercise. The 480 km long Polarled pipeline that will connect Aasta Hansteen, located 300 km west of Bodø, to the existing pipeline system, was initially supposed to be supported by several other fields (Taraldsen, 2014). The projects Linnorm, Kristin and Asterix were intended to connect to the pipeline further south, but all these projects are now either cancelled or postponed. The ownership in Polarled was divided between the partners based on the expected volumes they would require. The result being that the partners of Aasta Hansteen will account for 100 per cent of the throughput, while their ownership in Polarled will be about 64 per cent. The table below illustrates the ownership structure in the two projects.

	Ownership share (%)	
	Polarled Joint Venture	**Aasta Hansteen**
Statoil	50.33 %	75 %
OMW	9.07 %	15 %
ConocoPhillips	4.45 %	10 %
Petoro	11.95 %	
Shell	9.02 %	
Total	5.11 %	
RWE Dea	4.79 %	
Edison	2.40 %	
Maersk Oil	2.40 %	
Gdf Suez	0.49 %	

Table 1 - Overview of Aasta Hansteen and Polarled ownership (Statoil, 2013)

The result of this is that either the tariffs need to be set 56 per cent (100/64) higher than initially planned, or the pipeline will yield a lower return than intended. Statoil, OMW and ConocoPhillips will argue that the tariffs should be based on the volumes that were expected when starting the pipeline project, while Petoro and the other owners will argue that the tariff should be set so that the pipeline yields the 7 per cent government target for its investors. The final outcome is still uncertain.

The situation in the Barents Sea creates a timing paradox. Before the O&G companies feel certain that there will be an infrastructure solution in place, they will be hesitant to explore the region. Likewise, funding new infrastructure will prove difficult until there is absolute certainty that there is enough commercial resources to support the infrastructure. No infrastructure - no exploration, no exploration - not enough resources to justify the infrastructure. In other words, if the infrastructure is not built the resources may never be found and the profitability of a new pipeline or LNG train will remain unknown.

In light of the discussion presented above we have focused this paper on addressing whether the timing paradox is possible to overcome, and more importantly, if the cost of overcoming this problem creates a desirable outcome.

4 Methodology

In order to answer our research problem presented in subchapter 2.1, the thesis is divided into a synthesis and an analytical part. The synthesis seeks to answer the first three sub-questions regarding the resource potential, the market for natural gas and the cost of field development. The analytical part relates to the fourth sub-question and looks at how a potential infrastructure solution could be financed. In addition, the thesis provides an overview on the theoretical framework used in the analytical part.

4.1 The Synthesis

A multitude of sources make up the foundation for the research concerning the resource potential, the natural gas markets, and the cost of field development. The synthesis is based on both primary and secondary data sources.

4.1.1 Primary Data

The primary data used in the synthesis is semi-structured interviews with key stakeholders and interest organizations on the continental shelf. Semi-structured interviews are non-standardized interviews used for exploratory research (Saunders, Lews, & Thornhill, 2003). The researcher has a pre-determined list of subjects and questions to be covered, although these may vary depending on the interview-respondent. Given the exploratory nature of our study, it was important to let the respondent present their perspectives and thoughts on the research question. Semi-structured interviews provided us with the opportunity to acquire in-depth knowledge on topics the respondent felt relevant to cover, and further build our thesis on these responses. An important part of the semi-structured interviews is the interview guide.

4.1.1.1 The Interview Guide[2]

The interview guide was developed after carefully reading available information relevant for our thesis. A general introduction about what we wanted to examine was sent to target companies and organizations a few weeks prior to the interviews, which enabled us to get in touch with people possessing key competence in our area of interest. Spending time on understanding how the natural gas industry works before developing the interview guide, allowed us to focus the interviews on the key discussions related to our topic of research. The first round of interviews were based on the same focal questions, but the focus was adjusted depending on responses from the interviewees. After working with the information collected in the first round of interviews, we found a second round of conversations with the present infrastructure owners and DNB relevant. The interview with the DNB-representatives is only used in the analytical part of the thesis, as this was a discussion exclusively related to financing the infrastructure.

4.1.1.2 The Reliability of the Primary Data

Bias constitute the main concern for the reliability of the semi-structured interviews (Saunders, Lews, & Thornhill, 2003). The first bias to consider is the interviewer bias, which assesses how the behaviour of the interviewer may influence the responses. Commenting on personal bias is always difficult. Yet, when considering the well-prepared interview guide and the purpose of the interview, we believe that interviewer-bias was limited.

[2] The interview guide is available in the appendix

Response bias make up the second source of bias in the semi-structured interview. Response bias occurs prevalently in semi-structured interviews as the purpose of the interviews is to seek explanations (Saunders, Lews, & Thornhill, 2003). Therefore, it is important to consider the personal opinions of the respondents when creating the interview guide. Careful planning increased our knowledge of the topics prior to the interviews, and as the respondents were aware that we had a strong factual understanding, this arguably increased the credibility of the data.

4.1.2 Secondary Data

Like most research, we needed to begin with extensive literature review of earlier studies on our topic of research. By reading and interpreting the secondary data, we acquired knowledge on the topics we wanted to research in the synthesis. The national and international importance of the topics covered has resulted in a number of studies presenting useful information for answering the research question. Considering the magnitude of available data and information, one of the main challenges in the synthesis was to refine the information collected, so that it could be presented in a concise manner.

The secondary data used in the synthesis primarily consists of published reports and statistics from governmental and intergovernmental agencies, published research by accredited academic institutions, and published reports and statistics from industry associations and corporations.

Most tables and figures presented, both in the synthesis and analytical part, has been created for the sole purpose of this thesis, and rely on information from a large number of different sources. For these tables and figures, a detailed list of sources and assumptions can be found in the appendix. Figures that rely on a limited number of sources are referenced directly in the caption.

4.1.2.1 The Reliability of the Secondary Data

When analyzing the secondary data it is important to bear in mind potential biases in the data. If the secondary data collected was collected for a different purpose than the intention of this paper, it is important to assess the data critically so that potential biases are avoided. Once the secondary data is used in the thesis, the reliability of the data becomes our responsibility (Cooper & Schindler, 2001). In our analysis, we were extra cautious for such biases when reading industry reports and statistics from industry associations and corporations, as these might lack neutrality. Most of the data collected by international organizations, governments and academic institutions are of high quality and reliable as they are collected and complied by experts using rigorous methods (Ghauri & Grønhaug, 2010).

4.2 The Analytical Part

In contrast to the synthesis, this part of thesis mainly builds on our ability to perform an independent analysis by applying financial economic theory and the information given from the synthesis. Consequently, this part provides an introduction to the theoretical frameworks relevant for the analysis. Relevant theory is selected by assessing if the theory allows for a deeper, and more holistic insight of the problem. As we look at whether project finance can provide advantages compared to corporate finance for the potential infrastructure development, Modigliani and Millers theory on capital structure has been discussed.

5 Resources on the Norwegian Continental Shelf

In this chapter we will look at whether the resource base and probability of new discoveries is sufficient to justify further natural gas developments in the Barents Sea. We will start with an introduction that emphasize why the Barents Sea has become a relevant region for future natural gas developments.

5.1 The Norwegian Continental Shelf Today

The oil and gas industry in Norway is in a different stage today than just 10-15 years ago. As depicted by figure 4, the overall production of petroleum resources reached its peak around 2004-2005. The production of crude oil had already peaked a few years earlier in 2000. In contrast, the production of natural gas keeps increasing. Currently, crude oil and natural gas contribute an equal share in terms of total production, measured in million standard cubic meter oil equivalents (MSm^3 o.e.). Looking forward, this relationship will continue to skew, as natural gas captures an increasing share of total production output. Estimates also predict that the natural gas will be greater than oil in terms of export value, but this prediction is dependent on the future prices of oil and gas (Ytreberg, 2014).

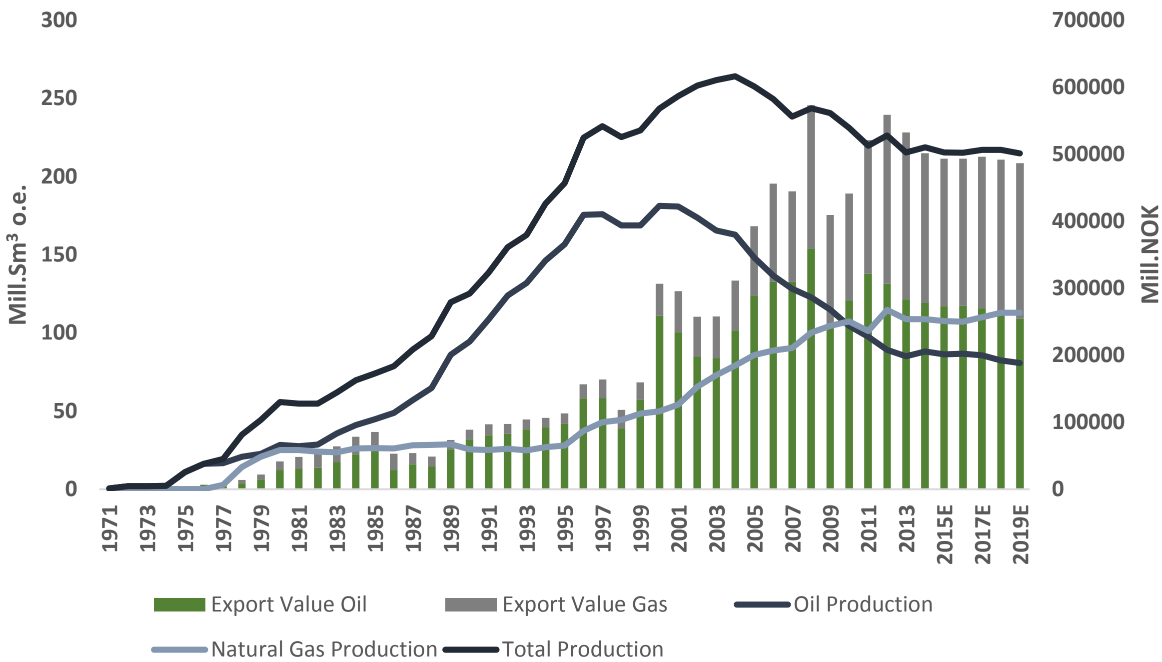

Figure 4 - Historical production and export value of crude oil and gas on the NCS (Norwegian Petroleum Directorate, 2015f)[3] (Statistics Norway, 2015)

Even though the overall petroleum production peaked in 2004-2005, the total cost of production is still increasing. As figure 5 indicates, have the yearly field investments more than tripled in size since the production peak. Many factors contribute to this tenuous link between total production output and yearly field investments. The maturity of the explored regions on the continental shelf and the aging of producing fields contribute to the high investment acitivity. Enhanced recovery rates from fields in production also contribute to the increase in field investments. In addition, persistently high Brent-prices the last 5-10 years have contributed to a lack of cost control in the petroleum sector. Due to the recent fall in the Brent-price, it is anticipated that there will be a slowdown in the field investments the coming 2-3 years. However, the fall in prices is only expected to have short-term effects. A substantial portion of the current field investments are in fields were the initial development took place in the 1970s, 80s and 90s (Norwegian Petroleum Directorate, 2014). These fields will in the coming years require additional investments in order to maintain production capability and technical integrity (Omre, interview, 05.02.15).

[3] Future export value is based on current oil and natural gas prices

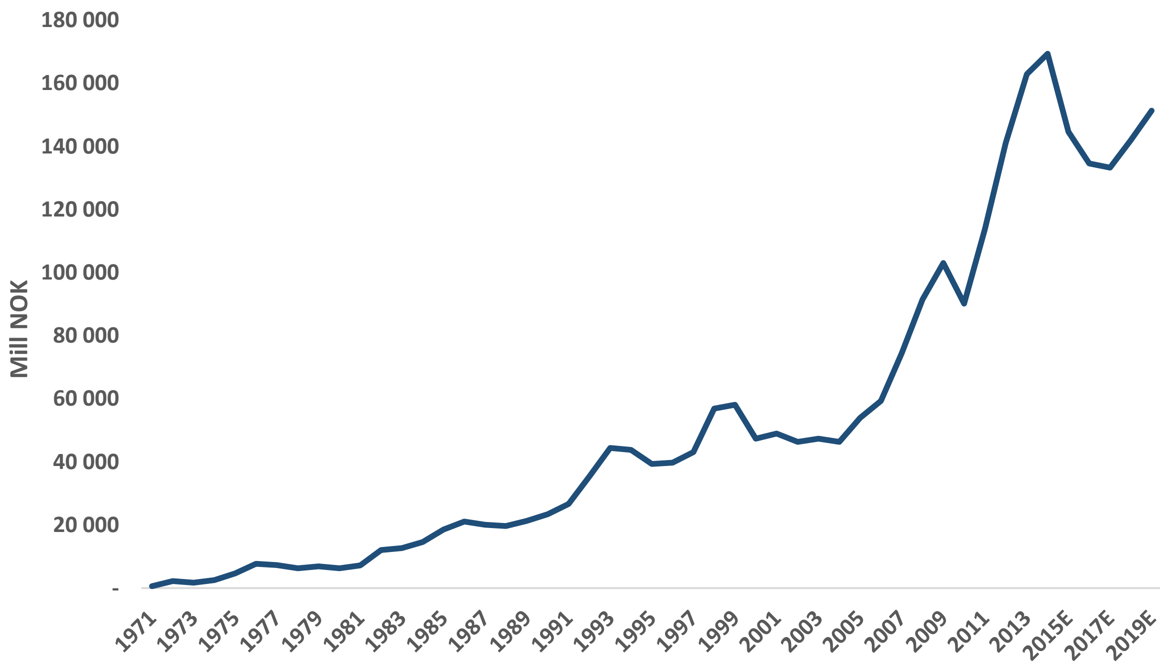

Figure 5 - Yearly field investments (Norwegian Petroleum Directorate, 2015b)

Falling total petroleum production and high expense levels miss the targets of the Government's White Paper from 2011. In order to meet the objectives of a long run value creation in the petroleum sector, the production and activity levels on the NCS need to stabilize. According to the MPE, an aggressive focus on the following three areas is necessary to ensure a stable activity level in the petroleum sector (The Ministry of Petroleum and Energy, 2011):

- Increased recovery rates and production lifetime of discovered fields and for fields already in production.
- Continuing active exploration and research of both mature and immature areas that are open for petroleum activity.
- Conduct opening processes for Jan Mayen and the part of the previously disputed area located west of the delimitation line in the Southern basin of the Barents Sea, which can provide a basis for renewed economic activity in Northern Norway.

New solutions, where the benefits of enhanced and improved oil and gas recovery in existing fields exceed the total costs, will create value in the short to medium run. Exploration in mature areas of the continental shelf will also contribute in this time frame. Meanwhile discoveries of new commercial resources in new and less mature areas achieve the objectives of the petroleum policy in the medium to long term. (The Ministry of Petroleum and Energy, 2011)

5.2 Resource Base

New discoveries on the continental shelf is necessary in order to achieve the objectives of the petroleum policy. Therefore, mapping of the discovered and undiscovered resources is a major priority for the oil industry. The Norwegian Petroleum Directorate (NPD), organized by the Norwegian government, is responsible for mapping the petroleum resources.

According to the NPD, the total amount of recoverable petroleum resources on the NCS is roughly 14.1 billion standard cubic meter oil equivalents (Sm^3 o.e.) The total amount of recoverable petroleum resources is the sum of the already produced and sold resources and the remaining recoverable resources. Today, roughly 45 per cent (6.4 billion Sm^3 o.e) of the total resource base is produced, while the outstanding 55 per cent (7.7 billion Sm^3 o.e.) remain recoverable resources. (Norwegian Petroleum Directorate, 2015a).

According to the NPD, the remaining recoverable resources consist of (Norwegian Petroleum Directorate, 2015a):

- **Reserves**: remaining recoverable volumes of petroleum resources that the license-holder has decided to develop. This include both resources in projects where the Norwegian government have approved a plan for development and operation (PDO), and those that have not yet been approved. Reserves are classified in project status 1-3[4].
- **Contingent Resources**: include petroleum deposits that are proven, but still subject to final development decision. The contingent resources are classified in project status 4, 5 and 7.[5]
- **Undiscovered Resources**: consists of petroleum deposits that are probably present and recoverable, but have not yet been proven by drilling. These resources are classified in project status categories 8 and 9.

[4] A list of the different classifications can be found in the appendix
[5] Category 6, resources whose recovery is not considered commercially viable, are not included in the resource accounts.

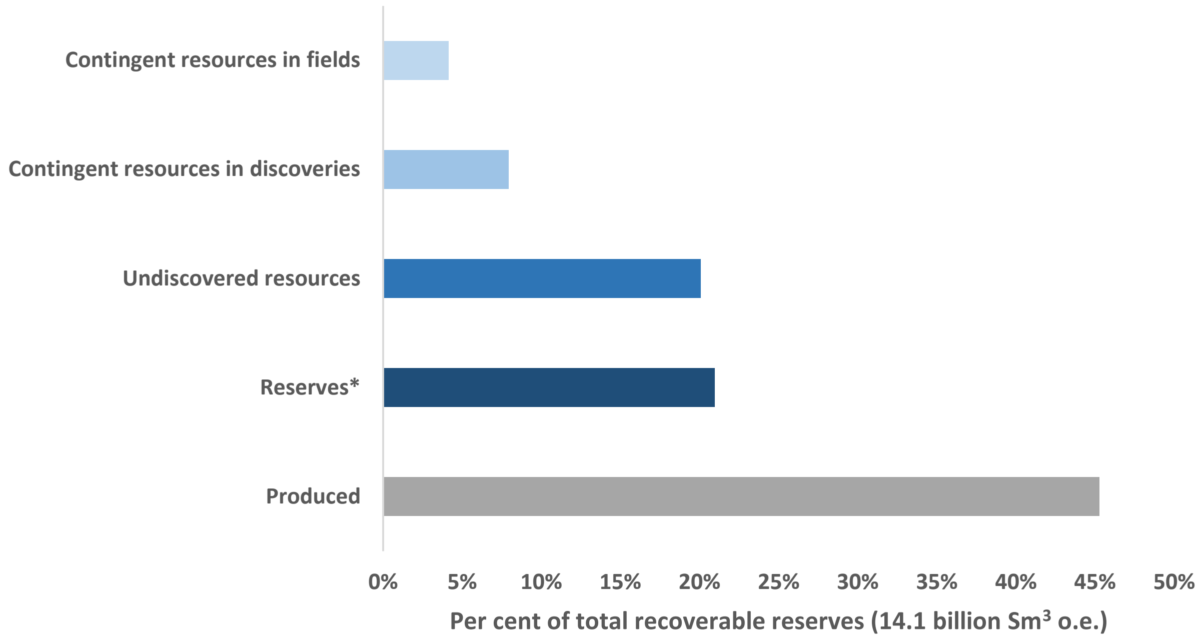

Figure 6 - Total resource on the Norwegian Continental Shelf (Norwegian Petroleum Directorate, 2014)

5.3 Undiscovered Resources

5.3.1 Estimating the Undiscovered Resources

In frontier areas, such as large parts of the Barents Sea, there is limited knowledge of geological conditions. In such little known areas, the uncertainty regarding the undiscovered resources will be related to (Norwegian Petroleum Directorate, 2013):

- The total resources
- The geographical distribution of the resources
- The distribution of resources by size
- The division between oil and gas resources

In order to limit the uncertainty the NPD uses play analysis when mapping the undiscovered resources. A play is a geographically and stratigraphically delineated area (basin) where a specific set of geological factors such as reservoir rock, trap, mature source rock, and migrations paths exist (Norwegian Petroleum Directorate, 2013). These are preconditions for petroleum to be provable. A single play can consist of discoveries and fields, together with mapped and unmapped prospects.

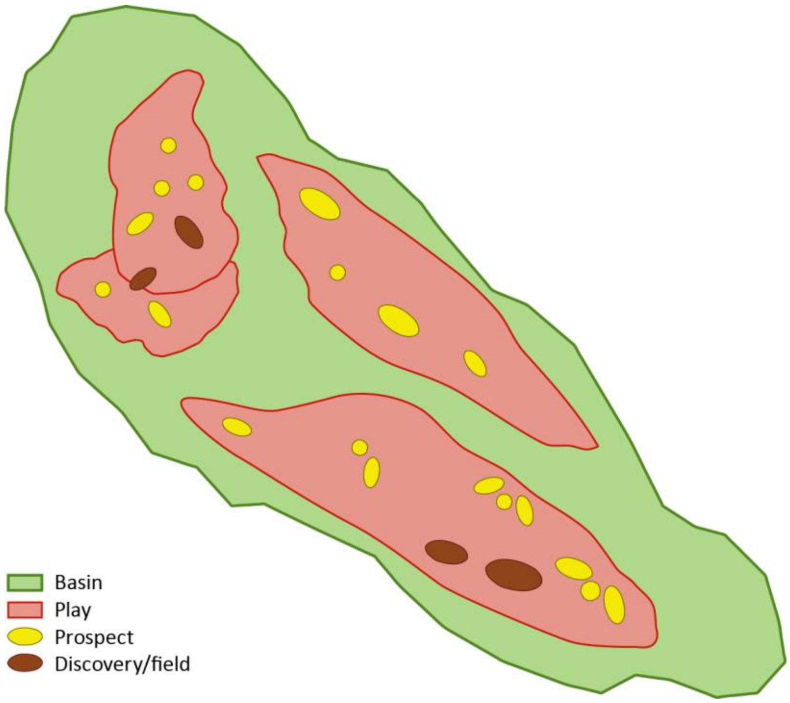

Figure 7 - The relationship between basin, play, prospect and discovery/field

The most fundamental element in a play is the prospects. A prospect is a potential petroleum deposit not yet drilled, but thoroughly mapped so that the quantity of possible producible resource volumes can be calculated (Norwegian Petroleum Directorate, 2013). The number of prospects and how much petroleum each prospect can produce determines the undiscovered resource estimates in a play. The play is unconfirmed until producible petroleum is proved. Uncertainty around the resource estimate must be accounted for if the play is unconfirmed.

Despite almost 50 years of exploration activity and a substantial factual basis of geological conditions, the uncertainty about the size of undiscovered petroleum deposits in the plays remains high. The NPD calculates the probability of success in order to limit the uncertainty in the estimates. The probability of success is a product of the play and the prospect probability (Norwegian Petroleum Directorate, 2013). The play and prospect probability denotes the likelihood for proving producible petroleum in a play and the probability of a prospect to contain the calculated volume of petroleum, respectively.

The probability of success measure the uncertainty in the producible petroleum estimates, and expresses the range of possible outcomes (Norwegian Petroleum Directorate, 2015a). Less knowledge about a play or prospect increases the uncertainty around the estimated resources. When expressing the estimated resources, the NPD specifies an uncertainty range: Low/P95 and High/P05. These uncertainty estimates are calculated using statistical methods, such as Monte Carlo simulations (Norwegian Petroleum Directorate, 2013). The high and low uncertainty estimates can then be described with statistical concepts. The P95-estimates are the conservative/low estimations indicating that, given the assumptions in the analysis, there is a 95 per cent probability of at least finding resource volumes equal to or larger than these estimations. Similarly, the P05-estimate has a 5 per cent probability of finding results equal to or larger than the P05 estimates. The P-value indicates the risk in NPD's estimations. In addition to the P95 and P05 estimates, the statistical resource analysis provides the expected value (P50). The expected value is the arithmetic mean of all the outcomes in the statistical distribution. It has the desired property that the expected value for various distributions can be summed to give a sum of distributions.

5.3.2 Current Estimates

Around 63 per cent (4.9 billion Sm^3 o.e.) of all remaining recoverable resources has been proved by drilling. These resources are found in reserves or are contingent resources in discoveries and fields. The remaining 37 per cent is classified as undiscovered deposits by the NPD. The NPD assumes that these resources are probably present and recoverable, but unlike the reserves and contingent resources, they are not proved by drilling. The undiscovered resources on the continental shelf amounts to 2.835 billion Sm^3 o.e., where 51 per cent is natural gas (Norwegian Petroleum Directorate, 2015a).

The expected value of the undiscovered resources in the North Sea, Norwegian Sea and the Barents Sea is 800, 825 and 1210 million Sm^3 o.e., respectively. As figure 8 illustrates the North Sea is expected to hold the largest undiscovered deposits of crude oil (530 million Sm^3 o.e.), while the largest deposits of undiscovered gas resources (740 million Sm^3 o.e.) is expected to be in the Barents Sea.

