Henley Business School
UNIVERSITY OF READING

OFFSHORE TRANSPORTATION OF NORWEGIAN GAS TO EUROPE

The case of The Barents Sea Gas Infrastructure

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Declaration

I confirm that this is my own work and the use of all material from other sources has been properly and fully acknowledged.

Michael Ingenbleek.

At the basis of the monopoly of the Standard Oil Company in the production and distribution of petroleum products rests the pipe line. The possession of these pipelines enables the Standard to absolutely control the price which its competitor in each given locality shall pay.

(ICC, 1907 cited in Boyce, 2014 pp.5)

Introduction

This study is concerned with Norway's role in supplying gas to Europe through offshore pipelines. One reason for choosing this topic is the difference in available research between the number one supplier of gas to Europe, Russia, and the number two, Norway, where there is much less published research. This study aims to bridge the gap by considering, for the Norwegian gas Sector, issues of gas supply, a competitive gas market, a sustainable effective, efficient offshore infrastructure and access for all where and when it is required. It further explores whether the regulation of the Norwegian Gas Sector, through national regulations, the Gas Target Model and three EU gas directives is meeting its goals or actually hinders development. Another reason to choose this subject is the low volume of investments in the Norwegian gas offshore infrastructure, which consequently will lead to reduced volumes of supply. In relation to the abovementioned, the third reason is to investigate whether current and anticipated prices justify further investment in Norwegian natural resources and offshore infrastructure. The fourth reason is to explore the possibilities and preferences for Europe to support investment in Norway's most promising sector, the Barents Sea, or if competition and pricing do not warrant further investment.

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Abbreviations

ATC	Available Transmission Capacity
BCM	Billion Cubic Metres
BCR	Benefit-cast ratio
BN	Billion
BOO	Build operate Own
BOOT	Build operate Own Transfer
BOT	Build operate Transfer
CBA	Cost-benefit analysis
CNG	Compressed Nitrogen Gas
CEF	Connecting Europe Facility
DBFO	Design, build, finance, and operate
DOE	Department of Energy
E&P	Exploration and Production
EEA	European Economic Area
EFSI	European Fund for Strategic Investment
EIA	Energy Information Administration
ETS	Emission Trading Scheme
EU	European Union
FLNG	Floating Liquefied Nitrogen Gas
GFU	Norwegian Gas Negotiation Comity
IA	Impact Assessment
IEA	International Energy Agency
IGU	International Gas Union

IOC	International Oil Company
IRR	Internal Rate of Return
Km	Kilometre
LNG	Liquefied Nitrogen Gas
LRMC	Long Run Marginal Cost
MiFID	Markets in Financial Instruments Directive
MIRA	Macquarie Infrastructure & real assets
MMbtu	Million metric British Thermal units
MPE	Ministry of Petroleum and Energy
Mtoe	Million Ton of Oil Equivalent
NCS	Norwegian Continental shelf
NGL	Natural Gas Liquids
NGU	Norges geologiske undersøkelse
NBIM	Norges Bank Investment Management
NOC	National Oil Company
NOK	Norwegian Krone
NORSOK	Norwegian shelf competitive position
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
NVE	Norwegian Water Resources and Energy Directorate
OECD	Organisation for Economic Cooperation and development
PDO	Plan for Development and Operation
PIO	Plan for Installation and Operation
PPP	Private Public Partnership
RES	Renewable Energy Sources
SEG	Society of Exploration Geophysicists
Sm^3 o. e	Standard cubic meter of oil equivalent
SPE	Society of Petroleum Engineers
SPE	Special Purpose Entity

SPEE	Society of Petroleum Evaluation Engineers
SRMC	Short Run Marginal Cost
SWF	Sovereign Wealth Fund
TCE	Transaction Cost Economics
Tcm	Trillion Cubic Meters
TOP	Take or Pay
UCITS	Undertakings for Collective Investment in Transferable Securities
VOT	Value of time
WPC	World Petroleum council

1. Norway as a Major Gas Transporter

1.1. INTRODUCTION

The Norwegian gas industry has been affected by challenges and opportunities. Chapter 1 will capture the development of the resources and the development of what has sometimes been called "the Norwegian model", and elaborates on these encounters and prospects, furthering the underpinning for the research. Section 1.2 aims to provide a better understanding of the influences, challenges and opportunities which affected the Norwegian gas sector before discussing the gas market in the period 2016-2017. It portrays a historical background on how the Norwegian resource development commenced and details how Norwegian regulations were established in a period where much uncertainty existed regarding potential resources and the boundaries of the Norwegian Continental Shelf (NCS). Section 1.3 provides a concise summary of the development of the Norwegian Gas Infrastructure and how fields are linked to treatment facilities and further to different countries. Section 1.4 describes the governmental structure, and the responsibilities of parties involved in owning and operating the transmission system from end to end. It also explains how gas is discovered and managed by the government through a licensing system which allocates acreage for certain areas in a set period to optimise the resources on the NCS. It provides an insight on how the Norwegian System operated during its "monopoly period" before supra-national regulation was implemented by the EU and establishes the level of investments in the transmission system to facilitate the market. Section 1.5 sets out the research questions, methodology and disposition.

1.2. DEVELOPING NATURAL RESOURCES - A HISTORICAL PERSPECTIVE

Norway is the third largest gas exporter in the world and the second largest exporter of piped gas to Europe after Russia. Norway exported about 115 BN Sm^3 gas to Europe in 2016 making it the largest volume of gas ever exported from the NCS in a single year. In a large part of Europe, gas is a critical resource of energy for domestic, industrial usage and for power generating facilities. Most of Norway's gas sold to Europe is transported through the offshore subsea infrastructure to Germany, the United Kingdom, Belgium and France. Overall Norwegian gas covers about 25 % of Europe's gas consumption and makes an important contribution to energy security in Europe (NPD, 2017b).

Efficient planning and utilisation of the natural gas infrastructure has created great value for Norwegian society. The Sovereign Wealth Fund (SWF), founded on natural resource sales and interest on capital invested, amounts[1] to NOK 714 BN or $88 BN(NBIM, 2016). The SWF[2] at times also called "the Norwegian Pension Fund" was set up in 1988 and has provided an annual return of 3.79% since then (Reuters, 2017). It is managed by the Norges Bank Investment Management (NBIM) and reports to the board of the Central Bank and the Norwegian Parliament. The fund has restrictions in choosing its investments: it is only allowed to invest in real estate, stocks, bonds abroad and is bound by an ethical mandate. In addition, it is only allowed to return 3% of the fund's value into Norwegian society directly (Reuters, 2017). According to the Ministry of Petroleum and Energy

[1] Accessed 10.10. 2016
[2] For in depth reading on the Norwegian oil fund (Lie, 2013)

(Regjeringen, 2013a) approximately NOK 3,000 BN ~$370 BN in 2017 money[3] has been invested in installations, pipelines and land facilities. Timely development of proved and unproved, natural resources and existing fields exploits this resource capacity while extending the producing life of the fields. The exploration, production, transportation and supply of natural gas is a complex process. It requires substantial capital investment with risk for stakeholders involved.

This thesis will focus on investments in the offshore pipeline system[4] on the NCS and ask if further extension of the offshore pipeline system into the northern, Barents Sea sector is a commercially viable option. The pipeline transmission system plays a deciding role in the development of natural resources on the NCS. Any alteration of the transmission system may have a significant impact on the resource management of natural gas and the financial requirements to build or expand this complex system. It requires long term planning from all stakeholders involved. The Norwegian offshore gas infrastructure consists of a myriad of subsea pipelines, platforms and onshore process facilities. With the exception of LNG from Snøhvit (5.4% of 2016's export equal to 6.1BCM), the major share of natural gas transportation from the Norwegian Continental Shelf to customers in Europe including the UK is through subsea pipeline systems. Since the first pipeline became operational in 1977, transmission system owners have been developing and constructing a transportation network that comprises approximately 8,300 km (Gassco, 2016). To put these dimensions into a comparable perspective, the pipeline diameters range typically from 28-inch (~72cm) to 42-inch (~107cm) in diameter and maximum internal working pressure is limited to approximately 2,800psi (193Bar) over a length approximately equal to that from Oslo to Houston.

[3] Extrapolated from 2013NOK to 2017NOK

[4] Pipeline, transmission and transportation system will have the same meaning unless explicitly stated differently

Influences

The Norwegian natural gas market has continuously been influenced by regulatory, economic, societal and physical uncertainties. These four types of influences will be briefly discussed and further explained throughout the research.

Austvik (2011) described the Norwegian government as entrepreneur and landlord when it adapted to these influences. For instance, the government as owner of natural resources used to favour barriers, shielding certain natural monopolies from competitive entry. European governments however enforced supra-national deregulation schemes[5] opening the market up for new participants, thus influencing economic returns. As a result, national policies and ownership changed, making Norway "prefer" competition in parts of the value chain at a cost to the pipeline owners.

The long-term life cycle, typical for natural gas development, has allowed for new technologies to be developed and applied to optimise natural gas recovery. The NOK 3,000BN (~$370BN) depicts the capital-intensive nature of the industry and makes decisions on long term growth targets important. Considering the appetite of the industry for short term Return on Capital Employed (ROCE) and dividends, natural gas prices between $5-$8/MMbtu that have been dominant since 2014 combined with the high rate of supply of natural gas have put investments under strain. In addition, long lead times to actually get gas flowing through the transmission system require timely investment ahead of supply decline. Consequently, leaving the resources in the ground and thus requiring no extension to the existing transmission system has been the outcome on several investment decisions on the NCS. Simultaneously, the low 2014-2017 gas prices suffered by the sector resulted in consolidation between major

[5] The process of Norway implementing (European Union) regulations will be discussed in more detail in Chapter 3.

players E.g. Shell and BG (Shell, 2016; MPE, 2016). Increasing mergers and acquisitions in the sector took place to reduce cost, divest and/or return to core business, yielding oligopolistic situations with a reduced number of players.

Societal influences on decarbonisation and reduction in the usage of fossil fuels creates additional uncertainties in decision making on further expanding the transmission system. The 2015 United Nations Climate Change Conference (COP21, 2015) further tempers the investment rationale for field development with the accompanied transmission system expansion.

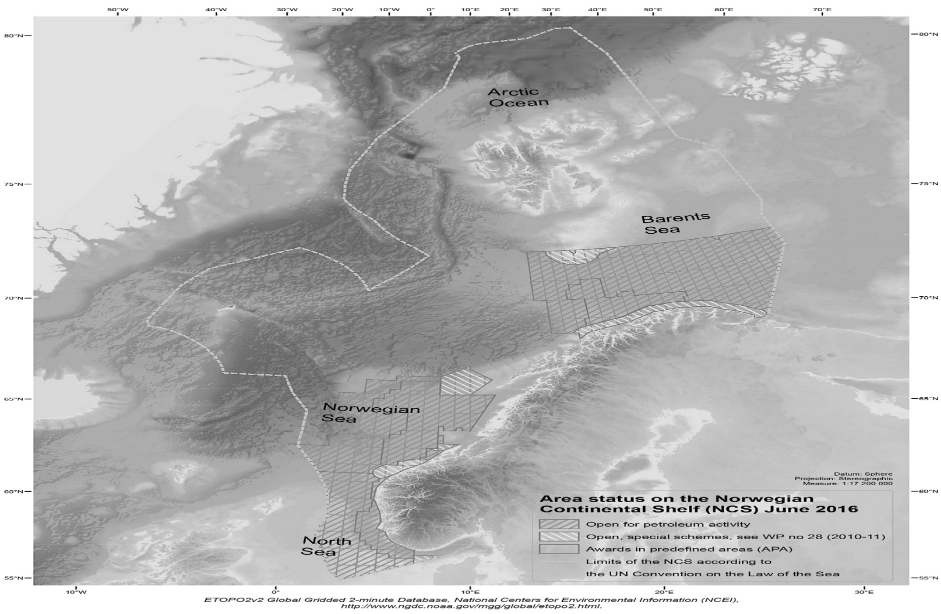

Figure 1 The Norwegian Continental Shelf
Source: Norskpetroleum (2016a)

The physical uncertainties are related to the natural resources on the Norwegian Continental shelf. The shelf is divided into four geographical sectors as depicted in Figure 1 which differ considerably. From South to North, the North Sea sector is in a mature state, followed up by the Norwegian Sea sector with a higher share of undiscovered resources and the most northern sector, the Barents Sea, with the largest undiscovered resources and seen as the highest potential source of oil & gas for the future.

The Arctic Ocean is not open for activities or schemes, however indicates the boundaries of the shelf. For this research only the first three sectors will be discussed.

The offshore transmission system plays an intrinsic role in resource management on the NCS. Changes in resource development and operations of the transmission systems inevitably affect the resource management indicating its importance.

Reconsidering Norway's natural resource potential

It was not until the discovery of gas at Groningen in the Netherlands in 1958 that experts revised their thinking on the petroleum potential of the North Sea (Ryggvik, 2010). This discovery led to optimism in a part of the world where energy consumption to a large extent was based on coal and imported oil. Prior to the discovery of Slochteren (Groningen) few people believed that the NCS could contain oil and gas deposits. After all, initial geological expertise on the NCS was negative to oil and gas deposits. In a letter of February 1958 to the Ministry of Foreign Affairs, the Norwegian Geological Survey wrote that: "The chances of finding coal, oil or sulphur on the continental shelf off the Norwegian coast can be discounted". This claim was based upon near-shore waters, but it remains a fact that geologists at the time did not believe oil or gas could be found on the NCS (MPE, 2013). Part of this perception could be attributed to the lack of appropriate data which, based upon the then present technology was not readily available or accurate. As Al Kasim (2006) described, perhaps the most challenging tasks in the petroleum sector at the time were to persuade Oil & Gas companies of the need and the right of the State to receive necessary data from E&P operations. The desire to obtain data on resources on the NCS became the foundation for the government to constitute specific regulations that would cover data collection through geological surveys in Norwegian waters. The potential for finding natural resources fuelled negotiations with O&G

companies who applied for permission for geological surveys on the NCS (Ryggvik, 2010).

The discovery of gas in The Netherlands and further exploration on the United Kingdom shelf led international oil companies like Philips, Shell, Mobil, Esso and Amoco, to enquire for exploration rights from the Norwegian government. The first company was Philips in 1962[6], asking for rights for the complete (yet to become) Norwegian Continental Shelf. Norway at that time was not too concerned[7] with exploration, considering no resources were likely to be found (based on the Geological Survey conducted in 1958). The only clearly defined regulation on coastal waters was laid down in the Geneva convention of 1958[8]. Norway[9] was hesitant to adopt the regulations for reasons related to fishery and shipping which were the main economic drivers at that time (Norskpetroleum, 2016b).

Based on an additional aeromagnetic survey conducted in 1959 by the Norges geologiske undersøkelse (NGU) Geological Survey of Norway, followed up in 1963 with another survey, including seismic surveys, the Norwegian government realised it needed to establish a legal basis for oil and gas activities on its to be defined Norwegian Continental Shelf. This resulted in a royal decree and was followed by the law of 1963 specifically not naming the NCS, however indicating the State's right to natural resources through the King. This allowed the King through the government

[6] This was seen by the Norwegian government as an attempt to obtain an exclusive concession for the whole shelf. This had happened in Denmark with Danish ship owner A P Møller and through meetings in Copenhagen with the A.P. Møller concern, it became clear that all doors there were closed. The concern had signed a 50-year contract for all of Denmark including the continental shelf. Besides, the company was already associated with several larger oil companies through D.U.C. (Dansk Undergrunds Consortium).

[7] In 1971 Norway ratified the Geneva convention. The Barents Sea southeast became a part of the Norwegian Continental Shelf after the Treaty on Maritime Delimitation and Cooperation in the Barents Sea and the Arctic Ocean between Russia and Norway entered into force on July 7th, 2011. In 2013, the Norwegian Parliament opened the Barents Sea southeast to petroleum activity.

[8] Geneva Convention states the 200 metres criterion – see next footnote.

[9] See Geneva Convention on jurisdictions on continental shelfs regarding 200-metre water depth criterion from the coast or in-depth Al Kasim page 11-12.

to issue licenses[10]to oil and gas companies wanting to explore petroleum resources on the shelf.

The next step on the road to develop a legal natural resources framework was the median line negotiation[11]and agreement of 1964-1965 between the United Kingdom and Denmark. The agreement meant that boundaries in the North Sea had been agreed upon before exploration began, clarifying the division of resources in fields which might later become debatable[12]. Due to the lack of a Ministry of e.g., Energy in those countries before 1965, these negotiations were conducted by the ministries of foreign affairs and the ministry of Industry, who prepared the first allocation for exploration (NPD, 2015b).

Realising the need for specific expertise, The Norwegian Petroleum Council (NPC) was appointed by "the royal decree of 1965" and provided its experience and advice to parliament on petroleum issues in the capacity of advisory board. The NPC approved the spudding of the first well by Esso in 1966 opening the Norwegian North Sea for development. The absence of clear rules and policies on what was considered data to be shared for exploration purposes, made it near impossible to develop the regions. In that same year (1966), the Petroleum Section[13] was appointed as a separate unit at the department of mines in the Ministry of Industry (Moses&Letnes, 2017), the unit that was tasked with the requesting of data from the international oil companies, eager to explore the Norwegian North Sea sector (Kvendseth, 1988).

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[10] In the earlier years, there used to be a reconnaissance and production licence (1965) The production licence gives a company or a group of companies a monopoly to perform investigations, exploration drilling and recovery of petroleum deposits within the geographical area stated in the licence. The licensees become owners of the petroleum that is produced. A production licence may cover one or more blocks or parts of blocks and regulates the rights and obligations of the participant companies with respect to the authorities. Production licences are awarded by the Ministry of Petroleum and Energy in numbered licensing rounds for the least explored parts of the shelf (frontier areas), or awards in predefined areas (APA) for mature parts.

[11] Agreement between Norway, the United Kingdom, and Denmark followed later, see below.

12 This proved valuable considering certain fields that were discovered post 1965 are located on the borders e.g. Sleipner, Cod, Blane, Varg, Flyndre and Ekofisk became de facto Norwegian fields, see Figure 4.

[13] The term petroleum Section and Oil Office are assumed to be interchangeable.

The discovery of the Cod field in 1968 gave the Government a further stimulant to expand the Petroleum Council and the petroleum administration subsequently prepared specified regulations for licencing and exploration purposes (Earney, 1982). The licensing[14]of blocks is an important part of the regulation in relation to managing natural resources. The regulations described exploration and exploitation rights which incorporated block size, duration, production and tax. These rules and regulations were combined and applied to 10 licences.

An interesting fact related to the establishment of tax legislation was that the Norwegian Government was determined to set a more attractive tax rate for international Oil & Gas companies than its neighbouring countries (Al-Kasim, 2006). The taxation and royalties were initially 42% and 10% in 1965. The rates increased to 76% in 1975 and increased further to 85% in 1985. The system gradually moved to one petroleum taxation form consisting of corporate income tax, special petroleum tax and royalties. The latter was to be phased out in 1986 and 1992 (Lund, 2014). Changes to the tax regime have been made for various reasons e.g. special taxation arrangements were made between the licensees and the government for sharing technological risks[15] involved in project developments.

All licenses that were awarded in the first allocation round in 1965 were of the concession type[16]. With the introduction of state participation in the following licensing rounds, joint venture[17] contracts were incorporated with subsequent taxation rights and obligations. Several tax revisions have been introduced in 1972, 1975, and 1986[18].

The main driver for the revisions was the rise and fall in oil prices and the consequent changes in risk and exposure. Starting in 1986 there has

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[14] See appendix for full layout of a license (Statoil)

[15] Water flooding became operative in Ekofisk in 1987

[16] Concessionary agreement is based on the conventional basis of a license whereby the licensee is entitled to carry out petroleum operations against the payment of royalty and tax to the resource owner

[17] Joint venture has two types: incorporated (equity) and unincorporated (Al-Kasim, 2006)

[18] For a detailed discussion see (Lund, 2014)

been a deliberate move towards a neutral system of state participation and taxation. Following the first licensing round in 1965 twenty-three rounds have passed, the last round being announced on 13 March 2017. The licensing rounds that made significant changes and impacts in relation to national regulation and ownership will be discussed in the next section (NPD, 2016c). The first licensing round represents an image of the situation and paradigm at the time.

The earlier mentioned median line agreement was signed by Norway in March 1965 (with the United Kingdom) and December 1965 (with Denmark) and limited allocation of blocks north of the 62-degree parallel. Furthermore, International Oil Companies (IOC) had an interest in exploring acreage in the southern sector of the North Sea close to the Dutch and United Kingdom sector. These two issues[19]and the lack of experience were foundations of the gradual move from south (North Sea) to the Norwegian Sea and later on the Barents Sea. This principle remained in place throughout the sixties and seventies. The licensees were selected on operational experience, financial strength, and to what extent the company would contribute to the Norwegian economy through local content and asset utilisation e.g. Norwegian vessels and construction companies (Austvik, 2011).

Another important factor was that only IOCs were involved. At the time, the government was cautious about participating and taking risks in oil and gas projects. In 1968 the NPC wrote a letter to the ministry raising the question of state participation.

There were two reasons for participation in future licensing. The first reason was the find of the Cod field and the second reason was related to the founding and control of OPEC (Ryggvik, 2010). The recommendation to participate was carefully pointing out that the state should not take risks with its own funds in drilling investments on the shelf. This consequently

[19] NPD, (Al-Kasim, 2006)

meant that the international oil companies would carry the weight, which in the following negotiations revealed resistance from the IOCs. Prior to the second allocation round the IOCs were free to draft their own agreements. The outcome of the second licensing round was that there would be state participation of 17.5% and the government recognised that it should draft the agreements from then on (NPD, 2016d). By the time the third license round was due, the issue of state participation was solved through the establishment of Statoil as the national oil company (NOC) and the Norwegian Petroleum Directorate (NPD) in 1972. Statoil had a minimum share of 50% in all blocks and had the option to further increase[20] this to 70%-80% in case of a commercial find depending on size, while the international licensees were carrying large parts of the cost [21] throughout the exploration period (Al-Kasim, 2006).

The reason for an increase of participation was the size of discoveries that were made in the first half of the seventies[22].The importance of and the connection between licensing and revenues was discussed in the Governmental Report No.25 of 1974. It discussed the regulation of the pace of resource development, the issue being that a rapid surge of development and consequently revenues could have a negative impact on Norwegian society. Specific targets were set to avoid a level of petroleum resource production and sales which could result in what has been called the Dutch disease[23]. Several production levels were discussed in parliament, whether e.g., 90 Mtoe could be argued as a moderate volume to capture unwanted excessive economic growth. A general agreement formed that the tempo of development should be regulated downwards (NPD, 2016d). Tempo

[20] In some licenses, Statoil's ownership share had been increased according to a "sliding scale" based on the amount extracted. (Lund, 2014)

[21] When it concerned a complete Norwegian setting, e.g. Statoil, Norsk Hydro or Saga. Statoil's role in resource development and infrastructure ownership took precedence.

[22] 1970 Ekofisk, Eldfisk, The Tor, 1971 Frigg, 1972 Heimdal, 1974 Statfjord

[23] The Dutch disease received its name from the increase in services in the petroleum industry after the find of the Groningen field in 1959 at the expense of other industries such as industry and agriculture

regulation came first through capping production and later through a cap on investment. The years of tempo down regulation had an impact on field development and restricted uncontrolled growth until the fifth licensing round in 1979 that was more liberal. Specific targets were set by the NPD. The most promising blocks were to be allocated to get an indication of the resources on the NCS, with "the golden blocks" to be allocated to Norwegian companies (NPD, 2016c).

The main motive for the tempo regulation change was to reduce investment and development. Two years after the fourth round in 1981 the fifth licensing round opened up the area above the 62nd degree, the Norwegian Sea and the Barents Sea (Regjeringen.no, 2011). The strategy was and still is to some extent to gradually move north and diversify the exploration effort. From 1979 onwards till 1985 rounds 6-10 followed the same licensing principles of small blocks well diversified over the three regions (NPD, 2016c). Figure 2 displays licenses awarded from 1965 till present over the three regions. In years when no allocation took place no data is presented.

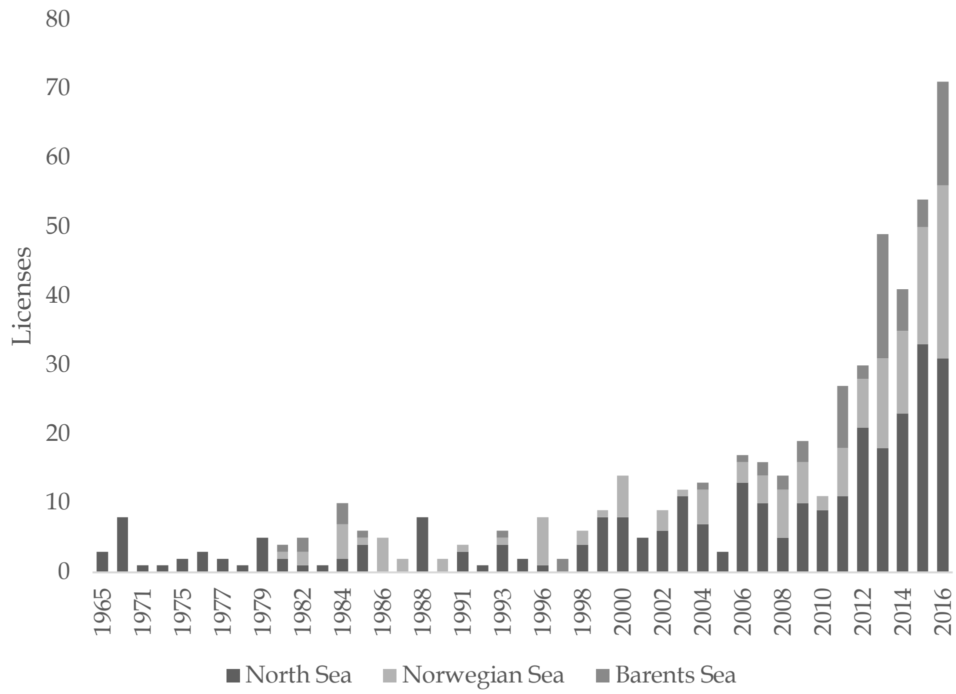

Figure 2 Awarded licenses from 1965 onwards
Source: NPD (2016c)

Several changes occurred post 1985. The NPD recognised that the quantities of remaining resources had decreased year on year. The findings were based on annual growth rate and the sizes varied from small to medium (Al-Kasim, 2006).

Gas recovery, distribution and the demand for gas in Europe was slowing down and the oil price was fluctuating and dropping significantly from $26 to $9/barrel in the period end of 1985 till mid-1986. This had an impact on the eleventh allocation round, in which the cost and taxes were reduced significantly (40%-15%) with the intention of accelerating oil discoveries. In the short term this resulted in considerable activity in the North Sea in 1988, as can be seen in figure 3. Most of these allocations were in the vicinity of existing offshore oil and gas platforms (Al-Kasim, 2006). The sixteenth round in 2000 increased the allocation in the North Sea and Norwegian Sea. In that same year, the NPD introduced a different approach and distinction in licensing (NPD, 2016c). Two types of licensing round with equal status were introduced on the NCS: Awards in predefined areas (APA) covering mature areas, and Numbered Rounds concentrating on frontier areas (NPD, 2016c). Mature areas are characterised by known geology and well-developed or planned infrastructure. In addition, they usually offer a greater probability of making discoveries than frontier areas, where geological knowledge is limited and infrastructure lacking. Frontier areas are likelier to yield larger discoveries than mature ones (Norskpetroleum, 2017c).

Increased availability of acreage has led to more licence awards (Figure 3). In the period from 2000-2017 the government has strengthened the predictability of the allocation system by holding APA rounds annually, while the numbered rounds generally take place every other year (Norskpetroleum, 2017b). Furthermore, the companies know in advance which principles govern the kind of acreage and the general work commitments for production licences in the APA rounds compared with "the numbered ones" (NPD, 2016c). Another metric that contributes to regulations and licensing is the acreage per license. As depicted in Figure 3 the acreage has dramatically decreased since the first round, while the number of block sizes has increased, and more participants were allocated and combined per block (NPD, 2016c). An additional indication that can be derived from the acreage figure is the sentiment of the licensees in years of high oil price and large find potential compared to lack of interest based on available acreage not being awarded.

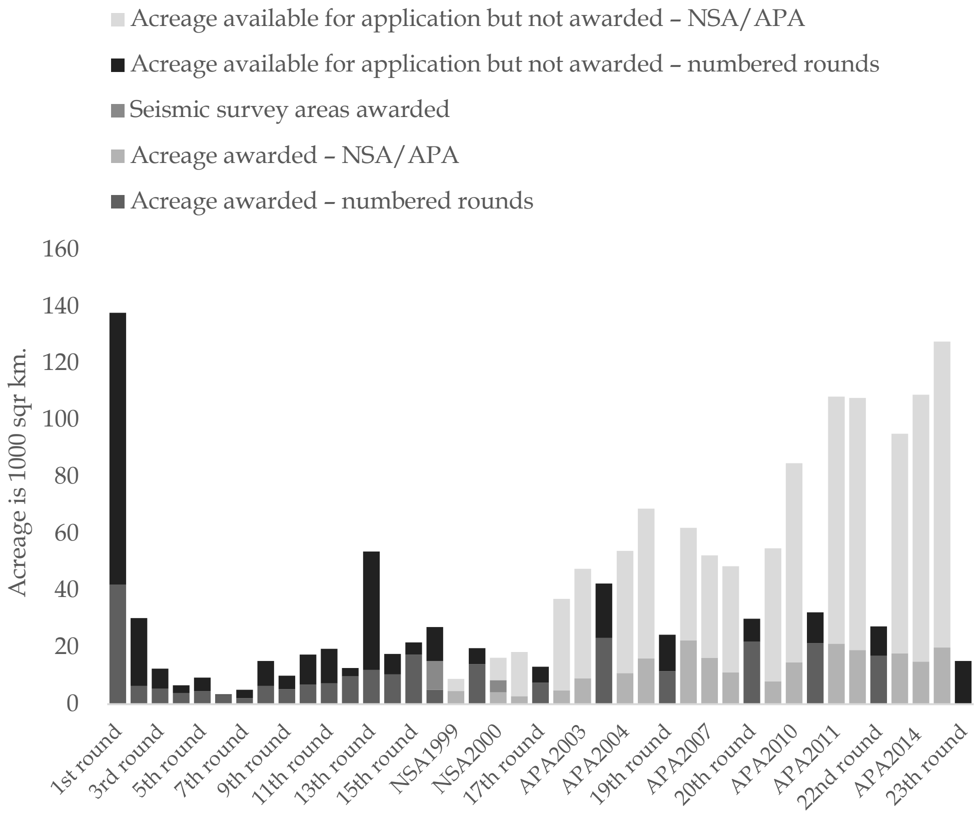

Figure 3 Licencing rounds and Acreage 1965-2015.
Source: NPD(2016c)

In connection with the 20th licensing round on the Norwegian shelf (2008), a new scheme was introduced involving a broad-based public consultation regarding proposed blocks. The Minister of Petroleum and Energy wanted to promote more transparency so that various stakeholders among the general public could voice their opinions before the Ministry makes its decisions, as well as to ensure critical examination of both social and technical consequences of the proposal (NPD, 2016c). From this period onwards, the licensing requirements have stayed the same and in line with a recommendation by the NPD, whether awards were in the pre-defined APA areas, which included acreage in the North Sea, the Norwegian Sea and the Barents Sea, or in numbered rounds (NPD, 2016a).

1.3. FIELDS AND INFRASTRUCTURE EXPANSION

After the allocation of licenses comes the discoveries and the development of fields. The US oil company Phillips Petroleum was first to apply for licences on several locations on the NCS (Ryggvik, 2010). Amongst the other international companies who applied for a license was Esso, which in 1966 towed in The Ocean Traveller from New Orleans, the first semi-submersible rig to enter the Norwegian Continental Shelf (North Sea). Although no resources were found, cores drilled indicated potential. The first commercially viable discovery was not until 1969 which went into the Norwegian oil and gas history as "The Christmas Present" due to the massive discovery that was plugged the day before Christmas eve.[24] Phillips had discovered Ekofisk[25] which contained oil and gas. With the discovery came the need for transportation. First oil was produced in 1971 initiating Norway's career as a producer and first gas was piped through the 440 km Norpipe to Emden in Germany in 1977 marking the beginning of gas exports to Europe. Figure 4 depicts the complete Norwegian offshore gas infrastructure in 2016 (Gassco, 2016).