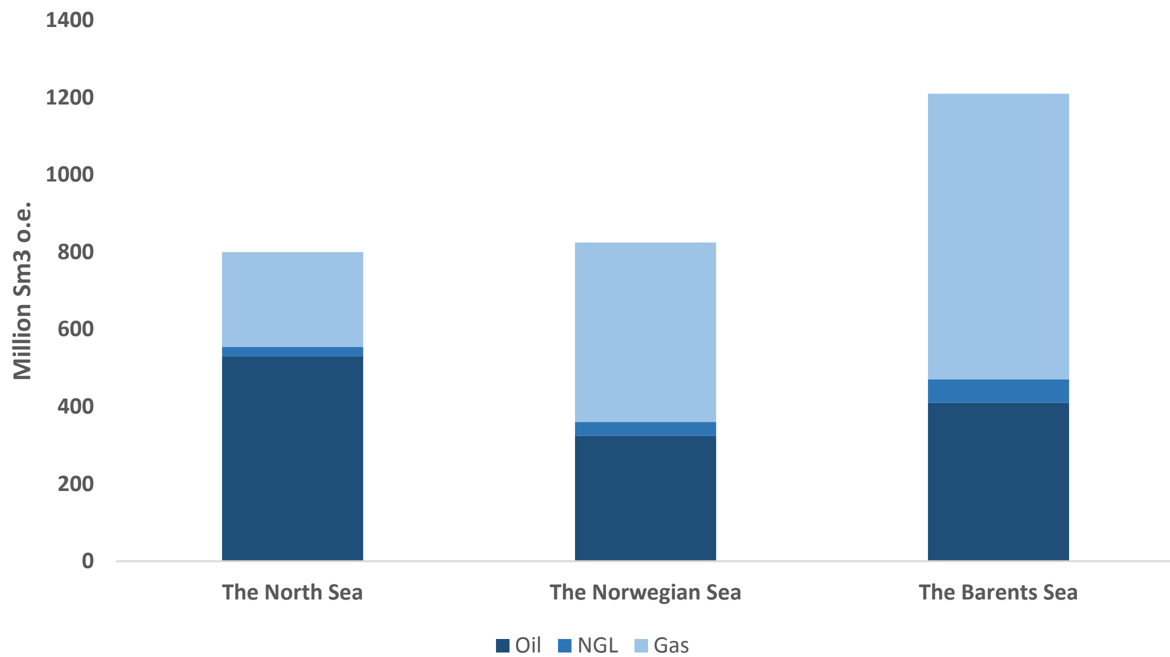

Figure 8 - Expected value of undiscovered resources by source (Norwegian Petroleum Directorate, 2015c)

The uncertainty in the estimates for the North Sea range from 485 (P95) to 1315 (P05), and that of the Norwegian Sea from 240 to 1795 million Sm^3 o.e. (Norwegian Petroleum Directorate, 2015c). The uncertainty range of the aggregated resource potential for the Barents Sea is 300-3040 million Sm^3 o.e. Compared with the two other regions on the continental shelf, estimates indicate that the Barents Sea holds the largest amount of total undiscovered resources. (Norwegian Petroleum Directorate, 2015c)

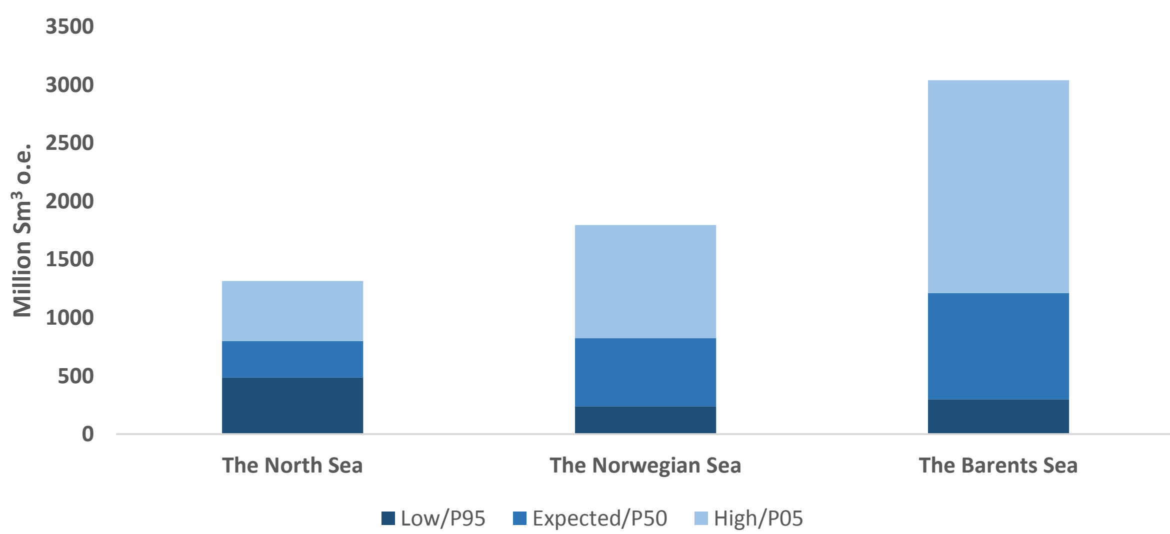

Figure 9 - Low, expected, and high estimates of undiscovered resources (Norwegian Petroleum Directorate, 2015a)

5.3.3 Exploration in The Barents Sea Going Forward

Throughout the history of the Barents Sea as a petroleum region, the mapping and drilling of exploration wells have been campaign based. Such campaigns have involved an extensive focus on the region over short periods. The Barents Sea did especially experience a lot of attention both in the 1980s and late 2000s. In total more than 140 exploration wells have been drilled since the opening in 1980. There are two types of exploration wells: wildcat and appraisal wells. The wildcats are drilled to explore the possibility of finding hydrocarbons deposits under the seabed in not previously explored prospects. If a discovery is made, appraisal wells are usually drilled to obtain more accurate data about the extent and size of the discovery. (Norwegian Petroleum Directorate, 2015d).

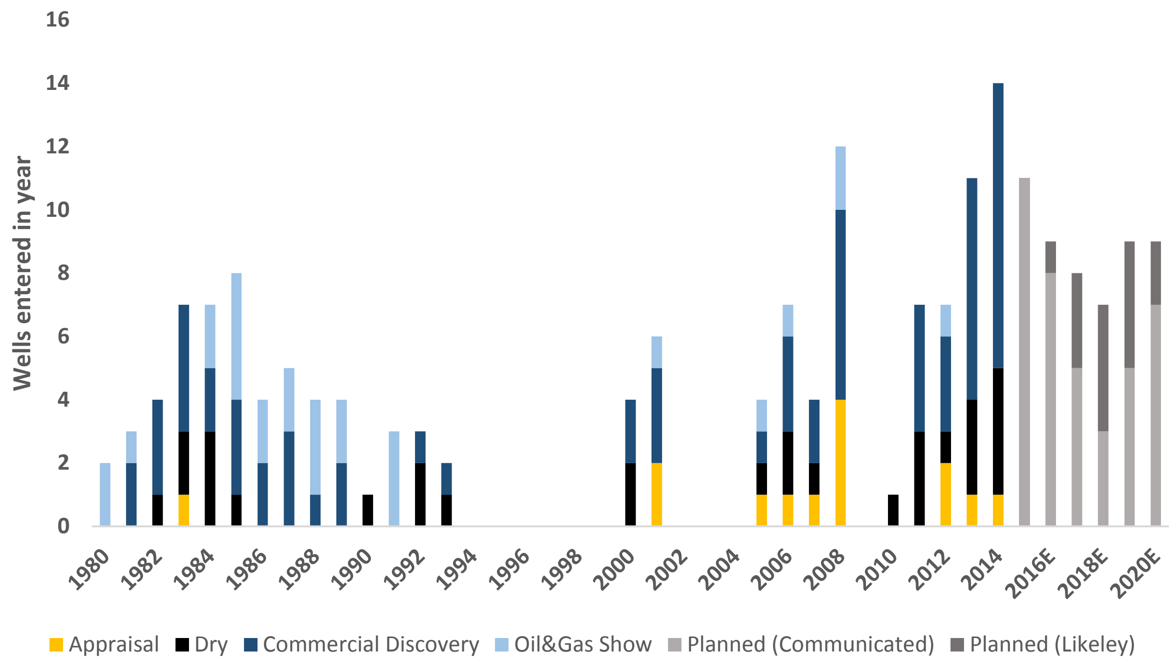

Figure 10 - Barents Sea exploration schedule (NPD factpages,2015) (Rystad Energy, 2014)

Rystad Energy expects the drilling of exploration wells to be on a more consistent basis going forward (Rystad Energy, 2014). Hence, the future drilling schedules in the Barents is expected to be more predictable, with a higher activity level. As seen in the figure above, the exploration wave initiated in 2011 is expected to continue for the coming five years. The oil and gas companies have communicated 39 wells to be drilled in the period, and another 14 wells are anticipated (Rystad Energy, 2014).

In the 1980s several wells showed resources of a commercial standard. Most of the discoveries, including Askeladd, Albatross and Snøhvit, were pooled together to form the Snøhvit-field.

The total deposits of recoverable resources in the region amounts to roughly 500 million Sm^3. At this moment, only the Snøhvit-field (260 million Sm^3)[6] is in production, but the Goliat-field, discovered by ENI in 2000, is set to start production in 2015.

Since 2010, several discoveries have proved to be commercially interesting. The most notable discoveries are Johan Castberg and Drivis discovered by Statoil in 2011 and 2014, the Gotha and Alta-prospect discovered by Lundin in 2013 and 2014, and Wisting discovered last year by OMV. In total, nine discoveries were made in the Barents Sea last year in which 5 were commercially interesting (Norwegian Petroleum Directorate, 2015d). Figure 11 shows the aggregated exploration results in the Barents Sea, since the opening of the region in 1980.

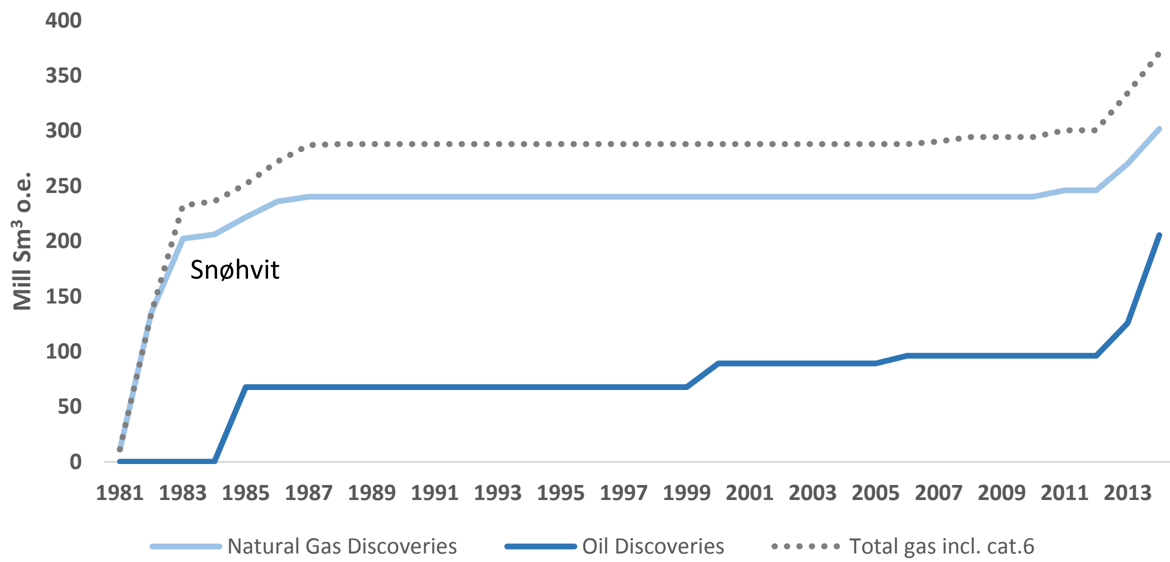

Figure 11 – Proved resources in the Barents Sea (NPD factpages, 2015)

5.4 Concluding Remarks

This chapter explains whether the resource base and the probability of new discoveries in the Barents Sea is sufficient to justify the development of a new infrastructure solution in the region. We believe that the gas resource estimates for the region elucidate the need for a new gas infrastructure solution in order to facilitate further field developments.

However, our point of view is that the proven resource base is not sufficient to justify building a new infrastructure solution. The claim is supported by calculations explained in subchapter 8.4.1, regarding

[6] 219 million Sm^3 o.e. of natural gas, 41 million Sm^3 o.e. of liquids

how the amount of discoveries relate to the transportation needs. The immaturity of the region might be part of the explanation for why such a large share of the resources is yet to be discovered. It is however possible that the timing paradox also have been contributing factor. This means that the limited exploration activity over the last 20 years is caused by lacking infrastructure. On the other hand, the planned exploration schedule indicates that O&G companies believe the region has potential, but it does not necessarily indicate that they are looking for natural gas. According to Oyvind Rummelhof is "oil driving the exploration in the Barents Sea. If we find gas we are not interested" (Rummelhoff, interview, 03.02.15). This indicates that the timing paradox will not be solved without intervention or a new approach to share the cost of a common transportation solution. Hence, we believe that it is appropriate to further assess whether it is profitable to build an infrastructure solution that solve the timing paradox.

6 The Natural Gas Markets

In this chapter, we will discuss whether the market for natural gas will be attractive enough to justify the investment in a new infrastructure solution from the Barents Sea. The chapter focuses on three main markets, Europe, the US and Asia, with emphasis on the European market. In excess of 98 per cent of Norwegian natural gas export goes to Europe, and consequently Europe is the most important market (Enerdata, 2014). Asia has recently been the region with the most attractive natural gas prices, and can be reached from Norway with LNG carriers. Assessing whether this market can be attractive enough to justify shipping gas the additional distance, is important as infrastructure solutions vary in terms of delivery flexibility. The US market is relevant to assess as it determines how much, and at what cost, US LNG can reach global markets and is thus an important element of the competitiveness in natural gas markets going forward. We discuss how gas prices have evolved across the world, and provide an estimate of where the prices are heading.

6.1 Historical Development

6.1.1 The European Market

Since the late 1990s, the natural gas market in Europe has gradually become quite similar to a traditional commodity market. This has not always been the case. In its developing phase during the 1960s and 1970s, all the natural gas was sold on legally binding long-term contracts (Rogers & Stern, 2014). The gas was sold to one or a limited number of large buyers, who had to commit contractually to agreed volumes of gas. This ensured underwriting the development of upstream producing gas fields and the transportation infrastructure from those field locations to the markets. The price was partly fixed and partly linked to the price of oil products (i.e. gas oil and fuel oil). (Rogers & Stern, 2014, p.2-10) As there was no gas price on which to base the long-term contracts, heating oil seemed a sensible alternative as a competitor fuel. For the suppliers it was difficult to take advantage of regional or national price differences since it was hard moving the point of delivery between different receiving terminals. It was equally difficult for buyers to move and trade volumes on the European continent. Thus, oil indexing was used to provide necessary price security for both the suppliers and buyers. (Froley, 2015)

There is still a link between natural gas and oil prices, but the relationship is weaker. The reason coming from the emergence of gas hubs importing both LNG and pipeline gas, giving increased supply flexibility, and an increasingly interconnected pipeline system enabling natural gas to be transported across borders. As the countries in Western Europe and Great Britain have the flexibility to trade and physically move natural gas across regions, the price differences between the different hubs in Europe have diminished and the natural gas prices have declined.

While Europe as a whole has continuously been moving away from oil-indexation, accounting for 43 per cent of total gas consumption in 2013, the move towards gas-on-gas competition has not been universal. In Central Europe, the Mediterranean region and South-Eastern Europe oil-indexation is still dominating. (The Market Observatory for Energy European Commission, 2014) The oil-indexed contracts often allow a flexible offtake, meaning that the buyers can adjust their offtake between 80-120 per cent of an agreed amount (Rogers & Stern, 2014, p.2). This means that when oil prices fall, and the oil indexed contracts become cheaper than the hub prices, it causes a 120 per cent off-take as the buyers see an arbitrage opportunity by selling oil indexed gas at the hubs. In the end, this arbitrage closes, meaning that the hub prices also decline. Often the oil-indexed contracts are based on the average oil price the last 6-18 months, meaning that the gas price to some extent follows the oil price with a time lag.

6.1.2 The Asian Market

Since Japan started importing LNG in the end of the 1960s, Asian countries have been highly dependent on LNG supplies (Enerdata, 2014). China is an exception as the country has domestic production and has been importing pipeline gas from Central-Asia and Myanmar. When the Asian LNG import wave started, the price was fixed, causing few problems until the substantial increase in oil prices in 1973, putting LNG at a discount to oil (International Energy Agency, 2014b). In the 1970s, LNG and oil were competitive energy sources for power generation. Consequently, the LNG suppliers gradually introduced long-term contracts where the price of LNG was indexed to crude oil prices. Today, most Asian natural gas contracts are linked to the Japan Custom-cleared Crude index (JCC). The JCC is the weighted average price of Japanese oil imports. Figure 12 illustrates the importance of the Asian markets for global LNG demand.

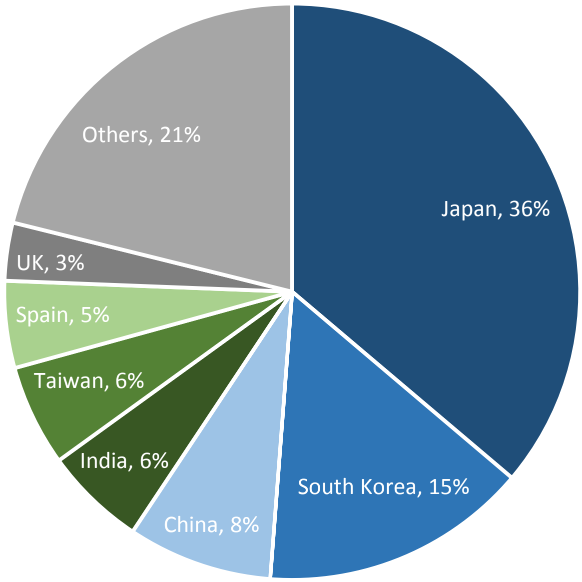

Figure 12 - LNG Imports 2014 by country – total 246 million tons per annum (Wood MacKenzie, 2015)

Since the Fukushima nuclear disaster, Japan has relied on energy generation from non-nuclear sources. This has led to soaring prices of LNG, as the bargaining power of Japanese utilities was week due to the urgent need for additional natural gas volumes, in an already supply constrained market (International Gas Union, 2014, p.15). In July 2012, LNG spot prices reached a historic high of $18.07/Mbtu. However, the prices have declined since the oil prices started to drop in the second half of 2014. The price the last day of February 2015 was down to $13.39/Mbtu. This price is the Japan LNG Corporation's index, which is based on monthly surveys of what natural gas importers paid for their acquired volumes. Other indices indicate an even more severe drop in prices. The Platts JKM Index, which is a benchmark for spot LNG delivered to Korea and Japan, indicated a year-on-year drop in prices of more than 60 per cent from March 2014 to March 2015. In March 2014 the JKM prices reached an historic high of 20.20/Mbtu. By comparison, March-delivery JKM prices in 2015 averaged $7.44/Mbtu, the lowest since June 2010. (PR Newswire, 2015)

6.1.3 The US Market

In the US, there has been an independent market for natural gas since the 1920s when natural gas was discovered in the American southeast. Initially, long-term contracts were the norm, and prices differed across the country. This started to change in the late 1970s, when price controls gradually started to be removed and the spot market started to evolve. (Moniz et. Al, 2012) Since then, the price has been highly correlated with the price of crude oil until the mid-2000s. Historically natural gas in the US has been priced at a thermal parity discount of around 40 per cent compared to oil, meaning that if oil prices where USD100 you would pay USD60 for the same amount of energy in the form of natural gas (Erdôs & Ormos, 2012). However, when the shale gas revolution started this relationship changed as the natural gas prices fell drastically while the oil prices soared. Before the oil prices started to decline in July 2014, the natural gas was priced at a thermal discount of 77 per cent to oil. This means that while oil was trading at around $100 per barrel for West Texas Intermediate (WTI), the price of the equivalent amount of energy in natural gas was around $23 per barrel of oil equivalent.[7]

6.1.4 Shared Characteristics

Looking at the historical development in the key natural gas trading regions, two shared characteristics are the increasing importance of gas-on-gas competition and the emergence of spot markets. 44 per cent of the world pipeline imports, and 29 per cent of LNG, has prices determined by gas-on-gas competition. The share of LNG traded on short-term contracts (less than 4 years) has been growing steadily from approximately 5 per cent in 2000 to around 65 per cent in 2013. (International Energy Agency, 2014b, p.20-22) The change form long to short-term contracts intensify the competition in the LNG market, and is a shift towards market driven pricing.

The figure below shows the historical spot prices at key trading areas. The NBP, TTF and Zeebrugge are three main trading hubs in Europe, located in Great Britain, The Netherlands and Belgium, respectively. As a result of a more spot driven market, these hubs have become much more liquid in the past decade (Medbøen, interview, 04.02.15)

[7] ${}^{\$}/_{Mbtu} * 5.8 = \$/BOE$

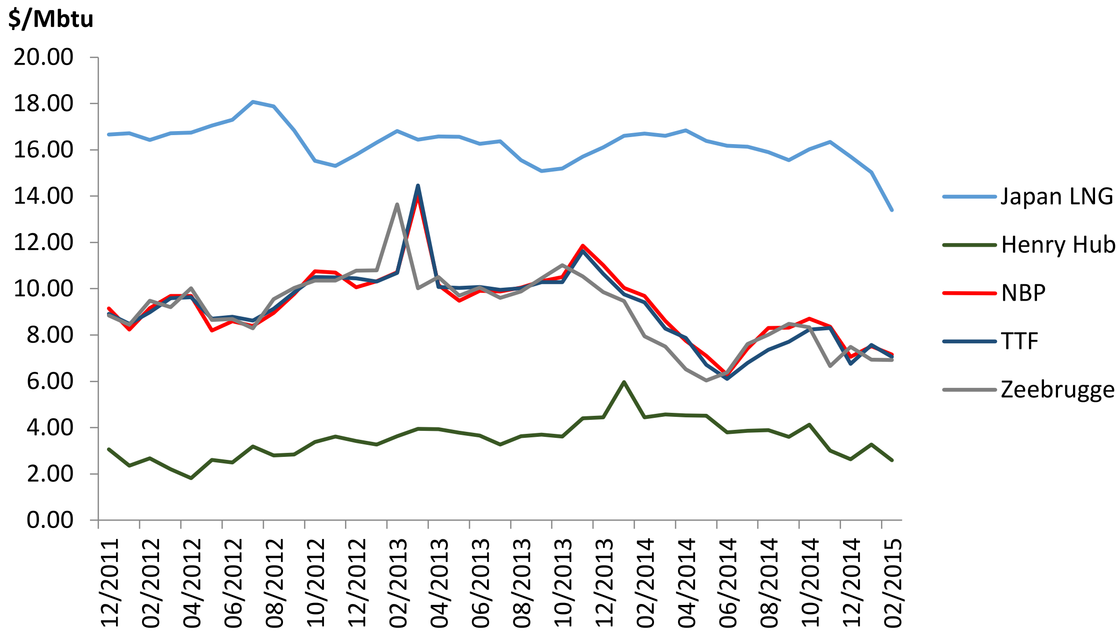

Figure 13 - Development of natural gas spot prices (Bloomberg Terminal, 2015)

6.2 The Changing Demand for Natural Gas

According to the IEA World Energy Outlook 2014, natural gas will be the fastest growing fossil energy source towards 2040. The global consumption is estimated to grow by more than 50 per cent over the course of the next 35 years. (International Energy Agency, 2014a)

6.2.1 The European Market

Europe's consumption is expected to stay below 2010-level until 2030. However, imports are expected to increase as the domestic production in the EU is expected to decline. (International Energy Agency, 2014a). One reason for the slow growth in natural gas consumption is the reemergence of coal in the energy mix. The shale gas revolution in the US has led to an increasing share of surplus coal being shipped over the Atlantic from the US to Europe. Being the most carbon intensive energy source, the growth of global coal consumption needs to slow down for Europe to reach the Intergovernmental Panel on Climate Change’s 2-degree target (International Energy Agency, 2014a). Another factor is the growing share of electricity generated by renewable energy sources. Figure 14 illustrates the total electricity generation in terawatt hours (TWh) for natural gas in Europe from 1990-2012.

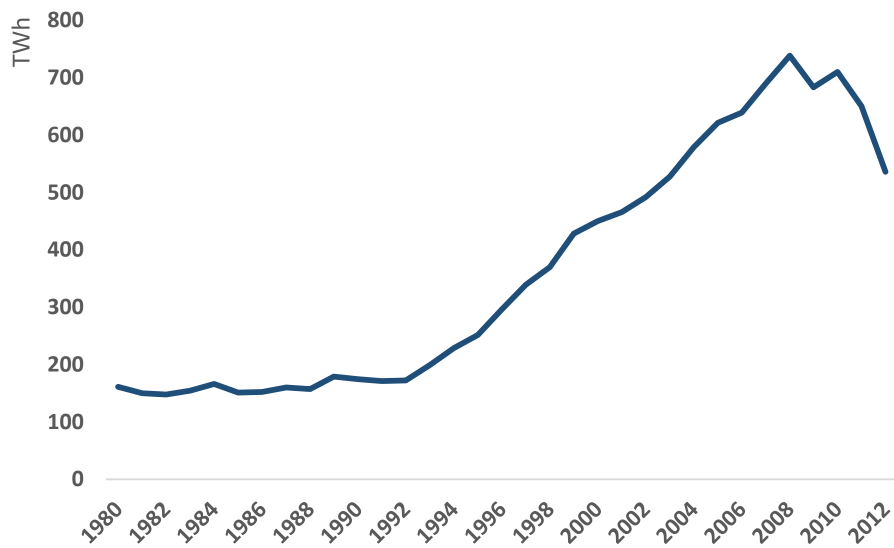

Figure 14 - Electricity generation from natural gas in the EU (The World Bank, 2014)

Coal and renewables have taken market shares from natural gas in electricity generation. Globally, electricity is expected to be the fastest growing final form of energy towards 2040, with an expected annual growth in demand of 2.1 per cent. However, in Europe, the annual growth rate over the next 35 years is expected to be only 0.7 per cent p.a. Slow economic -and population growth are the main reasons why Europe's electricity demand will grow at a slower pace compared to the rest of the world. Measures to improve energy efficiency are also part of the explanation. (International Energy Agency, 2014a)

Still, looking at electricity consumption does not offer the full explanation for the expected development in Europe’s natural gas demand. Figure 14 depicts that Europe’s trend in electricity generation is less important as is accounts for a small share of the total natural gas consumption on the continent.

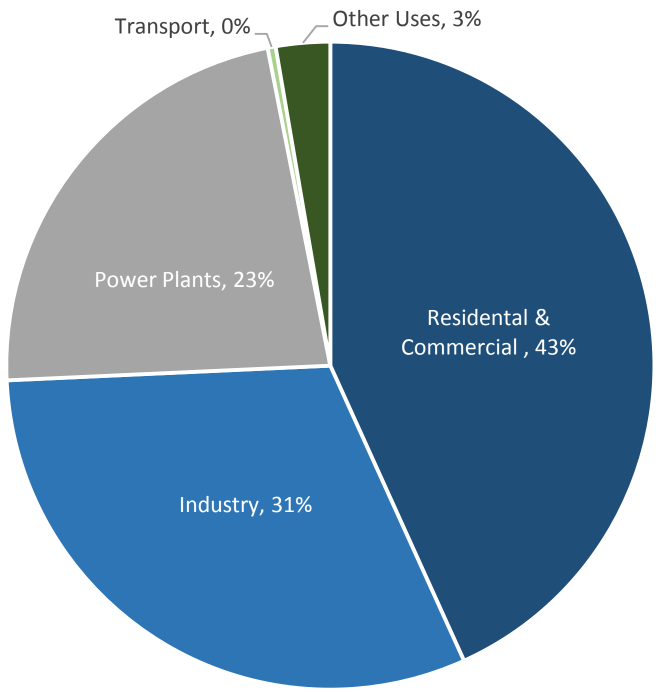

Figure 15 - EU28 Natural gas sales by sector (Eurogas, 2014)

As seen in figure 15, in excess of three fourths of the total consumption goes to other applications than power generation. Fuel switching in these sectors takes more time, and is actually expected to contribute to increased use of natural gas going forward (International Energy Agency, 2014a). The residential and commercial share of the consumption refers to natural gas used directly for heating homes, commercial buildings, and for cooking food. This demand varies with weather conditions, but is stable in terms of maintaining market share. The potential efficiency gains for this part of the consumption are also limited (International Energy Agency, 2014a). The share of industry using natural gas directly as feedstock is expected to increase due to fuel switching, but this increase in demand is expected to be partly offset by efficiency gains.

The cooling relationship between the EU and its main supplier of natural gas, Russia, has created political ambitions to reduce Europe's dependence on Russia’s main gas exporter, Gazprom. In the 1980s, the United States were actively lobbying for Western Europe to reduce its dependence on Soviet gas, and the US took an active position in promoting gas deliveries from Norway. In 1986, when the deal between Norwegian authorities, Ruhrgas, and Gas de France was reached regarding developing the natural gas resources from the Troll field. The price was according to analysts twice as high as current levels (Tagliabue, 1986).

Whether it is possible to find buyers in Europe, still willing to pay this kind of premium is doubtful. Still, there is a preference for Norwegian gas compared to Russian gas and we believe this will continue to be the case in the future.

6.2.2 The Asian Market

As previously discussed, the price of natural gas in Japan skyrocketed in 2011 because of the Fukushima nuclear accident. The accident caused the country to shut down all its nuclear power plants. As Japan has no domestic gas production or pipeline connection, the accident created an additional demand for LNG. The total consumption grew by 22 per cent between 2010 and 2012, but has since leveled off due to energy conservation measures triggered by high LNG import prices and the fact that gas fired power plants already were operating at high load factors (International Energy Agency, 2014a). In April 2014, Japan introduced a new strategic energy plan, which outlines a systematic reintroduction of nuclear power to the domestic energy mix. As a result, the natural gas consumption is expected to be back at pre-Fukushima levels in 2020 (International Energy Agency, 2014a). As Japan is by far the world's largest importer of LNG, the drop in LNG prices, has significantly pulled into question the profitability of the planned LNG export projects around the world (Meyer, McLannahan, & Hume, 2014)

China and India are expected to see the largest growth in natural gas demand between 2012 and 2040. These two countries combined stood for less than 6 per cent of global gas consumption in 2012, but this figure is expected to increase to almost 10 per cent in 2020 and 15 per cent in 2040 (International Energy Agency, 2014a). In China, gas will play an important role in mitigating coal use and related air pollution in cities. Thus, the Chinese government has introduced price reform initiatives, to bring domestic prices to levels that incentivize the development of domestic resources as well as covering the average costs of imported gas. Unlike many other Asian countries, China produces most of the gas it consumes domestically (72 per cent in 2012). The domestic production in China is expected to account for more the half the volumes consumed, somewhat limiting the need for imports. (International Energy Agency, 2014a)

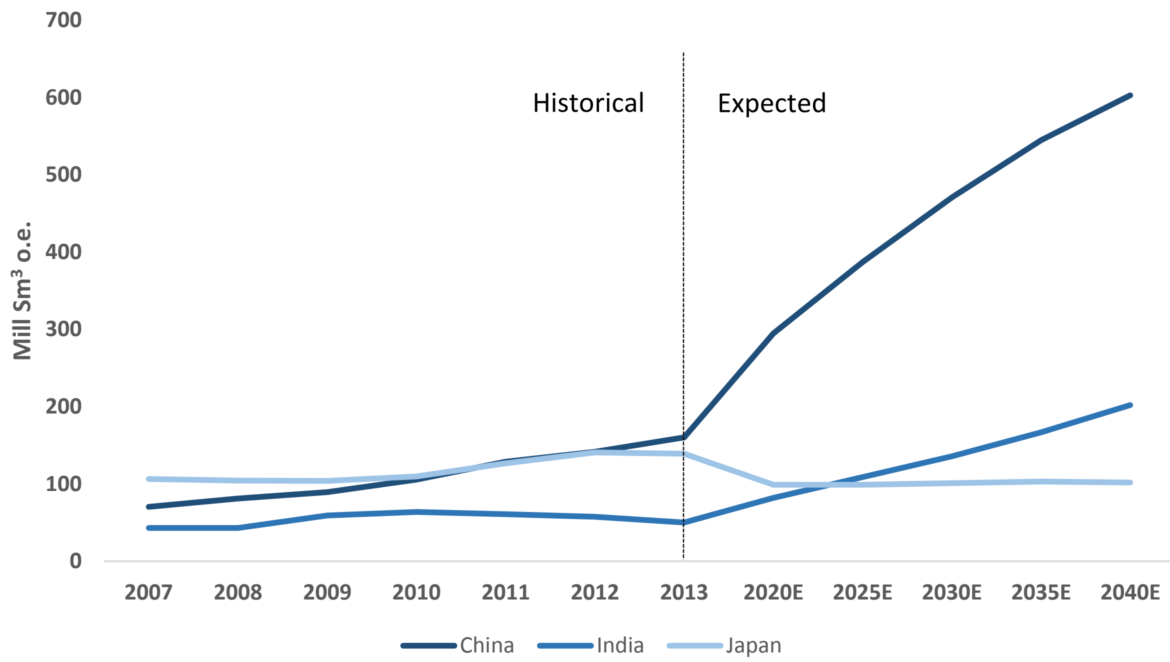

Figure 16 - Natural gas consumption in key Asian markets (Enerdata, 2014) (International Energy Agency, 2014a)

6.2.3 The US Market

The US accounts for in excess of 20 per cent of global natural gas consumption, and demand is expected to increase at an average annual growth rate of 0,7 per cent towards 2040. Ample supply and new policies that favor gas utilization over other fossil fuels in power generation and end-use sectors, are the reasons why natural gas consumption will increase and capture market shares from coal. Before the shale gas revolution, the US where set to be a net importer of natural gas, with supplies coming from Canada and from LNG (among others from Snøhvit LNG in Norway). Now the US is set to become a net exporter. However, how much gas that will be exported depends on the domestic US gas prices, and if the price difference compared to other regions will justify LNG exports.

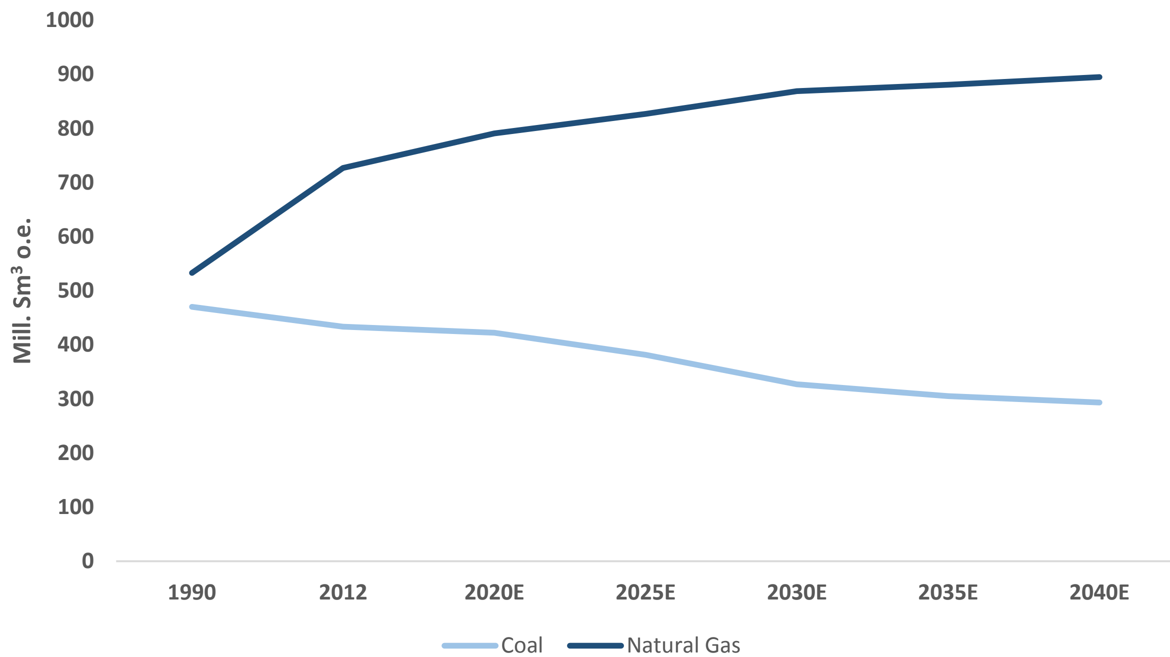

Figure 17 - Coal and natural consumption in the US (International Energy Agency, 2014a)

6.3 Price Expectations

Predicting future prices is a challenging exercise and unforeseen events can suddenly change dynamics of supply and demand drastically. The US shale revolution and the Japanese Fukushima disaster epitomize this.

We believe that gas prices going forward will be determined by supply and demand, meaning the oil-linked contracts will continue to be phased out. In the long run natural gas competes with all alternative energy sources like hydropower, wind, solar and coal. Oil is different since its high energy density gives a unique advantage for the transportation sector. The price of natural gas will thus in the end need to be competitive compared to other sources of energy.

"I do not think you ever will see the link between oil and gas back the way it used to be. The prices will be delinked. Oil and gas covers two completely different needs in the market" (Pettersen, interview, 04.02.2015)

6.3.1 The European Market

For power generation in Europe, natural gas is cheaper than renewables, but more expensive than coal. However, it is important to note that political ambitions to reduce carbon emissions, and in some countries phase out nuclear, will have an impact on the competitiveness of different energy sources. In Germany for example, the political program “Energiwende” set ambitious targets to increase the share of renewables in the energy mix, reduce carbon emissions, and at the same time phase out nuclear energy. The EU has set a target to reduce the overall greenhouse gas emissions from its member states by 20 per cent compared 1990 levels, by 2020. (European Commission, 2014) To reach this target, carbon emission taxation will have to be increased, providing a comparative advantage for natural gas compared to coal. We argue that increased carbon taxation will increase both the price of electricity and the price of natural gas. We therefore expect natural gas prices to increase slightly from current levels, as the low cost competitor, coal, will compete with a tax disadvantage.

The current price of gas in Western Europe is $7/Mbtu. US LNG exporters need a price of about $8/Mbtu to break even with current Henry Hub prices ($2.78/Mbtu) (EY, 2012). This will to some extent put a price ceiling for gas in Europe, as pipeline exporters will have to match the price of LNG to maintain their market share. The cost of bringing new supplies to Europe is believed to be about $7.50-$9.50/Mbtu. In the long-run prices will have to match the cost of bringing in new supplies.

“At some point in time, the price will reach an equilibrium were the producers break even. This will probably happen in Europe, but it will slightly depend on what Russia and Qatar will do if they try to undercut, as they can deliver cheap pipeline gas and LNG. If you look at what it cost to bring in new supply, either from Siberia, Haltenbanken or elsewhere, it will probably be around $7.5-9.5/Mbtu.” (Rummelhoff, interview, 03.02.15)

Our estimate of the natural gas prices in Europe going forward is $8/Mbtu. We believe that this is a conservative estimate, making it appropriate to use in further assessments of the infrastructure solutions.

6.3.2 The Asian Market

We argue that as the Asian spot markets continue to evolve, the premium Asia has been paying for LNG is likely to diminish. This argument is further supported by the China-Russia pipeline gas deal signed on May 21 2014. The agreed volume at 38 BCM/year represents almost 1.5 times the current Chinese LNG imports. The price at the Chinese border has not been officially disclosed, but consensus lies at $10/Mbtu (International Energy Agency, 2014b). Since Russian pipeline gas enters the Asian markets at prices significantly below LNG imports there may be the start of the convergence in prices between Asia and Europe. Russia will soon have the ability to move supplies from Siberia to both Europe and Asia, paving the way for a more integrated Eurasian market.

Up until now, most LNG projects have been structured in the same way as a point-to-point pipeline project, linking the resources to a defined set of buyers. Over time, the international LNG trade is set to open up, gaining characteristics similar to a standard commodity market. An important driver of this change is that a small but growing share of international trade is taken by LNG marketers, known as aggregators, that sell gas from a global portfolio and look for arbitrage opportunities between various regional import prices. (International Energy Agency, 2014a)

Shale gas production in China is also a major uncertainty for future LNG needs (International Energy Agency, 2014b). China is currently the largest shale gas producer outside North America, and the government has set aggressive targets for increasing its production. The wellhead prices of Chinese shale are currently around $10/Mbtu. (International Energy Agency, 2014b)

In Asia, LNG import prices differ widely from delivery to delivery, depending on what type of contract the gas is bought on. In 2012, China imported some LNG from Australia and Kazakhstan based on old long-term contracts to a price of $3/Mbtu, and some spot LNG from Qatar to $18/Mbtu. (International Energy Agency, 2014b)

- *"Large LNG liquefaction projects in Australia are soon coming on stream. Then you have Qatar with stable deliveries to the Asian markets. So I don't think the large price differences in LNG is sustainable"* (Moræus Hansen, interview, 04.02.2015)

- *"The imbalance (in gas prices between continents) cannot last forever. It is enormous investments being made to close this gap"* (Omre, interview, 05.02.2015)

We estimate that the natural gas prices in Asia will decline, reaching an average of $10/Mbtu. Prices might differ slightly between countries that have domestic production and access to pipeline supplies, and counties that is fully dependent on LNG, like Japan and South Korea. However, the difference will be limited as an arbitrage from moving LNG from mainland Asia to these countries will be closed, due to LNG traders seeking a profit from regional price differences. A final argument supporting a price estimate of $10/Mbtu, is that US LNG export deliveries to Asia break even at this price (International Energy Agency, 2014b)

7 Field Development Cost

Estimating the field development costs for natural gas resources is difficult as each field is unique and requires different technical solutions (Omre, interview, 05.02.15). However, estimating a range of the likely break-even costs is important to complete the analysis regarding whether it is profitable to develop the Barents Sea resources.

In the table below, we have compared the Snøhvit LNG development in the Barents Sea with the Ormen Lange and the Aasta Hansteen natural gas developments in the Norwegian Sea. Ormen Lange and Aasta Hansteen utilize pipeline infrastructure.

	Recoverable Reserves (BCM)	**Infrastructure (MNOK)**	**Field development (MNOK)**	**Total cost (MNOK)**	**Production (BCM/year)**	**Field development cost/Recoverable Reserves (NOK/ Cubic Meters)**
Snohvit LNG	218.7	39,300	19,000	58,300	5.8	0.087
Ormen Lange	283.7	46,800	19,200	66,000	25.0	0.068
Aasta Hansteen	46.5	24,100	30,100	54,200	5.2	0.647

Table 2 - Field development cost compared to recoverable reserves (Detailed list of sources in the appendix)

The field development cost for Snøhvit and Ormen Lange accounts for approximately one third of the total project development costs. This is in line with estimates for developments in the Barents Sea, which are that one third of the necessary investments will be related to infrastructure (Gassco, 2014). Aasta Hansteen is an exception, as the infrastructure accounts for more than half of the total investments. However, this infrastructure is planned to cover several fields in the area, which are to be developed later.

The single most important factor for determining the field investment cost per unit of gas is the size of the recoverable reserves in the field (Torvund, interview, 04.04.2015). As can be seen in table 2, Ormen Lange and Snøhvit with its considerable larger reserves, have a field development cost to recoverable reserves which is about 1/10 of that of Aasta Hansteen. This lower field development cost make these developments much more robust towards the fluctuations in the natural gas market than the Aasta Hansteen field (Torvund, interview, 04.04.2015).

There is a natural link between the size of the reserves and the annual production. The annual production will gradually be reduced over time due to the declining pressure in the reservoir. A high annual production volume in the beginning of a field's life will improve the economics of a field development. However, this will have to be optimized accounting for the additional investment required to increase the capacity at both the field level and in the infrastructure. As a rule of thumb, the majority of the total reserves should be produced over a period of 10-15 years (Torvund, interview, 04.04.2015).

Figure 18 illustrates the difference in the capital cost measured in USD per Mbtu for Snøhvit, Ormen Lange and Aasta Hansteen. The discount factor has been set to 8 per cent, and the regularity is set to 100 per cent for simplicity.

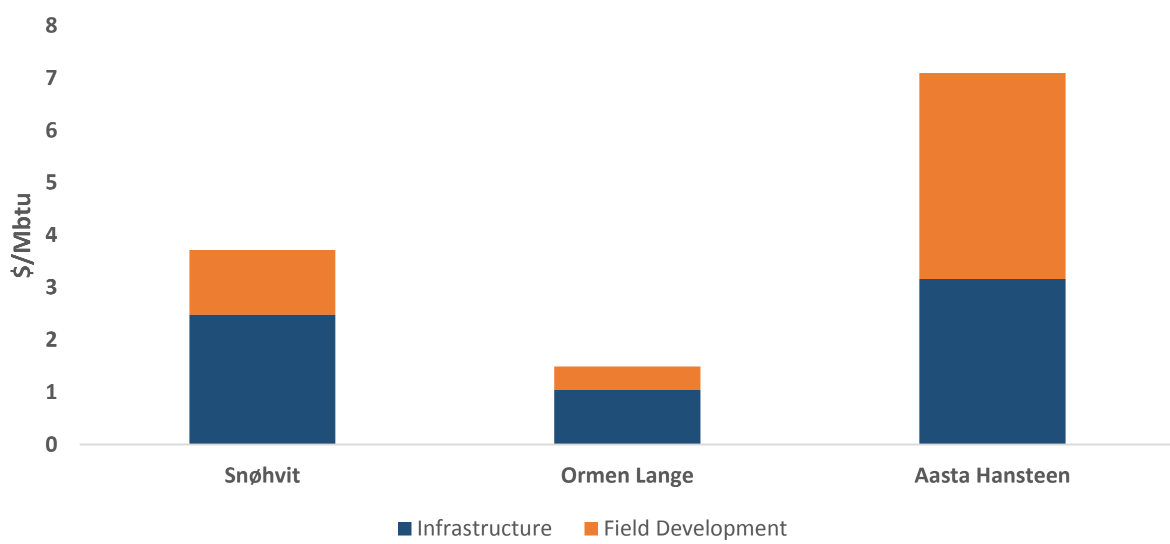

Figure 18 - Capital cost of selected natural gas developments on NCS (detailed list of assumptions in appendix)

In addition to the initial field development costs, the projects require that new production wells are drilled during the course of the projects lifetime to maintain production. The number of new wells that have to be drilled depends on the characteristics of the reservoirs (Torvund, interview, 04.04.2015). These investments have not been included in the calculations.

Field development cost is dependent on field specific characteristics such as distance to shore, sea level, reservoir characteristics, development concepts, and environmental requirements. Even ultra large fields can end up undeveloped, due to the particularly challenging nature of the Barents Sea region, and distance from existing infrastructure. The Shtokman gas field, located on the Russian side of the Barents Sea, is the largest discovered offshore gas field ever. Found in 1988, it is expected to hold approximately 3800 BCM of recoverable gas, almost 3 times as much as the Troll field. The location of Shtokman, 600 km from shore in the harsh Arctic environment, has caused it to be left undeveloped. Statoil who was selected to be a partner in the project wrote down its investment in 2012 and returned its shares to Gazprom.

Shtokman might be a particularly challenging project, and the fact that it lies in Russian waters might be a contributing factor for why it still is undeveloped. Still, challenges concerning distance to shore and weather conditions are also present on the Norwegian side of the Barents Sea, and these can have a significant impact on the cost of field developments.

Many factors influence the profitability of the natural gas deposits in the Barents Sea. The most important will be the size of total reserves per field. “The main challenge for an infrastructure development in the Barents Sea is the lack of a major gas field, which could be developed at competitive unit cost and thereby be the building block for a pipeline connection to the Norwegian Sea” (Torvund, interview, 04.04.2015)

It is difficult to apply a benchmark for the development cost as each prospect has field specific characteristics. However, as the Aasta Hansteen field is similar in size to several proven fields in the Barents Sea, like Norvarg, we choose to use this field as a proxy for the development costs. **Thus, our estimate of field development cost for further analysis is $3.9/Mbtu.** If larger fields are proven in the future, the development costs are likely to be lower.

8 Infrastructure

So far, we have concluded that the resource potential, the market price, and the cost of field development can justify further assessments of whether the resources can be profitably developed. In this chapter we evaluate different infrastructure alternatives, which allows for determining the costs that the natural gas can be transported to the markets.

8.1 Possible Transportation Solutions

There are three main options for capitalizing on the natural gas resources in the Barents Sea. One alternative is to use the natural gas locally, either by converting it to electricity and sell it on the grid, or use it directly as feedstock in local industry. Converting it to electricity will require investments in new high-voltage cables to increase the transfer capacity between Northern and Southern Norway, as well as the transfer capacity between Norway and Europe. This option is challenging since transporting electricity over large distances leads to quite large power losses.

Using natural gas directly for industrial applications involves building up a new demand. The petrochemical industry, production of fertilizers, metals, pharmaceuticals, plastics, and tiers are examples of industries that use natural gas directly as feedstock. Several gas rich nations have focused on developing a local demand for their resources, like Qatar where Norsk Hydro produce aluminum as a result of low energy prices. Taking into account that the gas in the Barents Sea requires large investments in upstream installations we argue that it will not be economically viable to sell locally. This conclusion is drawn primarily from the prices the fields have to match, which is at least those in the US of about $3/Mbtu, if not those in the Middle East. For energy intense industries to stay competitive, they need competitive prices on their most important inputs (Torvund, interview, 04.04.2015).

The other two options involve exporting the natural gas directly. This can be done either by pipeline or by ship. There are three main ways to transport natural gas by ship; cooled, compressed, or converted to liquid fuels. In industry terms, the options are liquefied natural gas (LNG), compressed natural gas (CNG) or gas to liquids (GTL).

8.1.1 Pipeline

The vast majority of Norwegian natural gas is exported via pipeline, which accounts for more than 93 per cent of total export volumes. In 2013, close to 90 per cent of Europe's gas imports came via pipeline, while the remaining share came in the form of LNG. Europe consumes 500 BCM of natural gas (2013), and imports in excess of 50 BCM of LNG. The remaining 450 BCM is transported via the pipeline system from sources located close and far from the market, especially from Europe, North Africa and Russia. (BP, 2014)

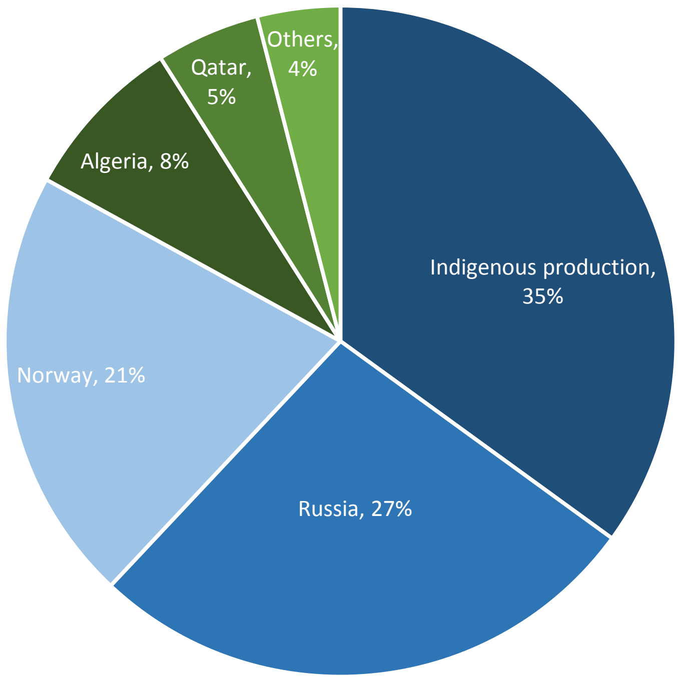

Figure 19- Breakdown of EU-28 natural gas supplies (Eurogas, 2014)

The key advantage of a gas pipeline is the volume flexibility. Since building overcapacity is relatively cheap, a pipeline can be scaled to take large additional volumes with little new investments involved. Pipelines have been the preferred choice for transportation of natural gas for a long time, especially for large volumes. The world's largest pipeline, the Nord Stream subsea pipeline, provides a direct link between Russia and Germany and transport 55 BCM per annum. The Troll gas field on NCS is also a major contributor to the German pipeline system, and the field alone produced 29 BCM in 2014 (Gassmagasinet G21, 2015). Capex in pipeline projects vary on a wide range of factors, including whether it is onshore or offshore, the capacity, the length, and the geological conditions of the terrain/seabed.

We argue that USD/BCM/meter is a good “bang-for-the-buck” indication when comparing pipeline projects as it accounts for both capacity and length. Table 3 shows the cost and capacity numbers for various pipeline projects around the world. We see that Barentspipe rank in the middle on the cost-capacity comparison, given the cost estimates provided by the Barents Sea Gas Infrastructure-forum. (Gassco, 2014)

Cost capacity rank	Project	Length (km)	Capacity (BCM)	Diameter (Inch)	Capex (MUSD)	USD/BCM/meter
1	Langeled	1,166	26	44	2,720	91.5
2	Europipe 2	642	24	42	1,690	109.7
3	Franpipe	840	19	42	1,866	116.9
4	North Stream	1,222	55	4x48	11,264	167.6
5	South Stream	925	63	4x32	12,800	219.6
6	**Barentspipe**	**1,000**	**45**	**42**	**10,000**	**222.2**
7	Blue Stream	396	16	2x24	1,700	268.3
8	ITGI	217	10	32	640	294.9
9	Europipe 1	670	18	40	3,750	310.9
10	Medgaz	210	8	24	806	479.8

Table 3 – Cost and capacity comparison of various pipeline projects (detailed list of sources in the appendix)

8.1.2 Liquefied Natural Gas (LNG)

Liquefied natural gas, or LNG, is natural gas cooled to minus 162 degrees Celsius, where it turns into a liquid. In this state, the gas takes up about 1/600 of the volume of its gaseous state, which makes it possible to transport significant volumes by ship. (Jensen, 2004, p.5)

LNG achieves a higher reduction in volume than compressed natural gas (CNG), which is about 2.4 times less energy dense. However, LNG is still less energy dense and it has a lower value per unit of energy compared to crude oil. The result is that the value of the cargo of two similar sized vessels, an oil tanker and a LNG carrier, is quite different at current prices. This means that shipping is a much more important cost component in the LNG value chain compared to crude oil. Table 4 illustrates the difference in newbuilding price between oil tankers and LNG carriers and the difference in value of the cargo.

	Type	Newbuilding price (Mill.$)	Capacity	Energy carried (Mbtu)	Price ($)	Value of cargo ($)
DHT Lion	VLCC	96.5	2.2 million barrels	12,122,000	65/bbl	143,000,000
Front Idun	Suezmax	65	1.1 million barrels	6,061,000	65/bbl	71,500,000
Golar Snow	LNG Carrier	200	160k cubic meters	3,776,000	10/Mbtu	37,760,000

Table 4 - Comparison of crude oil tankers and LNG carriers (all vessels delivered in 2015) (Clarksons, 2015)

The LNG market has been growing since the new millennium, partly because of new technology improving the profitability, and partly because of large regional price differences. Prior to 2000, LNG was mainly confined to markets lacking alternative supply options, therefore excluding sale to regions that had access to pipeline gas. However, new gas producing regions such as Trinidad and Tobago and Qatar entered the market, and these entrants were able to deliver at cost levels that challenged energy prices even in developed markets. (Songhurst, 2014, p.4)

LNG liquefaction capacity is measured in million tons per annum (mtpa). In 2014, 246 mtpa were produced in the world, which equals approximately 340 BCM. Another 30 mtpa is scheduled to be added in 2015 (Wood MacKenzie, 2015)

The capital cost of liquefaction has quadrupled since year 2000. Capital cost of liquefaction is measured in $/ton per annum (tpa), meaning the project's capex divided by annual output of LNG. This provides a measure of capex ($) to capacity (tpa). Norway's only LNG liquefaction plant, Snøhvit LNG, had a record capex/capacity[8] ratio when it was completed in 2007 (Songhurst, 2014, p.23). Figure 20 illustrates the steep increase in capital costs the last 15 years.