[24] 1969 – First commercial discovery.

[25] For an in-depth account of the discovery of Ekofisk (Norsk Olje og Gass, 2016) provides a historical time line.

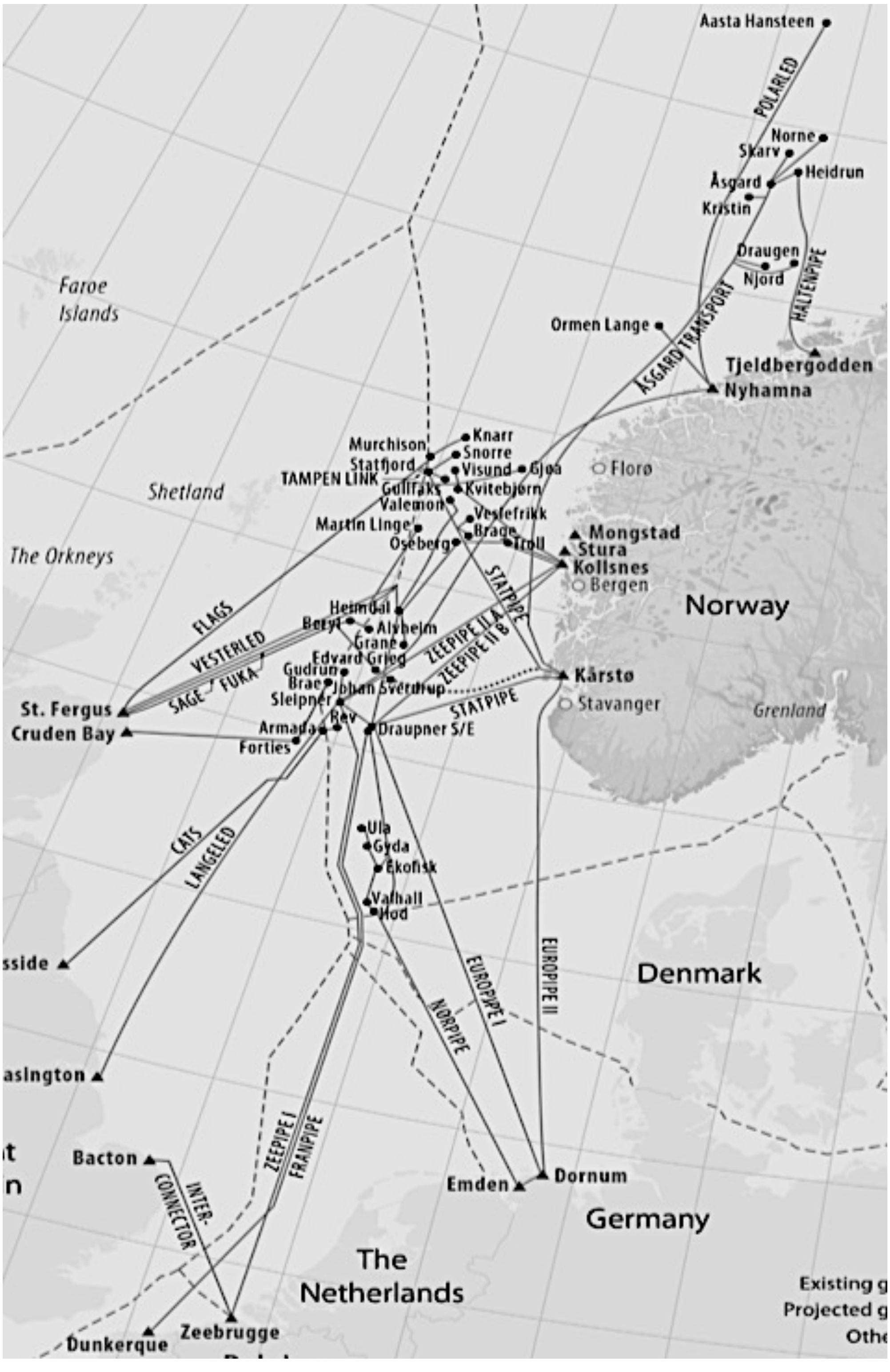

Figure 4 layout of the NCS
Source: Norskpetroleum (2016a)

Most if not all discoveries consist of several natural resources, e.g. oil, gas, NGL and/or condensate. Depending on the recovery strategy and resource management perspective, gas is at times used to lift the oil reserves out of the reservoir only to recover the gas at a later stage of the field's life. This research will focus on gas finds which are projected to, are being or were transported through an offshore gas pipeline system.

The first field of this kind was the Frigg gas field, discovered in the North Sea in 1971 and started producing in 1977 up till 2004. It was the first field were a Norwegian company (Norsk Hydro) was represented in the ownership through the Petronord Group[26]. The gas from the field was sent through the 351 km Frigg pipeline to St. Fergus in the UK (Ryggvik, 2010).

The Statfjord field is located on the boundary of the United Kingdom and Norway and started producing oil in 1979 and gas in 1985. This field required 880 km of pipeline, the Statpipe system, and the Kårstø processing plant where rich gas[27] transported from the field was separated into condensate and dry gas[28] which was shipped through Statpipe into Norpipe to Germany. Later Kårstø would receive and send gas from several pipelines.

The Statpipe project represented a major technological breakthrough as it led to the first crossing of the Norwegian trench by a pipeline. Ekofisk and the Frigg field received significant criticism in Norway, due to the fact that neither field landed the gas resources on Norwegian soil first but piped them directly to the United Kingdom. The reason for this approach was the depth of the Norwegian trench, which prevented an offshore pipeline reaching a Norwegian shore-based facility. In the early 70s depths of 300

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[26] Petronord group consisted of Elf Aquitaine, Total Oil Marine Norsk, and Norsk Hydro and the Norwegian State.
27 Rich gas is any blend of dry gas (methane) and NGL (ethane, butanes, propane and naphtha) (Gassco, 2016)
[28] Dry gas is natural gas which contains no liquid hydrocarbons under pressure. It consists largely of methane, but can also contain ethane (Gassco, 2016)

metres onwards were not technically possible for pipe lay operations. Diving operations[29] to repair possible calamities were even further away from this "magical" number. Thus, gas was transported to Britain and Germany through the Ekofisk-Emden, Ekofisk-Teesside and Frigg-St Fergus pipeline Systems (Dunn, 1975).

Figure 5 North Sea Water depths and the Norwegian trench
Source: Dunn (1975)

In 1985 the technical obstacles were overcome and both the 308-km rich gas pipeline from Statfjord to the Kårstø terminal and the terminal were ready to transport and process gas from Gullfacks and Statfjord. The dry gas from Statfjord is transported through three pipelines: a 228 km from Kårstø to the Draupner riser platform (installed in 1984 as part of the Statpipe system) (Norskpetroleum, 2017c) as depicted in Figure 4; a second dry gas pipeline installed in 1985 from Draupner to Ekofisk (203 km), and in 1986 a

[29] Deepest commercial dive in 1969 was ~185 meters

155km pipeline installed from Heimdal to Draupner S. The Draupner platform and the later installed Sleipner platform are hubs where gas is distributed and monitored for pressure, quality and volumes (NPD, 2016d).

The Sleipner field (Ost and Vest) was discovered in 1981 and contains gas, condensate and NGL. With the building of the offshore processing facility mentioned a riser facility was installed to connect the 814 km Zeepipe I pipeline from the field to Zeebrugge (see figure 4). At the time in 1993 this was the longest and largest (40 inch) offshore pipeline in the world. In the 1990s developments of the infrastructure accelerated. In the same year 1993, an agreement was signed between Norway and Germany for the construction of Europipe I. It became operational in 1995 connecting the Draupner platform to the Dornum terminal in Germany.

The giant of the North Sea, Troll was discovered in 1979, and started producing oil in 1995 and gas in 1996 (Norsk Olje og Gass, 2016). With this field on line Norway became a major producer of gas for Europe and has played a significant role in the development of the NCS. In order to transport and process the gas from Troll, three 36-inch pipelines run from the field to Kollsnes where a treatment plant was built. Later the Kvitebjorn and Visund gas fields would also transport gas to the plant for processing (Norskpetroleum, 2017d). The plant separates NGL, gas and condensate and initially transported the gas through the 303 km Zeepipe II-A to the Sleipner platform in 1996 (Norskpetroleum, 2017c).

In that same year, the Haltenpipe was installed from Heidrun to Tjeldbergodden opening up the Norwegian Sea for gas to shore. It was followed in 1997 by Zeepipe II-B pipeline from Kollsnes to the other hub Draupner, now providing gas from Troll to both hubs. A year later, in 1998, a pipeline was laid from the Draupner platform to France. The 840 km Franpipe transports (figure 4) gas from Sleipner and Troll to Dunkirk taking over the title of longest offshore pipeline from Zeepipe I. To meet natural gas demand in Germany Europipe II was installed directly from the Kårstø plant to Dornum in 1999 (Regjeringen.no, 2013b).

Although the Haltenpipe in the Norwegian Sea became operational in 1996, it was not until 2000 with the Åsgard Transmission System that gas from the Norwegian Sea could be treated at Kårstø and from there transported to the Draupner and Sleipner hubs to continue transmission to Europe (NPD, 2016). In that same year, 2000, the Oseberg Gas Transport system was connected to the Heimdal gas centre from where the gas is transported through the Statpipe system. The recovery strategy of the Oseberg field required initial gas injection to recover oil before the gas cap could be developed. The Heidrun field was also connected to the Oseberg system in 2001 (Regjeringen, 2013a).

The Frigg field was at the end[30] of its life cycle when the Frigg pipeline built in 1977 was tied in to the Vesterled system in 2001 connecting the Heimdal centre to St. Fergus. Through this configuration, Vesterled now has the ability to transport gas from Oseberg, Frigg and Heimdal (MPE, 2013).

The longest subsea pipeline in the world is the Langeled system which became operational in 2006. It is ~1200 km long, 42-inch diameter and provided the United Kingdom with approximately 20% of its peak demand for natural gas. The system was developed in two Sections (North, South), the Southern Section connecting the Sleipner platform to the Easington Gas terminal in 2006 (figure 4) and Langeled north installed in 2007 to run gas from the treatment facility at Nyhamna to Sleipner (Gassco, 2016).

Nyhamna gets its gas from the Ormen Lange field in the Norwegian Sea. Its significance will later be explained in the management of gas resources in relation to treatment on Norwegian soil and delayed development of resources in the North Sea, the Norwegian Sea and the Barents Sea. Two more pipelines were installed to meet United Kingdom natural gas requirements, the Tampen link which connected the Statfjord

[30] Shut down in 2004

field with the United Kingdom FLAGS system in 2007 and the Gjøa gas pipeline tying into the FLAGS in 2010 (Norskpetroleum, 2017c).

1.4. RESPONSIBILITIES AND RELATIONSHIPS

To further explore the roles and responsibilities of stakeholders involved in the offshore transmission system, a concise description is presented together with Figure 7.

The Ministry of Petroleum and Energy (MPE) in coordination with the Government, sets out policies to maintain a roadmap which delivers the natural resources in a timely, efficient manner taking the utmost consideration for the environment. The MPE is responsible for the execution of the activities as set out by Parliament (Storting) and the Government. The MPE established and maintains the framework for all Norwegian petroleum activities, including the opening of new areas for petroleum activities and major development projects. The Storting supervises the Government and the public administration through executive power over petroleum policy and is responsible to the Government for this policy. The Government applies its policy through the ministries and subordinate directorates and agencies, inter Alia the MPE. The MPE fully owns Petoro AS, Gassco AS, and partially owns Statoil. Additionally, it allocates and arranges the licensing (MPE, 2016).

The regulations and management of the resources is then monitored and implemented through the Norwegian Petroleum Directorate (NPD), which has the main responsibility for resource management. In addition, the NPD collects fees from the operators (IOC, NOC), and is responsible for geological and geographical data collection, compilation and analysis of the natural resource data on the NCS (NPD, 2001).

The state through its holdings in assets and licenses on the NCS is responsible for the State's Direct Financial Interest (SDFI) and is responsible for the highest possible value creation for Norway. Petoro was created for this specific task and inter alia, decides in which field developments it will partake in the name of the Norwegian State (Norskpetroleum, 2017e). Gassco operates and maintains the transmission system on behalf of the pipeline owners, Gassled, ships gas through the system for buyers and sellers and charges tariffs payable to Gassled (Gassco, 2016).

Gassled is a joint venture of companies owning rich and dry gas facilities that are currently in use or are planned to be used by parties' other than the owners. New pipelines and transport- related facilities are also intended to be included in Gassled (NPD, 2001). The fourth branch (Figure 7) under the MPE responsibility is the National Oil Company (NOC) Statoil. Statoil is the commercial segment of the "Norwegian model" and is a 67% state owned international public traded company. Statoil operates globally and executes, inter alia, exploration and production (E&P), research and development (R&D), pipelines, and decommissioning activities. In 2015, 39% of Statoil's production was from international equity, 61% was from domestic equity (Statoil, 2015).

Figure 7 provides an oversight of the structure of roles and responsibilities in 2017 (Norskpetroleum, 2017e). All roles have a part to play in the recovery and selling of natural resources. However, this research will focus predominantly on the left side of Figure 7 from parliament down to Statoil.

The approach as displayed in Figure 8 on the role and division of responsibility[31] in recovering natural resources has become a part of "the Norwegian Model". The Norwegian Model has been discussed and to a certain extent replicated in other resource rich countries (Al-Kasim, 2006). As depicted in the figure there are other participants directly involved in the recovery of resources e.g., Gassled and the PSA (how these arrangements evolved is discussed later in this section). How these parties interact and how the different stakeholders have evolved in particular roles,

[31] A detailed explanation of the Roles and Responsibilities see ibid, p.61

responsibilities and relationships to each other, will be detailed from a historical perspective.

Ownership and Control

Economies of scale play a significant part in the functionality of transporting natural gas and IOCs have just as much interest in control as governments. This appears applicable for producing countries as well as transit countries where the transit country is in a position to negotiate favourable terms on the delivery of the oil or gas in question. The control of pipelines has been equally important for Norway as producer of natural gas. Arve Johnsen (Statoil's first director) became fully aware of this fact during a trip to the US in the early sixties[32].

In the mid-sixties, the Norwegian government had relatively little say in the negotiations of the first license round e.g. the first two fields, Frigg and Ekofisk. The Frigg field[33] was on the median line (Norway-United Kingdom) and there was no immediate impetus to negotiate terms between the United Kingdom and Norway (Ryggvik, 2010), inter alia due to uncertainty about the geographical beginning and end of the continental shelf. In the development of the Ekofisk field (Norskpetroleum, 2017c) the Ekofisk license did not explicitly indicate where the potential pipeline should be laid and who should operate it. It was not until renegotiations (1973) started with the participation of Statoil, that the ownership structure of Ekofisk changed from 10% state participation after 2 years to a 50% operatorship of the infrastructure and potential takeover. (NPD, 2014). The thought behind this incentive was the potential significance of the Ekofisk infrastructure at a later stage in the development of the North Sea.

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[32] Johnsen identified the upsides of Rockefeller's strategy to own rail freight and pipelines to control Pennsylvania oil fields (Ryggvik, 2010).

[33] Since the Frigg field stretched into the British sector, it was feared that the British might drain Norwegian gas if agreement was not reached on a development strategy which led to Elf as operator in 1974.

When Norpipe was built (Ekofisk field to Emden in Germany) it still lacked the requirements set out in "the Ten Commandments" (NPD, 2010a). This was partially due to technological constraints in relation to the crossing of the Norwegian trench[34] to be able to reach Norwegian shores. Thus far subsea pipelines were laid in relatively shallow water gradually reaching the shore/surface over a natural seabed slope. This would have been an issue for Frigg as well however, where swift agreement with the United Kingdom was no longer on the table. The pipeline was laid to land on the English coast rather than the Norwegian, thus avoiding the crossing of the trench.

This issue of the crossing of the Norwegian trench resurfaced with the development of Statfjord and the then to be laid Statpipe infrastructure. Statoil as operator, in conjunction with Mcdermott and Comex-Seaway installed the pipeline across the trench to Kårstø, where gas would be processed and shipped back across the trench again to be connected to Norpipe (Norsk olje museum, 2015), in which the government, through Statoil, now had the majority share as a result of the negotiations of 1973. The building of Statpipe was a significant turning point for Statoil. It had implemented the parliamentary resolution by constructing and operating an actual pipeline independently of foreign IOCs. None of the many major petroleum-related industrial projects along the Norwegian coast, such as Kårstø, Kollsnes, Stura, Mongstad, Tjellbergodden, the Snøhvit plant near Hammerfest, could have been realised if the Statpipe project had not succeeded (Ryggvik, 2010).

The gas transmission system ownership changed several times. Initially the pipelines of the system were owned by "private[35] firms" with the (oil company) under the supervision? of Statoil-GFU, later Petoro. The GFU-SDFI owned 55% of Zeepipe, Europipe I and Norne, 60% of Europipe II and Franpipe, 46% of Åsgard, 51% of Oseberg. 65% of Heidrun and 58%

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[34] As displayed in Figure 5

[35] The Norwegian government owns a share of the system

of Draugen. Statoil and Norsk Hydro each held 10-15% ownership shares. Norpipe and Statpipe were established before the SDFI arrangement was activated (NPD, 2014).

Owners of the gas transmission system charge users for the transport of gas in the form of a tariff. In general, the individual "Norwegian" gas transportation companies who owned part of the transmission system, based the calculation of the invoices to users of the transmission systems on a cost-plus principle. Expenditures on infrastructure, operational costs, interest payments and profits were important components of this principle (Austvik, 2016a). Third parties wishing to make use of the pipelines in order to get produced resources to market, had to negotiate terms and would pay a higher tariff than the owners.

The change of operator-ownership from GFU-SDFI to Gassco-Gassled took place in 2003 with Gassco the 100% state-owned operator and Gassled as owner[36] of pipelines, platforms, onshore process facilities and receiving terminals abroad (Gassco, 2016).

The planning of changes in ownership was not initiated on a voluntary basis but as the result of formal anti-trust proceedings based on rulings in 2001 by the EU Directorate-General Competition. In the gas sector, DG Competition's antitrust activities focussed on two issues: (1) anti-competitive barriers to competition between suppliers and (2) anti-competitive obstacles for effective and non-discriminatory third-party access (Directorate-General Competition unit A-4, 2004).

The DG Competition was involved in several natural gas infrastructure cases e.g., GasNatural-Endesa in Spain and DUC System in Denmark. Marathon had two encounters with DG Comp on the NCS when it requested access to the pipelines. Marathon had a stake in the Heimdal field in Norway which it had explored and from which it produced gas but was not able to sell or transport through the Statpipe system at a cost (tariff)

[36] A joint venture that owns the majority of the gas infrastructure on the NCS

higher than the profit margin. The first case, in the early nineties involved three German gas companies, Ruhrgas, BEB[37], Thyssengas (today part of RWE), the Dutch gas company Gasunie[38] and the French company Gaz de France (Fernandez, et al., 2004). These companies refused access based on the desire to buy Marathon's uncommitted gas directly. After some further attempts to obtain access Marathon decided to sell the gas to the European gas companies directly rather than transport it through the transmission system (Directorate-General Competition unit A-4, 2004).

Marathon once more requested access to the gas pipelines of the European companies. The companies refused again on the ground that the contract was not terminated in a valid manner. (Fernandez, et al., 2004). Following the second attempt to obtain access to pipelines, Marathon eventually lodged a complaint with the European Commission arguing that the behaviour of the parties had amounted to a violation of European competition law (Directorate-General Competition unit A-4, 2004). Further investigations into the Marathon Third party access to gas networks, resulted in TPA improvements, but demonstrates the dynamics involved in offshore pipelines.

The GFU case was considered even more high-profile. The GFU, consisted of Den Norske Stats Oljeselskap AS (Statoil, 100% State owned) Norsk Hydro AS (100% State owned) and Saga Petroleum AS (50% State owned), and negotiated all sales contracts on behalf of Norwegian operators with privileges on tariffs, capacity allocation and priority on delivery (Austvik, 2011).

The court argued that all gas sales from Norway were made through the GFU resulting in manipulation of trading conditions e.g., price fixing and volume control. The European Commission started an investigation in 1996 and in 2001 initiated formal proceedings, arguing that the GFU scheme was

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[37] A joint venture between ExxonMobil and Shell
[38] Owned by the Dutch State, ExxonMobil and Shell

incompatible with European competition law (EU, 2001). The GFU as well as the Norwegian Government claimed that European competition law should not be applied, since the GFU scheme had been discontinued for sales to the European Economic Area (EEA) as of June 2001 following the issuing of a Royal decree by the Norwegian Government (Austvik, 2011).

It was also argued that European competition law could not be applied, since the Norwegian gas producers had been compelled by the Norwegian Government to sell gas through the GFU system established by the Norwegian Government itself. Whilst maintaining Norway's legal position, GFU and the EC investigated common ground for a settlement (Directorate-General Competition, 2002). A division was made between

(1) the permanent members of the GFU,

(2) six groups of companies actually selling Norwegian gas through contracts negotiated by the GFU,

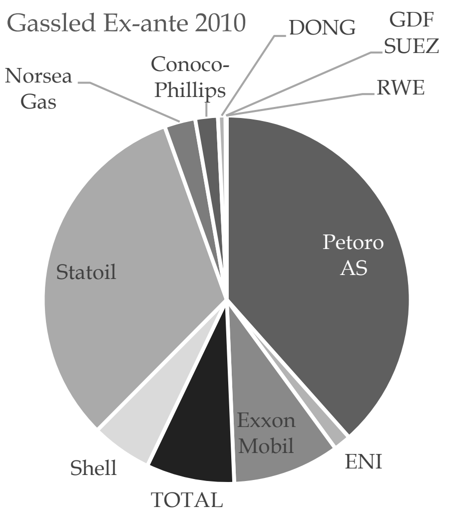
(3) all other Norwegian gas producers.

All companies, except those listed under (3), submitted commitments to the Commission to settle the GFU case (EU, 2001). Based on these commitments, the Commission decided to close the case. (Directorate-General Competition, 2002). The settlement resulted in the closure of sales and marketing of gas through one agent (Statoil, Norsk Hydro) unless it was compliant with Europe law. The other result was the abolition of reserving volumes for customers and preferential allocation.

With the departure of the GFU came Gassco. Gassco is a neutral and independent operator of the gas transmission system and has both special and normal operatorship. The special operatorship is regulated through the Petroleum Act and Regulations, and includes tasks such as developing new infrastructure, managing the gas transmission system's capacity and coordinating and managing the gas streams through the pipeline network and to the markets (Gassco, 2016). In addition, it sets tariffs, regulates capacity, manages resources, plans network expansion and potential investments required in association with expansion.

The transformation of independent offshore pipeline owners to a uniform single Gassco-Gassled transmission system was requested by the Storting in 2001. The MPE invited ConocoPhillips, Norsk AGIP, ExxonMobil, Dong, Norsk Hydro, Total, Shell and Statoil to participate and negotiated the consolidation of Gassled, representing nine of their pipelines into a single partnership (Austvik, 2003b). Each of these pipeline owners charged different tariffs[39]. Additionally, the assets had different values resulting in significantly different amortisation values.

The partnership agreement establishing Gassled was signed on 20 December 2002 and came into effect on 1 January 2003. Gassled's licence runs to 2028 (Regjeringen, 2004). The Norwegian government's intentions to maintain control over its resources and sales came in the form of Petoro, in the form of 1) state participation in projects and 2) managing the SDFI (Statoil's share, ex-post privatisation) in the assets, resources and licenses Petoro secured itself a position in the Norwegian natural gas value chain.



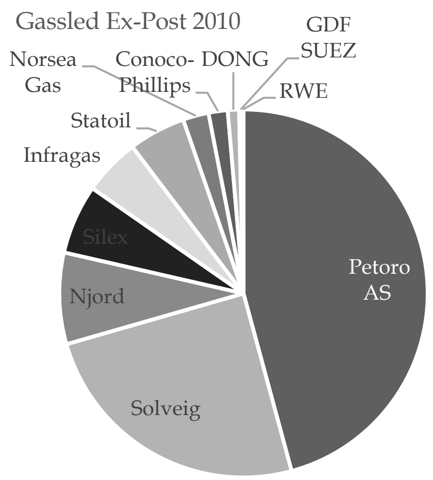


Figure 6 Gassled ownership ex-ante and ex-post 2010
Source: Adapted from Gassco (2016)

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39 Tariffs will be further explained in Chapter 3

In 2010, the benefits of Gassled ownership for the gas shippers were abolished. Until then, the owners had preferential access rights in the primary market. One year prior to the benefit reductions, Statoil, ExxonMobil, Shell, Total and Eni sold a significant number of shares in Gassled as displayed in Figure 6. This opened up possibilities for external investors aiming to get a fixed long-term 7% return (Njord Gas Infrastructure AS, 2015). The 2013 reduction of tariffs (ex-post selling of stakes in Gassled) without the accustomed discussion between owner and government was ill received by a significant part of the Gassled owners. This was an example of national regulations influencing ownership (GFU-Gassco-Gassled) and financial returns (tariff reduction) in the natural gas value chain, driven by national policies, whilst the unbundling of the GFU was of supra-national origin.

The supra-national European[40] Gas Directives and Gas Target Model (GTM) have several goals; security of supply, accessibility, sustainability and competition. With the introduction of the Gas Directives and the GTM competition has been introduced into Norwegian gas infrastructure. Competition is supposed to shorten contract duration, ultimately resulting in a supply of gas at its lowest possible price. A downside of this incentive is the potential for a larger number of competitors to lead to lower prices and a reduction of incentives to invest. The gas directives have gone through several changes and have increased unbundling, access and coordination. However, some differences between the directives and Norway are still apparent from a Norwegian context, e.g., the distinction between the gas directives written for shore-based infrastructure/transmission systems and third-party access whilst Norway has an offshore subsea transmission system.

Modifying an offshore transmission system is demanding and costly thus investments need solid justification. Decisions on where to build new

[40] The supra-national regulations will be further discussed in Chapter 3

pipelines, compressors, or platforms, in what sequence, and when to phase out fields near depletion, influence the ability to exploit the transmission system's capacities. Due to different compositions in the various fields, network modifications have substantial impacts on the TSO's ability to maintain the required quality specifications (Gassco, 2005). Factors such as growing gas demand based on economic growth of the European market (customers) and decline of natural resources of indigenous European countries with different types of gas, influence investment for expansion of the infrastructure. Gas demand uncertainty as seen from 2011-2017, an oversupply of LNG and the Paris Agreement COP21 have had additional influences on the directives (IEA, 2017; ACER, 2015).

Following the COP 21 agreement, the European Commission presented legislative measures and framework, founded on three overarching goals:

- Energy efficiency
- Europe as the global leader in renewables
- A fair deal to consumers

Natural gas could play a part in the transition to a "clean sustainable energy infrastructure" from e.g. coal and lignite to renewable energy sources[41] in addition to compensating for the currently still intermittent nature of these renewable resources (COP21, 2015).

A primary objective of the Norwegian MPE in order to meet both resource development and COP21 agreements, is to ensure high value creation through efficient and environment-friendly management of Norway's energy resources. This can be seen from a social public good perspective where the "pension fund" and e.g. the development of the

[41] The discussion of renewables being capable of supplying 100% of customer needs is an important topic however outside the scope of this research. Key points will be discussed in Chapter 5.

Northern Norwegian region to support Barents Sea development play a part. In addition, MPE aims to ensure efficient market outcomes by supplying natural gas to its customers at a "reasonable return".

This is a balance between economics and security of demand. Investment in the Norwegian offshore gas transmission system is capital intensive, project specific and has long payback periods. In the 2017 market with natural gas prices between $4-$6/MMbtu, the industry as a whole is marked by cost containment. Norway has historically been the leader in high cost operations, which presents this specific segment of the gas value chain with significant investment risk. If gas prices of $4/MMbtu are prolonged, new transmission system investments may be delayed or terminated.

The set-up of the Norwegian gas infrastructure is interdependent e.g. gas from potential new tie-ins in the Polarled (Norwegian Sea) or higher up north (Barents Sea) will travel through the southern part (North Sea) of the offshore pipeline system to its end customers. Investment decisions in the Norwegian transmission system may have significant implications from an internal-national perspective as well as external-international (non-Norwegian) perspective in relation to Norway's GDP and end-users/customers.

From an internal perspective investment, in e.g. The Norwegian Sea and Barents Sea region comes with social economic growth in the northern provinces and potential ripple effects[42] which require logistic support, infrastructure and personnel to support construction and operation. To which extent the 2014[43] alterations of Norwegian tax composition provide a

[42]For an in-depth review of the Ripple effect in the Norwegian Sea, Aasta Hansteen and Polarled (Jenssen, et al., 2015)

[43] Ordinary business tax was reduced from 28% to 27%, special tax is increased from 50% to 51%marginal is constant at 78%.

competitive investment climate or result in the lowest possible cost factor for an offshore transmission system remains to be seen.

From an external perspective, additional investments secure future supply and promote competition. The liberalisation process of the gas directives redirected the security of supply responsibilities to the market participants, and could potentially result in more competition, with incentives for lower prices, reducing cost. Alternatively, there are suspicions of reduced investments, excessive production levels, low quality and supply shortages (Spanjer, 2008).

Regulations stimulating security of supply, competition and sustainability might not contribute to optimal efficiency and reduce incentives for investment in the offshore infrastructure. Which key drivers influence the option to expand the infrastructure and how are these drivers influenced by regulatory restrictions? Historical data appears to indicate that investments were highest in the GFU[44] period. To which extent this was over-investment or over-dimensioned or efficient requires further investigation and explanation.

The emphasis of this research is on the Norwegian offshore transmission system, future investments and how these are affected by regulations, operators and owners. The different stakeholders, e.g. owners, (national and supra-national) regulators, operator, government have different interpretations, objectives and incentives when confronted with investment choices and regulations.

1.5. RESEARCH QUESTIONS, METHODOLOGY AND DISPOSITION

Based on the introduction and influences in relation to providing gas as a resource to Europe from Norway, the main question is "Can Norway maintain economically viable, operationally and technically efficient natural

[44] Norwegian Gas Negotiation Comity, further explained in Chapter 4

gas transportation to Europe[45] under the European regulatory framework[46] and Norwegian regulatory regime(s)?"

This research question could be unfolded further by stating two sub-questions:

1. Do the European regulatory framework and hub prices provide sufficient incentives for new investments in Norway's offshore pipeline export infrastructure?
2. Do Norway's national policies and regulations support investment in offshore gas infrastructure?

To answer these questions, the following judgements need to be made:

A. Which specific Norwegian offshore pipeline cost characteristics and regulations are most important for Barents Sea decision makers?
B. Which specific European Union regulations will be most important for Barents Sea decision makers?

Research Methodology

In order to answer the research question, sub-questions and come to judgements on A and B, the research draws on a dual discipline investigation. (1) A descriptive study portraying an accurate profile of events and situations. (2) An explanatory study, establishing relationships between neo-classical economic theory and Transaction Cost Economics, Principal-Agent Theory and Financial Analysis.

The research investigates potential investment in subsea infrastructure expansion and identifies economic and political

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45 Unless indicated specifically Europe, European Union and EU are the same region. E.g., Norway, although part of the European continent will be seen as part of the European Economic Area (EEA).

46 The European Union regime being the Gas Target Model, three gas directives and four network codes.

argumentation within decision making about the Norwegian offshore gas infrastructure. In order to achieve the objectives of this research, the economic theories have been applied and adapted to a conceptual framework aiming to differentiate the various drivers and barriers which accompany investment decisions in the gas transmission system. A case study analysis will be applied to discover factors influencing investment choices. The theoretical underpinning will be further detailed here in Chapter 2.

There is a notable amount of literature available on the regulation of natural monopolies, but where a narrower focus on infrastructures and regulations is present[47] they provide limited indications on efficient investments in offshore natural gas transmission systems to provide security of supply and demand (Hirschhausen, 2008). The subject of this thesis is quite unusual in relation to general utility monopoly literature which usually discusses situations where an onshore vertically integrated monopoly, gas or power, is the incumbent controlling the assets and sales to customers. A situation where a country has a set of offshore gas pipelines without onshore pipelines or deliveries to end users in its own market is unusual, and quite likely unique in the world (Stern, 2017c). The motivation for regulatory decision-making as publicised in practice and displayed in the various databases e.g. European Union, NPD, MPE is approached from a practical rather than an in depth juridical perspective.

Research Outline

This research is structured as follows. Chapter 2 provides the relevant theoretical background for the research and explains the reasoning behind the approach.

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[47] (Joskow, 2006)(De Joode 2012)

Introduction

Chapter 1
Norway as a Major Gas Transporter

Chapter 2
Theoretical Perspective

Chapter 3
Regulations and Investment Decisions

Chapter 4
Regulatory Factors on the NCS

Chapter 5
Norway's Role in the Natural Gas Market

Chapter 6
Norwegian Sea Gas Infrastructure

Chapter 7
Barents Sea Gas Infrastructure

Chapter 8
Summary and Conclusions

Figure 7 Research Outline

Chapter 3 explores the supra-national regulations and the implications for Norway as a gas producing and exporting country before with specific focus on offshore gas transmission systems. Chapter 4 continues this discussion from a national perspective and explores the implications to natural gas infrastructures from a Norwegian standpoint.

Chapter 5 continues the research and explains Norway's position in the global natural gas market and the influences the market has on Norwegian gas transport on its subsea transport system. Chapter 6 and 7 provide case studies on the Norwegian and Barents Sea Gas Infrastructures and apply theory to empirical examples. Chapter 8 concludes and addresses theory, the research question and sub-questions, case studies and further research.

Chapter **2**

2. Theoretical Perspective

2.1. INTRODUCTION

A substantial amount of literature relates to capturing monopolistic behaviour and has a focus on the European gas directives and onshore gas pipelines. The latter have end-users that are affected by monopolistic behaviour and its influence on the commodity directly. However, the research has not been able to identify a theory specifically applied to the regulation of offshore gas pipelines. In addition, limited literature is available related to offshore gas transmission systems.

Norway has a subsea offshore network and serves shippers who buy capacity in this transmission system, selling it further downstream to onshore facilities and end-users. This might imply that theories applied to onshore facilities are less relevant to the Norwegian transmission system. The purpose of this Chapter is to support the discussion on theory and literature applicable and available on Norwegian offshore gas pipelines.

The European natural gas market has been based on neo-classical theoretical assumptions, however, the natural gas market and infrastructure fail[48] due to subadditivity, lack of investments, cross-subsidisation, price discrimination and externalities. For this reason, the gas directives (and other regulations) play their regulating part.

This chapter departs from economic assumptions that there could/should be a perfect market with perfect competition. In order to

[48] Market failure is where scarce resources are not put to their highest valued uses. (Hertog, 2010)

answer research sub-questions and judgements, the theoretical foundations of the regulations are discussed and reviewed. Historical examples are provided, highlighting inefficiencies and providing a foundation for the debate of mitigating options.

Chapter 2 continues with an explanation of the theoretical foundation. As indicated by (Stern, 2002; Stern, 2017c) due to the absence of generic theoretical foundations for energy security studies in offshore transmission systems, the basis for this research will be founded on concepts of neoclassic economic theories and Transaction Cost Economics as discussed by (Williamson, 1998; Joskow, 2002b; Joskow, 2006).

Section 2.1 provides insight and discusses the implications of the neoclassical economy approach which served as the foundation for the regulation of transmission systems with monopoly characteristics. In particular the interaction of monopoly rent, market power and competition. Section 2.2 elaborates on the identified market failures and countermeasures e.g., Rate of Return Regulation, price and or production cap regulations and explores the validity and appropriateness of neo-classical economic theories based on work from (Joskow & Tirole, 2002a; Joskow, 2007; Joskow, 2009; Joskow, 2013). Section 2.3 provides an alternative approach to the neo-classical theory in the form of Transaction Cost Economics (TCE), which is a theory concerned with understanding how variations in certain basic characteristics of transactions lead to the diverse organisational arrangements that govern trade in a market economy (Joskow & Tirole, 2003). The Section portraits the various approaches that have been applied to natural gas monopolies in the past and the particular shortcomings, through TCE, as discussed in work from (Williamson, 1998) (Joskow, 1987)[49], (Spanjer, 2009), (Glachant, 2011), and (Haase, 2008) further supplementing

[49] (Joskow, 1987) demonstrates a positive relation between contract duration and investment size in the coal industry. (Neumann & Hirschhausen, 2004) confirm a similar result in European natural gas contracts.

the rich discussion on the TCE foundation[50]. Section 2.4 elaborates on the Principal-Agent Theory and how this is seen in the case of the Norwegian offshore gas infrastructure and regulatory policies. Discrepancies exist between Gassco as an agent of the government, and Gassco serving the owners of the infrastructure Gassled. The European Union regulations and resultant directives are based on the believe that the market will become a perfect market with perfect competition in a neo-classical economic sense, either through competition or regulatory intervention. Section 2.5 concludes.

Review of Economic Theories on Regulation

Several theories have been advanced to explain the observed pattern of a government's regulation of the economy. These include the "public interest" theory and versions of the "interest group", proposed either by political scientists, economists, or "capture" theory (Posner, 1974). This research will divide the theories into two bodies of Economic Regulation Theory. The first is "Public Interest Theory", in which information regarding e.g., cost, supply, demand, and quality is abundant and implementing authorities and regulators support public interests. Market failures and efficient government intervention are key to Public Interest Theory, regulation is expected to increase social welfare. However, curing market failure by regulatory intervention generates costs as well as benefits (Joskow & Noll, 1981).

The second body of theory assumes deficient information about the factors mentioned above. As a consequence, the regulators have limited powers to impose public interest. This body of theory is frequently called Private Interest Theory" of regulation (Hertog, 2010). The exchange of information and cost have an influence on other "agents" involved in the market. It is assumed that the economic agents may pursue other interests and objectives than the public interest. Private Interest Theory explains

[50] (Williamson, 1988)

regulation from interest group behaviour. Interest groups in this context could be e.g., consumers, operators, producers. Transfers of wealth to the more effective interest groups could potentially reduce social welfare (Hertog, 2010).

Within both bodies of theory, several strains of regulation are discussed, e.g., social, conduct, structural and economic regulation. Economic regulation is mainly focussed on imperfect markets and monopolies. Because this research involves both imperfection and monopoly it is economic regulation that will be discussed. Within economic regulation literature a distinction is made between normative economic regulation, which investigates efficiency and effectiveness of regulations. There is also positive economic theory of regulation, which provides effect analysis and explanation (Joskow, 2009). Another description suggests that positive theories of regulation examine why regulation occurs. These theories of regulation include theories of market power, interest group theories that describe stakeholders' interests in regulation, and of governmental opportunism based on Principal-Agent theory.

General assumptions within these theories include that regulation occurs because the government is interested in overcoming information asymmetries with the operator and in aligning the operator's interest with the government's interest, Customers desire protection from market power when competition is non-existent (Body of Knowledge on Regulation, n.d.). Normative theories of regulation suggest regulators should encourage competition where feasible, minimize the costs of information asymmetries by obtaining information and providing operators with incentives to improve their performance (Body of Knowledge on Regulation, n.d.).

Regulations have aimed to remove or reduce "monopoly power" with perfect competition as a goal whilst considering technological barriers and the high investment cost of creating offshore natural gas pipelines. Several options have been put into practice in the natural gas industry and will be discussed in this section, with theoretical underpinning.

It could be argued that the regulation of a monopoly, e.g., a subsea gas infrastructure, to achieve perfect competition should provide, as a minimum, a return to cover the cost to sustain the voluntary supply of service and resource. In addition, it should provide an incentive to invest in the infrastructure. Whether a market is regulated, deregulated, or hybrid, a price mechanism must be in place to provide incentives for the (de- or semi-) regulated transmission system owner to provide goods or services against reasonable returns (Joskow, 2007).

The making of a monopoly

The high cost associated with investments in transmission systems results in subadditivity and plays a dominant role in defining a natural monopoly. The concept of subadditivity is a precise mathematical representation of the natural monopoly concept (Baumol, 1977) and is realised if no combination of multiple firms can collectively produce industry output at lower cost than a monopolist (Berg & Tschirhart., 1988). To balance the argument, it could be proffered that the Gassled transmission system possesses the characteristics of subadditivity, considering the cost factor of replacing the transmission system. In addition, there is a lack of another combination of firms willing to invest in a potential alternative system. Thus, the transmission system should be regarded as a natural monopoly.

Often, monopolies exist because governments create market power. Governments might, as in the case of Norwegian gas, offer the market powerful incentives for investments that might otherwise not occur. The profit from such investments may well outweigh the deadweight losses[51] from underproduction that arises due to the granted market power. As an example, the social welfare of developing a remote northern region in Norway might well outweigh deadweight loss for a set period. Another

[51] Total (consumer plus Producer) surplus. For a detailed explanation on deadweight loss see Appendix

example is when the Norwegian Government did not allow such market power in the case of Philips[52]. In 1962 the oil company had the intention to obtain a license for a significant section of the Norwegian shelf bestowing "concentrated benefits" (Austvik, 2010c). Although the company did not receive the license for the complete Norwegian Shelf, it did manage to obtain a license and constructed the first international gas pipeline.

As discussed in Chapter 1, natural gas was not the preferred commodity to begin with, oil was. This changed in 1973 when Philips constructed Norpipe, transporting natural gas from the Ekofisk field to Emden. The selling price of gas[53] through this pipeline was indexed to the heating oil price for a 30-year period (Norsk Oljemuseum, 2017) and was contracted under "Take or pay" principles. Furthermore, due to the size of the fields the sales were based on complete depletion of the field in question.

To capitalise on potential natural resources the Norwegian government increased its participation in exploration and production, creating incentives that outweighed loss of market power. The further development of the Norwegian Continental Shelf resulted in the transmission system becoming a natural monopoly. This deserves further explanation about how, through increase in discoveries, production, economies of scale and high oil prices, gas sales increased. Although the definition of a natural gas monopoly could be applied to a multiple-product natural monopoly, e.g. dry gas, liquids, refining, in this particular case[54] this Chapter will address the transmission system as one system and natural gas as one commodity.

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[52] See section 1.5 above

[53] For detailed explanation of gas sales on the NCS, Chapter 4.

[54]For this purpose, multiproduct firms are firms that have technologies that make it more economical to produce two or more products within the same firm than in two or more firms. Production technologies with this attribute are characterized by economies of scope.

That a pipeline system can function as a monopoly was recognized in 1907 when the US Interstate Commerce Commission (ICC), which regulated pipelines and rail roads, stated:

> At the basis of the monopoly of the Standard Oil Company in the production and distribution of petroleum products rests the pipe line. The possession of these pipelines enables "the Standard" to absolutely control the price which its competitor in each given locality shall pay. (Boyce, 2014, p. 443)

The same condition was recognised by the Norwegian authorities in 1973 when Phillips applied for permission to build Norpipe. The government realised that a transmission system with the capacity to transport third parties' gas could provide the owner of the pipeline system a monopoly position, allowing it to demand high tariffs from shippers of gas lacking access to alternative transmission solutions (Regjeringen, 2017c).

Several economic principles have been applied to monopolies, aimed at improving social welfare by controlling the monopolist charging monopoly rent. Considering the unique nature of the infrastructures it is plausible for several reasons that pipeline monopolies should be regulated in a unique manner. As De Joode pointed out, transmission systems have different physical and economic characteristics, thus regulators may make different trade-offs, for instance between the objective of economic efficiency and achieving an affordable gas price (De Joode, 2012).

There is a substantial base of theory and practice available to address the negative effects of a monopoly, less used principles are e.g., outsourcing as an alternative to privatisation. A government has the option to create a competitive playing field through auction or tendering for the right to operate the monopoly in question for a predetermined time period (Laffont & Tiróle, 1993). This incentivises interested parties to bid on a contract whilst the aim of the regulator/state would be to reduce monopoly rent to zero.

Another form identified was "User management" in which managers of state-owned enterprises (SOEs) have profit incentives. Chongwoo investigates optimal managerial decisions under the enterprise reform in China and poor performance relative to enterprises with other ownership forms (Chongwoo, 2000). Although these methods have a place in the body of economic theory on monopolies, for the purpose of this research four main principles to be used in addressing a monopoly will now be discussed in historical order.

Nationalisation

Possibly the most radical approach is to nationalise a monopoly. The regulator and/or government set a level of production at a socially acceptable price. In this way, the profit incentive can be removed, and the monopolist must adjust production levels to the level where the marginal willingness to pay equals the marginal cost (Pindyck & Rubinfeld, 2012). Commercial insufficiency as a result of average cost exceeding the price of the good or service under government ownership is directly or indirectly distributed over the taxpayers.

State ownership was frequently used in the past (1950s to 1980s) by utilities in continental Europe. Instead of having a privately-owned monopoly with profit-seeking shareholders one could institute a publicly owned enterprise with less concern about profits. In addition, governments tend to have a longer payback period for financial returns, suggesting adverse selection and diminished effectiveness. This poses the question what objective replaces the profit incentive? Imposition of vague incentives often results in diminished accountability which imposes the risk of inefficient results (Depoorter, 1999). Privatisation and competition are trends that appeared to occur more from 1990 onwards. A distinction can be made between Europe, where natural oil and gas monopolies have predominantly been organised in public enterprises, and the USA where monopolies were regulated by authorities. When the change to privatising the public gas companies came in Europe, politicians and regulators argued that a form of regulation was needed to control the monopolist, until effective competition was established. The US method of "fair rate of return regulation" of the monopoly firms was introduced (Hertog, 2010). A distinction is made between regulation of assets (i.e. pipelines) and regulation of commodity prices to different classes of customers. This research investigates pipeline regulation, given that offshore pipelines are the subject of the thesis.

Rate of return regulation

Rate of return was historically the first attempt to capture monopoly power and pricing. It was first introduced during the US civil war when a growing stream of farmers felt they were suffering unfairly (Sherman, 1989). The first case on which the Rate of Return principles were applied in the gas sector was the Hope Natural Gas Company (later to become Standard Oil) in 1944. The supreme court in the USA decided that:

> The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. (Brown, 1944, p. 399)

Regulation of a monopoly through a return on capital (6.5% in the case of The Hope Gas Company) has been used in utilities such as water, telephone and railroads in the USA. The principle of rate of return regulation is less used now and was partially replaced by cap regulation,[55] starting in the United Kingdom in the 1980s. One of the downsides of this mechanism

[55] See Cap regulation

was that the monopolist under such a regime had little reason to make an effort to reduce cost. Rather, there was an incentive for the monopolist to increase production capital to a higher level than the socially optimal, in order to obtain a higher regulated income. Averch & Johnson[56] provided arguments why a company with regulated returns could choose to accumulate too much capital relative to other inputs (Averch & Johnson, 1962). Rate of Return Regulation Basic Formula combines a company's costs and allowed rate of return to develop a revenue requirement. This revenue requirement then becomes the target revenue for setting prices. Introducing return regulation might therefore result in a higher level of capital in the company than would otherwise be the case. Return regulated monopolies were shown to prefer high capital levels to receive higher profits. A monopoly could set relatively low prices in situations of high demand to justify major capital investments. Alternatively, the monopoly would set monopoly prices for earning profits on low demand. As a result, price disruption would occur in constrained and open market situations. Other issues that were identified were over-estimation of asset value and slower amortization of capital than real values of asset and replacement cost. Despite its shortcomings and critical reviews in the economic literature e.g. (Averch & Johnson, 1962) rate-of-return regulation functioned until the mid-1980s.

Norwegian variant on Rate of Return Regulation

The Norwegian government makes use of Rate of Return regulatory principles, albeit with different constituents compared to the "traditional" Rate of Return regulation. Through a framework of laws, regulations and licensing systems the state, as owner of all the natural resources, governs oil and gas activities on the NCS. A concise description will be presented to relate the regulatory principles to the topic of the research "Norway's

[56] For further details on the mathematical underpinning see appendix.

offshore gas pipeline system". The origins, establishment and implications of laws and regulations will be further discussed in Chapter 4.

As an owner of natural resources Norway's main interest is to explore and produce gas from the fields. The transmission system is seen as a means to support this objective as discussed in e.g., Report to the Storting No 28 (2010–2011). To support this objective, the returns from the gas transport infrastructure are regulated by the government, thus ensuring earnings are extracted from the fields and not in the transmission system (Regjeringen, 2017c). This return is set at approximately 7% before tax on the total capital and provides the transmission system owner(s) with a reasonable return, locking in any potential for monopoly rent. The basis for calculating the rate of return (total capital) is the historical investment in the physical gas infrastructure (Regjeringen, 2017c).

Cap regulation

Until 1986 the state-owned British Gas held the monopoly for the sale and distribution of natural gas to end-users, controlling the complete value chain. There was no gas-to-power market until the 1980s (Webber, 2009). With Prime Minister Thatcher coming into power, one of the first measures put into place to counter British Gas's power was the Gas Act of 1986 resulting in the privatisation of British Gas. Littlechild's principles, which provided the cap regulation for the telecom sector were transferred to the natural gas industry in 1986. It was also known as RPI-X regulation, the idea being that the monopolist was allowed the rate of inflation minus an efficiency factor the incentive being that if the monopolist could find greater efficiencies then it could increase its profit margin (Littlechild, 1983).

This was fundamentally different to the US system which, before deregulation, was cost-plus for wellhead prices, and rate of return for assets (Stern, 2017c). Public Utility Company prices e.g. in the US made use of a system that sets a pricing cap on a product or service with periodic calibration of the cap to reflect changes in cost of product or service (Joskow, 2007). A similar approach is a cap on revenue. The advantage of this model is that it creates an incentive for the monopoly to reduce cost, which would otherwise offset against revenue, thus leaving more profit (Hirschhausen, 2008; Bhattacharyya, 2011). Drawbacks of these incentives are that the government, or regulator, needs to be aware of potential cost increases or decreases, and there is a potential for the monopoly to charge premium prices with excess profits in low cost periods. This emphasises the need for adequate information streams. Furthermore, revenue capping does not address the monopoly problem of charging monopoly rent. For instance, a monopoly under revenue cap regulation has an incentive to reduce production levels and thus raise prices above monopoly levels. Dalen et al. suggest that price cap regulation, provides a punishment system if prices increase above an accepted level (Dalen, et al., 1998). It has been argued that the regulator and its regime in implementing price cap mechanisms could be seen as a function of acceptable rates of return and sets a cap accordingly.

An example is a sliding scale in combination with capped prices. In the United Kingdom price cap regulation had immediate benefits in the ex-post privatisation era as a relatively simple system which could be swiftly implemented by a small regulatory authority. However, as the regime evolved and particularly as price cap regulation was extended to transportation charges, it became increasingly complicated and for instance, started to incorporate a rate of return (Stern, 1997).

Both regulations have commonalities with return regulation and leave room for economic inefficiencies. It could be argued that price cap regulation is better suited for cost efficiency solutions of a transmission system owner. However, if investment incentives are a condition, price regulation might not be the preferred incentive, on the grounds that investments are more commonly thought to be motivated by profits rather than by prices (Hertog, 2010).

2.2. FACTORS ON MARKET FAILURE

Section 2.1 set out several methods to limit monopoly power through regulation incentives. That an economic regulatory theory approach does not always or continuously meet the intended requirements is explained in this Section. From a theoretical perspective, the European directives aim for a perfect competitive market with economic efficiency. Whilst exploring the competitive capacity of the Norwegian infrastructure several definitions require explanation in the context of the research.

Perfect market, perfect competition and subsequent economic efficiency will be briefly described. A perfect competitive market[57] is the theoretical optimum in which the market achieves economic efficiency[58] (assuming no externalities[59]). This does not imply that an infrastructure monopoly cannot be competitive, however for the purpose of this section the monopoly competition's price is assumed to exceed marginal cost, indicating inefficiency and creating deadweight loss[60]. As a result, the value to consumers of additional units of output exceeds the cost of producing those units. This consumer and or producer surplus can be used to demonstrate the efficiency of a competitive market and the implemented directives. Pindyck & Rubinfeld (2012) suggest that perfect markets fail for four reasons, market power[61], incomplete information, public goods and externalities. To highlight the issues that are applicable to the gas infrastructure, this will be further explained.

[57] A perfect market should meet the following characteristics: 1) Fragmented: Many small firms, none of which have market power, 2) Undifferentiated Products: Products that consumers perceive as being identical. 3) Perfect Pricing Information: Consumers have full awareness of the prices charged by all sellers in the market. 4) Equal Resource Access: All firms have equal access to production technology and inputs. (Pindyck & Rubinfeld, 2012).

[58] Maximisation of aggregate consumer and producer surplus. (Pindyck & Rubinfeld, 2012)

[59] Situation in which each individual's demand depends on the purchases of other individuals.

[60] Total (consumer plus Producer) surplus.

[61] Market power according to the OECD refers to the ability of a firm (or group of firms) to raise and maintain price above the level that would prevail under competition and is referred to as market or monopoly power. The exercise of market power leads to reduced output and loss of economic welfare.

The argument for regulatory intervention, as discussed in this research, is to move to a perfect competitive market through controlling monopoly power which would be applied by the monopolist on the market.

Authors in favour of monopoly rent seeking argue that a monopoly might well be minimising cost, allocate all resources available and optimise efficiencies. Empirical data suggest that the amount to be gained by increasing X-efficiency[62] is significant, as is further described by (Leibenstein, 1966; Depoorter, 1999). If a firm fails to anticipate or match the cost reductions of its competitors, it might suddenly find itself in a market dominated by its competitors.

Incomplete Markets

Another possibility contrasting a market dominated by competitors with a complete market with a perfect pricing mechanism, is an incomplete or missing market in which the market, despite willingness of clients to pay e.g., premium price, does not facilitate the availability of the good or service. An example is a spot market function or hub for Eastern Europe with perfect communication and transactions. Whilst North-Western Europe has established a significant presence with e.g., NBP, TTF, the interaction between East and West Europe is to an extent missing and incomplete.

Incomplete Information

The first factor that can influence market failure is the earlier mentioned incomplete information, otherwise defined as symmetric information.

The essence of asymmetric information is the benefit that it might give to a producer or owner. E.g., a pipeline operator might have better insight into the cost function than the owner or regulator and thus benefit from this advantage in information. Game theory has produced rich

[62] 'X-efficiency' indicates the internal wastes that occur when a firm acquires monopoly power and is no longer pressured by strong competitors to keep its costs at the competitive minimum. (Depoorter, 1999)

documentation regarding strategies with incomplete/asymmetric information. To establish an optimal cost-strategy can be rather complex with symmetrical information, resulting in optimal cost-price equilibrium and competitive positions in the international market. Determining the same task with asymmetric information is increasingly more complex. (Fundenberg & Tirole, 1983) studied a two-person extensive-form bargaining game with incomplete information, and (Gasmi & Oviedo, 2010), (Gasmi, 2012) investigate how asymmetric information affects capacity planning for a given control scheme and provide a framework, introducing adverse selections by assuming that the local monopoly privately knows its marginal cost and that the regulator has only some beliefs about it described by a probability that it takes on either a low or a high value. Joskow adds to the debate through its rationalisation in extensive form games with incomplete[63] information (Joskow, 2007). Although game theory and its applications have been used for forecasting purposes, further research suggests that this differs from reality due to the significance of assumptions that have to be made. Asymmetric information will be further discussed as part of Transaction Cost Economics, in which information plays a significant role related to excess cost.

Public goods

Public goods in economic theory are subdivided into four broad categories, exclusive, non-exclusive, rival and non-rival goods. Additionally, they must meet criteria of marginal cost of provision, e.g., adding an additional consumer should equal zero cost and people cannot be excluded from consuming the good. The public interest theoretical approach[64] justified state intervention on the basis of the concepts of market failure and public

[63] For further reading on the topic (Freixas, et al., 1985) discuss the central planning of production performed under asymmetric information and the use of an incentive schemes.
[64] See Section Interest theories on regulation

goods under which Pareto-optimal decision-making[65]was not to be expected in the gas sector.

Public services, such as safety or security of supply (SoS), were assumed to be public goods (Spanjer, 2006). Ultimately, security of supply cannot be divided into sub-sections and sold off for a price. Furthermore, securing one customer for supply does not have an influence on the other customers, suggesting that SoS is non-rivalrous (Goldthau, 2013). In order to support SoS, gas pipeline transmission capacity could be recognized as a public good. It provides the infrastructural foundation upon which a liberalised market can function.

That regulatory intervention has been applied to counter market failure and transfer from private to public goods is demonstrated with, inter alia, the European Union gas directives. Examples include the transition of natural gas from a utility (public good) to a market commodity. Furthermore, with the implementation of ownership unbundling and third-party access to pipeline systems the status changed from exclusive to non-exclusive. From a supranational perspective, the European Commission supported the establishment of pipelines, interconnectors and other transport infrastructure that exhibit public goods characteristics (Goldthau & Sitter, 2014). Because of the public goods characteristics, the natural gas infrastructure projects typically involve national or European financial institutions, leveraging risks or supporting the investment. (Environmental) policies or incomplete information may impact the amount of public support available for crucial infrastructure projects in Norway to connect additional regions with the infrastructure. Additionally, supranational (European) bodies exert power thus influencing investments in critical infrastructure. Boersma (2015) takes this a step further by suggesting that "in essence the investments in the infrastructure required are a public good, yet the European Commission counts mostly on private financial means to make

[65] See Section 2.2. Efficiencies

them happen", adding to the debate that although the European Commission has implemented gas directives, and investment bodies supporting Projects of common Interest (PCI), market failure is still apparent.

Externality

The third factor is the cost or benefit that affects a party which did not choose to incur that cost or benefit. Morey (2015) states that there is an externality if an economic agent(s) does something that directly influences (albeit not indirectly through market prices) some other economic agent(s) and there is the potential to make one of the parties better off without making some of the others involved worse off.

Industrial organisation economists have studied a variety of other market failures, involving information problems and a range of externalities such as environmental damages (Tirole, 2014). In relation to gas infrastructures network externalities are "two-sided" in the sense that the value of the network platforms depends on getting buyers and/or sellers on both sides of the market to use them effectively through pricing arrangements and market rules. While these kinds of problems may be solved by regulation, the more typical solution is for the network participants and the networks to negotiate access pricing arrangements and market rules to deal with the potential inefficiencies created by network externalities and market power (Joskow & Tirole, 2003) (Laffont & Tiróle, 1993). This plays a significant role in relation to the Norwegian gas infrastructure and especially relates to the abolition of the GFU, FU, and Norwegian resource management[66] establishment to address European competition law. Externalities in gas marketing have had a significant

[66] Dahl (2001) and Sunnevåg (2000) discuss this topic in more detail.

impact during the GFU period where the GFU controlled small producers' market shares instead of allowing them to market gas individually and thus potentially maximise profits independent of decisions of other parties on the NCS. As a consequence, prices did not drop, due to the lack of increased competition, which resulted in an increase in revenue for the SDFI, but reduced resources available for public goods.

Sunnevåg (2000) defines three kinds of externalities, exploration, development of field infrastructure and gas marketing externalities as described in the GFU case. Whilst exploration externalities have affinity with infrastructure as earlier discussed, it is out of the scope of this Section. Network externalities however could pose a problem in the gas market as a result of the total size of supply and demand. As a network expands to meet demand, extensions to connect to the network will become shorter and thus theoretically cheaper.

The intention of the liberalisation to close the gap from the perfect market was to create smaller firms through equal access thus invoking perfect competition as a result. Perfect competition relies on three basic assumptions, price taking, product homogeneity, and free entry and exit aiming to get the price of gas to equal the marginal cost. This was the objective of the third-party access to the infrastructure, more firms competing upstream and utilising the system compared to a controlled single source e.g., the GFU system. With all firms having equal access this would create competition and lower prices.

Cross subsidisation

Cross subsidisation has been described by Joskow (2007) as "the notion that one group of consumers subsidizes the provision of service to another group of customers by paying more than it costs to provide them with service while the other group pays less". Posner (1969) referred to cross subsidisation as taxation by regulation.

Examining cross subsidisation of a sustainable natural monopoly in the light of cost function, it is highly likely that the price will be above margin for all consumers. At least, it has to be more than one to meet an above break-even price for the service or commodity. To take a practical example, if the European Union wanted to implement a policy of keeping regulated gas prices low in order to promote total European service/distribution, and provide subsidies for the remote countries, it would have to maintain a higher price to cover the cost for additional remote customers, which would be above the marginal cost of the existing closer network customers. A side effect of this higher price would be an inefficient market, attracting entrants for a "high margin, remote customer base". Thus, "when a firm has natural monopoly characteristics, an objective definition of "cross-subsidisation" is not straightforward" (Joskow, 2007). Several types of cross subsidy can occur in the natural gas industry; cross subsidy of prices, usually industrial customers cross-subsidising residential; and cross-subsidy of tariffs i.e. postalised tariffs which do not take distance into account. The latter is the focus of the research relating to offshore pipeline tariffs.

Price Discrimination

The traditional classification of the forms of price discrimination is based on work from (Pigou, 1920) cited in (Schmalensee, 1981) who classifies price discrimination in three degrees.

First-degree (perfect price discrimination) involves the seller charging a different price for each unit of the good in such a way that the price charged for each unit is equal to the maximum customer willingness to pay for that unit.

Second-degree price discrimination, (nonlinear pricing) suggests prices differ depending on the number of units of the good bought, but not across consumers. That is, each consumer faces the same price schedule, but the schedule involves different prices for different amounts of the good purchased. Quantity discounts or premiums are examples.

Third-degree price discrimination suggests different purchasers are charged different unit prices, but each purchaser pays a constant amount for each unit of the good bought (Pigou, 1920).

Efficiencies

Investigating efficiency and effectiveness of regulations is part of the normative economic regulation (Joskow, 2009). With the competitive factors such as externalities, cross subsidisation and price discrimination in mind, it is imperative to identify efficiency as intended by the energy directives. In the neoclassical understanding, optimal economic efficiency is achieved when goods are produced in the least costly manner (productive efficiency) and distributed to those who value them most (allocative efficiency) (Haase, 2008). The European gas directives discuss two main areas of efficiency, one being energy efficiency considerations related to optimal usage and saving of energy for environmental reasons, the second relating to the operation, maintenance and development of a secure, efficient and economic transmission system of natural gas. The latter will now be discussed.

The ulterior motive for economic efficiency is cost reduction and optimised utilisation of the infrastructure. This can be achieved through various objectives.

Dynamic[67] efficiency measures the response to market changes. Due to the long lead times in the development of fields and infrastructure there are limited changes and new inventions. Gas infrastructure is characterised by large sunk cost; any new technological changes appear to be deployed at the end of the product life. In pipelines this can range from 15-50 years. This is most applicable for green fields where competition might play a part in the design of new infrastructure, when technological changes might prove

[67] For an in-depth analysis (Gilbert & Newbery, 1994)

an advantage leading to cost reduction in the short, but most likely long term. (Dahl, 2001) states that static efficiency concerns two objectives, optimise the depletion of Norwegian natural gas resources and maximise the profit from the natural gas exports. This might not necessarily be the case in connection to liberalisation and competition.

Allocative efficiency according to (Dahl, 2001) suggests that all customers who are willing to pay a price equal to or above marginal cost of production and transportation shall be supplied with gas. When it comes to transportation services in isolation, the aim is to have sufficient capacity to serve all shippers who are willing to pay a tariff equal to or above marginal costs of transportation. With the energy directives, this might become more relevant when competition on the selling-side provides options to different providers other than the Norwegian Gas Infrastructure.