[8] Measured at $/tpa

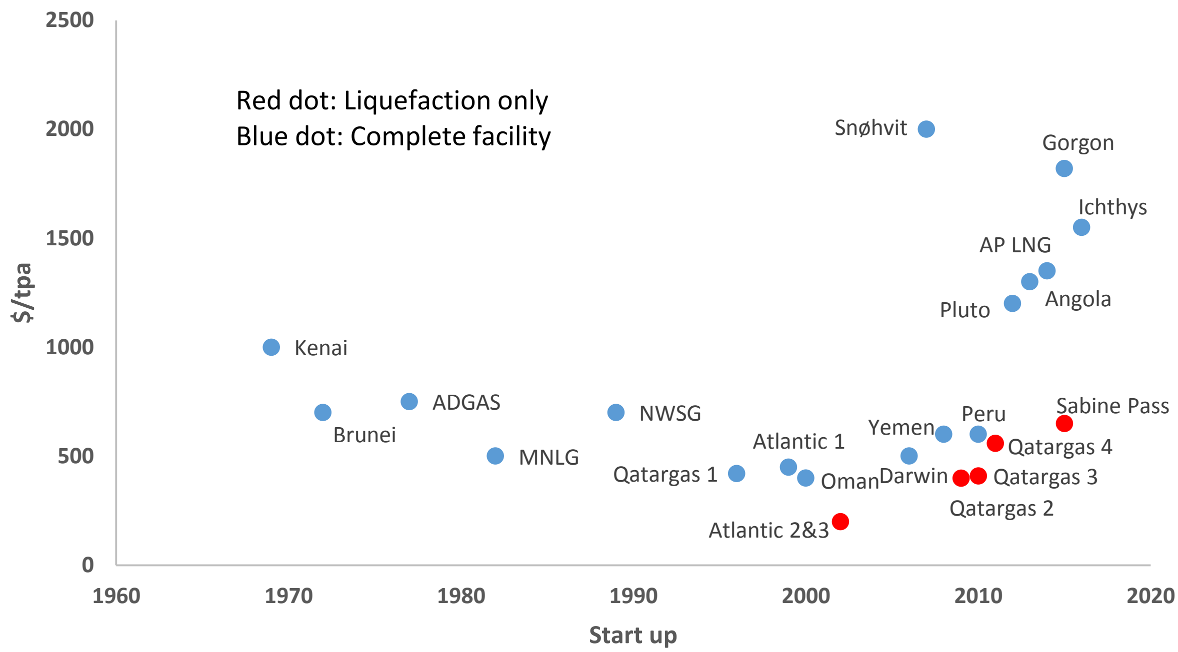

Figure 20 - Capital cost of liquefaction for various LNG projects (Songhurst, 2014)

8.1.3 Compressed Natural Gas (CNG)

Compressed natural gas is gas turned into liquid form by applying high pressure. As CNG occupies more than twice the volume compared to LNG, more vessels are needed to transport the same amount of natural gas. The advantage of CNG is that the compression and decompression facilities are less expensive than liquefaction and regasification plants. This implies lower capex and higher operational expenditures (opex) than LNG. (Coselle, 2015)

CNG carriers utilize a new and unproven technology, which is not yet tested on a commercial scale. The first commercial CNG vessel is scheduled for delivery in May 2016 to the Indonesian state-owned energy company Perusahaan Listrik Negara (Wainwright, 2014). CNG is considered a viable transportation option for markets that are 1000 km or less from the source of the natural gas. As the distance from the market increases, LNG or gas to liquids (GTL) become more favorable, assuming that sufficient volumes of gas are available. The threshold volumes required for CNG are expected to be relatively small compared to LNG and GTL. (McIntosh et al., 2001)

CNG could be a viable alternative for transporting associated gas from oilfields in the Barents Sea. However, as the distance to the closest market is in excess of 2000 km, current CNG technology will not provide an economical solution for pure gas developments.

8.1.4 Gas to Liquids (GTL)

Turning natural gas into liquid fuel (GTL) has been done on a small scale since the 1920s. Large-scale GTL plants are relatively new. Qatar has the only operating commercial large scale plant, and there is another being planned in Louisiana. These plants convert natural gas into diesel fuel by applying a technique called Fischer Tropsch technology. In areas of the world with large price differences between natural gas and oil, this technology could offer an attractive opportunity. In Qatar for example, the domestic price of gas is $1/Mbtu, which means that even with low oil prices converting gas to diesel could make sense. Global GTL production is about 215,000 bpd, but the output is projected to increase to 360,000 bpd in 2025 and 1,000,000 bpd in 2040 (International Energy Agency, 2014a).

GTL plants exist in areas where there is a large price difference between oil and gas, meaning that gas sells at a significant discount in terms of thermal parity. Due to high capex associated with GTL projects, it is difficult to make GTL profitable with oil prices below $80/bbl. Even with optimistic capex estimates of $100,000/bpd, natural gas needs to be valued at a discount in excess of 70 per cent compared to oil to be profitable (Salehi, Nel & Save, 2013). This means that for GTL to be profitable with current oil prices at $65/bbl, the feed gas must have a price below $3.25/Mbtu for the plant to deliver an internal rate of return around 10 per cent. The development of the plant in Louisiana has been postponed due to low oil prices, which could be a sign that the price spread needs to be even larger to turn a profit (McGroarty & Sider, 2015). On the other hand, the decision to postpone the plant was made in late January 2015, when WTI traded below $50 and Henry Hub at $2.9/Mbtu. A 70 per cent thermal discount of $50 oil would give a gas price of $2.5/Mbtu, meaning that the spread was below 70 per cent at the time.

For associated gas, where the alternative is reinjecting the gas to the reservoirs, the feedstock price for GTL is close to zero. This means that, under the assumption that bringing the gas to shore is relatively cheap; GTL could be a viable alternative in the Barents Sea. Small sized GTL plants for associated gas are relatively small and simple, and can thus be placed offshore on the production platform. (Kelly-Detwiler, 2013)

8.2 Choosing the Right Infrastructure

8.2.1 General Assessments

A general rule of thumb goes that if the gas needs to be transported more than 2,500 kilometers, LNG is the best solution (White, 2012). For shorter distances pipeline is more economical. In the oil and gas business, each project is different, and it is therefore important to be careful when relying on historical data for making investment decisions. In the Barents Sea, the distance to the European markets is approximately 3,000 kilometers; however, 2/3 of the distance is already covered by the existing pipeline system, which will have free capacity to take on additional volumes from the next decade and onwards (Aarhus & Nestass, interview, 06.02.15). When comparing pipeline and LNG, it is also important to address which markets the solutions enable the gas to reach. The potential benefit that LNG can provide in terms of delivery flexibility will be discussed later in this segment.

GTL and CNG on a commercial scale are both new and unproven technologies. It is therefore difficult to say under which circumstances these technologies are advantageous. The first ever CNG vessel is currently under construction for the purpose of transporting natural gas to remote islands in Indonesia (Wainwright, 2014). Fields that have a short distance by sea and a water depth that makes subsea pipelines challenging, is possibly where the advantages of this technology comes clear. For GTL, low oil prices have reduced the attractiveness of the technology in areas were the gas alternatively can reach the market in its original form. GTL emits very high levels of CO_2 compared to the other alternatives, which will reduce its economic potential in countries like Norway where CO_2 emissions are taxed. We argue that the future for GTL could be for associated gas in remote areas on shore, where the oil is transported from the production sites by railway, or where gas transport is challenging for other reasons.

The table below presents the characteristics of the different transportation solutions. Pipeline and CNG are similar in that flexibility regarding the point of delivery is limited. GTL and LNG on the other hand, make it possible to achieve the highest prices in the market. Further, LNG and pipeline are similar in that both technologies are well proven on a commercial scale, while GTL and CNG, with the capacity needed for exploiting pure gas developments in the Barents Sea, exist on a very limited scale.

	Capex estimator	Capacity (16 BCM/year)	Capex (MNOK)	Price of output	Value of output per day (NOK)
Pipeline	$222/BCM/m	45 MSm3/day	75,000	$8/Mbtu	95,350,500
LNG	$2000/mtpa	12 mtpa	180,000	$10/Mbtu	119,188,125
GTL	$135,714/bpd	140 000 bpd	142,500	$65/bbl	68,250,000
CNG	N/A	N/A	N/A	$8/Mbtu	95,350,500

Table 5 - Comparison of technologies, equal capacity (16 BCM/annum)

The capex estimates in table 5 are based on similar projects in the case of LNG and GTL. The GTL cost estimate is based on information about the Shell Pearl GTL in Qatar, which is the only existing GTL plant of this scale. The LNG estimate is based on capex from Snøhvit LNG, and then scaled to size. As discussed has the cost of LNG liquefaction quadrupled since 2000 (Songhurst, 2014). The cost may decrease through learning curves, but there is no evidence of this happening. The economies of scale for LNG liquefaction has historically been limited for plants with capacity over 5 mtpa, meaning that a plant with 10 mtpa costs about twice as much as a plant with a capacity of 5 mtpa. The pipeline capex is based on the Barents Sea Gas Infrastructure research report from Gassco (Gassco, 2014).

It is important to note that the value of output per day does not include natural gas liquids (NGL). In the case of Pear GTL for example, the facility produces 120,000 barrels per day of NGL in addition to the GTL. As NGL is priced quite equal to oil per barrel, this significantly changes the project economics. The NGL will however be produced regardless of infrastructure solution chosen, and can therefore be left out when comparing the alternatives.

In conclusion, we believe that pipeline and LNG are the most attractive alternatives for pure natural gas developments in the Barents Sea. These technologies are well proven and suit the characteristics of the region. We will therefore focus the rest of this segment on these alternatives.

8.2.2 Pipeline Capacity Flexibility

For a pipeline, the cost/capacity relationship is far from linear. This means that when there is potential of linking an uncertain amount of resources to a market with excess demand, building overcapacity often makes sense. The Barents Sea is an immature and relatively unexplored petroleum province, with a good chance of finding large volumes of natural gas. As mentioned earlier, the Troll gas field produced 29 BCM in 2014, close to 80 MSm^3/day. The 42-inch pipeline that the industry suggests as a possible solution for the Barents Sea has an initial capacity of 45 Msm3/day (Gassco, 2014). However, a relatively modest investment of MNOK 6,000 in increased compression can increase the capacity to 72 MSm^3/day. In comparison, increasing LNG export capacity by the same amount would cost close to MNOK 110,000, based on the $2,000/tpa benchmark estimate.

	Original capacity	Additional capacity	Measures needed	Cost (MNOK)
Pipeline	45 Msm3/day	27 Msm3/day	Increased compression	6,000
LNG	12 mtpa	7.3 mtpa	1 large LNG train	109,500

Table 6 - Additional capex needed to increase capacity

8.2.3 LNG Flexibility Value

The number of LNG receiving terminals around the world has increased drastically since 2008. By the end of 2013, 29 countries had LNG import capacity, compared to 18 countries in 2008. The global receiving capacity (regasification capacity) was 688 mtpa, compared to the 291 mtpa liquefaction capacity (IGU, 2014). The difference in import and export capacity is expected to become smaller as US and Australian projects come on stream, but the market is still expected to be supply constrained in the years to come. This means that LNG exporters have had the opportunity to direct their supplies to the most attractive markets. (IGU, 2014)

Modern LNG vessels can transport gas over long distances with very little loss of energy (boil off) (Hammer, interview, 19.05.2015). This has given LNG exporters the opportunity to direct their supplies to wherever they can get the highest prices, without being constrained by distances. LNG from the US east coast is intended to supply the Asian markets, and shipments of LNG from Snøhvit has found its way from the Barents Sea to Japan through the Suez-canal.

The access to global markets is a clear benefit for LNG exporters. However, some LNG import terminals might be intended rather as a bargaining chip than an actual supply source of gas. In Lithuania for example, the pipeline system is more than capable of supplying the demand, but an LNG receiving terminal has still been built to diversify the source of supply. In 2013, the average utilization rate of European LNG receiving terminals was 26 per cent (IGU, 2014). However, the utilization rate of the 120 mtpa of US regasification capacity was 1.4 per cent the same year. These terminals were built before the shale gas revolution, when importing LNG in to the US was believed to be an attractive opportunity.

8.2.4 Optimal Scale

The optimal capacity of infrastructure will be different depending on the solution. The cost/capacity relationship for an LNG facility gives an incentive to scale the facility to match the discovered commercial recourses, while the economies of scale in a pipeline project gives incentives to build overcapacity to retain the potential upside. The LNG solution suggested by the industry is one LNG train of 5 mtpa, while the pipeline discussed has a capacity of 45 MSm^3/day (Gassco, 2014).

	Capex estimator	Optimal scale	Capex (MNOK)	Price of output ($/Mbtu)	Value of output per day (MNOK)
Pipeline	$222/BCM/m	45 MSm^3/day	75,000	8	95
LNG	$2,000/mtpa	5 mtpa	75,000	10	49

Table 7 - Comparison of technologies, optimal scale

In conclusion, the optimal transportation solution will depend on two factors. The effect of the LNG flexibility value and pipeline capacity flexibility will be examined in the following segments. Further in the analysis, we look at both LNG and pipeline infrastructure, and discuss how different financing approaches will affect the overall profitability of these potential developments.

8.3 Theoretical Framework on Financing Alternatives

The remaining parts of this chapter are related to financing the infrastructure. In this first segment, we will discuss the theoretical framework that is used as a foundation in these assessments.

8.3.1 Capital Structure

Modigliani and Miller assert that capital structure is irrelevant for the weighted average cost of capital if the following conditions are met (Miller & Modigliani, 1958):

- No taxes
- No transaction costs
- No bankruptcy costs
- Equivalence in borrowing costs for both companies and investors
- Symmetry of market information, meaning that companies and investors have the same information
- No effect of debt on a company's earnings before interests and taxes

This theorem is referred to as Modigliani & Miller Proposition II. It explains that the cost of equity depends on three things: the required return on the firm's assets, R_A, the firms cost of debt, R_D, and the firms debt-equity ratio, D/E. (Ross, et.al, 2006)

$$R_E = R_A + (R_A - R_D) * (D/E)$$

Equation 1 - M&M Proposition II

The required return on the firm's assets, R_A, is equal to the weighted average cost of capital, $WACC$. $WACC$ is given by the following equation (Stephen A. Ross, 2006):

$$WACC = \left(\frac{E}{V}\right) * R_E + \left(\frac{D}{V}\right) * R_D$$

Equation 2 - Weighted Average Cost of Capital

Where V is the value of the firm's assets, E is the value of equity, and D is the value of debt.

Combining M&M Proposition II with the WACC formula, shows that the $WACC$ does not depend on the debt-equity ratio. The change in capital structure weights, E/V and D/V, is exactly offset by the change in the cost of equity, R_E, so the $WACC$ remains unchanged.

In order to make investors willing to finance a project, it has to generate a return that is greater than the weighted average cost of capital. When introducing taxes, leverage is relevant for determining the optimal capital structure, and the corresponding minimum weighted average cost of capital. This is because of the interest tax shield, which is the tax saving attained by a corporation from interest expenses (Ross et.al, 2006). The fact that interest is deductible for tax purposes generates a tax saving equal to the interest payments multiplied by the effective tax rate. For offshore activities on the Norwegian Continental Shelf, the effective tax rate is 78 per cent[9]. Hence, the effect of leverage on the weighted average cost of capital is substantial. The static theory of capital structure states that a firm borrows up to a point where the tax benefit for an extra dollar in debt is exactly equal to the cost that comes from the increased probability of financial distress.

[9] Both LNG and pipeline infrastructure is considered offshore activity

$$WACC = \left(\frac{E}{V}\right) * R_E + \left(\frac{D}{V}\right) * R_D * (1 - T_c)$$

Equation 3 - Post tax WACC

Where V is the value of the firm's assets, E is the value of equity, D is the value of debt, and T_c is the effective corporate tax rate.

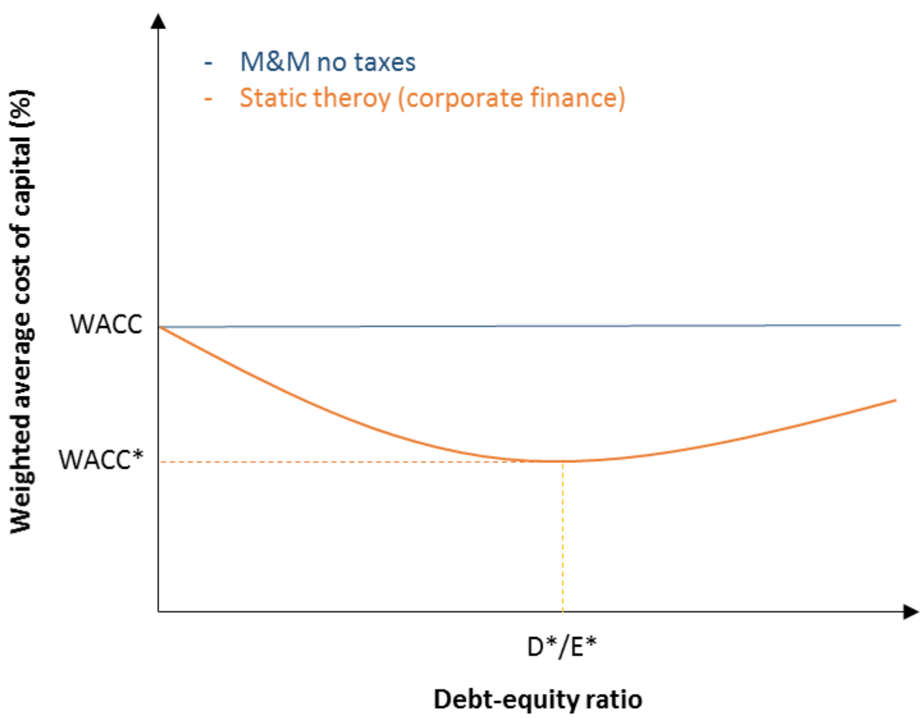

Figure 21 - The Static Theory of Capital Structure (Stephen A. Ross, 2006)[10]

Everything equal, reducing the WACC increases the net present value (NPV) of the project. However, the goal when determining capital structure for gas infrastructure is not to maximize NPV, but to minimize the tariffs/tolling fees required. The objective is that the value creation should happen when producing the resources, and not be captured in the infrastructure (The Ministry of Petroleum and Energy, 2013, p.6-7). For evaluating infrastructure alternatives, we argue that tariffs/tolling fees should be set to a level that gives the project an internal rate of return (IRR) equal to the WACC. In other words, we look at what level the tariff/tolling fees need to be in order to make the NPV of the infrastructure project equal to zero.

[10] D*/E* marks the optimal capital structure

8.3.2 Project Finance

In this section, we argue that a project finance approach will reduce the weighted average cost of capital. Project finance is the structured financing of a specific economic entity, referred to as the project company or a special purpose vehicle (SPV) (Gatti, Project Finance in Theory and Practice, 2013). Brealey, Cooper and Habib (1996) and Kim and Yoo (2008) characterize project finance by all of the following conditions occurring together: separate incorporation, non-recourse debt, high debt levels, detailed long term contracts, and the use of the incorporated entity to fund a single-purpose capital asset with finite life whose composition is not altered during the course of the entity's life (Sawant, 2010).

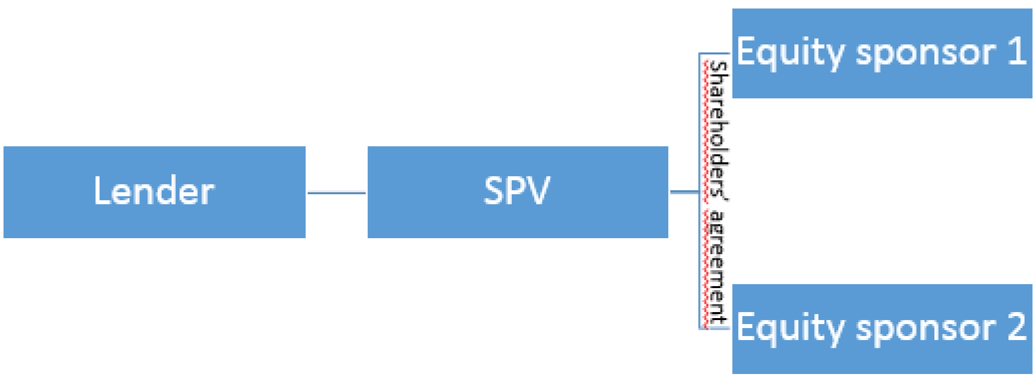

Figure 22 - Example of project finance structure

Under normal circumstances, a company that wants to launch a new investment project would finance it on-balance sheet. Setting up a separate project company is costly as it requires extensive due-diligence and legal contracts covering every aspect of asset governance and monitoring (Sawant, 2010). However, under some conditions project finance can reduce the cost of capital and thus be beneficial compared to corporate finance (Gatti, Project Finance in Theory and Practice, 2013).

Modigliani and Miller's Proposition II regarding capital structure irrelevance also apply to project finance transactions. The theory initially relates to the trade-off between debt and equity, but is also applicable in our case where we look at off balance sheet financing.

With real world market conditions, there are clear deviations from the conditions required for M&M Prop II to hold. The theorem holds in a world with no taxes, while the project analyzed in this thesis is subject to 78 per cent effective tax rate. Still, the M&M propositions provide a valuable intuition that is applicable under real world conditions, which is that the source of the funds or the number of funding sources does not change the underlying distributable cash flows (Stephen A. Ross, 2006). The question is then; does off-balance sheet financing provide any advantages compared to a traditional corporate finance approach?

For off-balance sheet financing to make sense, the asset needs, for some reason, to be worth more off balance sheet then on (Giddy, 1999). In other words, for our model to be superior compared to financing the infrastructure as a traditional offshore project, where the full amount of capital is raised on-balance sheet by the individual owners of the license, the cash flows from tariffs need to be worth more if administered by a SPV. If this is the case, the tariff/tolling fees can be reduced without making the NPV negative. Miller's analogy to illustrate the principle uses a pizza: cutting a pizza into a smaller or larger number of pieces does not change the underlying amount of pizza. (Slegel, 1998)

We argue that raising capital for this project off balance sheet in a project finance structure is superior for the following reasons:

1. **Project finance allows for a high level of risk allocation among the projects participants.** Therefore, this approach can support a debt-to-equity ratio that could not otherwise be attained (Gatti, Project Finance in Theory and Practice, 2013). Debt provides a superior governance structure compared to equity in the case of infrastructure assets. It helps solving the problem of monitoring managers by forcing operational efficiency in order to meet scheduled and legally binding interest and principal payments. Debt also helps force free cash flow to be paid out to capital providers and prevents managerial waste. Further, debt matches infrastructure asset characteristics and is a less costly form of governance since these assets have limited growth options, which do not require intrusive and discretionary management (Sawant, 2010).

2. **Possible correlation in returns between the infrastructure project and the operations of O&G companies**. This reduces the coinsurance effect of incorporating the infrastructure project on the balance sheet of O&G companies. High correlation, and thus a higher risk of bankruptcy, can result in the agency problem referred to as *risk shifting* for O&G companies. Risk shifting means that managers will have an incentive to pursue risky investments, possibly with negative NPV, as the upside goes to equity holders (and managers) while the downside is carried by debt holders (Jensen and Meckling, 1976). The threat of risk shifting induces new debt holders to pay less for

the O&G companies' debt, reducing their firm value. In this instance, separate incorporation leads to higher firm value because separation eliminates the probability of risk shifting, which induces new debt holders to pay more for the firm's debt and accept a lower yield. (Sawant, 2010).

We argue that there is a positive correlation in returns between the assets of the O&G companies and the infrastructure project. The willingness to invest in exploration and new field developments is positively correlated with the oil price, which directly affects the returns for O&G companies. This means that if oil prices are low, fewer fields will be developed resulting in lower utilization of the infrastructure. Low utilization of the infrastructure means low returns for the infrastructure project.

3. **Off-balance sheet financing will possibly provide better access to capital, as small and medium sized O&G companies will have difficulties raising capital for their share in the project**. In the case of low credit rated companies, raising capital on their own books is likely to be more expensive compared to raising capital through a SPV. (Ledesma, Young, & Holmes, 2012)

4. **Off balance sheet financing, allows O&G companies to shield their other assets from creditors, making them more willing to participate in the project.** (Gatti, Project Finance in Theory and Practice, 2013)

We believe that the benefits given by the arguments above outweigh the disadvantages of the high costs in setting up the project company and the corresponding legal structure. The fact that in excess of 70 per cent of the capital for LNG liquefaction projects has been raised using project finance supports this argument (Ledesma, Young, & Holmes, 2012). Figure 23 displays the benefits of project finance in the theoretical framework.

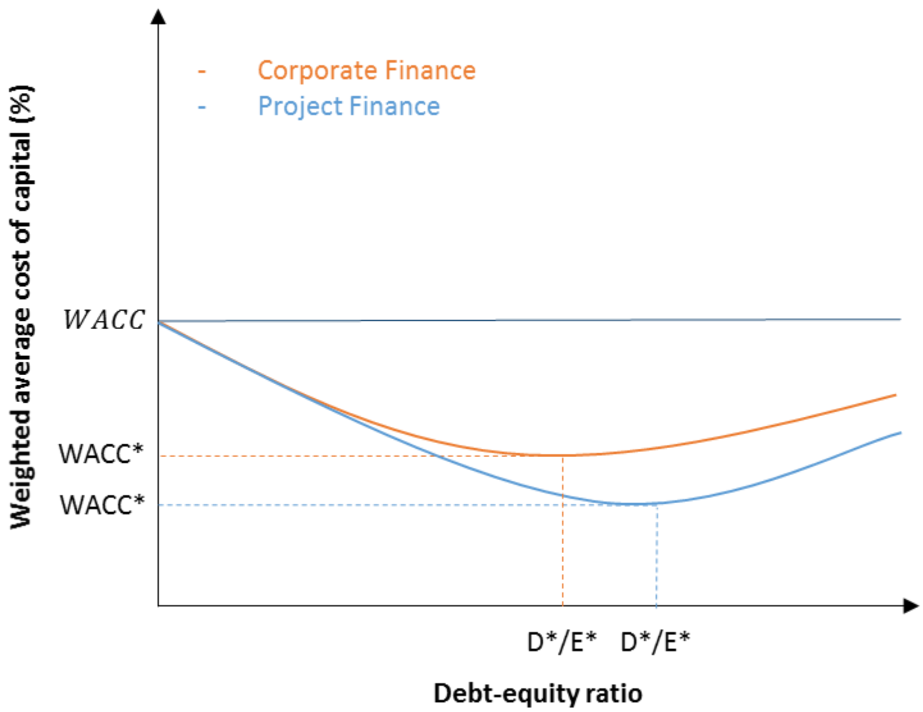

Figure 23 - Corporate finance and Project finance comparison[11]

In addition to reducing the cost of capital will the high level of risk allocation between project participants allow O&G companies to attain a risk return profile that suits their preferences. Investing in infrastructure is associated with low risk and low return, making it an undesirable investment for O&G companies as these characteristics deviate from their other assets. However, a project finance transaction allows for high leverage, making the equity sponsors able to attain an expected return their shareholders can accept.