Rationing efficiency in relation to the infrastructure suggests that distribution of services between customers is efficient, i.e. transportation services are given to those shippers who earn the most by using the service. Through the energy directives this has changed to equal distribution and access for all. This appears fruitful for the short run, however long run issues such as cost, and investment might suffer to some extent. It also ties in with cost efficiency which entails providing services at the lowest possible cost including managerial efficiency. According to (Dahl, 2001) this criterion is relevant in a short-term perspective when it comes to variable operational costs as well as for fixed operational and maintenance costs. The measure is also applicable in a long-run perspective related to minimising the cost of new capacity. This means that a pipeline company and a (large) customer will bargain over the tariff, given that the tariff should not give the pipeline more than a normal rate of return (Rosendahl & Kittelsen, 2004).

Several forms of efficiencies and the effectiveness of the implemented regulations on market failure have been described. Efficiencies play a substantial part in the discussion between neo-classical theory and Transaction Cost Economics. For instance, the counterintuitive relationship between long term contracts resulting in more efficient investments in offshore transmission systems versus multiple preferable hub-priced contracts, incentivised through the gas directives will be further investigated in Section 2.3 Transaction Cost Economics.

Interest Theories on Regulation

As part of the overarching principle of the interest of the stakeholders in a market, the research investigated the foundation of public and private interest theory. Whilst the public interest theory offers explanations and reasoning for regulating and correcting market failures e.g., externalities, market power, natural monopoly and asymmetric information, the approach of public interest theory has been criticised for several shortcomings. According to Hertog (2010), criticism has been directed at the theory because of market failure as model failure. Monopoly power, externalities, cross subsidisation and price discrimination are indications of inefficient allocation of resources, suggesting that the public interest theory and the model applied, did not take into account the transaction costs involved. In practice, it appears that the market mechanism itself is often able to compensate inefficiencies (Cowen, 1988). With the criticism of public interest theory came private interest theory, suggesting that regulation can function through prioritisation of the most effective (private) interest group in the allocation of wealth sharing and directing influential lobbying parties for the cause of the private interest group. This theory has been disputed by several critics, inter alia, (Posner, 1974; Stigler, 1971). As Den Hertog (2010) suggests "Private interest theory consists of strong incentive for a single entity to lobby for regulation. In the presence of market failure regulation is likely because of the large losses this inflicts on some interest groups". The body of private and public interest theory is broad. Although there are some connections for the research on offshore transportation of Norwegian gas other theories and regulations provide a more suitable foundation.

2.3. TRANSACTION COST ECONOMICS

Transaction Cost Economics excels in agreements beset with high investment cost for at least one of the participants in the contract and with the potential of getting locked in ex-post agreement by the high sunk cost.

Several cost functions are involved when investing in a transmission system. A distinction is made between financial cost, production cost i.e., CAPEX, operational cost (OPEX) and transaction cost. The latter is concerned with ex-ante contract coordination up until ex-post execution. Haase (2008) further defines ex-ante transaction costs as arising in the contract set-up phase, including drafting and negotiating the contract. Ex-post transaction costs arise after the contract has been agreed.

The possibility of ex-post opportunistic behaviour suggests the requirement for an ex-ante governance arrangement that mitigates the ex-post holdup potential. Joskow& Tirole (2002a) describe outcomes of such an agreement as a relationship “that supports efficient investments in specific assets, lower costs, and lower prices”. However, hierarchical contracts are incomplete and alterations to the contract, needed to overcome the inefficiencies, may result in opportunistic behaviour. These Transaction Costs should be included in the comparative economic assessment of contracts (Joskow & Tirole, 2002a).

Inefficiencies as discussed in Section 2.2 identified gaps between perfect competitive markets and empirical evidence. Transaction Cost Economics suggests that these inefficiencies can be explained by not identifying the specific cost. The benefits of transaction cost economics derive from the identification of factors that influence or conflict in the transaction. Williamson discusses four factors:

1) Asset specificity,
2) Frequency,
3) Uncertainty,
4) Complexity.

Asset specificity has been the most discussed factor in the literature and the four have been seen as interrelated. The extent of the fit of the factors/attributes supports the optimisation of the governance design choice (Williamson, 1998). The first of the four factors, asset specificity, has been differentiated into 6 different varieties namely, site, dedicated asset, physical asset, temporal, human and brand specificity. The applicable type of specificity will be further discussed in Chapter 6 and 7. A brief explanation of the other factors will now be provided.

Frequency is in Williamson's framework (see adapted version table 2-1) depicted in years for each level and indicates the frequency with which transactions occur. If there is a low frequency of transactions it may prove ineffective and inefficient to alter a governmental structure. Vice versa, for high frequency, it might prove cost efficient to manage the transactions accordingly (Tadelis & Williamson, 2010).

A remarkable distinction between neoclassical economics and TCE are the assumptions on risk versus uncertainties. The neo-classical approach suggests that contracts foresee all risks and mitigate accordingly, ergo market exchange is the most viable option. Whilst TCE suggests that uncertainties with an ex-post contract implication cannot be determined perfectly. Spanjer (2009) describes contractual completeness as "Even if we assume the possibility of contractual completeness, writing, monitoring, verifying and enforcing a complete contract will likely be prohibitively expensive". The fourth and final factor, complexity, as described by Williamson, indicates the intertwining character of the influencing factors by stating "Complex contracts are incomplete, by reason of bounded rationality" (Williamson, 1998). For this research, it will be assumed that all contracts related to transmission systems are incomplete and complex.

Transaction Cost Economics proves to be a viable theory for capturing or opposing some of the identified market failures. Transaction Cost Economics (TCE), is the product of two complementary fields of economic research. The first field is the New Institutional Economics, the second field has been described as the new economics of organisation (Williamson, 1998). A brief summary of the framework, founded on the two fields of economics, will be provided in this section with more detail in Chapter 3 and 4.

The Transaction Cost Economics model of Williamson has been applied in the arena of natural gas by inter alia, (Correljé 2008; Haase, 2008; Spanjer, 2008; Arora, 2012). The model has been adapted by the authors for specific research rationale. For the purpose of this research the adapted Williamson model of (Haase, 2008) is modified and used. Williamson's model distinguishes between four different levels. The model provides the opportunity to separate national from supra-national decisions and the influences the decisions might have on price, market structure and investments in the Norwegian transmission system.

The model as depicted in Table 2-1 has been adapted from the work of Williamson cited in (Haase, 2008). The purpose of the model is to divide the regulatory framework into conceptual parts and show the interaction (contract)between the stakeholders involved.

Level				Chapter
Level 1 Social Theory 10-30 years	Informal institutions	Broad values, norms, technological and physical characteristics	Broad (energy) policy objectives and balance between security of supply, market and environment	1, 2
Level 2 Economics / property rights 10-20 years	Formal institutional environment	Laws and constitutions	Regulatory models and market design	2,3,4

Level 3 Transaction Cost Economics 1-10 years	Institutional arrangements	Organisations, contracts and hybrids such as Public Private Partnerships	Actual regulatory instruments and decisions Forms of PP cooperation Firms' tariff structures and trading practices Public and private evaluation and sharing of risk, profit, market etc.	2, 4
Level 4 Neo-classical/ Agency Theory Continuous	(Market) behaviour	Interaction between actors with different objectives, strategies	Market strategies, investments lobbying, R&D, cooperation and conflict	3

Table 2-1 Transaction Cost Economics framework
Source: Adapted framework from Williamson cited in Haase (2008)

- Level one, is the level where social awareness finds its roots. It establishes society's view on, inter alia, energy policy. For gas, these informal institutions are concerned with issues such as the perceptions about sovereign energy resources, resource markets and energy policy objectives.
- Level two is concerned with regulatory design e.g. Gas Directives, Network codes that follow a transformation of European directives into national regulations and laws.
- Level three is the result of level 2 transformation and results into actionable regulation, such as contracts, guidelines policies and tariffs. This is the emphasis of the Transaction Cost Economics and will be further explained in Chapter 2, 3 and 4.
- Level four concerns the stakeholders' and shareholder's reaction in the gas value chain on regulations as indicated in Levels one-three and how this reaction affects investments in the infrastructure for the purpose of this research.

The function of the model in this research is to offer a structure to analyse regulations affecting the Norwegian gas infrastructure in the market.

The institutional environment impacts on the relative severity of the problems of coordination and transaction costs (Williamson, 1998). Political and legal governmental bodies determine the risk of governmental opportunism (Warshaw, 2012) and thus the contractual and regulatory arrangements between government and regulator in which the transmission system owner may be regulated. (Rossiaud, 2014). The research realises the limitations of the model but the interaction between the various stakeholders can be established on representative assumptions deducted from the Transaction Cost Economics model. Different periods in time, different types of infrastructure and variable forms of expansion can be explained through the application of the framework. Transaction Cost Economics, which makes the transaction the main focus of the analysis, appears well-equipped to assist in explaining regulatory influences on market functioning, based on earlier research and empirical data. The TCE has been complimented with Principal-Agent (PA) theory values, to capture the interaction between stakeholders with different objectives and, in the case of Norway, potentially with a similar objective, adhered to by e.g., Gassco, Gassled, Statoil, Petoro and the Government.

2.4. PRINCIPAL-AGENT THEORY

As a consequence of the potential gap between regulator and government, the Principal-Agent Theory investigates the relationship between these two organisations through analysis of ex-ante delegation and ex-post delegation relationships. This approach, its models and purpose are used to identify relationships between the various stakeholders and discuss regulatory incentives and effectiveness. The principal-agent theory is involved with the explanation of three issues in agency relationships. 1), the incentives of principal and agent may be different or conflicting. 2), the principal is not able to verify completely what the agent's execution of operations entails. 3) The potential difference in risk perception, e.g., risk loving, risk averse.

Principle-agent theory is applied in incentive regulation and multipart tariffs (Body of Knowledge on Regulation, n.d.). A significant body of economic theory has been published on variations of the principal-agent theory, inter alia in the arena of game theory. The models are mathematically based. Between the principal-agent theoretical foundations of (Laffont & Tiróle, 1993; Laffont & Martimort, 2002) and the game theoretical approaches of e.g., (Fudenberg, 1991; Ferreira & Trigeorgis, 2009), the former are more fitting for the research. The consensus of the principal agent theory for this research is to identify generally behavioural assumptions relative to principal-agent relationship which meets the principles of Laffont et al. Three behavioural assumption have been identified by the authors in relation to Principal Agent Theory:

1) actors are rational[68] utility optimisers,

2) principal and agents may develop different preferences

3) there is an informational asymmetry between principal and agent (Héritier, 2005) cited in (Haase, 2008)

Whilst the traditional agent theory departs from agents behaving opportunistically and taking advantage of e.g., asymmetric information, the concept could be seen in a broader perspective. Zardkoohi et al. (2015) expand this approach with a multidirectional framework contemplating,

1) agents behave opportunistically against the interests of principals,

2) principals behave opportunistically against the interests of agents, and

3) relationships between agents and principals representing confluence of interests affect the interests of third-party stakeholders (Zardkoohi, et al., 2015). The underlying motivation for this approach is the change of ownership from GFU to the Gassco-Gassled construction and, in addition,

[68] See Section 2.4 For the definition of rationality applied in this research

the court case between the Gassled owners and the Norwegian government. In the GFU-Gassled construction, the principal-agent concept was a new way of organizing transportation of natural gas. In 1993 the proposal came from the European Union to promote enhanced competition which was to be accomplished by unbundling (Golombek. Rolf, 1994). The initiative was that pipeline companies should agree to carry gas - which is owned by another agent - in return for payment (to the extent that there is capacity available). Other principal elements were a transparent and non-discriminatory licensing system and separation within vertically integrated undertakings of the management and accounting ("unbundling") (Golombek. Rolf, 1994). Controlling a pipeline transmission system resembles functions of this theory and touches upon factors identified in practice.

Just as in economic and political theory, asymmetric information creates challenges in the relationship between the principal and a performing party, referred to as the agent. Another empirical example is the production and development licence for Goliat which is shared between Statoil, ENI and Petoro. The Norwegian state as a principal via Petoro and Statoil allows ENI to participate in the operational and financial contractual agreements whilst the resources remain with the state. This requires a contract that satisfies all stakeholders involved. Other examples are employer-employee or a regulator and the regulated organisation. A typical asymmetric information situation consists of the agent possessing information that is difficult to obtain for the principal. Two main issues are identified in relation to asymmetry, moral risk and adverse selection.

Moral risk is related to the agent's active choices, not observable for the principal. E.g., the design of the contract between the principal and the agent could stimulate the agent to provide less effort than the principal anticipates and or provides (Joskow, 2009). This is an endogenous, or a “model internal" factor, which is not limited to the transmission system owner as agent only. The infrastructure operator has the ability to conceal information about its cost structure, thus enabling it to exact higher tariffs than are strictly necessary (Arts, et al., 2008). Furthermore, the shipper of natural gas who has to pay a tariff for the transport of gas may have an opportunity to pressurize the infrastructure owner to accept a low fee, again because of the sunk nature of the investment (Arts, et al., 2008).

Conversely, the regulator may have the possibility to pressure the transmission system owner's ex-post investment when it has become definitive and is sunk. The transmission system owner will have little room to move and is defenceless against a regulator that leaves too little room in the tariffs that it considers permissible for the operator of infrastructure to charge to the infrastructure users (Arts, et al., 2008). Guthrie (2006) argues this to be a frequent occurrence for transmission systems due to the 20-25-year depreciation period common in infrastructures. Regulatory opportunism is, of course, not without risks because of the negative effect it might have on the regulator/government's reputation.

The second issue that has been mentioned in relation to the principal-agent theory is effort aversion. For example, the agent possesses an information advantage regarding external factors that could affect the development of the contractual relationship (Law, 2014).

In the case of Norway and its gas transmission system, the MPE, the Parliament is regarded as a principal with Gassco and Gassled as its agent. That interaction between stakeholders with different objectives can become complex has been demonstrated in the Court case of Gassled owners against the Norwegian state for the abrupt reduction of tariffs charged for transmission of gas. The case was built up out of inter alia, "the lack of information" about such key aspects being a breach of what the private parties could reasonably expect of the Ministry in the situation in question (Regjeringen, 2017c). The government added to its defence that profits should be taken from the production segment rather than the transmission of natural gas. In addition, there was a lack of any systems for monitoring and measuring the return in Gassled and thus calculate the correct tariff

amendments (Regjeringen, 2017c). The court case has demonstrated in depth how Norway regulates its transmission system and will be explored in Chapters 4 and 6. Several weak links have been highlighted:
* European gas regulation is founded on theories which assume perfect market competition.
* Asymmetric, imperfect or incomplete information plays a role in the principal-agent framework present in the Norwegian gas value chain, in particular the transmission system.
* The cost factor is not taken into consideration inter alia in the principal agent concept.

This research will further, through its investigation of the export of Norwegian gas to Europe through the transmission system, apply theories of the Principal-agent framework to identify inefficiencies in information and Transaction Cost Economics to complement each other.

Cost Benefit Analysis

Due to lack of applicable real-world gas transmission system theories a framework adapted from (Stern, 2002) will be used to capture relevant data which are commonly utilised by established institutes including IEA, BP Statistics, NPD, OIES, Statistisk sentralbyrå[69](SSB) and Gassco to arrive at a Cost Benefit Analysis which will be applied to Gassco's report on the Barents Sea Gas Infrastructure (Gassco, 2014a). An adapted form of Stern's data set framework will take into consideration analysis of reserves, gas price, construction cost, uncertainty about the economic outlook, developments in environmental policies, depletion in producing regions; changes to legal, fiscal and regulatory regimes, delays in infrastructure and shipping capacity which will be deduced from empirical evidence (Stern, 2002). Within the boundaries of Transaction Cost Economics, several criteria have been identified to measure effectiveness. For the purpose of this research Cost

[69] Norwegian Statistics Bureau

Benefit Analysis will be applied to identify a positive, alternatively a negative quantifiable outcome.

Limitations of the theories

TCE provides an appropriate level of analysis and separation, displaying the factors and variables involved. However, as Haase pointed out "transaction cost economics is able to explain how governance structures relate to economic performance; but fall short in incorporating the political process into the theory" (Haase, 2008). Furthermore, in depth rationalisation of the stakeholders involved is not accounted for.

Rationality

Neo-classical theories assume rationality from stakeholders and that they possess complete information to act on the task set out. Similarly, as discussed in Section 2.2, humans are deemed never to be fully rational in the economic theory sense. Harbison described individuals as motivated by drives, hopes, desires, fears and frustrations (Harbison, 1956). Kahneman takes this a step further stating, "psychological theories of intuitive thinking cannot match the elegance and precision of formal normative models of belief and choice" (Kahneman, 2011). For the purpose of this research bounded rationality as described by Kahneman and Williams will be applied.

2.5. CONCLUSION

Chapter 2 started with economic assumptions of a perfect market with perfect competition and the role of monopoly. If perfect competition was in place, there would not be a need for regulations. Implementing regulations would add cost to the process, resulting in a sub-optimal perfect condition. Because the natural gas market and the transport of gas from Norway to Europe is not perfect, regulation is required. The market failures that are present in the gas value chain, incomplete information, price discrimination, externalities, have been highlighted. The shortcomings of regulatory interventions on such market failures have been discussed from a theoretical and historical perspective through rate of return, cap regulation and outsourcing. A first conclusion that can be drawn is that Norway regulates the offshore pipeline system with a variant of rate of return in which a fixed return of 7% is applied. This concept will be further explored in Chapter 4. The second conclusion that can be drawn is that from the review of theories, no direct practical relevant theory has been identified as being applicable to the Norwegian offshore pipeline system.

The chapter followed with theories that have proved to be capable of analysing shortcomings in regulation. Transaction Cost Economics were discussed, and key issues identified, including that relationship-specific investments have a significant impact on contracts. Other factors were that the potential increase in buyers and sellers reduces transaction contract cost. (Arora, 2012) furthermore indicated that there appears to be little theory to explain how strategic national behaviour influences will impact the global natural gas market. This research will investigate Norway's strategic national behaviour in perspective of the North Western European gas market through its offshore transmission system.

Principal-Agent Theory is qualified considering the Norwegian government as a principal has several agents in the natural gas value chain, from production (Statoil and Petoro), transmission (Petoro and Gassco) and gas sales (Statoil). The influences of national and supra-national regulations affected contract lengths. E.g., the move from long term gas contracts to hub price contracts add more risk to the process resulting in an increase in contract duration. From a Principal–Agent Theory perspective and TCE this can be explained. The final part of the Chapter discussed a realistic approach to investigate the cost and upside benefits of regulatory intervention on investments in the transmission system for this particular research.

3. Regulations and Investment Decisions

3.1. INTRODUCTION

To make a distinction between regulations initiated by a supra-national rather than the national Norwegian authorities, this Chapter starts with the European Union regulations related to natural gas divided into three sections, Energy Regulation (specifically the Gas Directives), Competition Regulation and Security of Supply. Within the three sections, the emphasis will be on offshore gas pipelines, or as described in the European Union Gas Directives, "Upstream pipeline networks".

Chapter 2 discussed several methods to regulate a monopoly from a theoretical perspective, however there needs to be an incentive to own, operate, and where needed, develop the transmission system as the monopoly. This Chapter will focus on sufficient investments in gas transmission systems to be able to secure supply. Investments in gas transmission systems can be differentiated between short and long term. Short-term investments are applied to operations on the transmission system whilst long-term investments aim to develop the transmission system. This Chapter will focus on the latter.

Chapter 3 starts with the national regulations and how these evolved in Norway under the influence of the European Union gas directives. Section 3.1 discusses historical attempts at regulating energy monopolies and how Norwegian sales to the European Union created displeasure that inter alia started the ground work for the European gas directives. Section 3.2 describes the history of Norwegian regulations and how it established sales in the natural gas market ex-ante and ex-post GFU-GU and the returns it made and invested in the transmission system. Section 3.3 starts and discusses the challenges the investors in the Norwegian offshore transmission system are encountering. It explains the tariff system applied on the NCS and the impact changing supra, and national regulations have on investors and the earlier identified gaps in communication and incentives. Tariffs can be seen as the return on investment for pipeline owners and are taken into consideration in financing offshore pipeline systems. Section 3.4 explains how investments in infrastructures are initiated in Norway, which procedures are applicable, and highlights gaps between Neo-Classical and Principal Agent Theoretical principles. The section highlights the responsible parties in initiating investments on the NCS and highlights contradicting situations where e.g. Gassco wears two different hats: one to advise the government on managing natural resources and two, to advise the Gassled owners on how to maximise returns on the transmission system. It then discusses the investments that have been made and potential investments that are under pressure due to financial challenges. Section 3.5 concludes.

3.2. EUROPEAN UNION REGULATIONS

In 1988, the European Union[70] drafted a working paper "The Internal Energy Market" (EU, 1988) with the aim of establishing a single European Union Member States market. By 1992 new initiatives like harmonisation of taxation, price transparency and interconnection of grids further structured this aim. It became clear that the position of the Commission from the mid-eighties, largely excluding the energy sector from the Single European Market, had changed (Rosendahl & Kittelsen, 2004). This change lead to the first gas directive from 1998 (EU, 1988) and was followed by two more gas

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[70] A complete list of EU regulations and directives can be found in the Appendix Section 8.6

directives in 2003 and 2009, in addition to four network codes and two gas target models[71].

Gas directives

To arrive at a correct judgement, it is essential to reiterate the terminology used in the Gas Directives and relate this to a Norwegian offshore pipeline context in the research. For example,

> upstream pipeline network means any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production project, or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal landing terminal (EU, 1998, p. L 204/5)

Through the upstream high-pressure network gas is conveyed with the purpose of anything other than delivery to end-users. This contrasts with distribution which delivers gas to customers. In a similar manner supply has been described as the delivery and/or sale of natural gas to customers, suggesting that it could involve transmission and distribution. Within the three gas directives the articles and requirements concerning access to upstream pipeline networks remained the same, albeit under a different Article number[72]. Contents consist of the ability to 1), obtain access to the upstream network, 2) in accordance with relevant legal instruments taking into account security, quality and regularity of supply, 3) have in place dispute settlement procedures and 4) have in place cross border dispute settlement procedures.

The implementation of the first gas Directive(98/30/EC) took place in 2002. A substantial part of the Gas Directive related to distribution and

[71] For a summary of the three gas directives, four network codes and two gas target models see Appendix Section 8.7

[72] First directive article number 23, second directive number 20 and third directive article number 34

thus downstream and processing, as a consequence the impact for the Norwegian offshore transmission system was minor[73]. A Royal Decree was implemented to include a new Chapter to the Norwegian Petroleum Activities Act. Norway does have a distribution network and low-pressure pipelines onshore however these are less trivial (Regjeringen, 2017c).

TPA and unbundling

There are several descriptions and terms in relation to the concepts of access/entry and competition on the natural gas infrastructure, the most commonly used is Third Party Access (TPA), The first directive (EU, 1988) introduced the concept of TPA and unbundling of services. The second directive (EU, 2003) focussed on national regulations and legal unbundling. The third directive (EU, 2009a) concentrated on unbundling and introduced ACER[74] a European regulator. Unbundling according to the Gas Directive, Member States shall at least ensure that integrated companies unbundle their internal accounts and do not abuse commercially sensitive information (EU, 1998). Open Access (OA) is a term used in the United States, in a quite similar way as the European Commission uses TPA. Finally, common carriage is a system whereby when the capacity of a pipeline system is over-subscribed, the requirements of all shippers are scaled back on a pro rata basis. The most common system is 'contract carriage' where capacity is (commonly) allocated on a 'first come first served' basis. (Stern, 1997).

[73] In 1991 the Norwegian Ministry of Petroleum and Energy concluded that the EU directives adopted to date had little or no consequences for Norway (Norwegian Ministry of Finance 1991:105). In the electricity section the prospect of open transit is discussed but not regarded as consequential for Norway. In the gas section, the price and transit directives are not even mentioned. (Claes, 2002)

[74] Agency for the cooperation of energy regulators, building upon the sustained efforts of National Regulatory Authorities (NRAs) and the continuous support of all stakeholders, ACER's Gas Department is working towards meeting all the challenges associated with creating a well-functioning, competitive, integrated, secure and sustainable European gas market, delivering tangible benefits to European consumers. Work still to be done includes aligning national market and network operation rules for gas as well as making cross-border investment in energy infrastructure easier. ACER's Gas Department is divided into three key areas of work, all aiming to support the achievement of the above-mentioned goals: Framework Guidelines & Network Codes, including the Gas Regional Initiative TSO Cooperation and Infrastructure & Network Development Market Monitoring

Although several terms have been described, TPA has been the most common denominator in the literature.

For the Norwegian government, the implementation of TPA and unbundling may have come at a convenient stage. Throughout the period of 1976-1995 a significant number of offshore pipelines were laid and had become operational. The pipelines were operated by different owners, each with different tariffs, terms and conditions. This resulted in a complex, inefficient arrangement to convey gas from a field to e.g., a treatment facility. A need arose for a coordinated transmission system, which came with restructuring of the Norwegian Gas Management System and included a unified access regime and the establishment of Gassco as operator (Regjeringen, 2017c). The government, initiated the negotiations between the relevant pipeline owners with the objective to consolidate the multitude of owners and JVs into one ownership structure. This resulted in the establishment of Gassled as transmission system owner and the "winding up of the GFU" (Regjeringen, 2017c). The latter will be discussed in Section 3.2 Competition. The restructuring of the gas management system was done through regulatory implementation of access, based on the new transport system. This included Gassled as owner with a separate regulation for tariffs. Furthermore, the regulation of the gas transport system reiterated that the return should be taken out on the fields and not in the transmission system (Regjeringen, 2017c). This proved to be an imperative sentence in the court case that followed in relation to tariff reduction.

Competition and Regulation

In the natural gas industry during the eighties a "public interest" view on price and entry regulation was discussed in the paper from the European Union (EU (83/230/EEC), 1983) "The internal energy market-energy for the Community". It became apparent that certain segments of the gas market in the European Union and in particular in Norway were so far vertically integrated that its natural monopoly characteristics might need alternative/additional regulation.

There are several descriptions of a monopoly e.g., by Pindyck & Rubinfeld (2012) "A Market with only one seller" or as Posner (1969) stated "does not refer to the actual number of sellers in a market but to the relationship between demand and the technology of supply".

A method to eliminate or reduce monopoly power is through the introduction of competition. The OECD (2016) provides a history of reform models for regulated industries, in addition (Joskow, 2009; Joskow, 2013) describe the typical elements of reform models as"

- To separate (structurally or functionally) the potentially competitive segments from the monopoly/oligopoly network segments that would be regulated,
- To remove price and entry regulation from the competitive segments,
- To unbundle the sale of regulated network service from competitive services,
- To establish transparent tariffs for access to and use of the network, and
- To allow end-users (local distribution companies or consumers in the case of gas to choose their suppliers of competitive services and have them arrange to have it "shipped" to them over an open access network with a regulated cap on the prices for providing transportation service" (Joskow, 2009).

The removal of national gas monopolies and opening up free market access to the infrastructure was seen as a condition for improving economic and environmental efficiency (Estrada, 1995). In theory, the rationale for effective regulatory intervention is to provide economic efficiency under perfect competition. However, efficiency in pricing, providing signals[75] from

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[75] Incomplete information, as discussed in Section 2.2, can have a significant influence on monopoly

and to consumers and producers to support decision making proves to be a difficult process (Tirole, 1999; Sappington, 1981; Joskow, 2009).

Due to the lack of a competitor, a regulator determines access/entry and a tariff. Joskow states:

> Firms with de facto legal monopolies that are subject to price and entry regulation inevitably are eventually challenged by policymakers, customers or potential competitors to allow competing suppliers to enter one or more segments of the lines of business in which they have de facto legal monopolies. (Joskow, 2007, p. 1230)

The literature on the liberalisation process, the introduction of competition through network access and pricing is extensive. However, in order to improve the functioning of the market, "notably concrete provisions are needed to ensure a level playing field and, inter alia to reduce the risks of market dominance" (EU, 2003).

Economists have long concluded that companies with market power have an incentive to control competition in that particular market, thus using the market power, which could be translated to, predatory behaviour (Haase, 2008). Competition policy aims to prevent such activities. Norwegian gas production, sale and transportation possessed several of these trademarks across the value chain with concentration of market power. This market structure originated from the concept of long term Take or Pay contracts (TOP) and field depletion contracts, required to build and operate the natural gas infrastructure. The natural gas value chain in its completeness left customers at times in the undesirable position of having either excess gas or the cost for non-used excess gas. This supports the

prices for regulated firms and the regulator.

natural monopoly argument in which a transmission system, in theory, will exercise market power and collect monopoly profit if left unregulated. The transmission system will aim to maximise profits at a throughput level where at a minimum the marginal cost equals marginal revenue. Leading to a situation where a single firm (or a small number of firms) emerges in equilibrium and may have market power and charge prices that yield revenues that exceed the breakeven level for at least some period of time. Which could subsequently lead to lower output and higher unit costs than is either first-best or second-best efficient (Joskow, 2006).

In Norway before 2001 and the implementation of the first Gas Directive, the ownership and sole access to the infrastructure was through the national transmission companies on the up-midstream side and local distributors on the downstream side. This situation provided Norwegian sales and transport committees/agents, GFU and FU, with considerable market power vis- a-vis customers. Monopolistic price discrimination became a practice in which a price was charged close to the price of available substitutes resulting in customers paying the maximum price they were willing to pay for gas. In addition, implying potential underutilisation of productive resources by the monopolist.

With the implementation of the Directive 98/30/EC by the Storting, the restructuring included the abolition of the GFU[76]. As a result, from 2001 onwards companies were able to sell natural gas individually, reducing the monopoly power of the seller as well as the downstream distributors in e.g., the Netherlands and Germany. The implementation had a considerable impact on gas sales, however a limited effect on natural gas transportation.

A notable effect of the directives is the gradual exchange of long term contracts and introduction of a fixed tariff for a third-party shipper. This had an effect on the risk taken by investors. Ex-ante 2001 long-term Norwegian "take-or-pay" contracts have mitigated investor risk. Ex-post, contracting

[76] A detailed explanation is provided in Chapter 4, Norwegian regulation on gas sales

arrangements are governed through e.g. gas-on-gas competition, gas re-sale contract clauses and TPA in line with European requirements. Thus, creating new market structures with different forms of risk. The major upstream producers identified the perceived threat to long-term contracts as a major risk to their business. Conversely, the introduction of competition could create issues for offshore transmission systems affecting European supplies in the long run, unless provisions are made to secure long-term investments (Austvik, 2010c).

A note on Cost

Under perfect competition the price should equal the cost, a price too high indicates excessive profits, a price too low would ultimately result in negative financial outcomes. The installed regulatory agent should determine access to the infrastructure and a price that should be charged. In its most basic form revenue minus cost equals profit. The challenge for the agent is to determine the efficient cost structures for production. An important issue that will reoccur in the thesis is the sunk cost factor that is present in infrastructure investment. According to Joskow & Noll (1981) sunk costs have not been considered directly in technological definitions of natural monopoly that turn only on cost sub-additive grounds. However, theoretically and empirically sunk cost have been a significant factor in the development of the gas infrastructure as a monopoly. Other information relevant for the regulator concerns demand, investment, management, financing, productivity, reliability and safety to regulate effectively.

Due to asymmetry in information the regulator/agent has to propose cost options. Arguably the regulatory intervention should as a minimum improve pricing and adequate supply over the monopoly which has advantages of economies of scale and scope, in addition sufficient investment incentives. That the regulator or government is not always in possession of the appropriate information has been demonstrated in the Gassled court case against the Norwegian State.

> This is underpinned by the lack of any systems for monitoring and measuring the return in Gassled. Nor was it well-defined what the maximum return in Gassled was supposed to be, or what value the Gassled return could be measured against. This is illustrated by the fact that the Ministry has itself stated that it spent a long time achieving clarity about what the correct basis was for measuring the return in Gassled (Regjeringen, 2017c, p. 42)

The investment factor in the long run[77] as a function of Long Run Marginal Cost (LRMC) is crucial to ensure that fields and transportation get developed. The interaction between optimal capacity at a range of natural gas prices determines the diameter of the transmission system pipes and compressor power, subsequently resulting in a higher investment cost for a larger diameter or compressor[78] and vice versa for a smaller combination. Gasmi & Oviedo (2010) and Cremer & Gasmi (2003) discuss economies of scale in natural gas pipelines[79].

Driving down cost as a consequence of competition appears to result in reduced investment in the infrastructure. Especially during periods of excess supply and low prices, asset-sweating instead of investment with a long-term perspective. This is recognised by the European Union stating that "market concentration and weak competition remain an issue and the European energy landscape is still too fragmented and does not lead to sufficient investments" (EU, 2015). In a number of Member States, regulated end-user prices still limit the development of effective competition, which

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[77] The debate on the relation between Short Run Marginal Cost (SRMC), Long Run Marginal Cost (LRMC) and Average Marginal Cost. This might have implications for tariff location once identified.

[78] For a complete explanation on the interaction between flow, compressor power and diameter selection see Appendix.

[79] For a discussion on numerically estimates long-run average cost (LRAC) and long-run marginal cost (LRMC) reference is made to Yépez (2008)

discourages investments and the emergence of new market players, this will only work if market prices send the right signals (CEER, 2016).

Security of Supply

There is a long history of Security of Supply (SoS) regulation both for energy in general and gas in particular. With the objective of creating a single European Energy market came the recognition of a strategy to secure energy supply, and more relevant for this research security of gas supply. In the EU green paper "Towards a European strategy for the security of energy supply", the European Union with a long-term perspective, expected an increase in dependency on gas from non-EU sources of supply (EC, 2004). However, the implementation of energy and gas directives did not provide a guarantee of supply as was recognised in The DG TREN memo "The Internal Energy Market – Improving the Security of Energy Supplies – Gas and Oil Stocks" (2003) stating the lack of a framework at "EU or IEA level guaranteeing a minimum level of security of gas supplies in the European Union". With the liberalisation of the gas market it became apparent that there was no incentive to take any form of responsibility for security of supply from the market. The completion of the internal gas market required a common approach EC (directive 2004/67/EC). A significant number of regulations[80] supported the preparation and mitigation of risks associated with natural gas supply (EU, 2017a).

80 "Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L 211, 14.8.2009, p. 94).
Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (OJ L 211, 14.8.2009, p. 1).
Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (OJ L 211, 14.8.2009, p. 3 6).
Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC (OJ L 295, 12.11.2010, p. 1)" (EU, 2017a).

That multiple internal and external sources should increase security of supply holds not necessarily true. As Stern (2002) noted it depends amongst others on source, transit and facility. A risk-based approach to assess the security of supply in the European gas market has been initiated for common and national risks. "October 2018 Member States shall notify to the Commission the first common risk assessment once agreed by all Member States in the risk group and the national risk assessments" (EU, 2017a). The foundation of risk is based on sustainability of gas usage for a set period of time.

> The N-1 formula describes the ability of the technical capacity of the gas infrastructure to satisfy total gas demand in the calculated area in the event of disruption of the single largest gas infrastructure during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. (EU, 2017a, p. Annex 2)

The Norwegian upstream supply has been categorised as the North Sea gas supply risk group. Through the mathematical model the risk exposure of the upstream supply of Norwegian gas supply can be calculated. Factors affecting the risk include the availability of an alternative route to transmit gas and bi-directional gas flow. In the Norwegian offshore gas supply this alternative could inter alia be captured with Sleipner and Heimdal for further transport to end locations. The Security of Supply Regulation appears to have little relevance for this research, e.g., there appears no bi-directional flow requirement to and from Norway. Furthermore, considering Norway's position as a non -European Union member and as one of the larger suppliers of natural gas to the European Union amounting to ~95% of its annual gas production. However, from the non-exhaustive list described in (EC, 2004) several security issues do have relevance for the thesis in relation to offshore transmission systems and will be briefly discussed.

Long-Term Contracts to Secure Infrastructure Investments

From a historical perspective, import depending countries wanted to reduce technical and political supply risk and secure natural gas supply. In addition to building gas storages and the upcoming of dual burner capacity, European gas importing countries preferred to have several sources of gas deliveries to secure the supply and reduce price fluctuations. Germany as first in the early 70ties, appeared to be willing to pay a gas price that made it possible to develop new Norwegian gas fields and subsequently ensure future gas supply. This came at a cost of a long-term gas contract. It was inter alia for this uncertainty that long-term contracts were used to minimise risk from the customer side. Typical gas contracts would last 15-25 years, could potentially contain a take or pay (TOP) obligation i.e. 80-90% of annual quantity contracted and were oil price indexed.

These long-term contracts, initially required to reduce risk and support the financing of the infrastructure, have been argued to be subsequently unnecessary for the assurance of security of supply. The infrastructure is in place and mature in the North Sea and to an extent in the Norwegian Sea. It could be argued that there would be less need for large capital investments to build new infrastructures.

Market liberalisation as set out in the gas directives does not indicate that long-term contracts have been redefined from 15-30 years to 5-10 years, however terms will become more flexible and are moved away from a monopolistic nature. The creation and expansion of traded markets will largely eliminate potential take-or-pay problems, by allowing market players to sell volumes which are surplus to requirements argues (Stern, 2002). Investments of up to $2bn will continue to be financed by new long-term contracts. But there might be a major issue as to whether investments in excess of $5bn, and particularly in excess of $10bn, in remote greenfield locations will find investment funds. That investments which cannot be made in stages, can obtain finance when these are selling into liberalised and competitive markets has been demonstrated in Norway with the building of the Langeled pipeline. At the cost of (2016)[81]NOK 9.28BN Langeled was the first major greenfield pipeline selling gas into a liberalised and competitive gas market in 2007. The owners of Gassled and Langeled initiated negotiations and agreed to transfer ownership in 2006. Langeled would provide a real rate of return of around 7% before tax (Regjeringen, 2017c).

There is not a large number of projects of this dimension, therefore European and national regulators have allowed for time-limited exemptions from access conditions during the finalisation of the 2nd and 3rd energy package if such projects can make a demonstrable contribution to source and transit diversification. The gas directives allow for temporarily granting partial derogations for "exceptional risk profile of constructing those exempt major infrastructure projects" (EU, 2003).

The research will further investigate whether the Barents Sea Gas Pipeline Infrastructure will be developed under these regulations, considering there is minimal infrastructure present, the location is remote, sensitive to higher risks, environmental issues and the gas prices that are significantly lower than before the Gassco 2014 study was conducted.

Security of Assets and Health Safety Environment (HSE)

Security of supply can also be seen from a physical asset-specific (Source, transit and facility) security of supply. The Norwegian gas history has had casualty related accidents e.g., Alexander L. Kielland[82], Sleipner concrete base in 1991, and a helicopter crash in 2016 which have had an impact on HSE and subsequent cost. However, further investigation has not provided evidence to assume supply interruption due to asset breakdown. The Norwegian gas infrastructure provides alternative routes for gas to be transported. Diversification of facilities is present, and the infrastructure is

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[81] approximately £1.7BN

[82] A Norwegian semi-submersible drilling rig that capsized while working in the Ekofisk oil field in March 1980, killing 123 people.

supported by the Pipeline Repair System (PRS) capable of rapid response for pipeline repair. The PRS pool was founded in 1987 and is owned by Gassco, Statoil, ConocoPhillips, Shell, Nord Stream, BBL Company, Lyse Neo, GdF Suez, BP and Woodside.

To what extent prolonged personnel strikes might have a significant impact has not been investigated to date. It could thus be argued that security of gas supply from Norway to its customers is dependent on resource allocation, field development and investments in the infrastructure to connect and ship the gas to the end user.

3.3. INFRASTRUCTURE INVESTMENT BARRIERS

Countries within the European Union and EEA have additional national regulations to address infrastructure investment barriers. Addressing all involved parties in each country is too broad and outside the scope of this research. A general approach is provided based on the assumption that the aim is the development of one trans-European network for transporting gas as set out in the Internal Energy Market (Europarl, 2017). With the implementation of the Third Energy Package in 2012 came the unbundling of ownership of transmission systems. This allowed for more competition, TPA and security of supply. Within the European member states and in Norway as an EEA member, ownership has been unbundled. Under exceptional conditions new infrastructure developments may be exempt from unbundled ownership by the national regulator (subject to approval by the European Commission) provided that certain conditions have been satisfied (Carter & Peachey, 2015). It appears thus prudent for investors in the energy infrastructure to make a distinction on ownership in the investments made, be it through share holder interest, management control or financial vehicles or other options.

Several funds have been set up, e.g., the Europe 2020 Project Bond Initiative designed to enable eligible infrastructure project promoters, usually public private partnerships (PPP) to be set up. The Trans European

Energy Network (TEN-E) is a part of the financial structuring of Projects of Common Interest (PCI). Within TEN-E, Ormen Lange and Nord Stream were designated as PCIs by the EU (EC, PCI, 2015).

Financial Regulatory Barriers

Financial regulations such as the Basel III and MiFID II have a direct impact on the availability of third-party finance and bank liquidity limits (Ledesma, et al., 2014). Several papers[83], have discussed the benefits of long term stability and governmental reliability for investments in e.g., transmission systems. The expected remuneration period for new infrastructure projects is a substantially shorter period than the project lifetime. Trust in a regulatory regime takes time to build and can suffer instant reputational damages that last over prolonged periods (Ma, 2016). Traditionally banks and financial lenders invested in the funding of transmission system projects. Tables 3-1 to 3-4 depict the various fixed forms of financing in the market. The financial expertise of the bankers and lenders enabled supervision of projects in construction and procurement, to identify and mitigate risk. However, two factors have altered the position of banks in meeting infrastructure investment needs. One factor was the growing long-term requirement for transmission system investments which had outgrown the financial resources available to the lenders and the second factor was the 2008 Credit Crisis[84]. Regulations implemented to avoid another financial crisis e.g., Basel III[85], MiFID II[86], Solvency II, UCITS IV[87] and the Dodd Frank Act[88] are making it more complex for financers to offer debt on long term projects exceeding 20-30 years. Basel III has had a significant effect on the structuring of Project Finance (PF) contracts, which will be

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83 (Culp, 2010; EC DG for Energy, 2011; Joskow, 2013)
84 (Havemann, 2008)
85 (BiiiCPA, 2017)
86 (FCA, 2016)
87 (EU, 2009a)
88 (U.S. Commodity Futures Trading Commission , 2010)

explained in more detail in Section 4.4. Inter alia, financial institutions are now required to hold a larger deposit of liquid assets resulting in tighter lending capacities. Furthermore, the financial institutions still capable of entering PF contracts will most likely reduce the length of these contracts to maintain the option to relocate assets to other projects. Project bonds (PB) have become an alternative with reduced risk, e.g., from the European Project Bond Institute. All the financial institutes mentioned receive returns from tariffs to recover the financing payments.

The intention of regulations was that the tariffs on gas transports would recover the cost of financing the transport system. Due to the size of the capital required to upgrade and expand the European infrastructure, the EU set up funds to facilitate investments to support PCIs. Connecting Europe Facility (CEF) and the European Fund for Strategic Investment (EFSI) are two examples of such funds (EC, 2015). For the period of 2014 to 2020, EUR 5.35BN of financial support has been made available.

> The financial instruments are designed to use public funds as a lever and catalyst to attract additional private investment and thereby increase the overall volume of funding available for PCIs. On a larger scale, the concept of encouraging private investment through public financing instruments is applied under the EUR 315 BN EFSI, the centrepiece of the Juncker Plan. (EC, 2016, p. 18)

Although funding has decreased during the years 2008-2017, the investment gap has been reduced. Financially attractive projects in western Europe, as opposed to more risk prone eastern Europe projects, have received capital. In a paper published by (Carter & Peachey, 2015) it is suggested that in accordance with the general EU strategy, support for PCIs is increasingly shifting to repayable financial instruments rather than grants. However, there remains a funding gap between the commercially viable and less viable projects. Pricing challenges play a significant part in the financial investment incentives, high prices draw more investors.

Oil & Gas Regulatory Barriers

According to the European Commission Directorate-General for Energy report[89], regulatory uncertainty was the most challenging factor related to transmission system investment in the EU. Issues include regulatory remuneration and the stability of the regulatory regime and related remuneration. These factors are equally important for the TSO as well as the external investors and lenders (EC DG for Energy, 2011).

The financing of large infrastructure investments went through changes around 2008-2010 (Gatti, 2008). Various factors played a part in these changes e.g., financial regulations, change in appetite for risk and a change in the attitude of the banking industry to institutional investors. With these changes, different forms of cooperation between stakeholders and financial institutions brought different investment options. Transmission systems in Norway are financed by the Oil & Gas companies and the government as shareholder in Statoil and/or Petoro. The Oil and Gas companies, at the beginning of the establishment of Gassco-Gassled in 2001, either joined the Gassled JV, sold the transmission system to the Gassled JV and or handed over operatorship to Gassco.

As a consequence of the change in regulations through the three gas directives, in combination with the 2009 low oil prices and divestment requirements to focus on core business, the large Oil and Gas companies[90] sold their shares in Gassled to insurance companies and infrastructure investors. Infrastructure investments returns are set by the Norwegian government at 7% pre-tax. The returns required to satisfy O&G[91] companies

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[89] Study results are based on 32 interviews with TSOs in the electricity and natural gas sector and 15 interviews with financial institutions.

[90] Statoil maintains a 5% stake in Gassled.

[91] Not taking into account the exact sub-sector of O&G companies and location. E.g., Oilfield service companies (OFS) could achieve returns between 8% and 12% (S&P, 2017) whilst pumping companies

IRR are estimated to be around 12-15%. Oil companies, desperate to keep shareholders satisfied by paying high dividends, additionally wanted to be able to receive the right amount of leverage based on strong returns. The financial institutions, normally investing in the upstream sector for high returns, were under pressure from financial regulators and the investments were restricted.

3.4. INVESTMENT SOLUTIONS

The OECD paper Infrastructure Financing Instruments and Incentives identified "the root cause solution for financial investment interest is risk mitigation" (OECD, 2015). This section explores financial investment solutions from a risk reduction and financial reward perspective based on different financial instruments.

A substantial number of different risks are associated with the development of a subsea pipeline, including engineering, procurement and construction (delays, extra costs, technical failure), operational (limited production, increase in costs, quality of the gas), supply contract (deficit or supply, interruptions, price of supply), financial markets (rates of return, currency), market fluctuations (demand, price of gas, delay in payments), and politics (expropriation, political turmoil, regulation). Major risks associated with field projects and infrastructures are transferred to insurance companies directly or indirectly through the insurance of the EPC firm e.g., SBM and the Yme platform in the Norwegian North Sea Sector (SBM, 2013). Insurance and reinsurance companies are often heavily involved in projects as providers of project completion insurance and O&M risks. In fact, (re)insurers play such a large role in some projects that they become de facto or de jure cosponsors of the project (Culp, 2010).

A gas project is subject to financial and non-financial risks. This section will focus on the financial risks. To further discuss solutions to the

might achieve higher IRR 15%-20%.

financing and investment challenges, the risks associated with these challenges will be divided into three categories. 1) Technical risk, related to engineering, producing and operating capabilities. 2) Regulatory risk e.g., as discussed in the tariff reduction in the Gassled versus The Norwegian Government case. 3) Economic risk as a result of non-viable resources as in the example of Polarled. An aggregate of multiple factors is required to interest sufficient financial investors, whether through private, public or PPP[92] funding.

Technical Solutions

The history of Norwegian resource development has been highlighted with technically innovative solutions. Furthermore, Gassco's performance record as operator has been optimal with a system regularity[93] of 99.71% and quality of 99.98%. In addition to the fact that the transmission system operator does not bear risk during the construction phase, the need to offer technical advances to financiers is deemed minimal. Typically, financiers prefer the use of proven technology (Ledesma, et al., 2014). Corielli (2010) discusses the risk shifting of non-financial contracts. Offtake agreements, supply contracts, equipment procurement contracts, guarantees in project financing are used to transfer risk to counterparties. However, the counter-party to the contract determines effectiveness of risk transfer.

Due to Gassco's high regularity and quality rate, in addition to the lack of significant disputes on technical transportation matters in Gassco's history, the risk related to the occurrence of technical issues will be assumed low. Subsequently technical solutions appear to have limited impact on investment decisions once the design has been approved during the PDO-PIO phase.

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[92] A comprehensive list of all public and private funding forms is described in the Appendix

[93] Regularity is measured as the volume delivered from the transport system (Gassled area D) in relation to shipper orders. Quality standards are measured in relation to the gas quality delivered from the transport system (Gassco, 2016).

Regulatory Solutions

Governmental decisions, e.g., policy changes, or supra-national regulations can have a substantial impact on an investment decision. Furthermore, it can have implications in different parts of the transmission system investment with later consequences. Table 3-1 depicts the regulatory risks associates with each stage of the development of the transmission system.

Development phase	Construction phase	Operational phase	Decommissioning phase
Environmental review, e.g., ministry of fishery	Permit delay or cancelation	Tariff changes	Contract termination
Rise in pre-construction cost	Contract re-negotiations	Currency convertibility	Decommissioning, Asset transfer
Change in Taxation			
Social acceptance			
Change in regulation or legal environment			

Table 3-1 Regulatory risk
Source adapted from: OECD (2015)

The final report to the European Commission Directorate-General for Energy (EC DG for Energy, 2011) discusses recommendations to close financing gaps regarding the trans-European energy networks (TEN-E). Five solutions were provided,

Solution 1) Improve the regulatory environment for the financing of energy infrastructure.

Solution 2) facilitate equity financing (see Table 3-3), Solution 3) Enhance debt financing (see Table 3-2),

Solution 4) Specific project financing (Table 3-4 provides an overview of the financial instruments) and,

Solution 5) Increase transparency in financial denominators or multiples (EC DG for Energy, 2011).

Not all solutions would provide a satisfactory result in a Norwegian investment context. E.g., the Norwegian regulations resulting in a permitting process taking between 2-6 months, are well documented, and incorporate environmental and social impact analysis from the engineering stage to decommissioning. Furthermore, increasing transparency through the use of financial indicators and standardisation of accounting practices in the EU are based on International Accounting Standards (IAS) (Regnskapsstiftelsen, 2017). The Norwegian Accounting Standards Board[94] (NASB) complies with these standards[95].

Changes in national regulations have a valid place as a financial and investment incentive, if changes can be made in favour of investment, but they can be opposed to (additional) investment. Norway faces challenges with inter alia social acceptance of usage of fossil fuels. The opposing implications of Norway's position as a supplier of natural resources can be seen on one side in the commitment to COP21, divesting from all coal power in its Sovereign Wealth Fund portfolio, but on the other side in discussing the proposal to open Lofoten, Vesterålen and Senja (LoVeSe) to exploration for oil & gas (The Conversation, 2016). The proposal was opposed in 2016 by environmentalists and has yet to be decided upon.

Solutions on a national level could be implemented through regulatory remuneration. This would provide the regulator with an option of a predetermined time frame and return to recover investments made in

[94] Norwegian companies listed in an EU/EEA securities market follow IFRSs since 2005. Dispute over IFRS for SME is June 2017

[95] Despite this compliance, Norway is stepping back from an ambitious plan to introduce of IFRS for SMEs based accounting standards (Deloitte, 2017).

the transmission system in each specific phase of the life cycle e.g., increasing the Return on Equity for infrastructure expansion[96]compared to maintenance. Taking the three gas directives into consideration, it is arguable that changes in regulation come with significant challenges.

Financial and Investment Solutions

There are several options for financing infrastructure, through private finance, on the balance sheet, project finance and through an EU fund/grant or through EU leverage. Private finance, i.e., corporate finance, for public infrastructure projects is not a new concept: the English road system was renewed in the 18th and early 19th centuries using private-sector funding based on toll revenues; the railway, water, gas, electricity, and telephone industries were developed around the world in the 19th century mainly with private-sector investment (Yescombe, 2013). With the growth of private sector investment in infrastructures came a new class of (infrastructure) investors such as Macquarie Infrastructure & real assets (MIRA), Brookfield Asset Management, Global Infrastructure Partners. In addition, subsidiaries from banks such as Deutsche Asset Management, JP Morgan, UBS and insurers like Allianz and Aviva. There are several reasons which justify investment in infrastructure from a financial institute's perspective; stable and predictable cash flows during the operational phase of the project's life cycle, ROI insensitive to fluctuations, with relatively high recovery rates compared with low default rates. Furthermore, good credit ratings and the possibility to enhance one's reputation by being seen to finance social infrastructure (OECD, 2015).

Private corporations have options to obtain resources to invest through lending. The fixed income options are depicted in table 3-2.

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[96] Germany utilises a 9.29% and 7.56% pre-tax return (EC DG for Energy, 2011).

Debt

	Infrastructure Finance instrument			Market vehicles
Asset Category	Instru-ment	Infrastructure project	Corporate balance sheet	Capital pool
Fixed Income	Bonds	Project Bonds	Corporate bonds, green bonds	Bond Indices, Bond Funds, ETFs
		Sub-sovereign bonds		
		Green bonds	Subordinated bonds	
	Loans	Direct/Co-Investment lending to Infrastructure project	Direct/Co-investment lending to infrastructure corporate	Debt funds
		Syndicated Project Loans	Syndicated Loans, Securitized Loans (ABS), CLOs	Loan Indices, Loan Funds

Table 3-2 Fixed Income bonds and loans
Source: Adapted from OECD (2015)

Bonds and loans are established instruments to obtain capital for private firms to invest in infrastructures. The cost of capital obtained will be shown on the corporate balance sheet. Another option for a private firm to raise capital is through equity. Table 4-2 below depicts the instruments available on the equity market.

Equity

Another form of finance that supplements debt is through equity. There is no standard equity funding structure and the exact details of timing and mechanisms for funding will be determined through negotiation between the sponsors and the lenders (Clews, 2016). The various types of funding for equity are displayed in table 4-3.

	Infrastructure Finance instrument			Market vehicles
Asset Category	Instrument	Infrastructure project	Corporate balance sheet	Capital pool
Equity	Listed	Yield/Cos	Listed infrastructure & utilities stocks, Closed-end Funds, REITs, IITs, MLPs	Listed Infrastructure Equity Funds, Indices, trusts, ETFs
	Unlisted	Direct/Co-Investment in infrastructure project equity, PPP	Direct/Co-Investment in infrastructure corporate equity	Unlisted Infrastructure Funds

Table 3-3 Equity financing
Source: Adapted from OECD (2015)

The listed and unlisted issuance of equity is often the only option available for exploration companies. E&P firms in general do not produce tangible energy resources and thus have limited options to result in debt in lack of significant cash flow of selling resources. In addition, gas price volatility increases the investment risk factor in the sector resulting in a smaller share of equity to debt in generated funds and corporate debt finance (Clews, 2016).

Hybrid Finance

Mezzanine finance provides credit for the potential funding gap between the senior debt loans and equity.

	Infrastructure Finance instrument			Market vehicles
Asset Category	Instru-ment	Infrastructure project	Corporate balance sheet	Capital pool
Mixed	Hybrid	Subordinated Loans / Bonds, Mezzanine Finance	Subordinated Bonds, Convertible Bonds, Preferred Stock	Mezzanine Debt Funds, Hybrid Debt Funds

Table 3-4 Hybrid financial instruments
Source: adapted from OECD, 2015

Usage of Hybrid Finance is increasing but is subordinated to "traditional" debt and equity loans. Mezzanine finance is a collective term for hybrid forms of finance and contains characteristics of debt and equity. Typical examples comprise subordinated loan, participating loan, 'silent' participation, profit participation and convertible bonds (EC, 2014). Table 3-5 depicts a hypothetical division of an investment into 4 parts (25% each) with the aforementioned finance forms and the anticipated return rates. Mezzanine finance lenders have a position inferior to lenders but superior to equity providers. Mezzanine finance is unsecured, provides higher returns and higher risk.

Tranche	Pay priority	Return
Equity	4) highest risk. Absorbs the first 25% of losses on the portfolio	15+%
Preferred Equity	3) absorbs the next 25% of losses	11-15%
Mezzanine Debt	2) the next 25%	6-10%
Senior Debt	1) final 25%, lowest risk.	4-5%

Table 3-5 Tranches of finance in mezzanine finance
Source Author's own, adapted from (EC, 2014)

The different tranches yield different returns for each investment form. Regardless of incentives to invest or investment form, all rational investors make use of decision criteria that are applied in corporate finance and which are accepted as common practice. In order to identify cost benefit, valuation methods with time value and without time value are used. Cash flow modelling and payback[97] rules are applied without time value. Both are valid methods to provide a reasonable result. Net present value (NPV) and Internal rate of return (IRR) are time value base methods[98] and provide more insight into returns over a prolonged time as is the case with transmission system investments.

A diversification of investors to meet the hybrid model is growing in the LNG market in which portfolio players with medium and long-term contracts see improving margins on sales linked to hub or LNG spot prices. Rogers (2017) further suggests that the advantages the oil and gas majors bring to the portfolio players compared with the independents and smaller players inter alia consist of well-developed portfolios of LNG supply sources and destination markets. These advantages would allow the portfolio player to see higher value in new LNG projects (intrinsic and extrinsic value) relative to the stand-alone player (Rogers, 2017).

Project Financing (PF)

The connection between Transaction Cost Economics and Project Finance as a potential option has been identified by Williamson;

> Whereas most prior studies of corporate finance have worked out of a composite-capital setup, I argue that investment attributes of different projects need to be distinguished. I furthermore argue that rather than regard debt and equity as "financial instruments," they are better

[97] For further reading on Cash flow modelling and pay-back rule see (Bhattacharyya, 2011 p. 175)
[98] A brief description of time valued methods has been set out in the appendix.

> regarded as different governance structures (Williamson, 1988, p. 576)

Project finance is a method of raising long-term debt financing for major projects through "financial engineering," based on lending against the cash flow generated by the project alone. It is dependent on detailed evaluation of operations, expected revenue risks, distribution of revenues between investors, lenders, and other parties through contractual and other arrangements (Yescombe, 2013). Project Finance in the O&G industry is used by project sponsors to raise capital as an alternative method next to capital and equity. Specifically, it provides an option for NOCs IOCs or JVs with smaller portfolios and reduced cash flows to attract equity or favourable interest rates to compete with large IOCs. Project finance might be an option. The BSGI report refers to “smaller players needing to bundle resources and assets to optimise the efficiency of a trunk-line”. The increased usage of Project Finance in the international petroleum industry is depicted in Table 3-6 denoted in executed projects.

Year	2007	2008	2009	2010	2011	2012	2013	2014
PF-Projects	42,725	51,836	28,437	37,257	43,450	64,652	50,281	77,195

Table 3-6 Project Finance projects per year
Source: adapted from Clews, 2016

The borrower is usually a Special Purpose Entity (SPE) that is not permitted to perform any function other than developing, owning, and operating the installation. The consequence is that repayment depends primarily on the project’s cash flow and on the collateral value of the project’s assets (Clews, 2016).

In the case of oilfield development, Project Finance started to be used in the United States during the 1930s and later in Europe at the beginning of the 1980s (Croce & Gatti, 2014). An advantage of Project Finance is the detailed contracting that needs to take place for the project to commence, thus reducing imperfect information and resulting in efficient credit appraisal. It could thus be argued that PF provides research settings free from portfolio effects, institutional overlap and historic precedents and clearly defined in terms of project context (Müllner, 2017). Project Finance has been frequently used in the O&G sector, more specifically on gas, consisting of large infrastructure projects with high initial capital cost before production (Ledesma, et al., 2014). The available capital for project finance is inter alia, dependent on the overall liquidity of the global financial system, and the relative competitiveness of that specific project (Giamouridis, 2015).

Project finance techniques have also been used more frequently to fund offshore infrastructure, particularly floating structures. In fact, project finance is now a well-established source of funding for FPSOs and similar offshore facilities. Finally, a similar judgement can be made for the shipping sector which has many features in common with project finance (Clews, 2016).

Advantages of Project Finance include separation of existing infrastructure from the to build pipeline. The Special Purpose Company i.e., a Special Purpose Vehicle (SPV) is the direct owner of the pipeline. Cash flows are generated through an agreement with e.g., Gassco as the operator of the complete transmission system. Such a construction requires regulatory approval. Investors in addition to the TSO have direct control over the asset. A project finance approach is clearly the preferred structure from an investors' perspective for legal separation and asset ownership (OECD, 2015). Disadvantages are the risk to investors of insolvency of the participants of the SPC and the TSO and, in the case of cross-border pipelines, more complex contracts.

3.5. CONCLUSION

EU energy packages and competition regulations were intended to promote perfect competition and economic efficiency. This was done through the separation of structural and functional segments of the transmission system, providing third party access and unbundling of sale and transmission services giving end-users an option to choose a provider matching the customer's criteria.

All three gas directives and regulations make note of upstream pipelines; however, the relevance is minimal to offshore high-pressure pipelines and more directed at regulation of low pressure gas transport to end-users. The impact on the implementation of the Norwegian offshore transmission system was minor. As for the timing, it could be argued that the gas directives came at a welcome time since pre-Gassled-Gassco, a plenitude of gas pipeline systems was established with different owners, different tariffs and different terms and conditions for transport. Transporting gas required several transport agreements with several owners, on different terms. This represented an obstacle to efficient utilisation of the infrastructure, and a need therefore arose for coordination of the transport systems (Regjeringen, 2017c). Gasled 1 was proposed in 1995 however did not receive governmental approval at that time. The establishment in 2001 of Gassco and Gassled solved the issue of multiple systems, owners and tariffs, albeit at the cost of access.

Whilst the origins of increasing competition through supranational regulation were a factor in several cases between the European Court and Norway, e.g., Ruhrgas, Thyssengas and GFU unwinding as discussed in Chapter 2, competition was opened up with the implementation of the gas directives. The Norwegian government provided a return on investment for the transmission system owners based on tariff payment for shipped gas. The intention was to provide "the owners with reasonable returns while also preventing additional profits from being taken out in pipelines and treatment facilities" (Regjeringen, 2017c). This ensures the earnings are extracted on the fields and not in the transport system and thus leaving the risk in the field development (Stern, 2017c).

Furthermore, the European Union regulation focussed on Security of Supply, as stated in the document "concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010". The document described that for matters concerning offshore pipelines "only when several gas infrastructures are connected to a common upstream or downstream gas infrastructure and cannot be separately operated, they shall be considered as one single gas infrastructure" (EU, 2017a). It could thus be argued that supranational regulations related to offshore pipelines are limited.

The introduction of supra-national regulation had as a downside reduced investments in infrastructure. Despite EU financial support in the form of grants, bonds and loans at reduced rates, for investment in EU Projects of Common Interest, the outcome has been suboptimal.

Whilst on one hand the regulations promote investment, from a financial regulatory perspective on the other hand, MiFID and Basel II and III reduced the funding power of the recognized financial institutions in energy transmission systems. Financing conditions, with infrastructure characteristics resulted in additional challenges i.e., higher costs of capital and prolonged credit maturities related to acquiring infrastructure investment capital. Under Solvency II a similar position has emerged for long term capital investments of pension funds and insurance funds. In addition, investment funds also face new requirements relating to the Alternative Investment Fund Managers (AIFM) Directive, making it less interesting for non-EU investors (EC DG for Energy, 2011).

Despite these barriers several solutions have been discussed. Technical solutions in this Chapter are seen as engineered financing models insured by the EPC companies. This has been arranged through various contract forms in which shared risk and participation of the EPC firm has been the coming trend. Regulatory solutions are another possibility, the EU gas directives are set up to leave the implementation to the regulators on a national level. However, implementation or change of regulations can be a prolonged process, and regulatory change can have a negative effect on investments long term if trust in a government diminishes. There are dispensation addendums in the energy packages and network codes to provide alternative options if agreed upon, with Nord Stream offshore pipeline as an example.

A foundation has been laid to explore the options for financial solutions. Based on theoretical underpinning of Transaction Cost Economics and the discussion of the value of Project Finance, its application will be further explained in the context of large capital infrastructure investments in which asset-specificity is a key factor. The upside and downside are discussed and reflected upon in light of TCE and PA theory in Chapters 6 and 7.

4. Regulatory Factors on the NCS

4.1. INTRODUCTION

From the moment evidence started mounting that Norway might have natural resources under its seabed, the government took a proactive role in developing them. Through implementation of royal decrees, laws, regulation and policies on one side, the Norwegian government controlled the gradual and guided development of ownership and resources. Through contract negotiations on the other side it developed the sales of natural gas to importing countries in Europe[99]. This provided Norway with a set of rules that allowed it to control the sales of gas to Europe through a state monopoly with commercial characteristics.