8.3.3 Infrastructure Asset Characteristics

All infrastructure assets share some common characteristics. This section will present the key economic characteristics and risks associated with investing in infrastructure assets.

8.3.1.1 Key Characteristics

In an investor's portfolio, an asset class is a group of assets that exhibit similar characteristics, behave similarly in different market environments, and are governed by the same laws and regulations (Sawant, 2010). Infrastructure projects are capital assets. Such assets are assets that are an ongoing source of something of value (Sawant, 2010). The value is a stream of expected cash flow, and consequently

[11] D*/E* marks the optimal capital structure

capital assets are valued using discounted cash flow models. The key characteristics of the infrastructure capital asset are:

Large up-front investments

Unlike many other assets, an investor investing in infrastructure cannot meet the capital expenditures from revenues (Sawant, 2010). The revenues from infrastructure projects are first generated when the entire capital expenditure is placed and the project is completed. Until then, the infrastructure owner does not receive any cash flow. Infrastructure projects also need large up-front investments due to the economies of scale related to the financial success of such projects. Large investments are required to obtain the preferable economies of scale.

Strong and stable cash flow

Another common characteristic of infrastructure assets is strong cash flows generated from high operating margins and large free cash flows. One of the explanations of the strong cash flows is the low variable costs associated with infrastructure projects. Apart from the recognizable strong cash flows and high operating margins, infrastructure also provides the owners with stable and predictable cash flows. The stable cash flows are a result of the monopolistic nature of the asset, the inelastic demand for infrastructure, and the lack of relevant substitutes.

Long life

The cash flow generated by an infrastructure investment is maintained for a long period. The long asset life tends to balance the initial capital intensity and sunk cost related to the large up-front investment.

8.3.1.2 Risks

Infrastructure projects face different risks during the various phases of the project lifetime. When assessing risk measures for infrastructure project it is important to go much further than just backward-looking volatility statistics, but also understand that certain factors are just genuinely uncertain (Inderst, 2010). For infrastructure projects and companies key risks include:

Construction and completion risk

When financing an infrastructure asset, the stakeholders are concerned with the risks of the asset not being constructed according to the required performance standards and completed on time (Gatti, Identifying project risks, 2013). Some common risk factors associated with the construction and completion of the asset are: the quality of the labor employed, the availability of labor and project material, cost overruns, time delays, insolvency of contractors and subcontractors, and unproven engineering.

Technological Risk

Technological risk arises when the contractor of the project and the technology supplier do not coincide, and the specific license, valid in theory, proves inapplicable in the real world (Gatti, Identifying project risks, 2013). Typical technological risks arise in projects involving innovative, new, and unproven methods that have not been adequately tested.

Operational Risk

This is associated with the infrastructure asset technically underperforming post completion of the asset. Such underperformance can potentially lead to operational cost overruns, low operating productivity, low managerial efficiency, and higher and more frequent maintenance cost (Grimsey & Lewis, 2002).

Counterparty risk

Counterparty risk is concerned with the financial strength and credit quality of the various parties involved in the financing and construction of the infrastructure asset. The creditworthiness of the contractor, input supplier, and the user of the asset is assessed through extensive due diligence processes.

Revenue risk

Revenue risk is associated with the volatility of prices and demand shortfall. It denotes the risk that the revenues generated by the asset are less than expected (Gatti, Identifying project risks, 2013). A great deal of emphasis should be placed on the competitive landscape in which the infrastructure asset operates. Sudden changes in market factors can significantly decrease the value of the infrastructure asset.

Inflation and financing risk

This risk arises when the cost dynamic is subject to sudden acceleration that cannot be transferred to a corresponding increase in revenues. Financing risk arises from inadequate hedging of revenue streams and financing costs (Grimsey & Lewis, 2002).

Regulatory Risk

Regulatory risk arises when local governments impose unfavorable changes that harm the value of the assets. Examples include government imposed legal changes, such as expropriation or nationalization of the infrastructure asset.

Force Majeure Risk

This risk is associated with the occurrence of natural (earthquakes, landslides) and unforeseen (terrorism, war) events that interrupt the expected course of the project. Assessing force majeure risk is a very difficult exercise, since estimating the probability and consequence of such events is challenging.

8.4 Pipeline Infrastructure

In this segment, we will evaluate the pipeline ("Barentspipe") as a transportation alternative for the natural gas resources in the Barents Sea. First, we assess the specific risks of the pipeline alternative and suggest possible risk allocations and mitigations. Following the risk assessment, we look closer at the various components of the projected cash flow. Finally, we suggest a project finance model as a potential financing alternative, in which we apply the theoretical framework presented.

8.4.1 Risks and Mitigations

Lenders would never accept financing an SPV subject to risks that are completely internalized (Jacobsen, interview, 06.05.15). This means that major risks cannot be retained in the SPV, but has to be transferred to counterparties or professional agents whose core business is risk management (insurers). In accordance with the infrastructure risks introduced in the theoretical framework, the following identify the risks the project faces and discuss how these should be allocated between the parties involved in the project.

Completion Risk

The risk of delayed completion, cost overruns and performance deficiency is always present in O&G gas projects. In a project finance transaction, the SPV or its lenders rarely carry construction and completion risk. As a result, it is the engineering, procurement, and construction (EPC) contractor or the sponsors that must carry this risk. We argue that it might be challenging to find an EPC contractor willing to carry the full risk of cost overruns and delays, as would be the case under a Turnkey construction contract (TKCC). This means that the sponsors either will have to guarantee for the full amount of debt until the project is completed, so called "hell or high water guarantees," or provide an obligation to fund cost overruns. The lenders ability to take recourse in the sponsors' assets will be eliminated once the project is complete and proves functional.

However, the EPC contractor should carry parts of the construction risk in the form of penalties if milestones regarding cost and timing are not reached. This ensures that the contractor and sponsors interests are aligned.

Considering that there already is 7980 km of subsea pipelines on the NCS, the technology for construction is well proven. There are several contractors with decades of experience from similar pipeline projects. The harsh Arctic weather conditions might increase the risk of delays, as pipelay vessels will not be able to operate when wave heights exceed 4 meters and wind speed exceeds 30 knots (GustoMSC, 2012). However, wind and weather conditions in the Barents and North Sea are quite similar. Therefore, we believe that the completion risk is limited.

Technological Risk

Transporting natural gas via subsea pipelines utilizes well-proven technologies, resulting in limited technological risk. The required on-shore processing facility we believe is subject to somewhat higher technical risk, because of the harsh Artic environment in which is must be located. However, the processing facility is limited in its complexity compared to many other O&G installations located in similar environments. Thus, we believe that the contractors in cooperation with the projects sponsors will be able to find solutions that limit the probability of unforeseen technical challenges.

Still, unforeseen technical challenges can arise, and we argue this risk must be carried by the contractors to the largest possible extent. Allocating risk to the responsible EPC contractor is done by TKCCs, where the EPC contractor guarantees that the project will meet the predetermined specifications.

Operational Risk

Once completed, Barentspipe will be incorporated in the existing transportation system that Gassco operates (Gassco,2014). Gassco will be responsible for the technical operation of the pipeline and administering the additional volumes in the existing Gassled system. The processing facility will be operated by a technical service provider (TSP) on behalf of Gassco. The role as TSP will be assigned to one of the O&G companies sponsoring the project.

The operational regularity in the Gassled system was 99.92 per cent in 2014 (Gassco, 2014b) Regularity is measured as volumes delivered to the receiving terminals in comparison to volumes booked by the shippers. Of the gas delivered and NGL produced, 99.99 per cent satisfied the buyers' demands regarding quality of the products. Based on these figures we believe that the operational risk is very limited, and thus can be carried by the SPV.

Counterparty Risk

As a pipeline from the Barents Sea would be connected to the Gassled infrastructure, which provides large flexibility in terms of where the gas can be delivered, we argue that the risk related to offtake is limited. The creditworthiness of the contractor and the sponsors, as they must provide a guarantee to cover cost overruns, represents the major share of counterparty risk. The required obligation to fund cost overruns in the construction phase limit the number of O&G companies able to participate in this project. The consortium of sponsors must be comprised of large creditworthy companies that are able to make the necessary guarantees to lenders.

Inflation and Financing Risk

Risk related to interest rates, exchange rates and inflation is present in all project finance transactions. All these risks can be reduced by using financial instruments like fixed rate lending, forwards, futures, swaps, options and money market hedging (Kisser, 2015). Determining to what degree the SPV should use financial instruments to hedge these risks requires an extensive analysis. We will not further assess how hedging strategies can be used to stabilize the expected future cash flows.

In general, we believe that loans should be in the same currency as the revenues generated by the asset. As the tariffs generate revenue in NOK, the loans should be denominated in NOK as well. A substantial portion of the capex is likely to be denominated in foreign currencies, which might make it beneficial to lock in these expenses using forward contracts (or other instruments) when the investment decision is made.

Revenue Risk

Project finance involves the separation between an existing company and a new industrial project. If the project is not successful, project creditors have no (or very limited) claim on the sponsoring (equity) firm's assets and cash flow. The tariff (price) charged for usage of the pipeline services is set ex-ante, based on the projected volume throughput. Consequently, there will not be any price volatility and the project company's revenues will depend on the actual volume throughput.

Figure 24, illustrates the volume throughput that will decide the level of the pipeline tariff ("reference scenario").

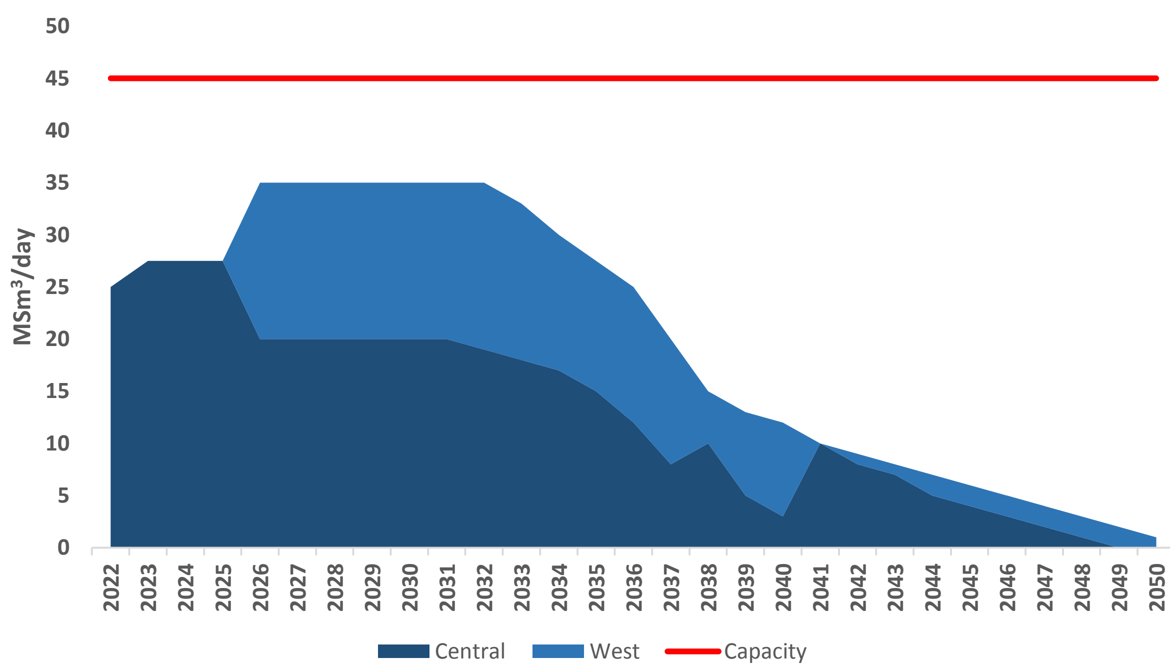

Figure 24 - Tariff volumes (existing fields and discoveries incl. 2014 exploration results) (Gassco, 2014)

As seen in the figure, the volumes are split between the western and central part of the Barents Sea. Potential volumes from the exploration activity in the Barents Sea Southeast are omitted from the calculations. In order to recover these volumes an additional capital expenditure of MNOK 50,000 is needed (Gassco, 2014). Hence, these volumes does not work as a mechanism for increasing the overall project IRR, as the additional capex will offset any potential extra revenue generated from the extra throughput. The total resource volumes in figure 24 amounts to roughly 212 BCM, in which 97.5 BCM derives from undeveloped existing fields and discoveries, 100 BCM from undiscovered resources, and 14.5 BCM from accelerated volumes at Snøhvit. If a pipeline is in place, some of the resources at the Snøhvit field can be transported through the pipeline instead of waiting for available capacity at Melkøya.

Today, the total resource deposits of undeveloped discovered resources amounts to 147.1 BCM. As seen in table 8, around 47 per cent of these volumes are classified with development not very likely, while the remaining 53 per cent holds various classifications. A significant amount of the resources in which development is not very likely, are not commercially viable as a direct consequence of the lack of a necessary infrastructure solution. Total EPs Norvarg-field, containing 30 BCM, is an example of such fields (Taraldsen, 2013). Hence, if the necessary infrastructure solution is in place, a significant portion of these fields could be developed. In the reference throughput scenario, 50 per cent of these discoveries are expected to change status if the infrastructure comes on stream (Gassco, 2014). Further, we assume that 50 per cent of the fields not evaluated will be developed.

Name	**Year**	**Status**	**Natural Gas Resources (BCM)**
Tornerose	1987	Planning phase	3.7
Drivis	2014	Planning phase	1.3
Johan Castberg	2011	Planning phase	12.6
Goliat	2000	PDO Approved	8
Skalle	2011	New discoveries, not evaluated	5
Alta	2014	New discoveries, not evaluated	9.7
Isfjell	2014	New discoveries, not evaluated	1.5
Pingvin	2014	New discoveries, not evaluated	12.5
Hanssen	2014	New discoveries, not evaluated	0.2
Wisting	2013	New discoveries, not evaluated	1.5
Alke	1981	Development likely but not clarified	11.4
Gotha	2014	Development likely but not clarified	11
N/A	N/A	Development not very likely	68.8
Total			**147.1**

Table 8 - Undeveloped proven resources in the Barents Sea (NPD fact pages, 2015)

In addition to the 97.5 BCMs derived from existing fields and discoveries, and the 14.5 BCM from accelerated production at Snøhvit, the reference throughput scenario includes an additional 100 BCM of undiscovered resources resulting from the anticipated exploration activity until 2017. Monte Carlo simulations performed by Gassco, in cooperation with major O&G-companies operating on the continental shelf, estimate an expected value of 200 BCM to be discovered in this period. In the reference scenario used when setting the tariff, 50 per cent of these 200 BCM will be developed. The 200 BCM is well in line with the resource scenarios elaborated upon in chapter 7.

Debt issuers

As the project company's only source of revenue is the pipeline-tariff, the debt issuers will not be able to take coverage in cash flow generated by other assets. Consequently, the project company's owners need locked-in guaranteed cash flows sufficient to service the debt (Jacobsen, interview, 06.05.15). Without committed throughput bookings, the debt issuers will perceive the project as too risky and thus not be willing to fund the project. However, if volumes are committed, the size of the debt will largely depend on the committed throughput.

To ensure that the suggested project finance model is based on reasonable assumptions, it is important that the contractually committed volumes ("guaranteed case") will be based on transportation needs the O&G companies envisage as certain. The P95-estimate for the exploration activity outcome in the Barents Sea the coming 3 years is 60 BCM (Gassco, 2014). As explained earlier such estimates are generated from Monte Carlo simulations based on play analysis, and show the undiscovered resource deposits expected to be recovered with 95 per cent certainty. However, as the size and production characteristics and the distance between the discoveries may vary, we have assumed that only 50 per cent of the P95 discoveries will be recoverable. Hence, in the project finance model it is assumed that 50 per cent of the already found fields and discoveries, and 50 per cent of the P95-resource estimates will be contractually committed.

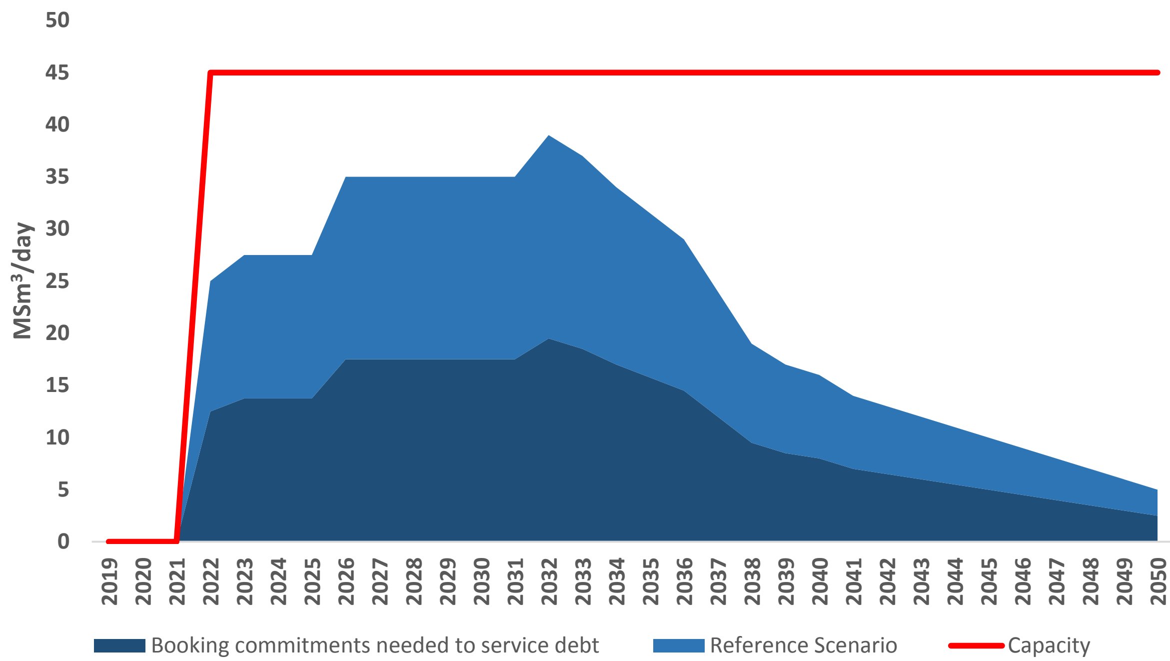

Figure 25 - Contractual committed volumes used to service project company debt (Gassco, 2014)

Equity sponsors

After the contracted volumes have serviced the debt, any excess cash flow will accrue to the equity owners. As this excess cash flow is not contractually committed, it is associated with higher risk. The equity owners of the project company are compensated for bearing this risk by receiving the potential upside. Hence, the equity owners receive a higher expected return than the debt issuers.

Figure 26 illustrate potential contribution of undiscovered resources beyond the P50-estimates used when setting the tariff. As seen, the upside potential for the equity owners will be limited to the maximum capacity of the pipeline. The total volume flow in figure 26 amounts to roughly 450 BCM. These figures are provided by the NPD, and are well within the boundaries of the P50-estimate of 740 BCM of undiscovered natural gas resources.

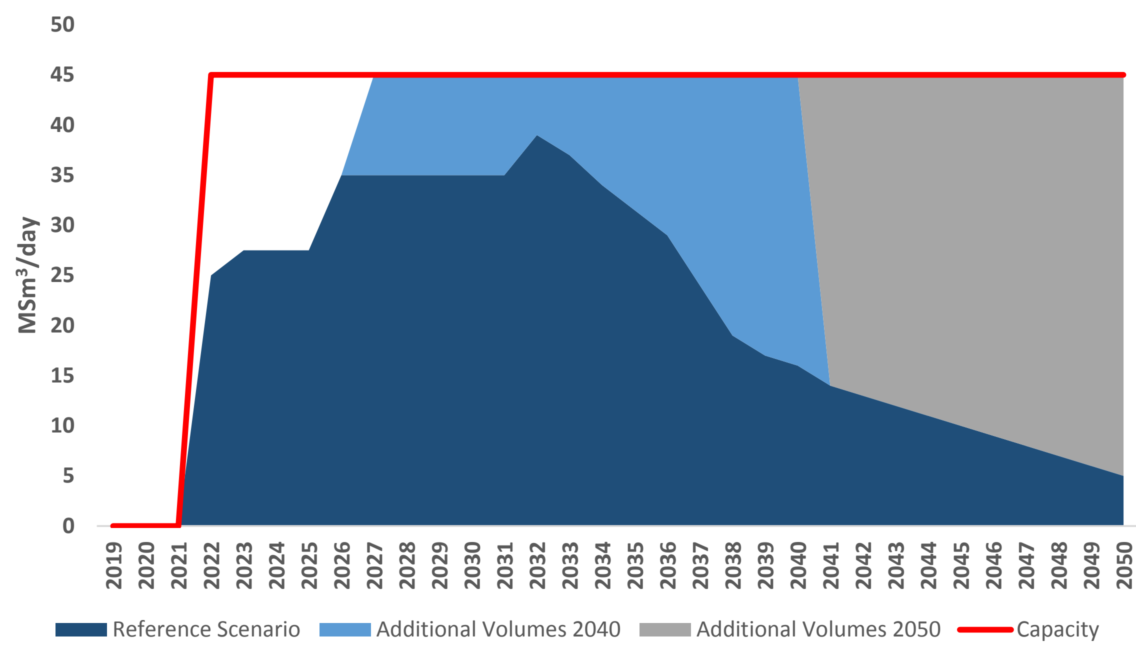

Figure 26 - Upside scenarioes 2040 & 2050 (Gassco, 2014)

In order to allow for potential volumes in excess of the original pipeline capacity, an extra compressor can potentially increase the capacity of the pipeline with additional 27 MSm^3/day. Figure 27 illustrates the throughput scenario if an additional compressor is added in 2028. In this scenario the total amount of volume flow in the pipeline amounts to 680BCM.

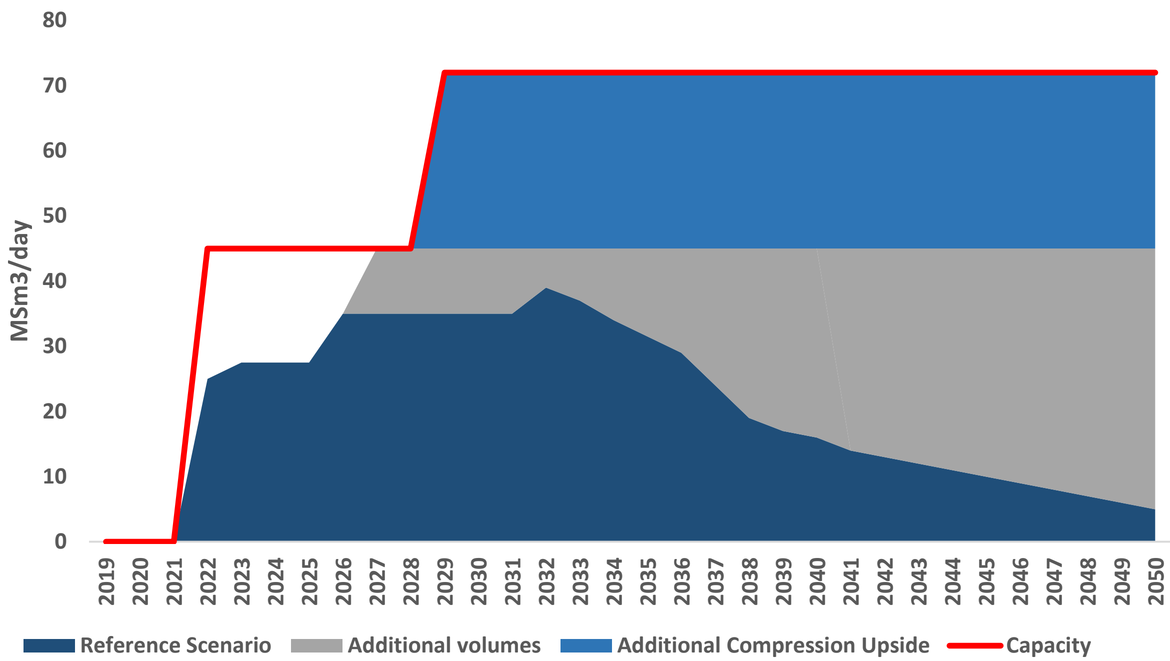

Figure 27 - Compression upside scenario (Gassco, 2014)

Regulatory Risk

Until recently, the political and regulatory risks on the NCS have been perceived as negligible. However, recent moves by the Norwegian government have damaged Norway's reputation concerning regulative stability. Historically, the tariffs in the transportation system have been set *ex-ante* in such a manner that it provides the owners with a rate of return corresponding to 7 per cent (Moræus Hanssen, interview, 04.02.2015). However, in 2013 the Ministry of Petroleum and Energy proposed changes in the pipeline tariff regime. The changes are only affecting new transportation agreements, and not already agreed contracts. MPE justifies the decision by arguing that lower tariffs in the transportation system is necessary to realize the goals of socioeconomic resource management (The Ministry of Petroleum and Energy, 2013, p.6-7).

Area	Unit	K-tariff for former contractual agreements	K-tariff for new contractual agreements
A	Øre/Sm3	5,5	0,55
B	Øre/Sm3	3,5	0,35
C - extraction	Øre/Sm3	10	1
D - entry			
Kollsnes	Øre/Sm3	1,93	0
Kårstø	Øre/Sm3	2,43	0
Nyhamna	Øre/Sm3	0	0
Oseberg	Øre/Sm3	2,43	0
Other	Øre/Sm3	0,43	0
D exit	Øre/Sm3	5,57	0,71
F	Øre/Sm3	6	6
G	Øre/Sm3	1,49	0,149
H	Øre/Sm3	3,5	0,35
I	Øre/Sm3	4,05	4,05

Table 9 - Overview of tariffs in the Gassled system (The Ministry of Petroleum and Energy, 2013)

As seen in the table 9, most of the tariffs in the transportation system are reduced by 90 per cent. The significant reduction of the K-element caught the Gassled owners by surprise, which had acquired the E&P companies' shares in Gassled two years prior to the tariff change. The new owners' response has resulted in an ongoing lawsuit between the Gassled owners and the Norwegian government.