The essence of this Chapter is not to depict the complete regulatory and legal system but to continue the discussion from Chapter 3 on regulation from a Norwegian perspective. The chapter describes the origins and interaction of the Norwegian regulations in place, which are used to control the exploration and production of natural resources on the Norwegian Continental Shelf.

Chapter 4 draws further on investments in the European transmission systems in light of neo-classical theory. Section 4.1. will explain the neoclassical theory which is applied in the European Union, where

[99] A distinction is made here that Norway is part of the EEA, however remains a non-EU member. This, inter alia, being the outcome of two referenda held in 1972 and 1994.

security of supply, competition and sustainability, three drivers of the European regulatory framework, have resulted in market failure through inefficiencies, externalities, poor communication resulting in sub-par investments. It could be argued that competition did not solve anticipated failure so that regulatory intervention was required. A substantial amount of research has been done on the implications of the European Union Gas Directives on Europe's security of supply and sustainability. Based on the gas directives and Norwegian national regulations the development of the transmission system is left to the communication between the oil & gas companies to incentivise investments through Gassco-Gassled and the Government. As Shaton (2014) discusses, efficient regulation is required to ensure long term investment for the transmission system. It is in this setting that there are additional discrepancies. Investments can be made through a variety of financial methods/vehicles. Currently there are two main streams of investment in offshore infrastructures, balance sheet and project finance.

There are several investor types which could invest independently, direct or in a public private ownership[100] in some form or structure. Project finance for the purpose of this research divides project finance into a private framework, or a public framework. The fact that project finance is growing could be argued as a sign that TCE is a valid method for this research, but the use of project finance is more complex[101] and thus less efficient. A Cost Base Analysis (CBA) can be made and will be explained in section 4.3 and applied in Chapter 7. Section 4.4 discusses several solutions which would increase investment and explains the different financial models and vehicles commonly used. Section 4.5 concludes on the possibilities and provides

[100] For further details on Private public ownership configurations see appendix Section 8.9

[101] Complexity can be thought of as the "incompleteness becomes more severe as the number of features of transactions (precision, linkages, compatibility) across which adaptations are needed increases and as the number of consequential disturbances that impinge upon these features increases" (Tadelis & Williamson, 2010).

support for question A and the judgements that can be deduced from the data.

4.2. NORWEGIAN GOVERNMENTAL ORGANISATION

The following description of the Norwegian regulatory system is a summary from (Norskpetroleum, 2017e). Although the Norwegian political organisation is founded on a significant number of decrees, policies and regulations, this Section will only discuss the roles, responsibilities and regulations that have a substantial impact on natural resource exploration and development and on offshore pipeline systems.

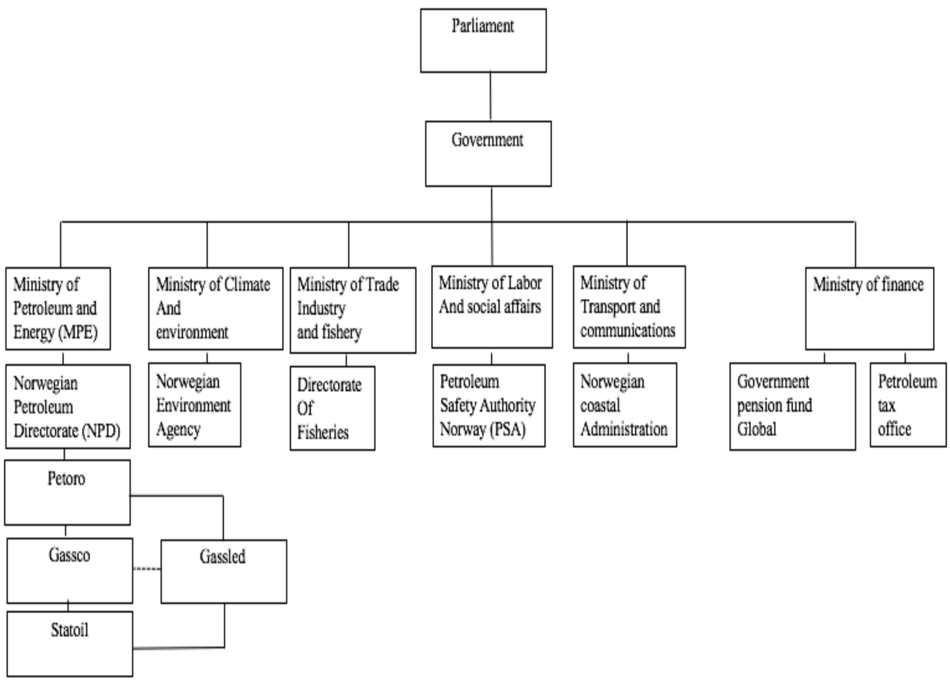

Figure 8 State organisation of petroleum activities
Source: NPD, (2017b)

The Storting (Norwegian Parliament) is responsible for the legislative framework related to petroleum activities. In addition, it participates in discussions on large projects which have an influence on the development of the NCS resources. The Storting controls the Government and Public administration. Despite changes in the ruling government between e.g., left

(Venstre[102]) and right-wing (Høyre) parties, the framework for Norwegian petroleum policy has refrained from significant changes.

From a hierarchal perspective the Government, assisted by the six Ministries as depicted in Figure 7, is responsible for the execution of the Petroleum Policies and reports to the Storting.

The Ministry of Petroleum and Energy (MPE) is responsible for resource management and the overall petroleum sector. In addition, it has taken on the task of managing the State's Direct Financial Interest (SDFI) in Gassco, Petoro and Statoil.

The Norwegian Petroleum Directorate (NPD) is directly responsible to the MPE. Its duties consist of petroleum management and it is an advisory body for the Ministry. The NPD has administrative authority over petroleum E&P in the NCS and has powers to adopt regulations, additionally make decisions under the petroleum legislation.

The Ministry of Labour and Social Affairs is responsible for the working environment and for safety and emergency preparedness in the petroleum sector.

The Petroleum Safety Authority (PSA) is the body responsible for technical and operational safety, emergency preparedness, and deals with accidents and issues related to the working environment. It reports directly to the Ministry of Labour and Social Affairs.

The Ministry of Finance has two main responsibilities in relation to oil and gas exploration. One is the taxation system of the oil and gas sector, the second is the responsibility for the Sovereign Wealth Fund i.e., "the Pension fund".

The directorate of Customs and Excise reports directly to the ministry of finance and is responsible for tax assessments.

[102] Sosialistisk Venstreparti (left wing Socialist party), Høyre is considered the Conservative party

The Ministry of Transport and Communications is responsible in relation to natural resources for any serious pollution which may occur in Norwegian waters.
The Norwegian Coastal Administration is the executing body which reports directly to the Ministry of Transport and Communications and is responsible for oil spill preparedness and response.

The Ministry of Trade, Industry and Fisheries is consulted as part of the procedures for awarding licences, to facilitate coexistence between the petroleum and fisheries industries. Additionally, The Norwegian Guarantee Institute for Export Credits (GIEK) is the central Norwegian governmental agency responsible for issuing export credits and investment guarantees. GIEK operates under the authority of the Norwegian Ministry of Trade, Industry and Fisheries, which contains a section that oversees export and investment guarantees and domestic industry financing.

The Ministry of Climate and Environment has overall responsibility for environmental policy and environmental protection in Norway. It has a subordinate agency, the Norwegian Environmental Agency, with responsibilities under the Pollution Control Act.

State participation

In addition to the ministries, subordinate bodies and agencies, the Norwegian government has significant stakes in the operational segments of the oil and gas industry. The Norwegian state participates 100% in Gassco, 100% in Petoro, 67% in Statoil and ~46% in Gassled through its share in Petoro.

Norway has an extensive institutional framework to foster sustainable development and coordinates with European policies concerning the natural gas market. Whereas several European countries have different approaches for onshore production, offshore production and transportation of petroleum resources, Norway does not. Facilities for the production of subsea petroleum deposits and facilities for transport of petroleum are covered under the Petroleum Act, regardless of whether the facilities are located offshore or on land (NPD, 2010b).

NORWEGIAN FRAMEWORKS/POLICES
1 Petroleum Act: Act relating to petroleum activities (the Petroleum Act), 29 November 1996, No. 72;
2 Petroleum Regulations: Regulations to the Act relating to petroleum activities, 27 June 1997, No. 65;
3 Regulations relating to stipulation of tariffs, etc. for specific facilities, 20 December 2002, No. 1724;
4 Regulations relating to third party access to facilities, 20 December 2005, No. 162;

Table 4-1 Norway petroleum regulations
Source: NPD, 2015c

The regulation of Norway's natural resources started with the royal decree of 1963 determining that:

> The sea-bed and the subsoil in the submarine areas outside the coast of the Kingdom of Norway are under Norwegian sovereignty as regards exploitation and exploration of natural resources, as far as the depth of the super-adjacent waters admits of exploitation of natural resources, within as well as outside the maritime boundaries

otherwise applicable, but not beyond the median line in relation to other states (Storting, 1963).

Since there were no previous private owners, it was a straightforward matter for the state to declare itself the proprietor. Both the cabinet decree, and the contracts which all International Oil Companies had to sign in order to be allocated concession rights, contained procedures to ensure the state's sovereign right of intervention and regulation of the IOCs' practices. The decree did not include any rules on safety as such but stated that if the state were to appoint inspectors, the companies had to provide access and follow directives (Ryggvik, 2010). Norway was careful to address the issue of the exact boundaries of the to be defined Norwegian Continental Shelf, whilst getting information about its resources. This required careful consideration on licensing[103]whilst ensuring the participation of IOCs (due to lack of an experienced NOC) with a limited budget. With these objectives, Norway offered licenses for a large section of its continental shelf and imposed low taxes and royalties. The royalties were set at 10% instead of the commonly used 12.5% in other North Sea areas with a corporate income tax of 41.8% (Lund, 2014). It could be argued that although Norway did not take an initial high financial risk, it risked a large portion of its shelf. It was the largest allocation ever in the Norwegian sector (42,000 km2) as depicted in Figure 3. Based on minimal regulatory conditions for IOCs and no noteworthy involvement by Norwegian companies, Norway represented a minority share in 21 of the 81 blocks allocated in the first round. The Ekofisk discovery from this round in which Petronord only had a 6.7% share (which due to the size of reserves is still a considerable share) proved difficult in relation to Norwegian participation and in the field development. It was recognised that "these matters should not be left to a small number of civil

[103] See Figure 2

servants and members of the government through the ministry of industry and foreign affairs" (NPD, 2017b).

Several issues were identified in that period. A main feature of the Norwegian political economy was and still is the desire to maintain national control over important areas of the economy, especially where it concerns the utilisation of the country's natural resources (Lie, 2011). This appears particular characteristic of Norway considering it has dominated two referenda[104] whether to join the European Union, inter alia over control of natural resources. The discovery of natural resources came with two significant problems. One was the revenue stream that accompanied the large finds of the early seventies and how to avoid what has been called "the Dutch Disease[105]". The second problem involved the recovery of natural resources in an organised timely manner. This led to further discussions[106] around the role of foreign companies (IOCs), the combination of private and publicly owned companies, and an increase of local content with sufficient knowledge in oil and gas matters.

The idea was to have a 100% state-owned oil company as political agent to maintain Norwegian traditions and have a national identity. Although there was an attempt to select Norsk Hydro[107]for the position the final decision on the14th of June 1972 resulted in the establishment of Den Norske Stats Oljeselskap A.S. (Statoil) a state-owned oil company, and the

[104] "Norway has applied for membership in the EC/EU four times: 1962, 1967, 1970 and 1992. The 1962 and 1967 applications were vetoed by France, as was also the case for the UK. In 1972 53.5 per cent of the Norwegian voters, in a referendum, rejected the 1970 application. In 1994 52.2 per cent of the voters rejected the 1992 application. Both in 1970-72 and 1992-94 long and hard negotiations between the EU and Norway took place. Before the EU referendum in 1994 Norway entered the EEA-agreement (European Economic Area)" (Claes, 2002)

[105] The Dutch disease received its name from the increase in services in the petroleum industry after the find of the Groningen field in 1959 at the expense of other industries such as industry and agriculture

[106] While the Labour party had traditionally looked favourably upon state-run industry, the more conservative and liberally inclined opposition was more sceptical and restrictive in its attitude to state ownership. (Lie, 2011), (Ryggvik, 2010), (Austvik, 2011) present further details of the political situation during this period.

[107] In 1971, just before the end of Per Borten's centre-right government, the Ministry of Industry had tried to create the conditions for Norsk Hydro to become the dominant Norwegian national oil company. A bank took on the task of secretly buying up shares in order to secure more than 50 % for the state.

Norwegian Petroleum Directorate (NPD) as regulator (Austvik, 2011). This set the foundation for Norway to control and govern its natural resource activities. With the establishment came the basis for Norwegian oil policies manifested in the 10 Oil Commandments:

> 1. National supervision and control must be ensured for all operations on the NCS.
> 2. Petroleum discoveries must be exploited in a way which makes Norway as independent as possible of others for its supplies of crude oil.
> 3. New industry will be developed on the basis of petroleum.
> 4. The development of an oil industry must take necessary account of existing industrial activities and the protection of nature and the environment.
> 5. Flaring of exploitable gas on the NCS must not be accepted except during brief periods of testing.
> 6. Petroleum from the NCS must as a general rule be landed in Norway, except in those cases where socio-political considerations dictate a different solution.
> 7. The state must become involved at all appropriate levels and contribute to a coordination of Norwegian interests in Norway's petroleum industry as well as the creation of an integrated oil community which sets its sights both nationally and internationally.
> 8. A state oil company will be established which can look after the government's commercial interests and pursue appropriate collaboration with domestic and foreign oil interests.

> 9. A pattern of activities must be selected north of the 62nd parallel which reflects the special socio-political conditions prevailing in that part of the country.
>
> 10. Large Norwegian petroleum discoveries could present new tasks for Norway's foreign policy (NPD, 2010a).

Until 1972 the IOCs dominated the Norwegian oil and gas industry. The government wanted to maintain the IOCs in place, but also wanted to grow Statoil into a company that would conduct operations across the complete value chain from exploration, production, transportation, and refining to selling oil and gas. The government wanted to build on the knowledge of the IOCs and grow local knowledge. It was decided that the state would have a minimum of 50%[108] of each production license and that this proportion could be increased or reduced as and when needed. The shared licenses insured knowledge sharing and transfer of competencies. In addition, with a minimum of 50% state participation, the authorities could directly influence the decision-making process through voting within the license group. There was thus no need for the authorities to approve directly the exploration plans as developed by the licensees. Another part of the agreement was that the license period provided an option for Statoil to take over ownership ten years[109] after commercial declaration (Al-Kasim, 2006). In addition to Statoil, wholly owned by the state, Norway's partly state-owned Norsk Hydro and private Norwegian oil company Saga Petroleum came to set their stamp on national offshore activities (Lie, 2011).

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[108] "The thinking at the time of the first licensing round was that the state's revenues from discoveries would come exclusively in the form of taxes and duties. Prior to the second round, however, the idea of state participation by means of "carried interest" was launched in order to increase the government take from a possible future oil enterprise. The arrangements meant that the state and the oil companies negotiated the size of a "carried interest" agreement for each one of the blocks likely to be allocated to the companies. The system was time-consuming and the cause of some friction between the government and the oil companies. Indeed, Gulf and Shell refused to accept the idea of state participation at all (Hanisch and Nerheim 1992, p153). As a result, the ground was prepared for a system which would assure the Norwegian state of a greater revenues in a more efficient way" (Lie, 2011 page 268).

[109] The idea of stipulating a take over from an international operator was first introduced in the Statfjord agreement. According to this agreement Statoil had an option to take over the operatorship of the field ten years after declaration of commerciality

It was resolved that resource management and control would be exercised by the government and the NPD. The government[110]wanted controlled development of the NCS and limited the number of blocks per licensing round in addition to size, location and time period. The period from 1969 till 1978 can be seen as a restrictive period (Al-Kasim, 2006). The main reason for tight administrative control was that Norway would not otherwise be able to exert the desired level of control on the development of its petroleum resources, particularly if the activity levels were to accelerate without a well-planned strategy. To be precise, Norway has a long-term interest in its oil and gas resources.

A link was laid between licensing and revenues. The only realistic way of regulating the tempo of petroleum operations was by regulating the speed of potential block allocations to oil companies. The mind-set behind this approach was that once blocks are allocated and provide resources, economic incentives would dictate putting the fields on stream, both from the company and governmental (treasury) perspective. Additionally, the Norwegian economy would only be able to absorb a set amount of production and subsequent revenues before the economy and social framework would suffer. However, the decision to focus on production turned out to have a negative impact.

In hindsight, it could be argued that production levels would be dictated after allocation and licensing, and furthermore that production ramp up periods could take more than 15 years to get oil and gas on line. In 1982, a government committee was appointed to oversee the tempo of petroleum activities. It proposed "the petroleum fund"[111] which created a cushion between oil and gas revenues and the national economy, which would be able to absorb uncontrolled oil and gas income and stop it from entering the Norwegian economy. The government's intervention regarding

[110] The Storting decides on the opening of new areas of the NCS to petroleum activity, and the government awards licences.
[111] (NBIM, 2016)

tempo regulation changed from production to investment. Storting[112] report No.46. said,

> An investment level of 25 BN Nok can be too high when viewed against the desired development in the rest of the Norwegian economy. The government will continue to evaluate the question of how high the investment in the petroleum sector should be (NPD, 2003, p. 15).

In the Storting report 56 of 1987-1988 [113] the government once more explained the need for levelling out investments as part of a national effort towards economic recovery. The proposition once more reiterated that if the operators' plans were to be followed without modifications, all fields would be developed in the course of two-three years. This would in turn bring the annual investment level up to 35-40 Million Nok (Al-Kasim, 2006). Realising that such high investment levels could not be sustained in the years to come, the government decided to prioritise marginal fields[114]. Essentially this resulted in developing gas fields in the North Sea, the Norwegian Sea and Barents Sea if and when an opening occurred in the gas market. It was established through the 10 commandments (NPD, 2010a) that gas should be exploited as a product, but marketing and selling proved challenging.

Regulating Gas Sales

Before 1973[115] licensees were free to negotiate terms for the sale of associated gas from the fields e.g., the Petronord Group for the Frigg field negotiated terms and sold gas directly to BG in the United Kingdom. The

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[112] "Storting Report/White papers (Meld.St.) are drawn up when the Government wishes to present matters to the Storting that do not require a decision. White papers tend to be in the form of a report to the Storting on the work carried out in a particular field and future policy". (Regjeringen.no, 2017)

[113] The petroleum law of 1985 would be altered one more time in 1996

[114] Fields that needed to be developed within the lifetime of the existing infrastructure

[115] In the early 1970s, each gas field was sold as one by the respective owners ("depletion" or "field" contracts from Ekofisk and Frigg) (Austvik., 2010) Depletion contracts are contracts which cover the entire contents of specified fields.

negotiation of gas sales proved be an important factor. There was no contractual requirement in the licensing that identified the need for gas sales. The royal decree of 1972 made a change to this practice and ruled that all oil and gas should 1) land on Norwegian soil and 2), require approval from the government setting the foundation for the controlling of gas sales in Norway. Furthermore Statoil, when it was established owning 50% shares of the licenses negotiated the sale of gas from 1973 till 1978. This approach proved effective in the negotiations for Statfjord, Heimdal and Ekofisk and resulted in the construction of the Statpipe I gas pipeline. As was set out in the "Ten Commandments" above the State oil company Statoil now controlled 50% of license shares and looked after the government's commercial interests and cash flow which became considerable following the oil shock in 1979.

It was argued that Statoil's political power became too large because of the government's power. It was thus decided in 1984 to reduce Statoil's power by "clipping its wings[116]" through the establishment of the State Direct Financial Interest (SDFI). The SDFI, established in 1985, was to control 80% of Statoil's shares in licenses, leaving Statoil[117] with 20%. A peculiar part of this arrangement was that Statoil negotiated the SDFI share (Stern, 2017c). Another action to further reduce Statoil's power was the establishment of several committees.

The combination of gas sales and building infrastructure underscored the Norwegian government decision to coordinate development further through the appointment of the Trunk line committee in 1977, tasked with the future development of pipelines on the NCS. In 1983, the ministry of oil and energy appointed the "gas committee" in order to coordinate all gas activities. This was considered necessary to optimise investments in the pipeline infrastructure in addition to flexibility in field

[116] For a detailed discussion see (Austvik, 2011) and Willoch in (The Economist, 1987)

[117] With the privatisation of Statoil in 2001 the SDFI went to Petoro, Statoil arranged the negotiations for the transaction.

development in a timely manner. In order to expand expertise in negotiations the GFU, Gas Negotiations Committee was established in 1986 (Stortinget, 1986). The GFU, initially set up to handle gas produced by the three Norwegian gas companies Statoil, Norsk Hydro and Saga was later transformed into the national GFU in 1987. The objectives of the latter were to secure field-neutral gas sale contracts allowing the government room to coordinate gas off-take in addition to optimal field development it already planned. Different types of gas sales contracts[118] were developed e.g. depletion contracts and delivery contracts, delivery contracts being the dominant type. The government established the GFU and promoted differentiated contract models to support a robust market position against the off-take market[119] in Europe, where a few large buyers dominated the buying market. As Haase (2008) described it in terms of transaction cost theory "hierarchy (vertical integration) captured potential risks related to information asymmetry, or behavioural uncertainty for instance by trading parties". Offshore gas transmission systems are subject to significant upfront investments, ergo it made sense to minimise risk through long term delivery contracts and reduce the risk of underutilisation of the transmission system. This concept was not newly invented and applied in Norway. The principles were first applied by the Nederlandse Aardolie Maatschappij (NAM) after the discovery the Slochteren gas field when the Dutch government had to renegotiate gas delivery terms. The concept was applied throughout Europe in the oil and gas industry. The contracts would contain one or more of the following criteria:

[118] MPE approves all commercial deals, pursuant to paragraph 19 of the Decree and designates contract volumes to individual fields. MPE's designating activities are called allocation of field and transmission system development and assignment of gas sales contracts to contractual field or supply fields. A contractual field is assigned the contractual responsibility for the gas deliveries to the customers, while the actual physical gas supplies may be assigned to other fields called the supply fields. (Dahl 2001)

[119] Big transmission companies on the Continent (such as Ruhrgas, Gasunie, and Gaz de France) collaborated as buyers ("the consortium"). (Austvik, 2010)

- Long-term: 20-30 years' contracts, matching the duration of investments.
- Take-or-pay: the buyer has to pay for a certain amount of gas each year regardless of whether he uses it or not in that year.
- Market-value principle: price of gas was linked to the price of the alternative fuels for that customer. This was added to the long-term contracts after the first oil crisis,
- Netback price: transportation costs were subtracted from the price the producer received. Destination clauses in some supply contracts assured that gas would flow to the destined market.
- Price review clauses (typically 3-year reviews): were introduced in the mid-1980s to ensure that the contract price always represented the market value (Talus, 2011).

The IOCs and buyers had mixed thoughts about this approach. IOCs were concerned about the pecking order. The IOC's position that was set both for field production and gas sales ahead of actual field development required decisions on which field should benefit from the export quotas obtained and on what terms. This could mean that it was not necessarily an IOC field that would get preference above a national oil companies' field.

The time critical resources (e.g. Associated gas) would still need infrastructures to end up on the market and the investment required to develop these resources[120] would be uneconomically high as stand-alone. Cost had become a major issue. Whilst in the seventies and early eighties infrastructure development focus had been on human and technological capabilities to install such pipelines.[121] Gas prices couple to low oil prices ($26/barrel to $9/barrel in the period ending in 1985 (BP, 2016) required cost containment, innovation and infrastructure optimisation.

[120] marginal resources were first mentioned in the NPD's annual report for 1983 (NPD, 1984)
[121] Norwegian trench, experimental saturation diving to 701 meters.

As a countermeasure to the rising unit cost of development there was emphasis on the optimal utilisation of existing infrastructure for new projects as a way of reducing new investments. It was however realised that by tying in production from several sources through few installations the vulnerability of the economy to accidents and unforeseeable events would increase. Against the backdrop of the smaller sizes of new discoveries, new concerns arose regarding the cost levels associated with development and thus the economic viability of these smaller discoveries. The authorities were therefore evaluating the merits and drawbacks of such joint utilisation of facilities from an overall national point of view (Al-Kasim, 2006).

Whereas the marketing of Statfjord gas in the late seventies was in a seller's market and the British Gas Consortium (BGC) and the continental consortium competed for the gas, the market in the mid-eighties was a buyer's market and Norway had to make an effort to sell gas to continental Europe (Stern, 1990). Thus far BGC sold Frigg gas to the United Kingdom through the Frigg pipeline and Philips marketed Valhall gas through its Ekofisk buyers. An attempt to sell gas from the Sleipner field to the United Kingdom was aborted by the United Kingdom government[122] in 1985 after the conclusion of negotiations between Statoil and BGC and the Department of Energy (DOE). It was not until gas from the Troll field was sold to European buyers based on a long-term contract (1986) which provided the option to sell associated gas from other fields, that marginal field development came into play. This was done with some considerable risk for the government, in addition to a reduction of 40% of the price[123]of the Statfjord gas (EU, 1988). It took the geopolitical[124] unrest between East and West involving the US embargo of Russian gas and its subsequent inclination towards Norway for Norway to become the preferred supplier of

[122] For a detailed discussion see (Stern, 1986; Austvik, 2010; Stern, 2002; Stern, 2004)
[123] For a detailed discussion see (Stern, 2002)
[124] For further details about this conflict see (Jentleson, 1986) and (Austvik, 1991)

gas to Europe. To draw even more control over the complete value chain to itself (and to some extent away from Statoil) the MPE established a Supply Committee (FU) in 1993, consisting of NOCs and IOCs to evaluate individual fields and subsequently which company/companies should supply gas from the field. In this manner, the FU was able to optimise resource development, and apply economies of scale and scope in a timely matter. The FU, GFU SDFI and Statoil all under control of the MPE represented the NGF and were the national policy instruments making it possible to achieve lower costs through economies of scope, and better resource management and strengthened the market position for Norwegian gas production and its sale (Austvik, 2011). In sum, the structure in which the NGF operated facilitated control which included timely investments in the infrastructure.

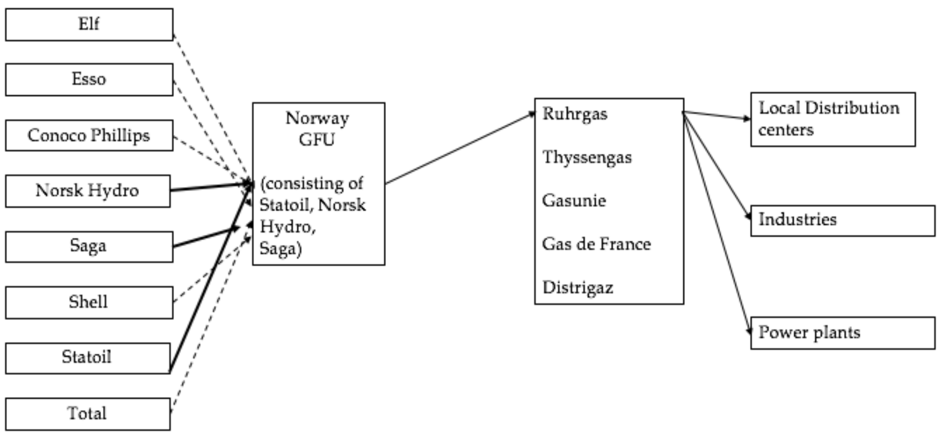

Figure 9 Organisation of sales in the GFU period
Source: Adapted from Austvik (2011)

Buyers had security of supply but depended on a sole seller through a Statoil-led committee. Furthermore, the GFU had options to partner in other ventures as well, including with Wingas and the Netra pipeline in addition to upstream and midstream ventures. Statoil-Norsk Hydro started to venture into downstream activities in Germany. When the GFU declined to sell gas to Wingas[125] this was not received well and ended up as a court case with the European Union. The GFU's intention was to maintain its position at the expense of Saga petroleum. The Wingas business, although not the only one, highlighted the frustration with the monopolistic character of the gas suppliers and transporters (Radetzki, 1999). There was an apparent need for European Member States to develop a common approach to energy price formation and the EU laid down general principles to be observed by each Member State in its energy pricing policies (EU (83/230/EEC), 1983) and ensure optimum use of the transmission networks and greater regularity in supplies during the year through further integration of the European gas grid. (EU, 1988). This further supported the liberalisation[126]process of the European Gas Market and would affect the MPE-GFU-FU system for producing, shipping and selling natural gas.

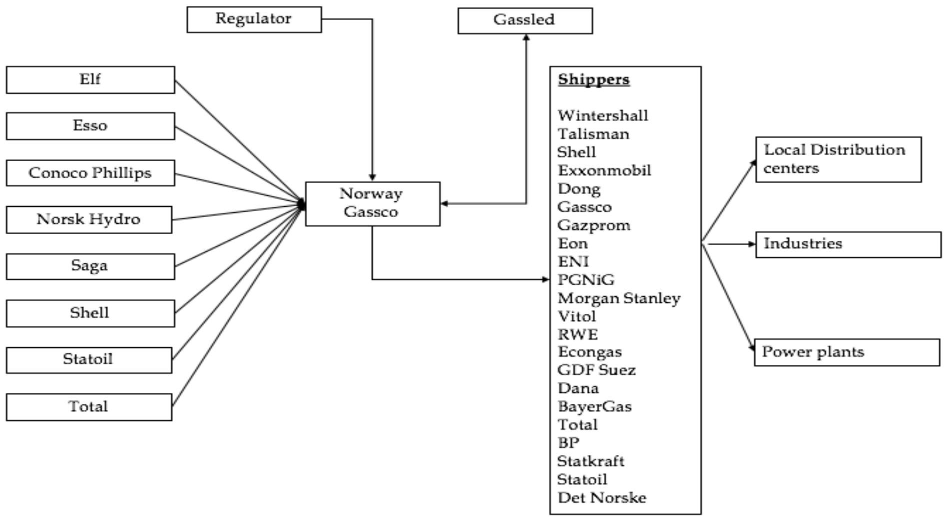

Figure 10 Gassco-Gassled Sales construction
Source: Adapted from Austvik (2011)

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[125] BASF complaint over high gas prices and competitiveness in the region. For further discussion, see (Radetzki, 1999; Claes, 2002; Eikland, 2004)

[126] "The term liberalization is used to describe the process that is currently underway in the European gas market. As noted by deregulation may remove restrictions on competition, but it may also remove regulation (which does not necessarily enhance competition). Liberalization, to the contrary, is used here to describe measures aimed only at "opening up for competition," or for "removal of restrictions on competition." (Dahl, 2001, p.33)

As described in Chapter 1 The change of operator-ownership from GFU-SDFI to Gassco-Gassled took place in 2002, with Gassco the 100% state owned operator and Gassled a joint venture owning the majority of the gas infrastructure on the Norwegian Continental Shelf i.e. pipelines, platforms, onshore process facilities and receiving terminals abroad. Gassled is the owner and the official decision-making body for the gas transmission system and subsequent budgeting. It could thus be argued that Gassled functions as a principal and Gassco as the agent. However, that would not do the situation justice considering that Gassco's role is more than that of operator.

Efficient utilisation of existing infrastructure is an important aspect of the Norwegian regulatory framework. Gassled is obliged to allow for TPA, providing opportunities for smaller discoveries, which would otherwise not be financial viable to carry the full weight of offshore pipeline investments. To support the efficient utilisation of the offshore transmission system, the costs of using other parties' facilities should be reasonable. "It has therefore been an important principle to ensure that as much as possible of the profit from petroleum production is taken out on the fields, and that it does not fall to the infrastructure owners" (Regjeringen, 2017c). The framework allows the owners of the system an acceptable return on investment but does not allow the owners to set tariffs.

Gassco is responsible for the architectural role of the transmission system and thus for advising Gassled how and where to invest. However, who will Gassco ultimately report to? The State? Gassled? Petoro? Other issues have been raised, for instance, "has an operator without ownership in Gassled the right incentives to ensure an efficient low-cost development and operation?" (Rekdahl, 2004). Objections to Gassco from the industry suggest that the company might have an incentive to expand the infrastructure (Løvås, 2011). As a state regulated monopoly, which by definition should not maximize its own profits or shareholder value, Gassco's management may have incentives to increase its own influence which is possibly within the regulations, but Gassco has no direct financial interest in Gassled and is not affected by any Averch-Johnson effect e.g., gold plating.

Several projects and studies have been initiated and or executed by Gassco that are not necessarily a direct requirement for its function. E.g., the Skanled pipeline (Gassco, 2007), Skogn (Gassco, 2005) and Kårstø's Co_2 capture system (Gassco, 2009) which were politically driven and not with focus on Gassled's interest. As set out in the Gassco (2016) annual report, bonus incentives and performance systems for personnel could be interpreted as ambiguous if there is a clear connection between the individual employee's efforts and success criteria bonus. On the other side, no punishment for failure is applied, leaving a risk prone situation open to managerial decision making.

Gassco does not have the same incentives[127] that shippers have i.e., wanting the lowest possible transport tariffs. It is natural to imagine that Gassco's foremost consideration is to avoid disruption and the unpleasant attention it brings to users, Gassled owners and authorities. The bonus system gives incentives in the same direction (Løvås, 2011). The question then is whether Gassco may have similar incentives to over-invest as financial owners can have and wish for "the robust" construction. Users' objections to increased tariffs can have little impact in such a trade-off.

4.3. REVENUE AND CASH FLOW

To offset the cost of installing and operating a transmission system, revenues must be made at least equal to this cost. Investments in infrastructure are perceived as lower risk[128] due to the long-life span of a project, frequently involving government and regulation. Transmission

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[127] On the question should there be incentives for the principal agent:
No: (Fama, 1980) Forces of reputation on managerial labour market enough to motivate manager to work hard, assumes managerial labour market works well
Yes: (Wolfson, 1985) Forces of reputation help to motivate manager, but incentive contract still needed, suggests that managerial labour markets do not work fully well.

[128] For a discussion on different preferences towards risk (e.g., aversion/neutral/loving) (Pindyck & Rubinfeld, 2012)

system owners are driven by a Return on Equity (ROE), a Return on Capital Employed (ROCE) or a Return on Assets (ROA). The transport systems established in the seventies were based on different return requirements. Tariffs were based on the risk associated with the investments, for example in Statpipe. Since it had to cross the Norwegian trench (the first transmission system to do so), there was additional risk, resulting in a higher rate of return of 10%. For the following offshore pipeline Zeepipe, the Ministry assumed that a return of 7% was sufficient (Regjeringen, 2017c).

Depending on the size of the return, investing in a transmission system becomes more or less attractive. Before 2010 transmission system owners on the NCS were also producers and would earn a return on investments through the resources (oil, gas, condensate) as well as the shipping of the resources. Gassled as owner of the transmission system is dependent on the tariffs as a return on investment. This Section sets out the function of the tariffs and how it translates into revenue.

When E&P companies had a stake in the transport system the IOCs' had the key advantage of distributing their own gas first with competitive pricing. With the installation of an independent operator (Gassco) transportation was separated from the owners (Gassled). Gassco takes care of transportation, capacity allocation and administration, whilst the MPE sets the tariffs[129] for gas transport through the transmission system. Inter alia, the MPE's control over the tariff is to ensure that profits are taken from the production segment rather than the transmission of the gas.

> The tariffs provide the owners with reasonable returns while also preventing additional profits from being taken out in pipelines and treatment facilities (Regjeringen, 2017c, p. 85)

[129]For 2017 tariffs: (Gassco, 2017a2)

Furthermore, the tariff ensures a rate of return for all shareholders, proportional to stakes in Gassled. In order to determine the rate of return, the tariff structure is explained. The tariff is calculated as the capital invested during the construction of the infrastructure *K* plus the investment cost per unit described as *I/Q* added to a factor to be able to expand the transmission system *U* resulting in:

K-Element

In order to provide a return on capital employed, the K element is based on throughput of gas over the pipeline's life. More throughput equals a lower K. The invested capital (CAPEX), plus a 7%[130] in return is calculated as a cost per unit, NOK/Sm^3 to make up the return to investors.

O-Element

Operational cost (OPEX) as discussed in Section 5.3 consists inter alia of maintenance and running cost. The cost element is fixed per area. Once the sum exceeds the upper limit the cost is carried on to the I-Element.

Area	Upper limit O element
A&B	40MM Nok x E
C	250MM Nok x E
D	200MM Nok x E
E	250MM Nok x E
F	40MM Nok x E
G	40MM Nok x E
BN	40MM Nok x E
I	40MM Nok x E

Table 4-2 Gassco AS investments in the O-Element
Source: Lovdata (2016)

[130] The reduction in 7% pre-tax return will be discussed below

I-Element

Investment on the transmission system that exceeds the limits of table 5-4. Differences between O and I element are pay-back periods. O-element is payed back the same booking year whilst the I-Element will be spread out over several years. Furthermore, the I-Element includes a 7% rate of return from the K-Element.

U-Element

Although the U-Element has never been applied, the function is to cover the cost of expanding the transmission system and cover engineering, production and installation cost.

E-Element

Escalating factor (E), The scaling factor for each year is determined on the basis of the Norwegian consumer price index published by Statistics Norway[131]. This results in the following formula:

$$t = \left(K + \frac{I}{Q} + U\right) * E + \frac{O}{Q}$$

Tariff Calculation NCS. Source: Gassco, 2017

Taxation

The petroleum taxation system is based on the Petroleum Taxation Act of 13 June 1975 No. 35. Due to sizeable returns on oil and gas production, O&G companies are subject to an additional special tax. In 2017 the "Ordinary" company tax rate is 24 %, and the "Special" tax rate is 54 % resulting in a marginal tax rate of 78 %. In 2016 the taxation rates were 25 % and 53 %. An additional feature is introduced to safeguard normal returns

[131] The ratio of the last index published before 1 January of the same year and the corresponding index as of 1 January 2002 (77.9). If the ratio is less than 1.0, E is set equal to 1.0. (Lovdata, 2016)

from the special tax. This comes in the form of a deduction called uplift. In 2016 the total uplift[132] was 22 %.

Operating Income (norm prices) -/-	
	OPEX
	Linear depreciation of Investments (6 years)
	Exploitation expenses, R&D and decommissioning
	Environmental taxes and area fees
	Net financial cost
	Corporation tax base (24%)
	Uplift (5.4% of investment for 4 years)
	Special tax base (54%)
= Net operating profit after tax	

Table 4-3 Tax break down
Source: adapted from (MPE, 2017)

"The petroleum taxation system is intended to be neutral, so that an investment project that is profitable for an investor before tax is also profitable after tax" (Norskpetroleum, 2017f). The purpose of this approach is to optimise revenues from natural resources and accompanied services and encourage companies to invest in commercial projects on the NCS. This is in line with allowing offshore pipeline owners reasonable returns while also preventing additional profits from being taken out in pipelines and treatment facilities (Regjeringen, 2017c). Furthermore, the approach supports resource recovery on the NCS.

With these objectives, the taxation system only taxes net profits and allows losses to be carried over to the following period with interest. The other benefit of this approach is the upside it provides for investment-based tax deductions. With such incentives, the Norwegian government has the

[132] 5.4 per year for 4 years = 21,6 % starting with the investment year

possibility, to a certain extent, to steer investments to exploration or e.g., transmission.

An example is the reimbursement system for exploration cost. The government's focus in the years 2016 and 2017 has been on E&P, in particular the Barents Sea, through licensing. With the reimbursement system for exploration costs new O&G companies are encouraged to invest in E&P projects as a financially attractive option considering the carried forward principle if the wells are dry. Furthermore, it is not uncommon to have lead times up to 15 years before production of a field is actually started and revenues are coming in. Carrying forward losses all these years is financially challenging for the companies (Norskpetroleum, 2017f). The reimbursement system therefore supports companies investing and paying tax in accordance with earnings. Companies that are making a loss may choose to request an immediate refund of the tax value of exploration costs from the taxation authorities or carry losses forward to a later year when the company has a taxable income e.g., when it does strike gas. If a company chooses the immediate payment option, the exploration costs cannot be deducted from income in later tax assessments (Norskpetroleum, 2017f).

Risks Associated with infrastructure investments

Cash flows from Norwegian sector projects are mostly in NOK, so that international investors face additional risks. Ehlers (2014) suggests hedging long-term currency risks is not feasible, international financing often comes in foreign currencies. Although this may present a significant risk for investors, for the purpose of this research it will not be taken into consideration, just as currency devaluation could be beneficial to an exporting country and not for the seller, as has been the case in Russia (Mitrova, 2017)

4.4. INFRASTRUCTURE DEVELOPMENT PROCESSES

With the change in ownership and control from Statoil and the GFU to the 2017 position of Statoil, Petoro, Gassco and Gassled, investment incentives and strategies have changed. Each participant plays a role in the development process leading to an investment. To determine roles, responsibilities and potential conflicts in investment decisions in transmission systems on the NCS, the roles will be further discussed. As operator of the transmission system Gassco has several responsibilities and roles (Gassco, 2017c).

1) Special operatorship, e.g., system operation, capacity administration and infrastructure development. The tasks are regulated in accordance with the Norwegian Petroleum Activities Act. This can be divided into three main sections:

- Capacity allocation
- System operation
- Development of the transport system

2) Normal operatorship consists of technical operations of the transmission system and processing and receiving terminals on behalf of the owners Gassled. This operatorship is agreed upon through the terms and conditions (T&C) set out in the "T&C for transportation of gas in Gassled (Gassco, 2015).

> The Operator[133] is Gassled's representative under the Transportation Agreement. The Operator will conduct all operations in the Transportation System and, on behalf of Gassled, provide the Transportation Services and execute all Gassled's rights and obligations under the Transportation Agreement". (Gassco, 2016)

[133] Where "Operator" means Gassco AS or its successor as determined by the Ministry

Framework conditions for Gassco are determined by the government in the Norwegian Petroleum Activities Act. From the Government side Gassco's activities are regulated by the Petroleum regulations (Regjeringen.no, 2016b). Gassco's relationships with the Gassled joint venture provides the relationship with oil and gas companies. They are regulated by the Act and also by the operator agreement with the Gassled joint venture (Regjeringen.no, 2015).

Gassco's task is to coordinate the processes for further development of the upstream gas transport network, and to assess the need for further development. In the context of this research it has the responsibility to develop and advise on efficient and effective exploration and/or investments to contribute to optimal management of the natural resources. Gassco's web-site indicates:

> Gassco is responsible for initiating and coordinating development processes for the gas pipeline network and related facilities (process plants and receiving terminals). It makes its own assessments and recommendations for infrastructure development (Gassco, 2016)

The licensee and the permit to develop a field/transmission system

Project undertakings such as field development and infrastructure building are cost- and time line-driven. An efficient permit approval process reduces the time taken to start generating revenue streams to pay debt and shareholders, and it reduces financial cost. An approved permit is a key component for actually releasing funds to a project. To explore the requirements, an insight into the development process will be provided. Excerpts from the NPD "A plan for development and operation of a petroleum deposit (PDO) and plan for installation and operation of facilities for transport and utilisation of petroleum (PIO)" will be discussed (NPD, 2010b).

Starting with the licensee i.e., the Oil & Gas company drilling for gas and having the intention to market the natural resources, distinctions can be made between a PDO and PIO. For simplification[134] the PDO will consist of the exploration phase, test production, plugging and abandonment of the well, and the PIO the installation of e.g., a modular construction to facilitate production and transport including transmission system. One interesting fact remains, that one does not have to be a licensee for a PIO, however must be for a PDO (NPD, 2010b). "If a licensee decides to develop a petroleum deposit, the licensee shall submit to the Ministry for approval a plan for development and operation (PDO) of the petroleum deposit" as per section 18 of the Guidelines for plan for development (NPD, 2010b). Furthermore, the PDO shall include "Information on the destination of the pipeline, route, dimension and transportation capacity, as well as the criteria for the choices that have been made". The submitted approval shall have undergone an impact assessment, inter alia identifying risks with the routing and transport of natural resources. Even if a PIO is, or will be submitted the transportation information shall be submitted (NPD, 2010b). The application shall be forwarded to the Ministry of Energy and Petroleum, Petroleum Safety Authority, NPD and Ministry of Labour. The MPE may decide that a licence to install and operate facilities shall be subject to conditions with regard to, inter alia:

1) The ownership of the facility;
2) The landing point of the pipeline;
3) The routing, dimension and capacity of the pipeline (NPD, 2015c).

The latter is then further detailed in "Contents of a plan to install and operate facilities". Highlighting the relevant issues in relation to transmission systems, an overlap of one issue seems apparent, the licensee is required to provide detailed analysis regarding inter alia, the transmission system's route and capacity in the PDO and the PIO. Gassco receives a copy

[134] (NPD, 2010) provides detailed specification of the requirements for PDO and PIO

of the PIO in addition, is responsible for making an assessment on infrastructure development and provide recommendations directly to the MPE. The multifunctional role of Gassco further encompasses the responsibility of the further development of the upstream gas pipeline network (and associated facilities) lies with the operator, based on the licensee's need for additional capacity (NPD, 2015c). This appears contradicting to the earlier sections in which the licensee was required to provide transport capacity and routing of the license. Figure 11 depicts the processes and participants involved in the infrastructure development process.

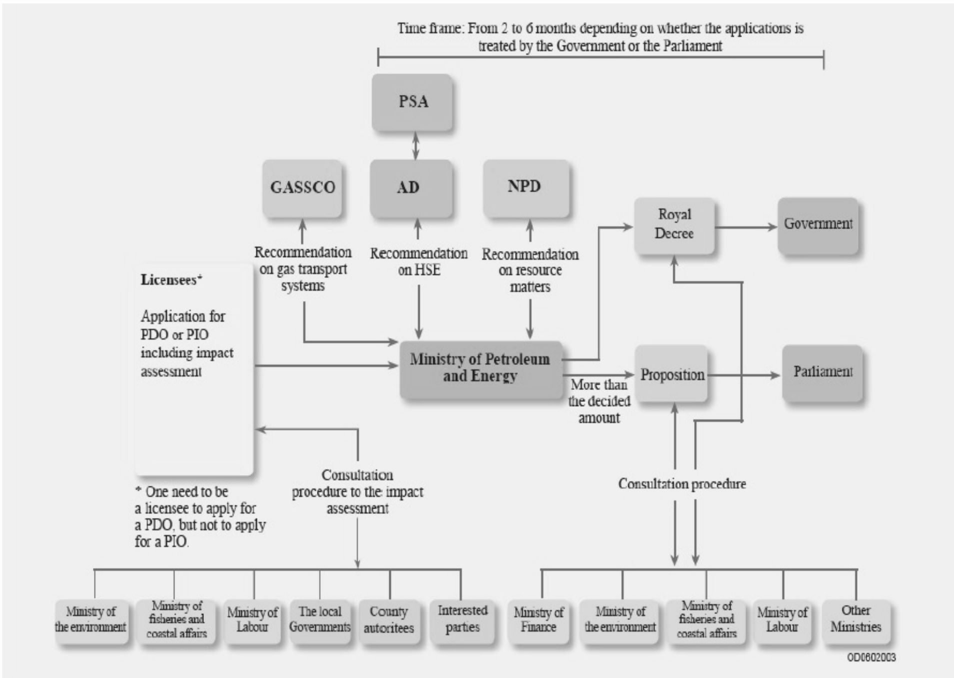

Figure 11 Procedures for development and Operation
Source: NPD(2010b)

The time required for the authorities to process a PDO or PIO is between two and six months. For example, the Aasta Hansteen PDO was submitted to the Norwegian Authorities in December 2012 and approved in June 2013. Process time depends in part on whether the matter must be submitted to the Storting as depicted in figure 10. The Storting must consider developments with an investment ceiling that exceeds a predetermined amount as stipulated in connection with the Storting's annual budget deliberations (NPD, 2010b). Permitting processes pose a potential risk to the timely completion and the cost of projects. This has an impact on the financing of projects, especially in the case of project finance via a separate project company (EC DG for Energy, 2011).

Financing proficiencies for investment

Development of a new transmission system or extending one is part of Gassco's responsibilities on behalf of the Government. The planning is initiated by the Oil and Gas companies through a PDO and PIO, indicating the volumetric needs, route and landing of the pipeline and connection to a facility e.g. Karmøy or Nyhamna. Engineering, procuring and constructing transmission systems are capital intensive projects and require large investments.

To which extent financing needs and financial challenges exist in a Norwegian context depends on various factors. If the transmission system is financed by Oil & Gas companies as part of the field development, and providing TPA is applicable, the transmission system could be integrated into Gassled[135]. Furthermore, a financial healthy O&G company or a financial Transmission System Owner will have the benefit of lower cost funding for the investment in the Norwegian infrastructure.

Credit ratings play a significant part in the potential of financial capabilities. Some of the owners of Gassled have credit ratings[136] allocated by one or more agencies for example S&P, Fitch and Moody's.

Company	Moody's	S&P	Finch
Dong	Baa1	-	BBB+
Petoro	n. a	n. a	n. a

[135] Separate arrangements are made for exceptional pipelines e.g., Grane and Heidrun pipeline are operated my Statoil.

[136] A comprehensive list of credit rating values is depicted in the Appendix.

Statoil	Aa3	A+
RWE	Baa3	BBB-
Norsea	n. a	n. a
Silex (Allianz)	Aa3	AA
Solveig	Pa3	
Njord		BB-

Table 4-4 Gassled JV Credit Ratings
Source: Moody's, S&P, Reuters, 2017

Gassco as a TSO does not have a credit rating. In the case of state ownership or significant ownership, the country's rating could serve as an indication of the TSO's rating. Norway has an excellent credit rating despite challenges of significantly lower prices for natural resources in the period 2008-2017. According to Moody's framework for assessment, Norway has the highest possible institutional strength AAA, compared to e.g., Russia which received BBB- after cutting interest rates. In addition, Moody's described Norway's fiscal strength very high even compared to peer AAA rated countries and marked Norway with a (+) due to a strong balance sheet with significant net assets (Moody's, 2017).

Investments in pipelines and subsea installations on the NCS

Following the oil price collapse in 2008 O&G companies reduced investment spending and increased a strong focus on cost cutting. Regardless of these actions the companies increased leverage[137]. Whilst debt cost increased initially, the availability and cost of bond financing has improved (IEA, 2017b). The development of the subsea infrastructure saw its peak in 2014. The delayed decline in investments can partially be explained by the lifecycle of the execution of ongoing projects (backlog). One PDO was approved by the authorities in 2016 for the development of

[137] Leverage describes the relation of debt to equity on a balance sheet. This is influenced by regulatory frameworks and the TSO's commitment to keeping a certain credit rating and thus leverage.

Oseberg West Flank and in 2017 four fields have been approved in Utgard, Byrding, Dvalin, and Trestakk, however only Dvalin is a gas field (Norskpetroleum, 2017b). Figure 12 provides historical financial investments versus the forecast in BN NOK.

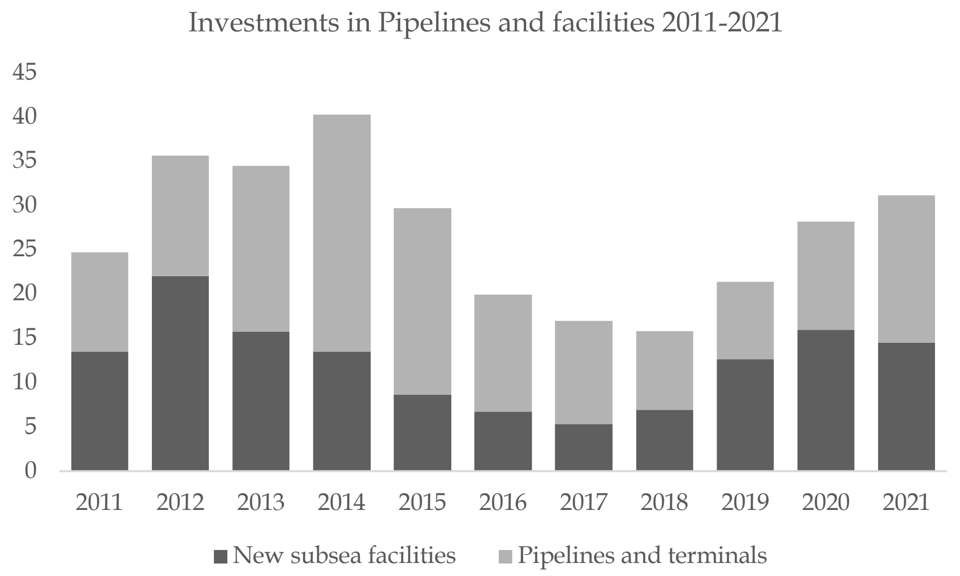

Figure 12 Investments in pipelines and facilities on the NCS
Source: NPD, 2017b

Development of the infrastructure in the light of Sustainability

Sustainability can be seen from several perspectives, customer, producer and/or public perspective. What both customer and producer have in common are two criteria related to sustainability. To be able, in this particular case, to maintain the price and/or volume of gas at a level which contributes to a sustainable energy future for Europe.

The Ministry of Petroleum and Energy (MPE) states that 2/3 of the resources remaining on the NCS accumulate to 4 Tcm, that natural gas production is levelling out, and that the production outlook remains stable and Norway remains “a supplier for the Future” (Lien, 2015). A quantitative descriptive study is needed to investigate how the required volumes and infrastructure can be sustained and potentially expanded based on regulations, prices and cost. Maintaining Norway’s position as a reliable supplier of natural gas to Europe will be further discussed in Chapter 6.

All these factors appear a challenge, considering the variables and dynamics that come into play. Furthermore, in the light of incomplete information this works two ways, to the European customers and to the network owners in relation to the tariff reduction.

The principal responsibility of the Ministry of Petroleum and Energy is to achieve a coordinated and integrated energy policy. A primary objective is to ensure high value creation through efficient and environment-friendly management of Norway’s energy resources (Regjeringen.no, 2016b).

The NCS has mature and frontier provinces which require effective resource management to maintain sustainable development of natural gas as a fuel. For greenfield developments in frontier areas this would involve new infrastructure, whilst in the mature Brownfield provinces this would necessitate a minimum tie-in to existing infrastructure, the former being more prone to risk than the latter. Depending on the definition of proved natural gas reserves based on volumes, cost and price, Norway as a producer potentially has to take a higher risk based on incomplete information and invest in infrastructure for long term customer demand whilst regulations might have a significant influence on the role of gas in the future (Inderst, 2010). Furthermore, the lifespan of the actual assets depends on the returns of the commodity. The volume of gas which could be profitably produced and delivered to its customers at different prices will be further discussed in Chapter 6 and 7.

Environmental regulation

With COP21 commitments and reduction of CO^2 high on the agenda, sustainability additionally relates to the public good “a clean environment now and in the future”. Environmental regulation is recognised and that this may result move away from fossil fuels might be an option, or that gas could function as a bridging fuel or that renewable energy sources will become the sole supplier of energy or that a combination may speed up the transfer and leave assets and resources stranded. However, sustainability related to the environment is too broad and out of the scope of this research.

4.5. CONCLUSION

With the implementation of the European Union gas directives several principles in the Norwegian regulation changed. It could be argued that the Gas Directives were "forced" upon Norway through competition laws and TPA. At the beginning of 2001 the organisation and regulation of the offshore NCS gas transmission system moved from a collection of individual networks owned by field licensees to ownership by Gassled and operation of a TPA system by Gassco.

However, considering that in the Ministry's view, it was not an expedient transport policy in the long term to let all fields have their own transmission systems (Regjeringen, 2017c), the Norwegian state chose to ensure that it has stronger regulatory powers for the petroleum activities than for other mainland economic activity, reasoning that its main interest is to recover the natural resources allowing companies to make profit from the field rather than the transmission system (Regjeringen, 2017c). The government allowed the transmission system owners a return of 7% pre-tax on investments made in the transmission system, which has changed from pipelines owned and operated by (NOC) oil & gas majors to a low cost common transmission system. The transformation of ownership to Gassled and operation to Gassco required compromises between profits on investment e.g., upside tariffs, social welfare through increased resource recovery[138] thus a low tariff for gas transport.

The implementation of EU directives provided a setting which opened a discussion about whether, despite best efforts and intentions, regulators may not be using the optimal mechanism to achieve public

[138] Moving away from profit on infrastructure and focus on wellhead recovery (Chapter 3)

interest goals. The regulation might not have the desired effect and may thus cause more cost directly, through the "independent" agent's service and indirectly by not resulting in an improved service or price for the public interest. Furthermore, political factors managed by stakeholders play a role in the introduction of the regulation and how it is implemented by the authorities. The direct cost incurred by the authorities through its regulations may not benefit the distortion in the market in relation to the indirect cost associated with the regulated, monopoly, commodity or price.

Observations of interest on infrastructure development

To provide an insight, the Norwegian infrastructure development system will be divided into four main stakeholders for explanatory purposes.

1) Gassco, the operator responsible for investments in the transmission system
2) The government, responsible for social welfare and maximising returns on natural resources
3) Oil & Gas companies, i.e. licensees, who either require a PDO or a PIO to market the discovered natural resources and need to provide a transportation plan.
4) Gassled, the infrastructure owners.

Besides the overlap of licensee (O&G companies) and Gassco providing supporting material for a PDO to the Government and Gassco, several other factors are highlighted. Gassco is a 100% government-owned non-profit organisation. In this capacity Gassco should aim for long term social welfare from a governmental perspective, additionally it should maximise returns to satisfy shareholders needs i.e., Gassled owners. Briefly returning to the principle-agent theory[139], where for example purposes

[139] See Section 2.4 Principal-Agent

Gassled and Gassco were identified as agents for the Government considering Petoro's interest in Gassled including Norsea Gas is ~47% (Petoro, 2017) and Statoil 5% bearing in mind that Statoil is 67% government owned. As discussed, multiple agencies (Gassco, Gassled, Petoro) continuously interacting with principals, MPE, NPD, Ministry of Finance, whilst Governmental institutions are normally multitasked with multiple principals. As a result, outcomes remain suboptimal because the principal imposes multiple constraints and conflicting interests (Gailmard, 2009). According to the definition, principals should be of equal power; there is no requirement regarding relative power of principals (Shaton, 2014). Gassco could thus be regarded as a common agent for two principals, Gassled and the Government. Furthermore, the majority share of Gassled is government owned, leaving a minority share of private investors.

Based on these findings a judgement can be made regarding the specific Norwegian offshore pipeline cost characteristics and regulations which are most important for Barents Sea decision makers. Theoretically and empirically sunk costs have been a significant factor in the development of the gas infrastructure as a monopoly. To regulate effectively the regulator needs data about demand, investment, management, financing, productivity, reliability and safety. It was recognised that an offshore pipeline system with significant additional spare capacity could result in a monopoly position compared to smaller discoveries that are not financially viable to justify their own transport. Time critical resources (e.g. associated gas) would still need infrastructures to reach the market and the investment required to develop these resources[140] would be uneconomically high as stand-alone. Cost is a major issue and has played a significant role throughout Norway's activity in the petroleum sector on the NCS, highlighted in the 1990s with the establishment of NORSOK[141]. Allowing

[140] Marginal resources were first mentioned in the NPD's annual report for 1983

[141] The purpose of NORSOK was to cut the number of company- specific requirements and to reduce time and costs for development and operation (Norskoljeoggass, 2016). That high cost still contributes to

TPA to existing facilities means that minor discoveries can also be profitable, assuming reasonable tariffs and that profit does not fall to the infrastructure owners. Thus, Gassled as transmission system owner of a monopoly has several factors that could result in imperfect competition. Reasoning from a perfect competitive market, potentially the freedom of entry and exit of the transmission system allows for direct imperfection. Furthermore, cross subsidisation and incomplete information are potential factors that would allow Gassled as transmission system owner to add additional cost resulting in an increased imperfect market.

Norwegian gas development will be further explained in Chapter 6 and 7.

5. Norway's role in the Natural Gas Market

5.1. INTRODUCTION

Chapter 3 explored the principles of the energy policies of the European Union, Norway's biggest customer. 98% of Norway's natural gas ends up in Europe and the major share of this amount of 115BCM is transported through offshore pipelines. Europe's energy demand is an important factor in Norway's supply of gas through its offshore pipeline system. Potential further investment in Norwegian natural gas and the Barents Sea Gas infrastructure in particular, are influenced by externalities such as price, climate policies, supply and demand. These variables are influenced by a wider network than the European Union alone. This Chapter will explore variables affecting the role of natural gas in the market worldwide and how these factors might affect Norwegian gas sales and transport.

Chapter 5 provides insights on changes in the natural gas market and the challenges it faces with the low gas price that has set the scene from 2014 to 2017. Section 5.1 discusses energy production in Europe, the reduced domestic production in Great Britain, the Netherlands and Denmark and externally Algeria's, Norway's and Russia's role in it. Section 5.2 discusses the European desire to become less dependent on Russia as a provider of gas, the geo-political consequences of a Nord Stream 2, and gas as a transition fuel. In addition, the use of gas instead of coal to compensate for the intermittency of wind and solar power have failed to gain acceptance from a variety of environmental, energy and political stakeholders (Stern, 2017b). The global oversupply of LNG (2017) which is expected to last between 2020 and 2025 (Corbeau & Ledesma, 2016), the wave of LNG which is coming on line between 2015 and 2020 and the influences it has on the global gas market and prices is described in Section 5.2. The demand side is then discussed in Section 5.3 in addition, are increasing demand from China, India and Southeast Asia still realistic or does it present uncertainties in terms of growth due to price sensitivity (Corbeau & Ledesma, 2016; Rodgers, 2016). Section 5.4 looks at future projections of Norway’s role. The Chapter concludes with Section 5.5 and provides insights relating to market and price uncertainties.

EU Energy consumption

Long term European projections suggest that energy consumption will be declining until 2040 where it plateaus as depicted in Figure 12 (EU, 2016). Within this mix of different energy sources oil will still be playing a significant role, as it is linked to transportation. Furthermore, solid fuels will see a significant reduction whilst nuclear energy and gas maintain a stable segment of the energy mix.

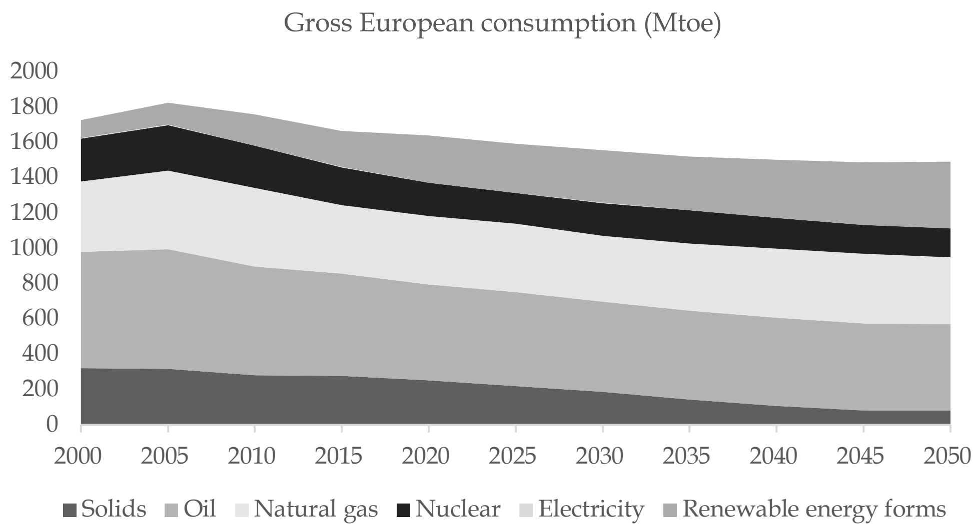

Figure 13 EU28 Gross European Consumption.
Source, Primes EU, 2016

When focussing on natural gas as a source of energy transported through Norway's offshore transport system different scenarios appear. The IEA scenario forecast for natural gas demand[142] in 2020 is 434 Mtoe, falling to 402 Mtoe in 2030 and to 381 Mtoe by 2040. In comparison, the EU 2050 forecast indicates 381[143] Mtoe for both periods.