If the decision is not overturned, the Gassled owners will not consider buying out the initial investors of Polarled, an ongoing pipeline project costing MNOK 24,100. In February 2014, Allianz pleaded Erna Solberg to reverse the changes in tariffs which where referred to as "an incomprehensible discrimination of long term investors". According to Bloomberg, Allianz alone booked a write-down on their investment in Gassled of 500 million euros because of the changes in tariffs (Holter, 2014)

Upon the announcement regarding the proposed tariff changes, bonds issued by Njord Gas Infrastructure was downgraded from A- to BBB by S&P (Njord, 2013). In the ratings review, Standard and Poor's explained: "We are lowering our long-term issue ratings on the bonds issued by Njord due to the continuing lack of transparency in the process launched by the Norwegian Ministry of Petroleum & Energy, and the impact this has on our view of the future stability and predictability of the regulatory regime" (Njord, 2013). When the tariff changes was adopted in June 2013, the bonds were further downgraded from BBB to BB (Njord, 2013a). The downgrading of the bonds issued by Njord shows the direct economic consequences of the changes in the tariffs.

The sudden changes in the tariff system have shown that the regulatory risk is necessary to address when evaluating the project. In collaboration with the World Economic Forum, The Boston Consulting Group has done extensive research on the mitigation of regulatory risk in infrastructure projects. A measure suggested by the BCG that can deal with regulatory risk in the Norwegian pipeline system, is the ownership and financial structure of the transaction. By drafting these structures with great care and attention, selecting the right partners and project participants can considerably mitigate the regulatory risk (Almeida & Rodrigues, 2015). One suggestion is to invite international owners, e.g. the infrastructure funds and financiers, such as the European Investment Bank, to participate in the project. The Norwegian government would then have to contend with large international institutions and banks, if sudden regulation of the asset is in disfavour of the owners. Such an ownership model is to some extent already implemented, as the equity owners of Gassled are large international pension -and infrastructure funds. Inviting international banks as financiers will make it more difficult for the Norwegian government to conduct changes in the regulation of the transportation system (Almeida & Rodrigues, 2015). Inviting domestic credit institutions, such as DNB, as financiers of the project can make it more difficult to suggest changes in the tariffs. Considering the potential leverage of the project, changes in the tariffs, and potential loss of debt repayments can considerably hurt the domestic credit institution.

The changes in the tariff system performed by the Norwegian government have proved that the regulatory risk in the transportation system is not negligible. The ongoing lawsuit can potentially have a significant effect on the availability of equity sponsors and lenders in the transportation system.

8.4.2 Project Internal Rate of Return

As mentioned earlier, the MPE has historically set the tariffs so that the pipeline projects yield a return of 7 per cent based on the anticipated reference throughput. However, the current Gassled owners suggest the required IRR for the Barentspipe project to be 10 per cent (Pedersen & Georgsen, interview, 19.03.15). In addition to increased regulatory risk, the higher required return comes as a result of more uncertainty related to the throughput compared to other pipeline projects on the continental shelf. Further, the possibility of O&G companies making contractual commitments to secure debt repayments was not discussed. The possible benefit of alternative financing structures was neither accounted for when stating the 10 per cent return threshold.

According to DNB, who have extensive experience in financing similar projects, a project IRR of 10 per cent is too high for infrastructure projects of this character. In a project finance structure with high leverage, a required rate of return of 10 per cent will indicate that the project is associated with too much risk for a commercial bank to issue debt. (Jacobsen, interview, 06.05.2015)

We believe that the risks associated with the Barentspipe project will require an IRR of 8 per cent given full utilization of the benefits of project finance, as explained in subchapter 8.3.

Figure 28 shows that the other pipeline projects on the NCS have a lower IRR than what is required for the Barentspipe project. We argue that this is caused by other pipeline projects being constructed with less volatility in terms of cash flow projections, as they were built in connection to much greater discoveries in terms of recoverable resources.

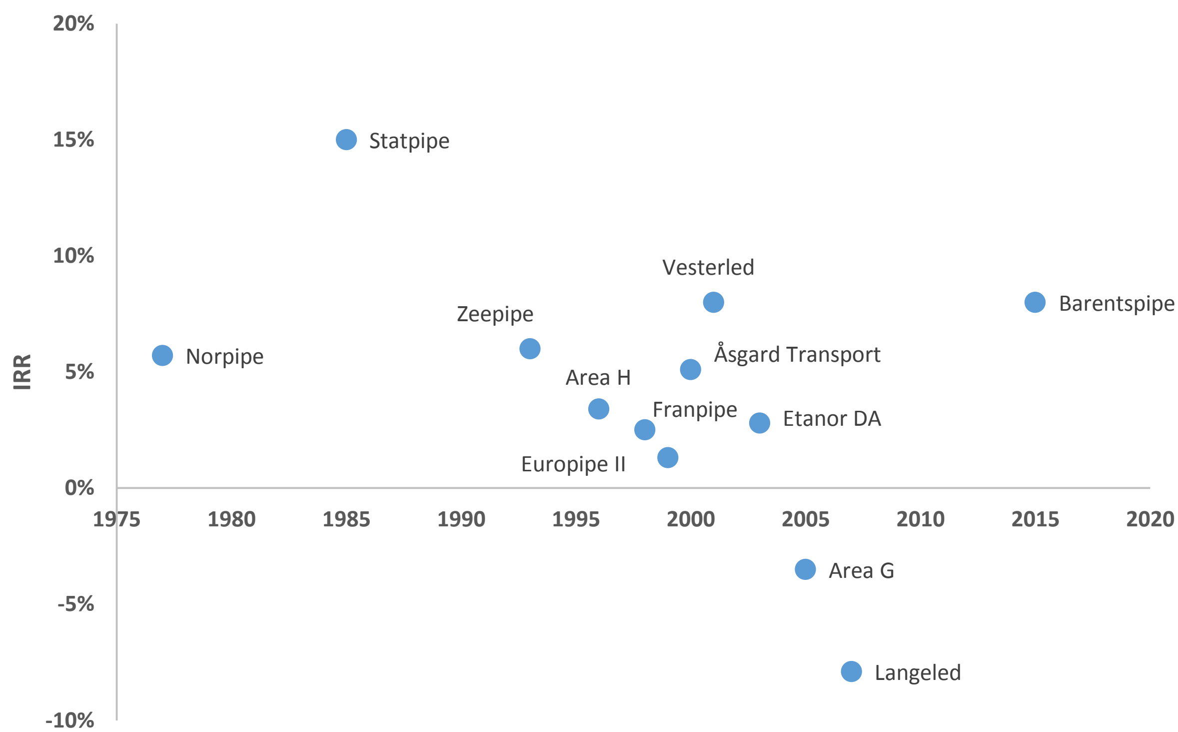

Figure 28 - IRR for various pipeline projects (Nørve, 2013)

8.4.3 Cost Overview

The cost estimate for the pipeline alternative is based on information gathered form published reports, interviews with industry experts, and our own assumptions.

Capital Expenditures

The total capex of the 42-inch pipeline, covering the approximately 1000 km from Haltenbanken in the Norwegain Sea to the Barents Sea, is estimated to MNOK 75,000. This estimate is made by the BSGI-forum, and has been verified by one of the lead authors of the report (Aarhus, e-mail, 19.05.15). The capex estimate includes processing and compression capacity equal to the initial capacity of the pipeline of 45 MSm^3/day. Further increasing compression can give the pipeline a capacity of 72 MSm^3/day, which will cost an additional MNOK 6,000.

Capacity (42-inch pipeline)	Capex (MNOK)
72 MSm3/day	81,000
45 MSm3/day	75,000

Table 10 - Capex for various capacities of 42-inch pipeline (Gassco, 2014)

Table 9 benchmarks the capex of MNOK 75,000 against the cost of similar subsea pipeline projects, and find that the Barentspipe capex is just above average when comparing cost/capacity adjusted for length. Removing the outliers, Langeled and Medgaz, give an average of $213/BCM/meter, compared to $222 for the Barentspipe.

Cast capacity rank	Project	Length (km)	Capacity (BCM)	Diameter (Inch)	Capex (MUSD)	USD/BCM/meter
1	Langeled	1,166	26	44	2,720	91.5
2	Europipe 2	642	24	42	1,690	109.7
3	Franpipe	840	19	42	1,866	116.9
4	North Stream	1,222	55	4x48	11,264	167.6
5	South Stream	925	63	4x32	12,800	219.6
6	**Barentspipe**	**1,000**	**45**	**42**	**10,000**	**222.2**
7	Blue Stream	396	16	2x24	1,700	268.3
8	ITGI	217	10	32	640	294.9
9	Europipe 1	670	18	40	3,750	310.9
10	Medgaz	210	8	24	806	479.8

Table 11 - Cost/capacity benchmark of various pipeline projects (detailed list of sources in the appendix)

Operating cost

Gassco publishes the operating cost in the existing pipeline system each year. We have assumed that there is a linear relationship between the length of a pipeline and the operating costs. Thus, we have based or operating cost estimate on the Åsgard Transport pipeline and adjusted for the difference in length. The Åsgard transport pipeline is quite similar to the Barentspipe in relation to diameter and length.

	Length (km)	Diameter (inches)	Capacity (MSm3/day)	Operating costs (NOK/Sm3)	Operating cost ($/Mbtu)
Åsgard Transport	707	42	70	0.0037	0.0140
Barentspipe	1,000	42	45	0.0052	0.0183

Table 12 - Operating cost estimate (Gassco, 2015)

We have not adjusted for the fact that Åsgard transport has higher capacity. As higher capacity requires more compression, it can be argued that our estimate for Barentspipe is at the high end.

Taxes

The taxes related to investing in the pipeline are calculated using the equation in table 13.

Revenues (tariff)
- Operating expenses
- Linear depreciation for investments (6 years)
- Net financial costs
= Ordinary tax base
- Ordinary tax (27%)
- Uplift (5,5% of investments for 4 years)
= Tax base liable to special tax (51%)

Table 13 - Calculation of the petroleum tax (Semmingsen, 2010)

8.4.4 Project Finance Model

Project Structure

In our project finance structure, we suggest a capital structure comprising three types of capital as explained in figure 29 below. In addition to bank debt, we suggest the Gassled infrastructure funds as a mezzanine capital partner ranking head of the O&G companies as common equity partners.

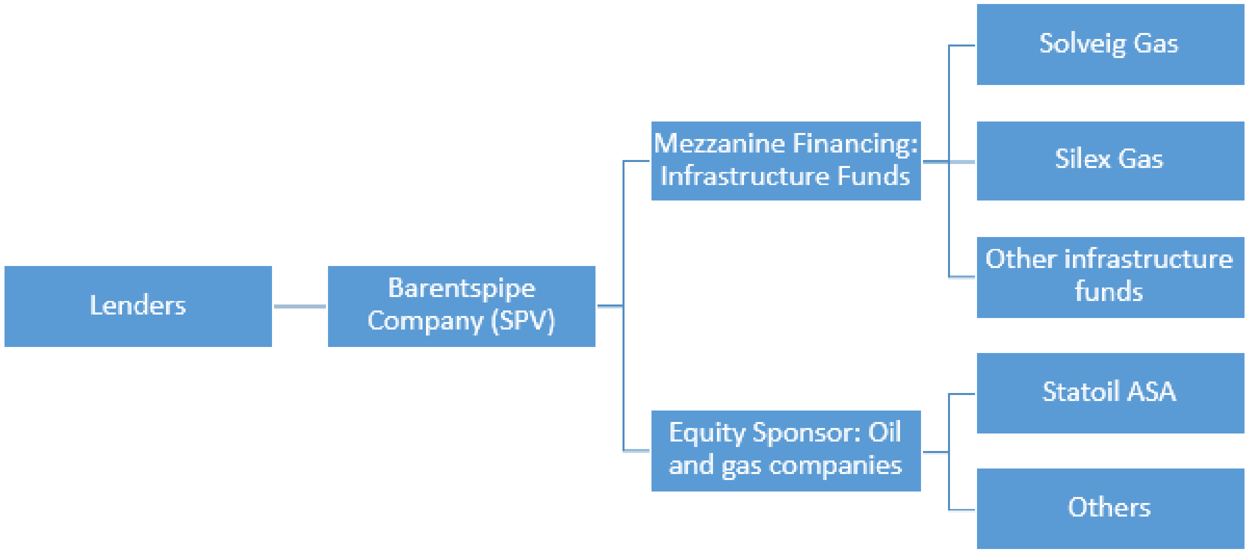

Figure 29 - Barentspipe Company project finance structure

Figure 30 illustrates the total free cash flow generated by the project. The tax paid is calculated assuming the company has no debt, and thus no interest tax shield. As seen, the revenues are first generated when the entire capital expenditure is placed and the project is completed. Once completed the pipeline generates strong cash flows from high operating margins. In the beginning of the pipeline's lifetime, the SPV will benefit from a tax loss carryforward. As the total capex is depreciated over 6 years, the company will not have taxable income in this period. As a result, a tax loss carryforward is created as the depreciation exceeds the revenues. In addition, the uplift depreciation charges the first 4 years and the high marginal tax rate of 78 per cent increase the size of the tax loss carryforward. Consequently, the SPV will not pay any taxes in cash the first 9 years of operation.

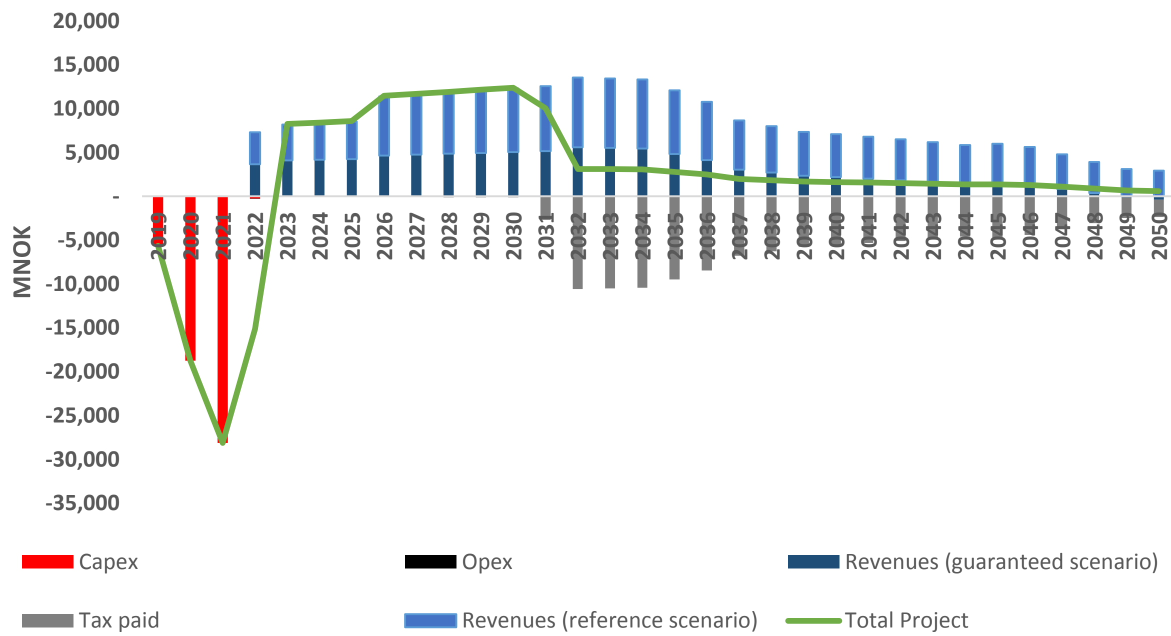

Figure 30 - Free cash flow to Barentspipe Company

Project Company Debt

The Barentspipe Company's creditors will look to extract a return that corresponds to the level of risk associated with their share in the project. As explained earlier, the project company's creditors cannot take recourse in other assets if the project company is not able to service the debt. Hence, contractually committed volumes and a resulting more visible cash flow, is a pre-requisite for the lenders to issue any debt (Jacobsen, interview, 06.05.15). The contractually committed volumes correspond to the "guaranteed" case discussed in subchapter 8.4.1 on risk assessments.

The size of the debt will largely depend on the size of the volume commitments, and consequently the creditors' risk assessments of the project. According to DNB, a project of this kind could achieve close to 80 per cent leverage if the volume commitments match the cash flow used to service the debt (Jacobsen, interview, 06.05.15). Hence, the size of the committed volumes determines the size of the issuable debt. Given the anticipated contractual commitments, we suggest that the Barentspipe Company will be funded with 60 per cent leverage.

The interest charged by the lenders consists of the benchmark rate plus the spread, where the latter depends on the project characteristics. The interest rate spread reflects the risk premium, and should thus reflect the expected performance of the loan (Kwark, 2002). The 10-year swap LIBOR is used as the benchmark rate. Given the project details and size of contractual volumes, DNB indicate an interest spread between 200 and 250 bps (Jacobsen, interview, 06.05.15). Thus, we have assumed that a spread of 225 bps is placed on the LIBOR providing an interest rate equal to 4.48 per cent.

Debt Structure	
Total debt outstanding (MNOK)	45,000
LIBOR rate (%)	2.23%
Margin (bps)	225
Interest rate (%)	4.48%
Repayment period (yrs)	15

Table 14 - Debt structure

Further, the debt repayment period is set to 15 years. The relatively short repayment period, compared to the pipeline's lifetime, is a result of the large cash flows being generated early in the project's lifetime. As discussed earlier in this section, the depreciation rules of the Norwegian petroleum tax system allow the project company to carry forward large tax shields. Intuitively, one could think that the company would repay its debt using all the cash flow generated early in the assets lifetime. However, retaining the debt also retains the interest tax shield, reducing the effective cost of capital. In addition, the equity sponsors have a preference for high expected returns, leaving it preferable to maintain leverage as it increases the risk and return for equity sponsors.

Some of the capital retained will be needed to service a shortfall in distributable cash flow to debt holders in year 2036 and 2037. This shortfall comes as a result of the tax loss carryforward no longer existing. Figure 31 shows the distributable cash flows from the anticipated committed volumes as well as the cash flow required to service debt. As seen in this figure the cash flow generated by the project together with the tax shield from the interest expense will be sufficient to service debt until year 2036. During the last two years of the debts tenor the debt must be serviced with retained cash or alternatively by the equity partners injecting more cash. We will argue that the overall debt service ratio is strong, and therefore believe that the project company would be able to obtain the debt financing described above.

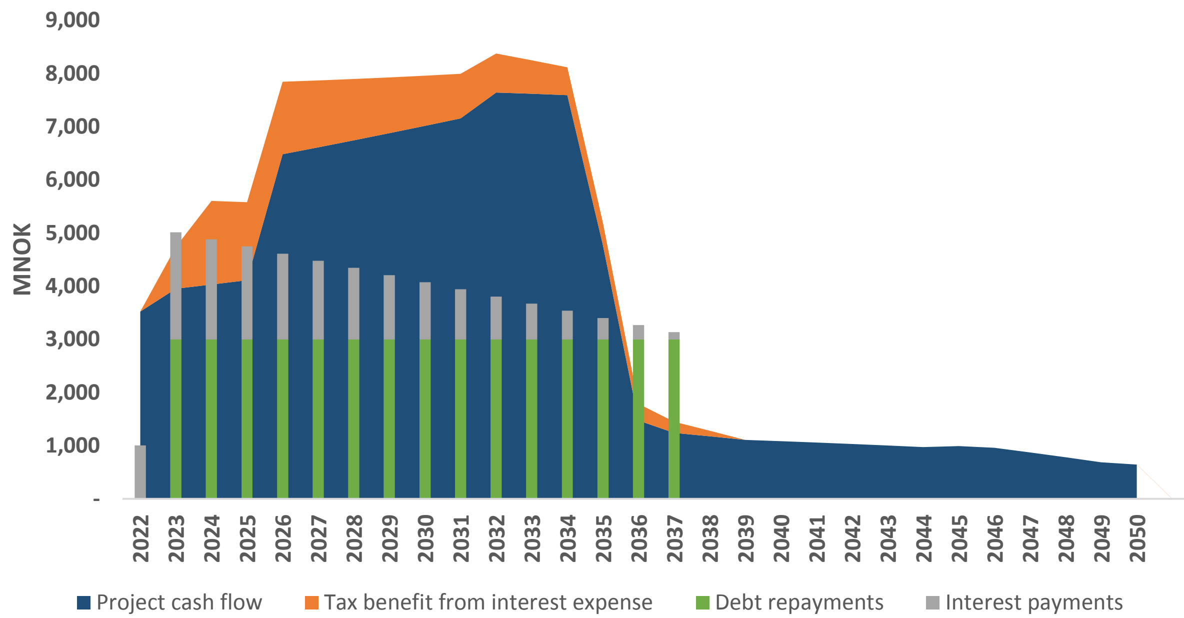

Figure 31 - Guaranteed cash flow available to service debt

Mezzanine capital

After the debt is serviced there is still contractually committed cash flow left. The contractually committed volumes are of a risk return characteristics that we would argue that does not fit the preferences of the O&G companies. We believe that the nature of the O&G companies' business engaged in exploration and early development of oil fields is characterized by high risk and high reward. We therefore assume that investors investing in such companies have a preference for higher risk and higher returns. Consequently, for the O&G companies to be willing to invest in the pipeline they would require a higher return than the contractually committed volumes can offer. Based on the interviews with the O&G companies, the owners expressed that, given the characteristics of the Barentspipe project, they would require a return of 18-20 per cent on their equity in order to invest. With the assumed debt structure, the cash flow after the debt is serviced is not sufficient to obtain such returns. Hence, the amount of contractual cash flow left calls for an instrument ranking between the bank debt and O&G companies' equity.

In the project finance model, we suggest the Gassled infrastructure funds invest as mezzanine capital partners. Redeemable mezzanine capital is a hybrid financial instrument displaying both debt and equity characteristics. The instrument we suggest has a mandatory redemption and dividends (a debt characteristic), while at the same time retaining equity characteristics, such as potential appreciation

(Kimmel & Warfield, 1995). It is important to stress that the dividends does not share the exact commonalities of a coupon payment, as the dividends are not tax deductible on the issuer's P&L.

The potential appreciation mechanism could for example be a warrant structure, allowing the mezzanine capital partner to acquire common equity in the project company at a fixed price. By exercising the warrant, the mezzanine capital partner therefore becomes a common equity partner in the project company. Thus, if the common equity price is greater than the exercise price of the warrant, the mezzanine capital partner will extract additional returns. The exercise price will typically be on a significant premium to the price at the date that the warrants are issued. By offering the mezzanine capital partner an upside potential, the dividends to the mezzanine capital partner will be lower than what would have been the case if there was no upside potential. In this thesis, we will not further assess the potential value of such a warrant structure.

We have assumed a mezzanine capital instrument in the amount of 20 per cent of the required total capital expenditures. Given that there are some contractually committed volumes left to partly service the required dividends and the potential value of the warrant structure, we believe that the Gassled infrastructure funds will require a base-case return on their investment of approximately 10 per cent (Pedersen & Georgsen, interview, 19.03.15). Further, we have assumed that the mezzanine capital is redeemed after 10 years.

Figure 32 illustrates that the cash flows in the reference throughput scenario is sufficient to service the dividends to the mezzanine capital. As the figure illustrates the guaranteed cash flows will not be sufficient to cover the 11.5 per cent dividends required to provide the infrastructure investors the 10 per cent return. Hence, there is significantly more risk associated with owning the mezzanine capital than debt, and consequently must the infrastructure funds be compensated by higher returns and potential upside.

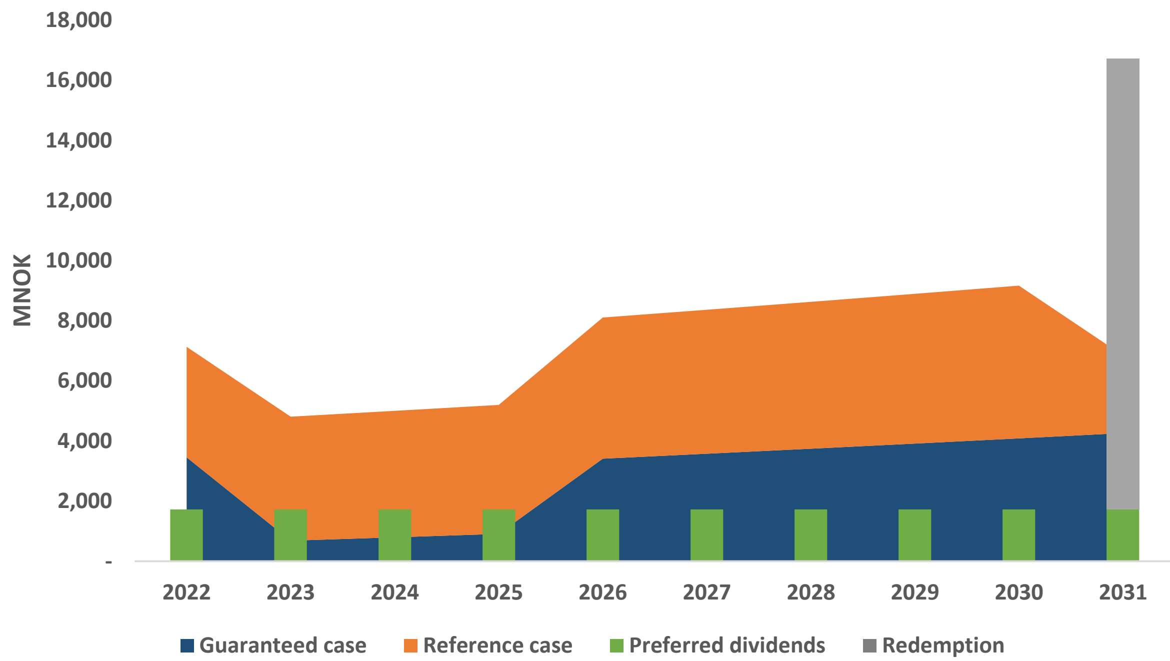

Figure 32 - Cash flow mezzanine

Common Equity

One of the most important features of the preferred equity is that it is senior to common equity in the capital structure. This implies that the common equity is associated with higher risk, and should thus be compensated with a higher expected return. Figure 33 illustrates the cash flow left to the O&G companies after the debt is serviced and redemption provisions is paid to the preferred equity holders.

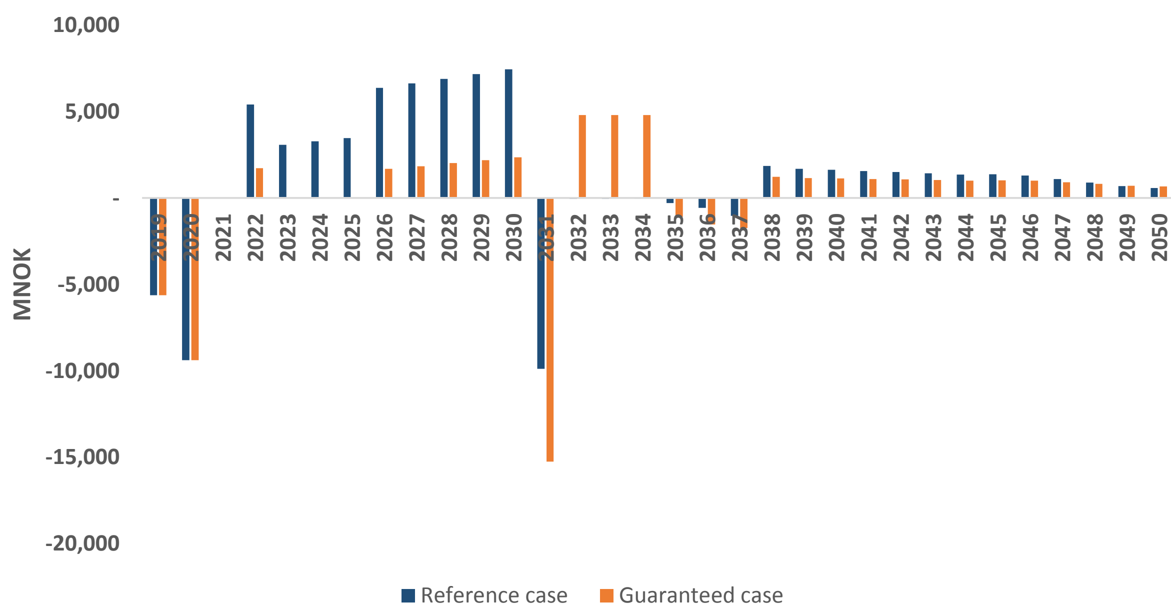

Figure 33 - Cash flow available to common equity holders

The key observation from figure 33 is that the project generates significant cash flow to the common equity partners both from the contracted volumes and especially in the reference case during the first 8 years of operation. In year 2031 the mezzanine capital will be redeemed, and as discussed above there will be a need for additional capital injections from the common equity owners unless some cash is retained in the SPV from the 8-year period of significant cash generation.

The contractually committed volumes will provide the common equity holders with a return equal to 1.6 per cent, which is much lower than their required return of [18-20] per cent. However, ignoring any potential exercise of warrants by the mezzanine capital partner, all additional cash flow after service of debt and dividends to the mezzanine capital will accrue the common equity holders. If the reference throughput is achieved, the common equity holders will receive a return of 19.0 per cent. This estimate, based on our interviews with the O&G companies, is in accordance with their return preferences on such projects.

Figure 34 summarizes the IRR for the various investors in the Barentspipe Company. By allocating risk and return preferences within the capital structure of the company, it is possible to attract various investors such that the necessary funds are raised for constructing the pipeline.

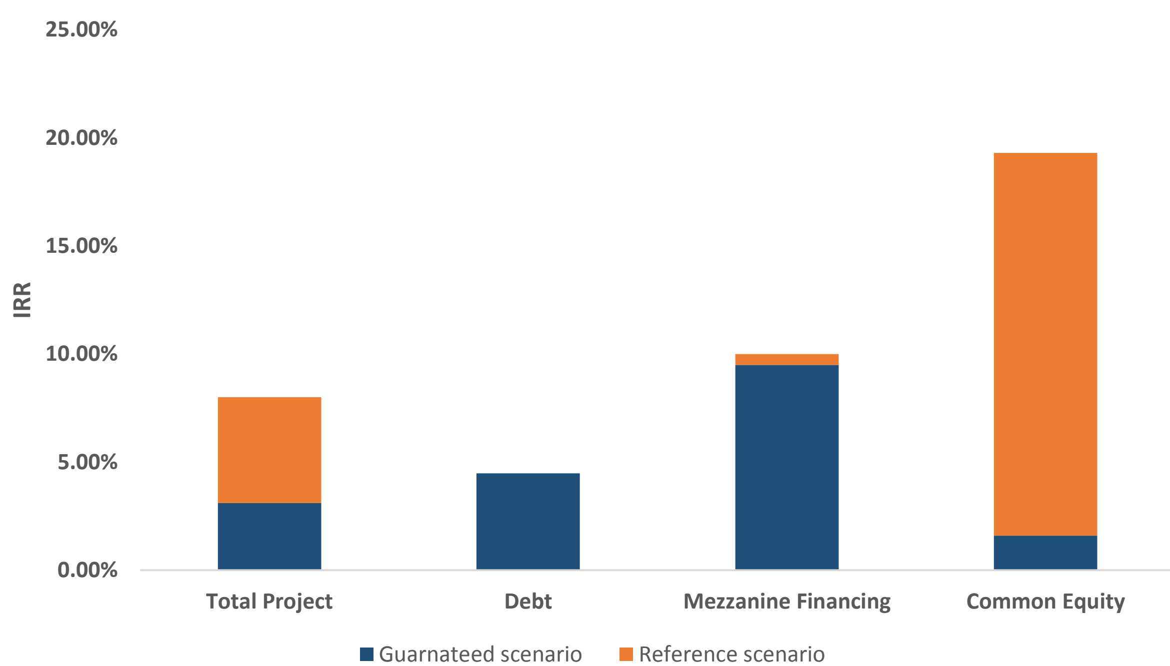

Figure 34 - IRR to the capital providers of the Barentspipe Company

8.5 LNG Infrastructure

In this segment, we will evaluate a second LNG-train at Melkøya (Snøhvit) as a transportation alternative for the natural gas resources in the Barents Sea. Our risk assessment is based on experiences gleaned from LNG projects around the world, with Snøhvit in particular. Commenting of specific technical details that may, or may not, be different as a result technical progress, is not within the scope of this thesis.

8.5.1 Risks and Mitigations

Completion risk

The risk of delayed completion, cost overruns, and performance deficiencies is substantial for LNG projects. Experiences from Melkøya and other liquefaction projects in the world show that large costs overruns and delays in the construction phases are common. Operations at Melkøya started one year late, and the liquefaction plant cost 160 per cent more than initially budgeted (Steensen, 2005). The Gorgon LNG project in Australia has experienced a cost overrun of MUSD 17,000, and is so far 6 months delayed (ABC AU, 2014). The experiences from Melkøya and Gorgon underline the uncertainty related to the construction phase of LNG projects.

The construction risk can be reduced by awarding turnkey construction contracts (TKCCs) to large creditworthy ECP contractors. Selecting an EPC contractor with a strong track record, regarding timely delivery and technical know-how, will reduce the construction risk for the LNG project. It can be argued that there has been a steep learning curve since the construction of Melkøya, and that technical issues and challenges related to project management, are less significant today. As the second train at Melkøya would be a brownfield expansion, the contractors will have extensive knowledge of the geological and climatic conditions, making the construction more predictable compared to pioneering greenfield projects. Thus, we believe the completion risk for a Snøhvit expansion is lower compared to the risk of the first greenfield plant.

However, we still assert that the risks related to delays and cost overruns are higher for a second LNG train at Melkøya compared to building a new pipeline. Compared to the pipeline building process, a second LNG-train is a much more complex technical solution.

Technological risk

Snøhvit LNG is the northernmost LNG liquefaction facility in the world and is subject to harsh climatic conditions. Even though the basic technology is well proven, its location requires the plant to handle climatic conditions not present for most other LNG plants. This increases the risk of the plant being constructed with technology not able to meet the predetermined requirements, which can result in operational deficiency. We believe this risk is present, but limited, as experiences from Snøhvit train 1 can be utilized.

Operational Risk

LNG liquefaction utilizes technology that has been used on a commercial scale since the 1960s. Still, the liquefaction process is complex and the facility depends on all components satisfying their specifications. Snøhvit LNG has experienced unscheduled downtime during the first years of operations due to unforeseen technical issues, such as problems with central components in the cooling system (Statoil, 2010). The plant is not stronger than its weakest link, and as there are many components, achieving high operational regularity can be challenging. However, Snøhvit now has "an operational regularity that matches the best in the LNG business" (Gjertsen, 2014).

Again, we believe that a second LNG train at Melkøya will benefit from the experiences acquired during the years the existing facility has been in operation.

Counterparty risk

As LNG is traded in a functioning and growing global spot market there is no risk related to the creditworthiness of the final buyers/consumers of the product. As for a pipeline project, the creditworthiness of the contractors and sponsors represents the major share of counterparty risk. In order to underwrite the development of the facility, the O&G companies and SPV must make contractual price commitments. As the LNG tolling fee will not be subject to government regulation, a predetermined price is necessary both to secure sufficient revenues for the SPV and to avoid monopoly pricing.

Inflation and Financing Risk

We assert that the risks related to inflation, interest rates, and exchange rates are equal for a pipeline and LNG development. Chapter 8.4.1 elaborates on how these risks can be mitigated.

Revenue Risk

As discussed in subchapter 8.4.2, the optimal scale of a LNG facility is at a size that suits the discovered commercial resources in the area. As overcapacity is expensive, a potential plant would be built supported by several licenses that ensure full capacity utilization for many years.

Figure 35 illustrates the anticipated utilization in a new 5 mtpa LNG train at Melkøya. The guaranteed utilization represents the same amount of contractually committed volumes of natural gas as used in the assessment of the pipeline alternative. The volumes used when setting the tariff ("tariff setting utilization") amounts to 195 BCM, which gives a utilization rate of 100 per cent in the new LNG facility. However, as the LNG processing requires energy to cool the gas, a total of 205 BCM are needed to produce the 195 BCM. The total amount of natural gas necessary to maintain the LNG facility at 100 per cent utilization is lower than the reference throughput scenario used in the pipeline alternative. Thus, the volume risk is lower in the LNG alternative. How this affects the size of debt and equity will be discussed in subchapter 8.5.4.

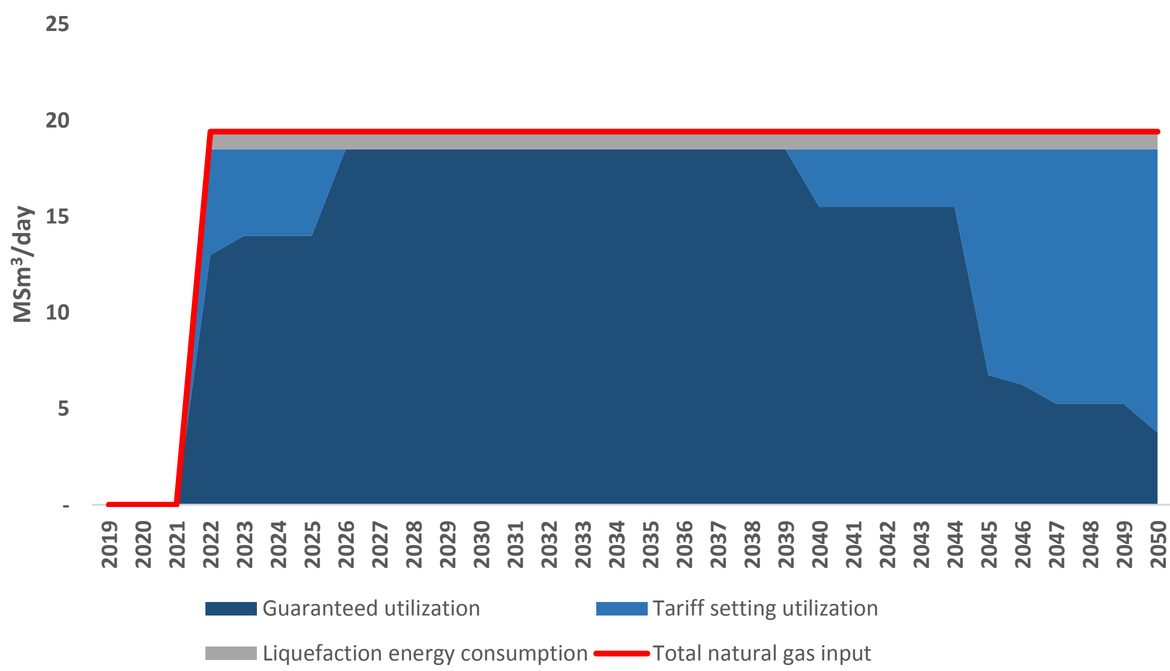

Figure 35 - Volume Scenario LNG Train II

Regulatory Risk

An LNG export facility can contribute significantly to employment in the surrounding area and generate large tax revenues for the local community. This was part of the reason why the Norwegian government granted Snøhvit LNG a special tax break in order to the secure the development. The tax break involved accelerated depreciation of capital expenditures. The construction of the LNG facility was halted two months in 2002 as a result of Bellona, an environmental organization, appealing EFTA to investigate the tax break as unlawful state aid. The case was however dismissed as the current minister of finance, Per Kristian Foss, made the accelerated depreciation a general exception for LNG facilities in Troms and Finnmark. We assert that the considerations for the local communities still is high on the political agenda, which will make regulatory risk for future LNG projects limited.

8.5.2 Project Internal Rate of Return

We believe that given the risks associated with a brownfield LNG facility at Melkøya it is required a lower IRR compared to a pipeline. This is because the contractually committed volumes constitute a larger share of the reference utilization. As figure 35 indicates, roughly 80 percent of the total utilization in the LNG train is contractual volumes. Considering that such substantial part of the total cash flow from the new LNG train will be from contractual volumes, it would not be applicable to apply the same internal rate of return as in the Barentspipe case. We believe that the higher risk related to construction, operations, and technology is compensated for with the significantly lower revenue risk. Hence, we have used a total project internal rate of return of 6 per cent. Consequently the tolling fee needs to be set to a level that gives the project the suggested IRR. Based on the reference case throughput, this gives a tariff of NOK 0.8084/MSm^3 .

8.5.3 Cost Overview

The cost estimations for the second train at Melkøya are based on information gathered through interviews with industry experts, who took part in evaluating the Snøhvit expansion in 2012. We have also used industry benchmark studies to crosscheck the estimates we were provided, as well as to calculate the operational costs.

Capital Expenditures

In May 2012, Statoil estimated the capex for an expansion of the Snøhvit LNG terminal at Melkøya to be MNOK 52,300 (Pettersen, e-mail, 02.06.15). An expansion of the existing facility is called a brownfield expansion, and is viewed as the most feasible alternative for increasing the LNG export capacity in the Barents Sea (Tjelta, 2012). Gassco estimated in 2014 that the cost of a new greenfield LNG facility would be MNOK 60,000 (Gassco, 2014). Both estimates are for a facility with capacity of 5 mtpa. In subchapter 8.1.2, we used a benchmark of $2000/tpa, which has been derived from the cost of Snøhvit phase 1 (Songhurst, 2014). Using this benchmark gives a cost of MNOK 75,000. Further, in our analysis we have used Statoil's capex estimate of MNOK 52,300, as we believe it is a reasonable assumption that a brownfield facility will be less expensive.

Operating Cost

The following assumptions have been made regarding the operational expenditures for the LNG facility.

Cost element	**Metric**
Liquefaction energy consumption	5% of feed gas
Annual operating cost	MNOK 1,000

Table 15 - operating cost (Pettersen, e-mail, 02.06.15)

The liquefaction energy consumption is not a cost in itself, as the alternative price that can be achieved for the gas in the region is very limited. Contrary it can be regarded as an efficiency loss, meaning that if the gas fields produce 20 MSm^3/day, 1 MSm^3/day is used in the liquefaction process, and 19 MSm^3/day can be exported.

As mentioned in subchapter 8.1.2, the shipping cost is a substantial element in the LNG value chain. Table 16 illustrate the shipping cost from Snøhvit to the most relevant markets.

Destination	**Europe**	**Japan**			**India**	
Route	Direct	Via Cape	Via Suez	Via Arctic	Via Cape	Via Suez
Freight cost ($/Mbtu)	0.6	4.6	3.9	3.0	3.8	2.7

Table 16 - Shipping cost from Snøhvit to various destinations (International Energy Agency, 2014b)

In addition to shipping, the LNG has to be regasified at the point of delivery. Table 17 illustrate the cost of regasification in relevant markets.

	Europe	**Japan**	**India**
Regasification cost ($/Mbtu)	0.9	0.9	0.7

Table 17 - Regasification cost at various destinations (International Energy Agency, 2014b)

Taxes

The taxes related to investing in the LNG facility are calculated using the equation in table 18.

Note that the second LNG-train at Melkøya will be subject to accelerated depreciation (3 years instead of 6 years).

Revenues (tariff)
- Operating expenses
- Linear depreciation for investments (3 years)
- Net financial costs
= Ordinary tax base
- Ordinary tax (27%)
- Uplift (5,5% of investments for 4 years)
= Tax base liable to special tax (51%)

Table 18 - Tax calculation for LNG in Troms and Finnmark (Semmingsen, 2010)

8.5.4 Project Finance Model

Project Structure

Figure 36 show the suggested project finance structure for the Barents LNG Infrastructure. As seen, we suggest the same structure for the second LNG train, as with the Barentspipe Company.

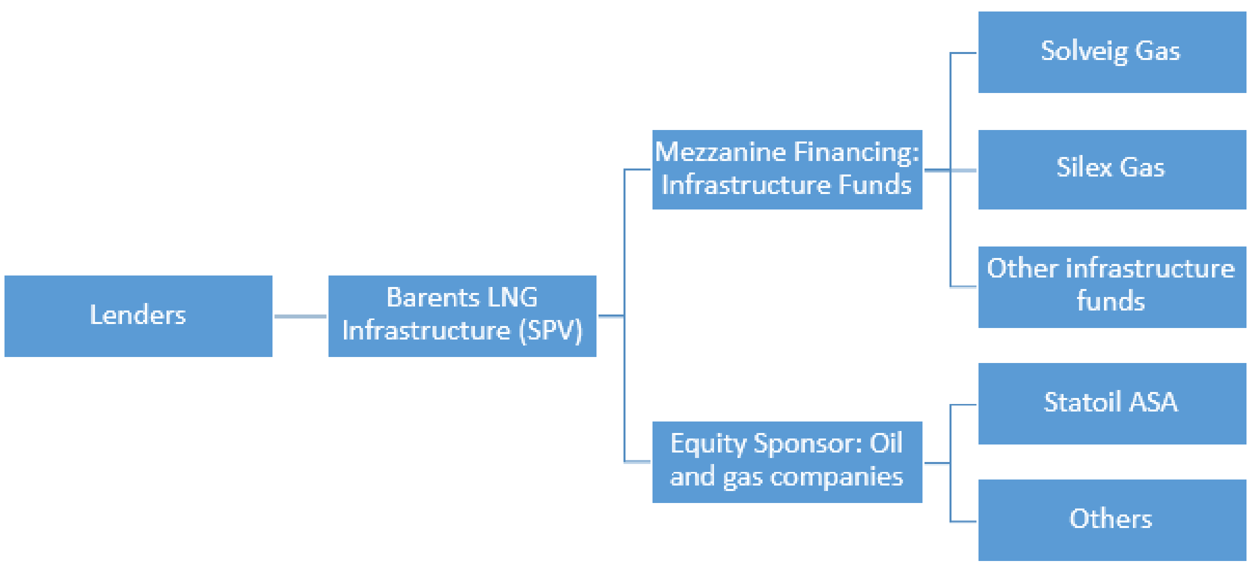

Figure 36 - Barents LNG Infrastrucutre Company project finance structure

Figure 37 illustrates the total free cash flow generated by the LNG project. Again, the tax paid is calculated assuming the company has no debt, and thus no interest tax shield. As the new LNG train will be subject to special depreciation rules (3 years instead of 6 years), the tax loss carryforward will be accumulated faster. As discussed in subchapter 8.5.3, the new LNG train has higher operating cost, and thus a lower operating margin compared to the pipeline. The most important feature of the second LNG train is the low risk related to the revenues. Figure 37 illustrate that almost 80 percent of the revenues generated are contractually committed. This substantially reduces the overall risk of the project, as we believe the most significant risk related to the Barents Sea infrastructure is revenue risk. In the following, we will elaborate how we can attract the various investors from figure 36 to fund the investment in the second train at Melkøya.

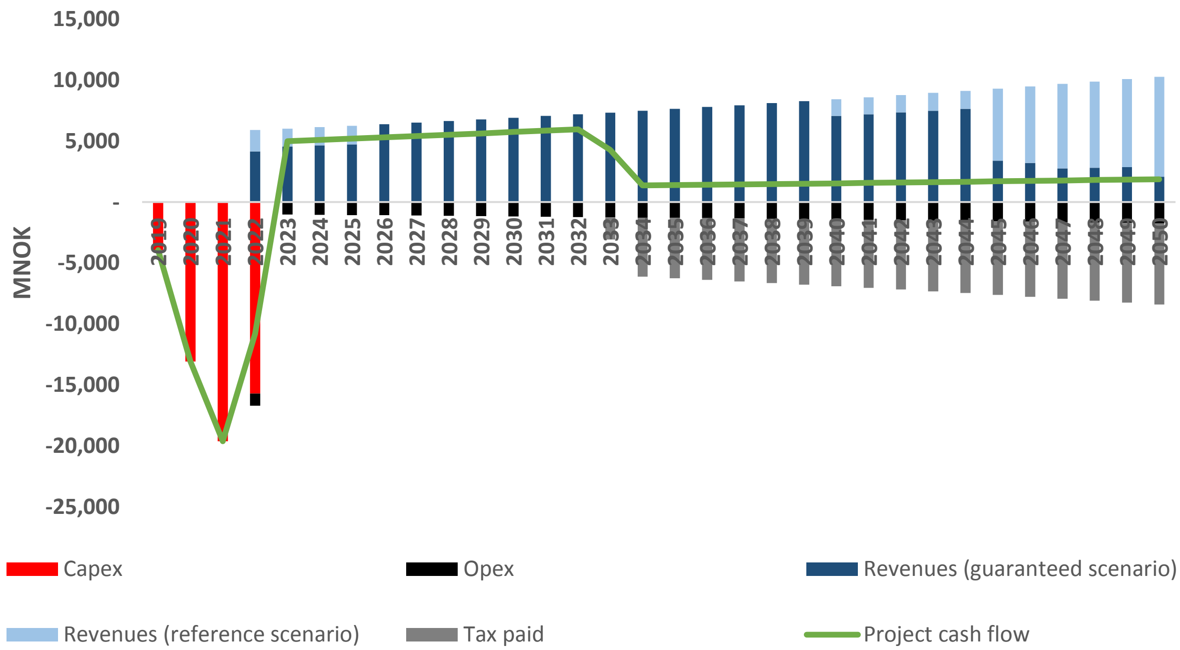

Figure 37 - Free cash flow Barents LNG Infrastructure

Project Company Debt

As discussed in subchapter 8.5.2, the contractually committed volumes correspond to roughly 80 per cent of the total capacity in the new LNG train. Given the anticipated contractual commitments, we suggest that the Barents LNG Infrastructure Company will be funded with 70 per cent leverage, which is 10 per cent higher than for the pipeline. As explained earlier the creditors will look to extract a return that corresponds to the level of risk associated with their share in the share in the project. The creditors risk is reflected in the cost of debt. We assert that the increased total share of committed volumes will offset the higher leverage, meaning that the cost of debt will be the same as for the pipeline case.

Debt Structure	
Total debt outstanding (MNOK)	36,610
LIBOR rate (%)	2.23%
Margin (bps)	225
Interest rate (%)	4.48%
Repayment period (yrs)	12

Table 19 - Debt structure

Further, the debt repayment period is set to 12 years. The relatively short repayment period, compared to the LNG train's lifetime, is a result of the large cash flows being generated early in the project's lifetime. As discussed earlier in subchapter 8.4.4, the depreciation rules of the Norwegian petroleum tax system allow the project company to depreciate the asset over a 3 year period resulting in large carry forward tax benefits. As the equity sponsors have a preference for higher risk and expected returns, maintaining leverage is preferable for equity sponsors. In addition retaining debt will also increase the interest tax shield and reduce the overall cost of capital. Hence, a shorter debt repayment period would not be beneficial for the project company.

Figure 38 show the distributable cash flows from the anticipated committed volumes as well as the cash flow required to service debt. The figure shows that the cash flow generated by the project together with the tax shield from the interest expense will be sufficient to service debt until year 2033. As the project cash flow is not sufficient to service the debt and interest repayment in 2034, meaning that some of the capital retained from previous years will be needed to service the debt holders in 2034. As explained earlier the short fall in distributable cash flow is a result of the tax loss carryforward no longer existing. Again, we argue that the overall debt service ratio is strong, and believe that the project company would be able to obtain the debt financing described above.

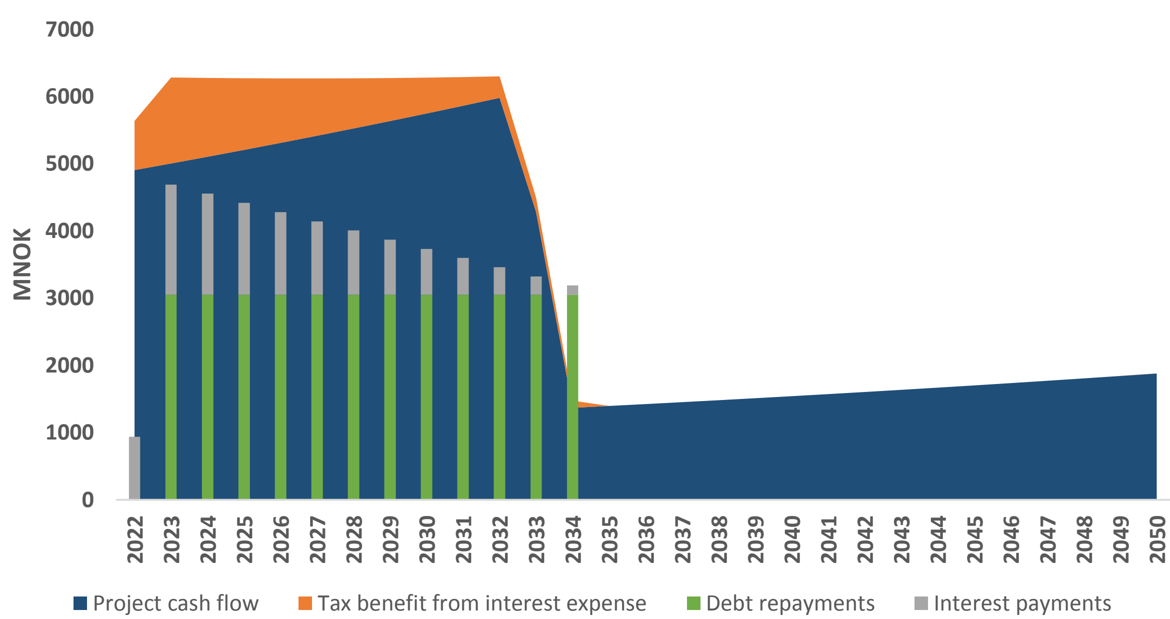

Figure 38 - Cash flow available to service debt

Mezzanine capital

Considering the substantial amount of contractual volumes left after the debt is serviced, the risk and return characteristics of the remaining cash flow does not fit the preferences of the O&G companies. In the LNG project finance model, we again suggest the Gassled infrastructure funds as mezzanine capital partners. We have assumed a mezzanine capital instrument amounting to 25 per cent of the required total capital expenditures. Compared to the pipeline case, the majority of cash flow left after the debt is serviced is contractually committed. Although there is more risk associated with owning the mezzanine capital than owning debt, the risk borne by the infrastructure funds is significantly less than in the pipeline project. Hence the required rate of return for the mezzanine financing should be lower than in the pipeline example.

As there is less revenue risk, the mezzanine financing will be cheaper compared to the pipeline project. Hence, we suggest a base case internal return of return of 8 percent for the mezzanine equity providers. We assume that the mezzanine capital partners will receive some upside potential as discussed in subchapter 8.4.4. The IRR of 8 per cent is compatible with our discussions with the current infrastructure owners (Pedersen & Georgsen, interview, 19.03.15). Further, we have assumed that the mezzanine capital is redeemed after 10 years. Figure 39 illustrates that the cash flows in the reference throughput scenario is sufficient to service the dividends to the mezzanine capital.

As with the Barentspipe company, the mezzanine capital will be redeemed in 2031, and there will be a need for additional capital injections from the common equity owners unless some cash is retained in the SPV from the 11-year period of significant cash generation.

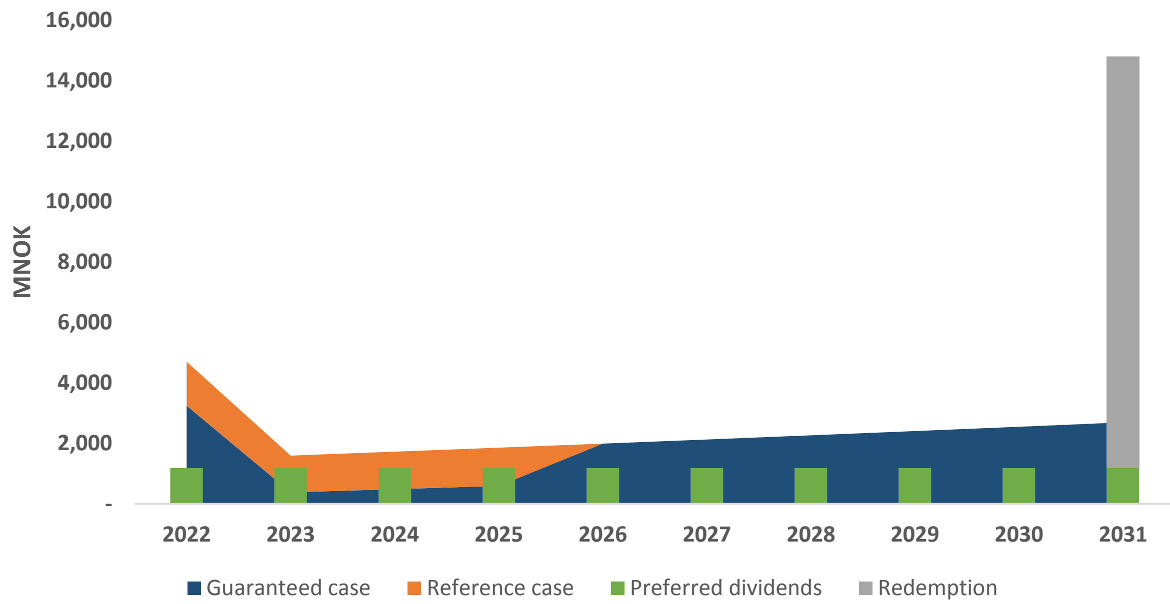

Figure 39 - Cash flow mezzanine

Common Equity

As with the Barentspipe company, the mezzanine capital will be redeemed in 2031, and there will be a need for additional capital injections from the common equity owners unless some cash is retained in the SPV from the 11-year period of significant cash generation.

The contractually committed volumes will provide the common equity holders with a return equal to 10.7 per cent, which is lower than their required return of 18-20 per cent. If the reference throughput is achieved, the common equity holders will get a return of 24.4 per cent that, based on our interviews, is in accordance with their return preferences on such projects. Hence, in order to obtain the preferred risk and return profile on their investments the O&G companies will need to obtain an overall leverage (debt and mezzanine capital) as high as 95%.

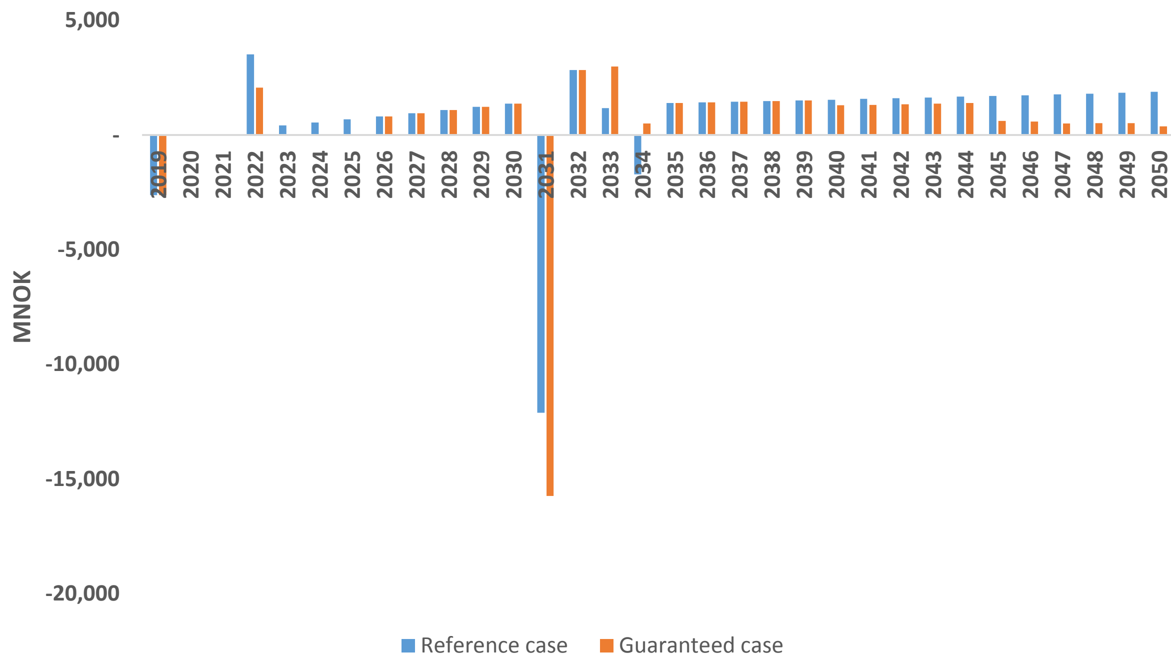

Figure 40 - Cash flow available to common equity holders

Figure 41 summarizes the IRR for the various investors in the Barents LNG Infrastructure. By allocating risk and return preferences within the capital structure of the company, various investors can be attracted such that the necessary funds are raised in order to construct the pipeline.

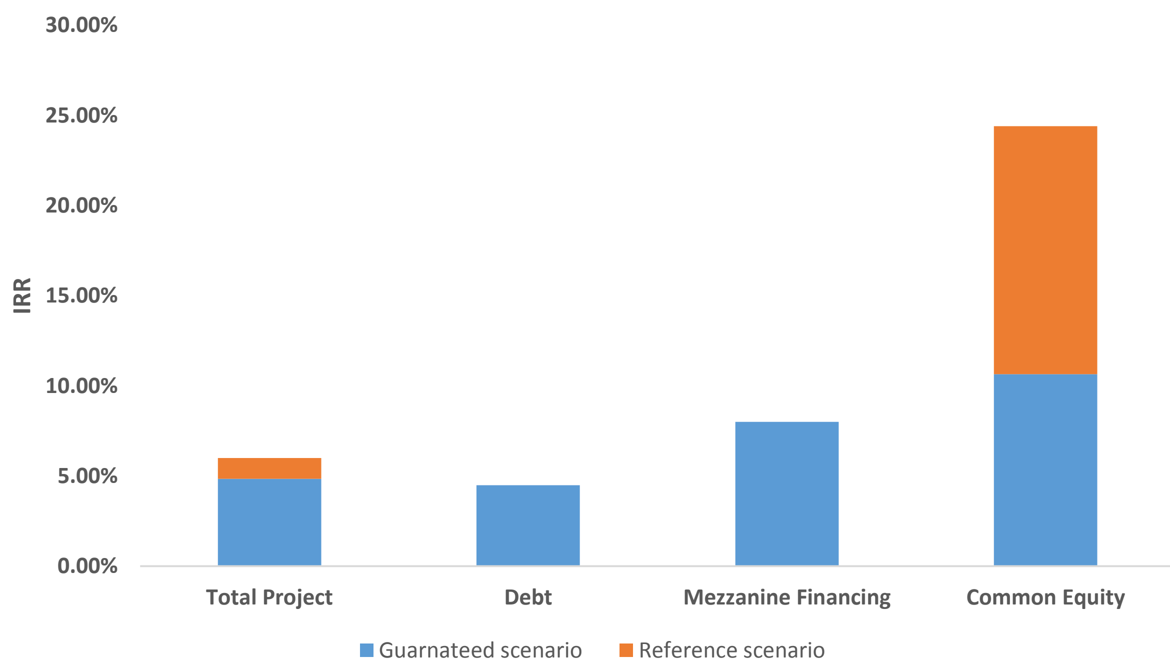

Figure 41 -IRR to the capital providers of the Barents LNG Infrastructure

9 Conclusions

9.1 Viability of developing the resources

The assessments in the previous chapters provide the following estimates regarding the profitability of developing the Barents Sea natural gas resources.

Pipeline ($/Mbtu)	**Europe**
Market price	8.0
Cost of field development	3.9
Cost of infrastructure	2.8
Margin	**1.3**

LNG ($/Mbtu)	**Europe**	**Japan**	**India**
Market price	8.0	10.0	10.0
Cost of field development	3.9	3.9	3.9
Cost of infrastructure	3.1	3.1	3.1
Cost of shipping	0.6	3.0	2.7
Cost of regasification	0.9	0.9	0.7
Margin	**-0.5**	**-0.9**	**-0.4**

Table 20 - Profitability of developing the Barents Sea natural gas resources

Table 20 shows that a pipeline from the Barents Sea is a profitable solution for developing the Barents Sea natural gas resources. In order for a second LNG train to be a more profitable solution, the prices in Asia need to be at a premium of $3.7/Mbtu compared to European prices. However, that fact that the project is profitable does not necessarily guarantee that the pipeline will be constructed. The reason being the timing paradox discussed in chapter 3.1.

9.2 Solving the timing paradox

9.2.1 Contractual booking commitments

As discussed in chapter 8, the development of the infrastructure solutions relies on the assumption that the O&G companies are willing to make contractual volume commitments in advance. This will involve making commitments beyond the transportation needs from existing fields and discoveries. Our discussions with O&G companies on this subject suggest that they are not willing to make such commitments at this point in time. Viste-Solheim at Eon explains that "Currently, I do not believe that there are any O&G companies willing to commit paying for capacity before they are 100 per cent certain that they have discoveries supporting these potential transportation needs" (Solheim, e-mail, 07.07.15). Rummelhoff in ConocoPhillips further support Solheim's argument "Given what happened with Polarled, where many of the gas discoveries making the foundation for the investment were significantly postponed, I have difficulties believing that O&G companies are eager to commit volumes and corresponding liabilities to pay tariffs, in a new Barentspipe" (Rummelhoff, e-mail, 07.05.15). Our discussions with O&G companies indicate that the earliest possible time of making such commitments is when the plan for development and operations (PDO) is delivered. "I do not think OMV will make volume commitments before the Wisting development is certain and the PDO is delivered" (Bogen, e-mail, 22.05.2015).

Even though our assessments indicate that it is possible to profitably develop the resources in the Barents Sea, the O&G companies lack of willingness to commit to contractual bookings make it hard to realize the project. Thus, the timing paradox remains unsolved, resulting in the resources not being developed.

9.2.2 State financing

To solve the timing paradox someone needs to make the first move, either by actively exploring the Barents Sea for natural gas without a clear plan for how potential discoveries can be made commercial, or by building the required infrastructure without knowing whether sufficient volumes to justify the investment will be discovered. The government already funds 78 per cent of exploration expenses through the tax system since they are tax deductible. To increase exploration activity, the Norwegian government introduced in 2004 a system where companies without taxable income could get a cash refund for exploration expenses. We believe that further increasing the incentives for exploration can create negative side effects, as it allows O&G companies to take risks as the Norwegian government carries the majority of the downside. Making the Norwegian government carry a larger share of exploration costs can also lead to a lack of cost control in the O&G companies.

Consequently, solving the timing paradox with more exploration might prove difficult. However, another possible solution is for the Norwegian government to incentivize building or to finance the infrastructure. The Norwegian government holds the unique position of being equally invested in all parts of the value chain on the continental shelf, as a result of all offshore activities being subject to the same 78 per cent tax rate. This means that as long as the total development is profitable, it is also profitable for the Norwegian government. Therefore, it can be argued that the Norwegian government should take the first move to solve the timing paradox by financing the infrastructure. The tariffs charged should, as in the project finance model, reflect the risks of this investment making the tariffs charged equal the model discussed in subchapter 8.4.2. As the level of the tariff allows for a profitable development of the resources, it is not necessary for the Norwegian government to require a lower return than private investors. We believe that staring to develop an infrastructure solution is the most feasible way to solve the timing paradox. Our interviews with the O&G companies indicate that an infrastructure solution will trigger the exploration, “if the industry knew that it would be an infrastructure in place, there would be more exploration” (Tjensvoll, interview, 06.02.2015).

In conclusion, we believe that state financing could solve the timing paradox. By ensuring the O&G companies that an infrastructure solution will be developed, more exploration and consequently more discoveries will follow, assuming that the NPD’s resource estimates proves accurate. Whether state financing for this project is politically doable is uncertain. The Norwegian government’s funding of the gas pipeline can appear as form of selective business support that would require strong arguments in order to be justifiable. Whether the arguments presented in this thesis will convince opponents that this is not a subsidy, as the Norwegian government requires the same return as private investors, is uncertain.

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Tables and figures

Table 21 - Field development cost compared to recoverable reserves:

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Figure 18 - Capital cost of selected natural gas developments on NCS:

Capex allocation: 4 year construction – 10% year 1, 30% year 2, 40% year 3, 20% year 4
Discount rate: 8%
Volumes: Full capacity until 5 years remaining, linear declining tail.

Table 22 – Cost and capacity comparison of various pipeline projects:
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Appendices

The Interviews

List of Interview Respondents

Name	Company	Position
Dag Omre	Centrica Resources	Senior Vice President
Øyvind Rummelhoff	ConocoPhillips	Commercial Manager
Per Aage Jacobsen	DNB	Senior Vice President, DNB Project Finance and Advisory
Håkon Hammer	DNB	DNB Markets Investment Banking Division
Suzana Jensen	Dong Energy EP	Commercial Manager
Rasmus Jacobsen	Dong Energy EP	Commercial Advisor
Bjørn Tore Viste Solheim	Eon	General Manager Commercial
Arve Tjensvoll	Eon	Manager Business Development
Arve Ouff	Eon	Tax Specialist
Tor Eirik Medbøen	Faroe Petroleum	Group Manager Economics and Planning
Tore Torvund	Former StatoilHydro	Executive Vice President Exploration and Production
Britt Aarhus	Gassco	Project Manager
Ola Nestaas	Gassco	Advisor
Maria Moræus Hansen	GdF Suez EP	Managing Director
Geir Pettersen	GdF Suez EP	Special Advisor - External Consultant
Tommy Hansen	Norsk Olje og Gass	Director Communication and Government Relations
Andreas Treichell	OMV	Asset Development Manager
John Bogen	OMV	Commercial Operations Manager
Kurt Georgsen	Silex Gas	Chief Executive Officer
Trygve Pedersen	Solveig Gas	Chief Executive Officer

Information About the Interview Presented to the Respondents

Erling Hammer & Tord S. Torvund
Norwegian School of Economics
February 2015

Information regarding the interview

Dear XXX

In connection with our master thesis in financial economics at the Norwegian School of Economics, we wish to conduct a series of interviews with important players in the Norwegian oil and gas industry. In the interviews we wish to address challenges and opportunities for further developments of Barents Sea natural gas resources. With respect to our research it is important for the quality of our thesis to conduct interviews with key decision makers and experts in the industry.

The process of the interview

The estimated time of each interview is approximately two hours, and is done only with signatories present. During the interviews we would prefer to use a tape recorder to ensure correctness of the data collected and allow us to concentrate more on the conversations. It is up to each individual respondent to determine what questions they wish to answer.

Kind Regards,
Erling Hammer and Tord S. Torvund

Declaration of Consent Presented to Respondents

Master Thesis within Masters in Science
Norwegian School of Economics
February 2015

Authors: Erling A. Hammer and Tord S. Torvund
Supervisor: Associate Professor Tommy Stamland

I hereby confirm that I understand the research topic of Erling A. Hammer's and Tord S. Torvund's master thesis in financial economics at the Norwegian School of Economics, and herby consent to the following:

- Participation in interview with Erling Hammer and Tord Torvund
- Recording of the interview
- Transcription of the interviews in its entirety
- That both the writers and supervisor have access to the transcription in its entirety in the repercussion of the interview
- That I may be quoted from the interview in the master thesis

I confirm that my participation in the interview is voluntary

……………………………….

……………………………….

Location/date	Location/date
……………………………….	………………………………….
Erling A. Hammer	Tord S. Torvund

The Interview Guide

Questions for O&G companies – 1st round of interviews

Market Conditions:

- Natural gas consumption in Europe has gone down the recent years, does this effect the attractiveness of further developing Norwegian gas resources?
- How does the emergence of gas hubs and decreasing share of long-term commitments effect the dynamics of natural gas developments?
- Do you think political ambitions in the EU to reduce carbon emissions will be important for natural gas demand going forward?
- What do you think about global natural gas prices? Will they converge and what will be the equilibrium?
- What do role do you think natural gas will have in Europe's energy mix going forward?
- Is the delinking between oil and gas prices in some way attractive for you as an E&P company? Considering that it reduces the exposure to the oil price?
- New innovation in natural gas production, like FLNG, is that reducing the attractiveness of further developing Norwegian natural gas?

Regulatory

- How do you see the regulatory risk in Norway with regards to the changes in the petroleum tax system in 2013?
- Is opening of Lofoten and Vesterålen important for the further development of the Norwegian Continental Shelf?
- Does the petroleum tax system need to change in order to trigger further developments of natural gas resources?

The Barents Sea

- What needs to come first – a plan for a shared infrastructure or more exploration and resources?
- Should the Norwegian government incentivize developments in the Barents Sea by adjusting the tax system (i.e special allowances that have been introduced on the British Continental Shelf)?
- Pipeline or LNG form the Barents Sea?
- Does the lack of infrastructure in the Barents Sea reduce your willingness to explore natural gas prospects in the region?
- Is it oil that is driving the exploration in the Barents Sea?
- Can associated gas in oilfields be a trigger for developing gas infrastructure from the region?
- Is it possible that several small fields can establish a shared infrastructure? Or do you need one large discovery to trigger a potential investment?
- Is global natural gas prices an important factor when it comes to considering exploration for natural gas in the Barents Sea?

Questions for O&G companies – 2st round of interviews

- Would your company be willing to make contractual commitments (book "use it or loose it" transportation rights) in an infrastructure system from the Barents Sea at this time.
- If making early commitments were given a discount, would this change the situation?
- How low do you think is the tariff in a potential new infrastructure would need to be in order to make natural gas developments attractive?

Additional Questions for Solveig Gas and Silex Gas regarding their investments in Gassled and thoughts about new infrastructure from the Barents Sea:

- How has the regulatory changes in tariffs effected your willingness to invest in gas infrastructure on the Norwegian Continental Shelf?
- Could you also invest in other gas infrastructure solutions than pipelines?
- How do you evaluate an investment opportunity, what is your risk reward preferences and risk tolerance?

Additional Questions for DNB regarding project finance:

- What will be a reasonable debt/equity ratio for this project? How is the capital structure decided in project finance?
- What is the typical repayment structure and what margin over LIBOR would you need to pay?
- What type of debt would be involved? Commercial bank loans/syndicates, Export credit agencies, bonds?
- Is it a problem that the loan is not secured in a liquid/exchangeable asset?
- How far above over the "secure cash flow" can the preferred equity carry?
- How is the share of equity in the SPV distributed among the sponsors?

Additional Questions for Tore Torvund regarding cost of field development:

- What are the major components of the field development cost?
- How does the size of the field effect the total cost of developing a field?

Project Status Categories

(All information in this retrieved from NPS' resource classification (Norwegian Petroleum Directorate, 2015g))

Category 0 Sold and delivered petroleum

Petroleum resources in deposits that have been produced and have passed the reserves reference point. It includes quantities from fields in production as well as from fields that have been permanently closed down.

Category 1 Reserves in production

Remaining, recoverable, marketable and deliverable quantities of petroleum which the licensees have decided to recover, and which are covered by plans for development and operation (PDO) which the authorities have approved or granted exemption from. Should production be temporarily shut down, the reserves must, nevertheless, be added to this category. The reserves in this category are shown by subtracting the sold and delivered petroleum quantities from the originally recoverable reserves. Quantities of gas covered by approved plans for development and operation and on hold in fields from which delivery has started are also reckoned as reserves in this category.

Category 2 Reserves with an approved plan for development and operation

Category 2 F

Recoverable quantities of petroleum described under category 1, but which have not been put into production.

Category 2 A

Additional (or deducted) reserves that are in categories 1 or 2F, which are a consequence of projects to improve production, and which have the same status as regards decisions as reserves in category 2F.

Category 3 Reserves which the licensees have decided to recover

Category 3 F

Recoverable, marketable and deliverable quantities of petroleum which the licensees have decided to recover, but for which the authorities have not yet approved a PDO or granted exemption therefrom. This category also contains supplementary reserves from new deposits with the same status as regards decisions, and which can be connected to fields in categories 1 and 2. 9 The category also covers quantities of petroleum (mainly gas) that have been held back, but which can be sold without significant investments at a later date.

Category 3 A

Additional (or deducted) quantities of petroleum in categories 1, 2 or 3F, which are a consequence of projects to improve production and which the licensees have decided to recover, but for which the authorities have not yet approved a PDO or granted exemption therefrom. The category also covers quantities of petroleum (mainly gas) that have been held back, but which can be sold without significant investments at a later date.

Category 4 Resources in the planning phase

Category 4 F

Discovered, recoverable, petroleum resources that are expected to be covered by a PDO or granted exemption therefrom, and where specific activity is taking place with a view to clarifying whether a development will be implemented. Development is expected to be decided by the licensees within about 4 years. This category also contains supplementary resources which can be connected to existing fields that have reserves in categories 1 and 2, and discoveries that have reserves in category 3.

Category 4 A

Additional (or deducted) quantities of petroleum in categories 1, 2, 3 or 4F, which are a consequence of projects to improve production and which have the same status as regards decisions as resources in category 4F.

Category 5 Resources whose recovery is likely, but not clarified

Category 5 F

Discovered, recoverable petroleum resources whose recovery is likely, but not clarified. This category contains discovered, recoverable petroleum resources which are not being considered for development at the moment, but which can be developed in due course. It also contains supplementary resources from new deposits which can be tied in to fields and discoveries with resources in categories 1, 2, 3 and 4, but where matters regarding recovery have still not been clarified.

Category 5 A

Additional (or deducted) quantities of petroleum that are in categories 1, 2, 3, 4 or 5F, which are a consequence of projects to improve production, and which have the same status as regards decisions as resources in category 5F.

Category 6 Resources whose recovery is not very likely

Discovered, recoverable petroleum resources which are not expected to be profitably recoverable even in the long term, and resources in small, untested discoveries whose recovery seems unlikely. Option values will normally be included in assessments of profitability. The option values emerge as a result of uncertainties surrounding future recovery factors (price, technology, etc.), and where recovery of the resource is considered to be an option (a right, but not an obligation) that will be realised only if the situation develops sufficiently favourably. This category contains petroleum resources that require substantial changes in technology, prices, etc., to be recovered profitably, and where it is not very likely that the changes required will take place.

Category 7 Resources that have not been evaluated

Category 7 F

Recoverable petroleum resources in new discoveries where the discovery evaluation report have not yet been submitted to the authorities so that only a provisional resource estimate exists.

Category 7 A

Recoverable petroleum resources in fields and discoveries which have resources in categories 1, 2, 3, 4 or 5 and which may be recoverable with the help of production techniques beyond those that are considered to be conventional, or with the help of known methods which there is still no basis for employing. For the individual field or discovery, this estimate of the resource will typically be based on rough valuations. There may be great uncertainty as to whether the measures can be implemented. Estimates are normally only stated for the total potential of the measures, not in respect of individual measures. (This category covers resources, which were previously categorised as "Resources from possible future measures to increase the recovery factor").

Category 8 Resources in prospects

Undiscovered, recoverable quantities of petroleum in mapped prospects that have not been discovered by drilling. It is uncertain whether the estimated resources are present. They have been risk-weighted, i.e. they reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated.

Category 9 Resources in leads, and unmapped resources
Undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated. The unmapped, recoverable resources are calculated by analysing plays. The total resources of the plays include both discovered and undiscovered resources. The unmapped resources are the difference between the aggregate resources of the plays and the discovered and mapped resources.

Conversion table

Conversions		
1 Sm^3 of oil	=1.0 Sm^3 o.e.	
1 Sm^3 of condensate	=1.0 Sm^3 o.e.	
1000 Sm^3 of gas	=1.0 Sm^3 o.e.	
Gas		
1 cubic foot	1,000.00	BTU
1 cubic metre	9,000.00	kcal
1 cubic metre	35.30	cubic feet
1 cubic metre	0.0367	Mbtu
Crude Oil		
1 Sm^3	6.29	barrels
1 Sm^3	0.84	toe
1 tonne	7.49	barrels
1 barrel	159.00	litres

	MJ	**kWh**	**TKE**	**TOE**	**Sm^3 natural gas**	**Barrel crude oil**
1 MJ, megajoul	1	0.278	0.0000341	0.0000236	0.0281	0.000176
1 kwh kilowat hour	3.6	1	0.000123	0.000085	0.0927	0.000365
1 TKE, tonne coal equivalent	29300	8140	1	0.69	825	5.18
1 TOE, tonne oil equivalent	42300	11788	1.44	1	1190	7.49
1 Sm^3 natural gas	40	9.87	0.00121	0.00084	1	0.00629
1 barrel crude oil	5650	1569	0.193	0.134	159	1