	2020-2030	2030-2040
EU 2050	381	381
IEA	402 (from 434)	381 (from 402)

Table 5-1 Forecast gas demand

The IEA scenario and the European Union forecast arguably display a similar gas demand in the period 2030-2040. Ex-post 2040 projections would strongly depend on the extent of aggressive decarbonisation policies. Stern (2017a) states "In order to retain its place in European energy balances these policies will require the gas industry to make significant progress towards decarbonisation".

EU Energy production and import

European domestic fossil fuel energy production is declining, and this trend will have its biggest impact in the fossil fuel energies as depicted in Figure 14. The United Kingdom and the Netherlands North Sea regions are at the end of the lifecycle and some fields are already depleted. In addition, the Dutch province of Groningen[144] is suffering from earth tremors caused by gas recovery which are forcing the government to reduce

[142] For an in-depth analysis of the IEA scenarios see (Stern, 2017)
[143] Averages for the periods 2020 to 2030 and 2030 to 2040 are 381.1 Mtoe and 381.53 Mtoe.
[144] For more detailed discussion on the impact of earthquakes caused by gas extraction in the Province of Groningen, The Netherlands read (van der Voort, 2014)

production drastically. The decline is anticipated to be offset by an increase in Dutch renewable energy production, with solar and wind gradually increasing from around 17% in 2015 to 36% in 2050 (EU, 2016). This decline will not only have consequences for the Dutch gas market where 98% of consumers are connected to the distribution system, but also for Belgium where Dutch L-gas is the main source of supply.

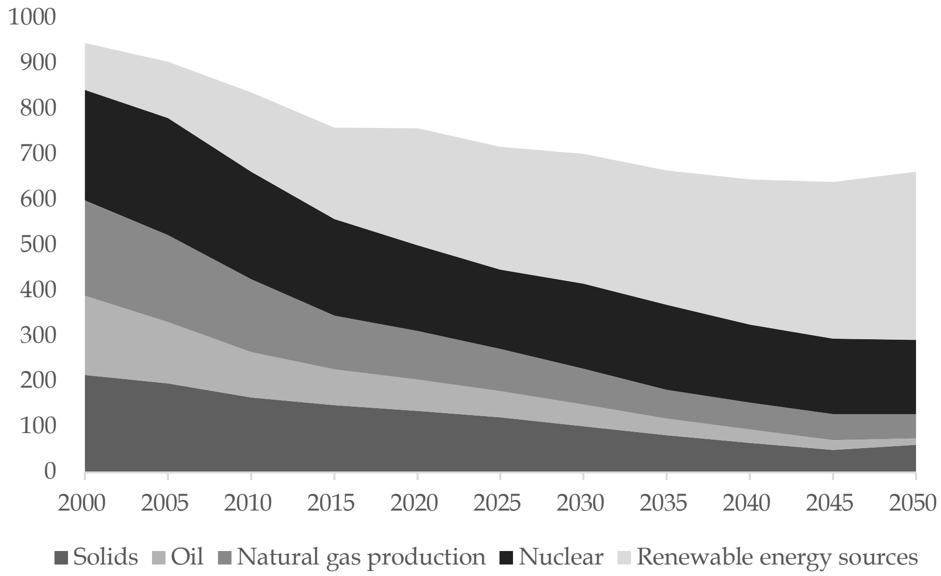

Figure 14 EU Energy production (Mtoe)
Source, Primes EU, 2016

Reduction in output from Groningen requires changes in the treatment of N-gas on each system. Additionally, the North-western European network as a whole uses Dutch gas as buffer supply for winter surges. The continuing reduction of production from Groningen will have an impact on security of supply (Honoré, 2017).

Despite the anticipated offset of renewables, the EU will continue to be dependent on imports of gas - the consumption of gas is expected to be 387 Mtoe in 2020, whilst in the decade 2020 to 2030 it is assumed to drop only to 371Mtoe. To cover this difference gas imports are anticipated to rise from 278 Mtoe in 2010 to 332 Mtoe in 2050 as depicted in figure 14 (EU, 2016).

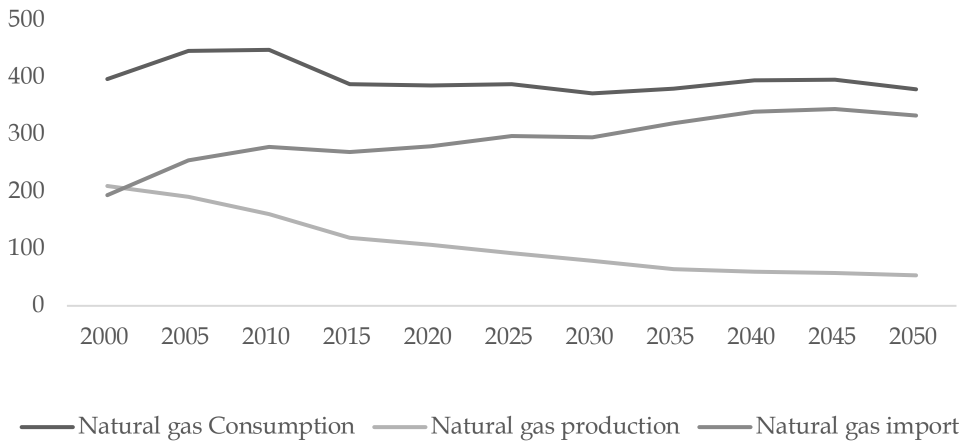

Figure 15 Gas - production, net imports and demand
Source: primes EU, 2016

The gap between natural gas production and import is filled with LNG and gas imported through pipelines.

5.2. EXTERNAL SUPPLIERS OF GAS

The three main sources of pipeline gas to Europe are Russia, Norway and Algeria, in addition to LNG. According to the European Commission's second quarter report of 2017, EU gas imports were 8% higher than in 2016. The growth was driven by increasing flows from Russia. Ukraine remained the main supply route for Russian gas coming to the EU covering 43% of extra-EU imports (EU, 2017b).

Norway has been seen as a stable and key supplier of (33%) of external European Union natural gas imports (Lien, 2015). Despite reductions in the export of gas due to planned maintenance activities in some fields and processing plants, gas flows from Norway increased by 5% year-on-year in the second quarter of 2017. Norway has been exporting around 115BCM per year and projections remain around 115-116BCM up to 2021 (Norskpetroleum, 2016a)

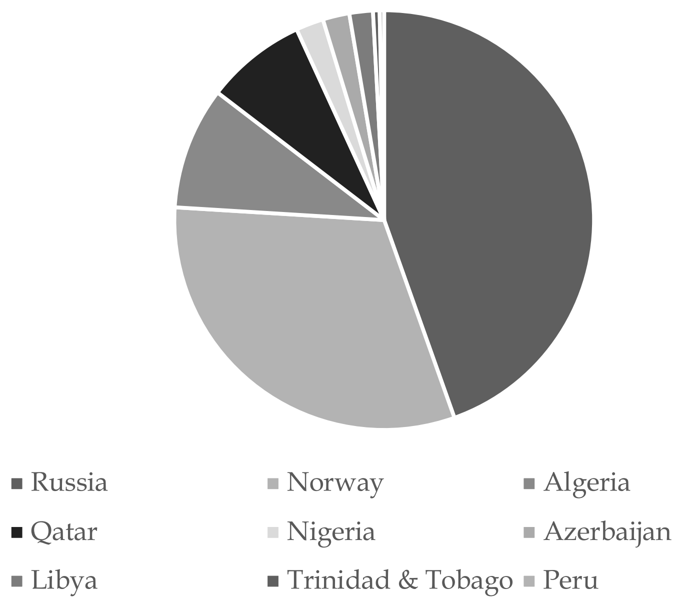

Figure 16 EU natural gas import in Twh.
Source: BP statistical review 2016

Algeria[145]as third largest exporter to the EU has shown flexibility regarding oil indexed pricing, however the country's main problem concerns capacity. It is not able to maintain export levels due to upstream issues and lack of investment (Stern, 2017c). Pipeline imports have fallen compared to the same period in 2016 (EU, 2017b).

All three countries deliver gas through pipelines[146] and due to the economies of scale as set out in Chapter 2 lean towards a regulated monopoly supplier. The relationship between piped gas and security of supply has been a topic of much interest in the media, e.g., the Southern Corridor, Nord Stream 1 and Nord Stream 2. The strategies involved in investment, in new routes and ownership have been described as "pipeline wars" and provide a picture of natural gas as a "highly politicised commodity" (Franza, 2016).

[145] Algeria approx. 9bcm (LNG) and 20.7 BCM (piped), Russia 159.8 bcm piped, Norway 109.5bcm piped (BP, 2016)
[146] Algeria is also an LNG Exporter

Europe's dependence on natural gas is divided. Certain countries rely more on Russia as supplier of natural gas than others[147]. The overall European dependence will not change before 2020-2025 for several reasons. The first is the long term contractual agreements for 115 bcm/year up to the early 2020s falling to 65 bcm/year by 2030 (Dickel, 2014). The second reason is that replacing Russian gas in the period up to 2030 with domestic sources would require an increase in production, which is unlikely to come from the United Kingdom and other domestic producers. External pipeline delivery other than from Russia, e.g., from Algeria and Norway and the Southern corridor, are not capable of capturing Russia's 55 bcm/year share (Nord stream 2 capacity). This is before taking into consideration the competitive pricing advantage Russia has with other pipelines and LNG (Henderson & Mitrova, 2015). LNG is struggling to compete with Russian and Norwegian pipeline supplies, leading to a decrease of LNG imports (EU, 2017b).

LNG Supply Wave

Pipeline trade still accounts for the majority of global gas supplies, yet LNG has secured 33% of the global gas trade and its share has been increasing. LNG made rapid gains in the late 1990s and 2000s, however its share has stabilized around 10% since 2010: in 2014 LNG accounted for 9.8% of global gas consumption. Still, LNG retains the highest growth rate of the gas supply sources, expanding by an average 6.6%/year since 2000 with a drop to 2.2% between 2010 and 2014. Europe has over 200bcm of LNG receiving terminal capacity, with utilisation rates reaching an average of only 25% in 2015, suggesting that a significant amount of LNG could be absorbed if it became available (IGU, 2016).

[147] "Countries in the Baltic region and south- eastern Europe which are more dependent on Russian gas, and hence vulnerable to interruptions" (Dickel, 2014)

It could thus be argued that LNG could contribute as a potentially flexible source of natural gas supply to the EU (Corbeau&Yermakov, 2016). There are several factors that support this statement. One is the oversupply of natural gas on the market, which is anticipated to reach a peak around 2020. Spot and short-term[148] LNG trade is expected to continue rising, potentially reaching 45% of global LNG trade by 2020 (Corbeau&Yermakov, 2016).

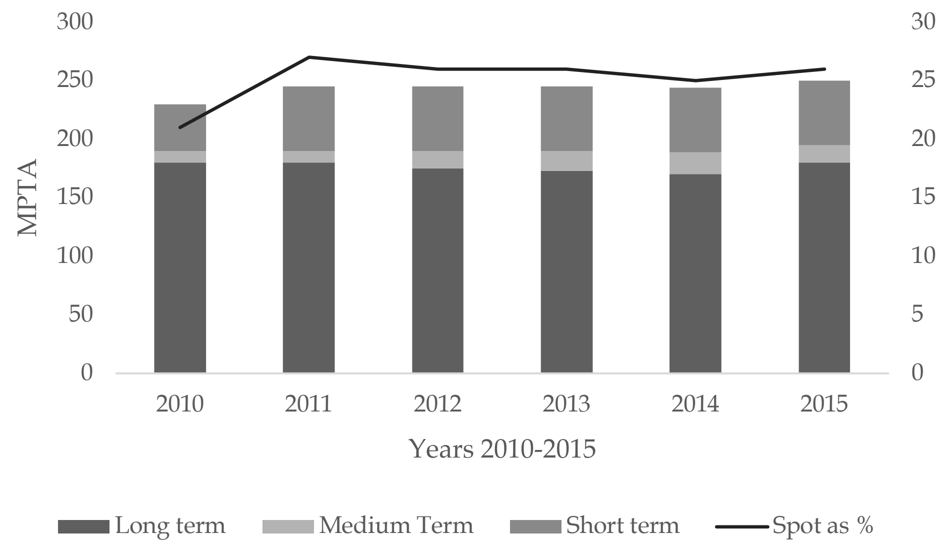

Figure 17 Short, medium, long- term LNG trade 2010-2014
Source: IGU, 2016

Two, the decline in European LNG consumption which occurred during 2011 ended with 2015 imports rising by 4.6 MT as supply was redirected away from weaker Asian markets and the Asian-NBP[149] price differentials narrowed significantly. "All but one European importer (France) registered a YoY gain in 2015, (with the UK showing the third-largest gain overall at 1.3 MT), causing the region to have the highest global YOY growth" (IGU, 2016). Absent of premium paying Asian customers,

[148] Short-term LNG means contracts of less than four years (Corbeau & Ledesma, 2016)

[149] The UK National Balancing Point, (NBP) is a virtual trading location for the sale, purchase and exchange of natural gas.

LNG seemed to end up in the European market (Corbeau&Yermakov, 2016; Corbeau&Ledesma, 2016). A significant increase in LNG export capacity came into the market in 2009-2010 as well as some minor (=<10bcm) projects in the years from 2011-2013 which would have balanced the market out according to the IEA (2015). After a massive capacity increase in 2009 and 2010, few additions followed between 2011 and 2013. The average annual capacity increase was less than 10 bcm, with just one or two projects added each year (IEA, 2016b). These low volumes would have gradually helped rebalance the LNG market following the supply glut of 2009/10, but the unexpected surge in Japan's LNG demand in the aftermath of the Fukushima Daiichi nuclear accident in 2011 vastly accelerated that process, tilting the market from balance to tightness. In 2014 capacity was ramped up with new projects.

Country	Project	Capacity in bcm	Completion date
Australia	Wheatstone	12.1	2016-17
Australia	Prelude FLNG	4.9	2017
Australia	Ichthys	11.4	2017-18
Russia	Yamal LNG	22.4	2017
Malaysia	PFLNG 2	2.1	2018
United States	Cove Point LNG	7.1	2018
United States	Cameron LNG	16.3	2018-19
United States	Freeport LNG	18	2018-19

Table 5-2 LNG projects 2017-2020
Source: IEA, 2015

The gas market in 2017 does not invite investment in new LNG projects. As displayed in table 5-1, LNG capacity remains firm for the years up to 2020. Absent strong demand, oversupply and projects awaiting to come online, new investment decisions for LNG projects would require strong financial benefits for approval. Corbeau&Ledesma (2016) argue it would be unlikely that project sponsors would trust financial derivatives to hedge project risk and move ahead without sufficient long- term contracts. Furthermore, the 45% increase in export capacity between 2015-2021 is based on investment decisions already made before 2014. These projects where signed off under long-term contracts whilst the market currently tends to favour short term and spot price contracts. “A growing spot market with sufficient liquidity will force contract terms to adapt to provide the flexibility desired by buyers including the end of destination clauses and competitive LNG pricing structures” (Corbeau&Yermakov, 2016).

One of the largest contributors to the LNG oversupply is the United States. Up until 2008 its LNG imports were expected to increase for decades to come, however the increase in the recovery of shale gas in combination with the 2008 economic crisis turned it from a net gas importer to an LNG exporter (IEA, 2017).

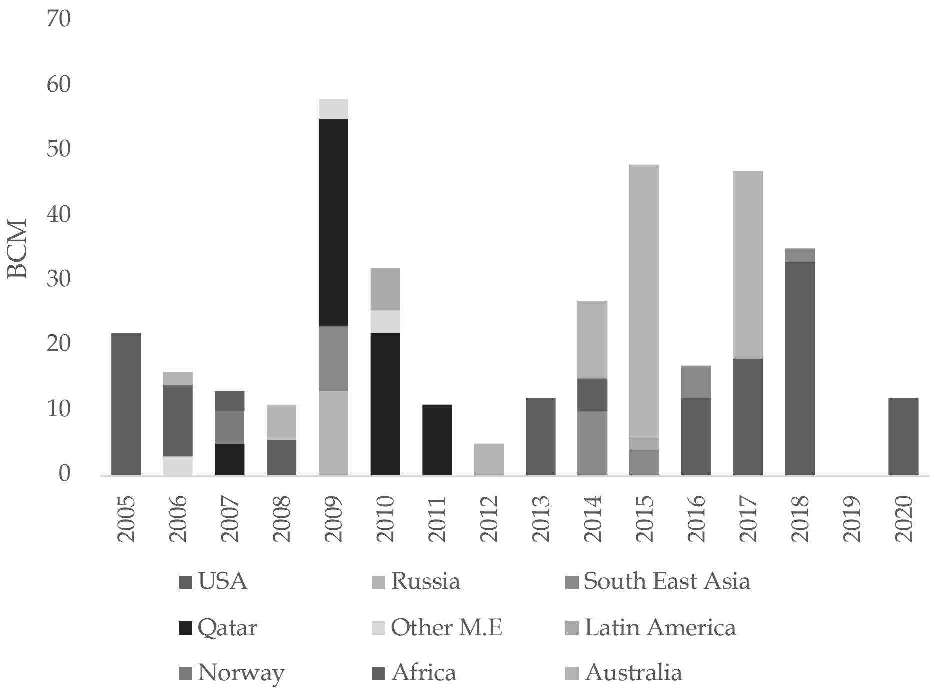

Figure 18 Additional LNG capacity 2005-2020
Source: IEA, 2015

While LNG projects with long lead times were still being built, the spare LNG capacity, predominantly from Qatar and aimed for the United States, entered the global market leading to the “gas glut”. Because of this oversupply gas spot prices dropped. Demand uncertainty and liberalisation in Asia increasingly exposed LNG importers to risks in deregulated markets, making importers and consumers more reluctant to commit to long-term contracts/volumes. The reduction in demand and change in long-term contract volume resulted inter alia in a higher volume of uncommitted[150] LNG with fragile demand and prices around $6.27/MMbtu[151] (Corbeau&Yermakov, 2016). United States production growth is anticipated to be relatively flat during 2017. Despite low oil and gas prices the United States shale industry appears resilient. Supported by data from table 5-1 global LNG export is expected to increase by 45% between 2015 and 2021, of which 90% will be delivered from the United States and Australia with Australia predicted to become the number one supplier in 2018 (Corbeau & Ledesma, 2016). Based on the data available it is highly likely that Europe will receive a significant amount of LNG between 2020 and 2025. However, after this period LNG availability becomes much more uncertain (Stern, 2017).

5.3. ASIA AND THE ROLE OF THE USA

It would be too broad and complex for this research to depict each country and its natural gas balance. The essence of this Chapter is to provide an oversight of how global supply and demand affect Norway’s supply to Europe. Several general judgements will be made on the demand side. Natural gas consumption growth is likely to be dominated by Asia, a reduction in demand is anticipated to be seen in the United States. Europe’s

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[150] Another factor that adds to the oversupply are destination clauses for over contracted LNG
[151] (Ycharts, 2017)

demand is anticipated to stagnate. The Asian and United States markets will be further drawn upon to provide a general overview of developments.

Asia, and in particular China, is anticipated to maintain a positive demand for gas in line with its Strategic Energy Action Plan[152] (2014-2020) and its national 13th Five Year Plan (2016). Japan (113.4 bcm) and South Korea (43 bcm) follow as the largest importers of LNG in 2016 (BP, 2016). Furthermore, the enormous increase (~20%) in natural gas demand in China in 2017 should be taken into consideration if this demand trend continues (Rodgers, 2016).

The United States are anticipated to change role from importer to exporter. The shale gas production on one hand and the steady increase of gas consumption worldwide on the other, provides opportunities to export substantial volumes of natural gas. As indicated in table 5-1 there is an increasing LNG supply wave as a result of new projects coming on line. It is anticipated that a vast majority of US natural gas production will be shipped to Asia as LNG.

As depicted in Figure 18 and discussed previously, shipping natural gas to Asia provides a higher return. In the period 2011 to 2014 gas prices reached the highest level recorded in Asia and were at a prolonged high level in Europe. If Asian LNG prices remain higher than European prices, after allowing for the transport cost and insurance, the effect of global LNG supply on Europe will be one of more dependency on exogenous pipeline gas from Russia.

[152](Stats.gov.cn,2016; Stats.gov.cn, 2017)

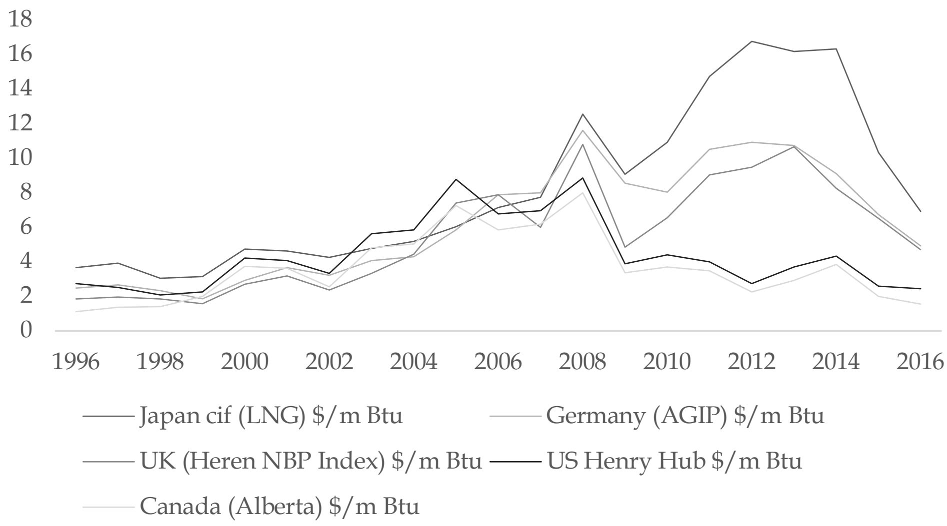

Figure 19 Natural gas prices across five regions
Source: BP, 2016

Global change in demand for gas?

Global fossil fuel demand[153] has been slowly growing by 1%/year in 2014 and 2015. Natural gas has a market share of 24% (oil 33%, coal 29%). Emerging countries were responsible for this growth with China being the largest with 1.5%, China's slowest growth in 20 years. Reduced fossil fuel demand, energy efficiency and intensity have resulted in a reduction in global gas demand from a 10-year average of 2.2% to 1%. (IEA, 2016b) The IEA predicts natural gas demand to be 3.9 trillion cubic metres increasing at an average annual rate of 1.5%, equivalent to an incremental 340 bcm between 2015 and 2021. This will contribute to a marginal growth of natural gas use in the total energy mix. Despite low gas prices it is difficult for gas to compete with low coal prices and favoured/subsidized renewables. The oversupply of natural gas on the market will thus not be absorbed in the 2020-2025 period unless a significant supply disruption occurs.

[153] Based on data from (BP, 2016; IEA, 2015; IEA, 2016; IEA, 2017)

Inter-fuel competition and complementarities

Another relevant factor affecting the global gas market is the relative prices of different sources of fuel. The interaction of fuel prices in inter-fuel competition will be briefly discussed in light of the effects of Norwegian gas consumption in the European Union.

Although coal is recognised as one of the more polluting fossil fuels, coal will remain a competitive fuel source unless political and or environmental intervention redirects incentives otherwise, e.g., through carbon taxes.

From 2014 to the beginning of 2017 weakened economies and low oil prices (~$114 to ~$50 a barrel) have contributed to a lower gas price and as depicted in Figure 18 a merger of regional prices closing the spread significantly. Saturated gas markets supported by new American and Australian projects coming online, are most likely to keep gas prices relatively low due to volumes of "flexible" LNG. This gas oversupply is estimated to be present during 2020-2025. Ex-post 2025 demand might increase, and gas prices rise (Corbeau & Ledesma, 2016).

Lower gas prices are more competitive and promote a switch from coal. In a similar way, a rise in oil prices might have a positive effect on consumption of gas, which is cheaper than oil. This spread between the prices between the fuel types might accelerate the reduction of the gas glut. LNG contracts in Asia are predominantly oil price indexed with occasional short-term contracts. Saturated markets could support a change to other contract forms than long term contracting. As the IEA (2016) suggests "As spot prices remain under pressure, buyers will search for better pricing and non-pricing terms from sellers". Furthermore, it is anticipated that oil markets will recover before natural gas markets, and that natural gas will likely be based more on hub pricing and move away from oil exposure in long-term contracts.

Inter-fuel competition varies across sectors, e.g., the power sector has different incentives than the residential sector. Competition also varies widely across regions making it complex to provide a concise summary. The power sector is the larger consumer and will be the centre of focus. Within the European market inter-fuel competition is inter alia dependent on availability of domestic resources and policies. Based on COP21 agreements it could be argued that power sectors currently running on lignite and coal might become affected by policies, moving away from CO_2 high coal, to gas and renewables. To what extent gas will be used as a bridging fuel for renewables in the coal-gas-renewables-nuclear configuration remains uncertain. Oil fired power generation is small scale in Europe and considering the cost of oil, gas may become favourable. At present renewable energy is in favour with many European governments and provides financial incentives e.g., the Netherlands, Germany, Denmark. Other factors that could influence choice of energy sources are the development cost of building new power plants or upgrading plants and switching cost between fuels.

Although natural gas prices have come down from the 2008-2014 high and prices across the five main regions have come closer together as depicted in Figure 18, this high price period might have done long-term damage. Large European countries e.g. Germany have moved away from gas and towards cheaper coal and renewables. Notably the exchange of renewables-coal for gas offset an intrinsic part of carbon reduction incentives. Despite dropping gas prices demand growth has been absent, suggesting factors other than pricing might have a larger influence. The IEA (2015) described the combination of cheap coal and continued policy support for renewables as factors supporting weak gas demand. Moreover, gas prices in 2014 and 2015 in the IEA (2015) market demand setting did not provide an incentive to switch from coal to gas. In 2016-17 significant growth in European gas demand (albeit from a low base) and considerable switching from coal to gas especially in the UK but also to some extent in Germany have taken place (Stern, 2017c).

5.4. NORWAY’S ROLE OVER THE NEXT TWO DECADES

A significant number of supply and demand predictions are available, including an equal number of software forecasting tools. However, accounting for all (geo-)political, economic and price uncertainties appears near impossible. The 2008 financial crisis followed by the 2014 oil price downturn providing evidence of unexpected events.

However, starting from the principle that Norwegian gas trunk lines operating at 100% utilisation are optimally efficient and have a 100% quality of gas (it is 99.98% now), and assuming that we calculate a gas transmission tariff based on costs, there should be 111 BCM of Norwegian production until 2030 (and possibly beyond). Maintaining these flows beyond 2030 would depend on putting on line new fields with high pipeline construction and operating costs. Nevertheless, Norway will play a crucial role for the foreseeable future (Norsk olje og gass, 2016).

Approaching this question from a TCE perspective, it could be argued that from an environmental perspective 0% could be considered as the best possible quantity of Norwegian production. Additionally, the EU from a Level-1 TCE framework standpoint has a different perception of efficiency related to dynamic demand. Gassled cost characteristics are determined by several cost factors. For the purpose of judgement CAPEX and OPEX will be considered the main contributors and further discussed from an empirical perspective in Chapter 7. However, to provide some insight into the judgement from a theoretical perspective, Norway has to consider the volume of resources it wants to open up to the market and has a substantial influence on the price. The price volatility the market is willing to accept and the price elasticity for each of its customers is a variable environmental uncertainty. Customers also bring behaviour uncertainty. Norway as a supplier of natural gas depends on agreements supporting long term demand, whilst investors in transmission systems are reliant on fixed regulations to allow for an ex-ante determined investment return. The, investors, as agents, would like to avoid a locked-in position and as agent being dependent on the non-opportunistic behaviour of the principal.

It could be argued that the extent to which gas is a political commodity depends on the contractual agreements that need to be put in place. In order to receive an appropriate rate of return on a pipeline infrastructure investment, a long-term contract seems to be the most viable solution. Depending on the speed of policies driving climate change induced transition, several oil & gas assets will not be able to recover the investment cost in the life time of the asset, rendering the assets stranded. The capital involved in stranded assets is complex to value due to the timing of climate policy interventions, macro-economic growth, investor appetite and regulatory incentives. Being boxed-in through a long-term contract, whether or not oil indexed, may appear less appealing when the aim is moving away from fossil fuels and thus looking at LNG for smaller volumes of natural gas supply may proof a solution. Chapter 6 and 7 will explore cost factors and investment returns on gas infrastructures to provide a basis to apply to the Barents Sea Gas infrastructure.

Gas future and decarbonisation

The EU Roadmap to 2050 acknowledges natural gas as a bridging fuel and as supplement to renewable energy sources. The former statement is a similar judgement to that in the 2011 report from the IEA "Are we entering a golden age of gas?" (Birol, 2011) where it seemed that natural gas was determined to become the energy source of choice. "Based on the assumptions of the GAS Scenario, from 2010 gas use will rise by more than 50% and account for over 25% of world energy demand in 2035 – surely a prospect to designate the Golden Age of Gas" (Birol, 2011). But the scenario, as set out in the report missed all of the targets, except in North America where the gas production and demand assumptions were exceeded. Despite the shortfall in predicted gas demand, natural gas still has the potential to play a significant role considering the upside factors identified in the report. Natural gas is the fossil fuel that produces the lowest emissions per unit of energy produced. As suggested by Van der Veen (2015)[154] changing out coal for gas to produce power would support the 2degree Celsius limit, indicating that gas could still play a role in the transition towards a cleaner energy mix. Besides a lower CO_2 content than oil and coal, natural gas reduces poor local air quality when used in power generation, as an industrial fuel and as a transportation fuel. In addition, changing from coal-fired to gas- fired power generation, and using gas to back up intermittent renewable power generation are the quickest and most cost-effective way to reduce carbon emissions (Stern, 2017a). Interestingly, the areas that have increased gas consumption over other resources, appear to provide no evidence that the move has been politically motivated to reduce emissions. In Europe gas, unlike renewables, appears to lack a specific policy support as a fuel. (Franza, 2016). A potential tool, the European Trading Scheme (ETS)[155], to catalyse coal to gas exchange lacks clout to perform as stimulus[156], leaving the industry relying on national measures, e.g. the UK carbon support price which has progressively favoured gas over coal, and emission performance standards (EPS) (Stern, 2017a). Alternatively, thought should be given to the possibility that gas might need to be phased out before newly built infrastructure is amortised leaving stranded investments (Stern, 2017c).

[155] For further reading on the European ETS https://ec.europa.eu/clima/policies/ets_en

[156] "The early phase III of the ETS has seen a significant surplus of allowances, amounting to 2070 Mt in 2014. Due to ETS back-loading and from 2019 the start of the MSR and the continuously decreasing number of available allowances, the surplus is decreasing. The surplus would reach equilibrium levels shortly before 2025 and that the ETS price will follow a slowly increasing trend until 2025 and thereafter." (EU, 2016 p 26)

5.5. CONCLUSION

A global surplus of natural gas will, barring any significant disruption, remain till the period 2020-2025. After this period predictions are uncertain for various reasons. Next to the uncertainty of demand in a decarbonising world is the uncertainty about the cost of fossil fuel relative to low carbon alternatives. Potentially more important than the cost of the fuel source itself, would be the needed future investment in production. The long lead times and capital-intensive nature of the energy sector and power sector require a commercial return on investment and the sector will not invest if assets may be stranded. Operational cost, regulatory requirements, return rates will depend on fuel sources and ultimately on investment decisions. Long term investments require price signals that provide optimal financial efficiency, whether in low carbon technology or renewables. Low oil prices have significantly reduced incentives to invest in new projects.

To see potential trends in energy demand, a "longer" perspective provides a better insight. There are other reasons for looking at a long-term energy demand,

1) offshore pipeline project lead times

2) political and regulatory implications take long to see results

3) COP 21 and decarbonisation programmes have a 2degree Celsius limit over a prolonged period in mind

4) finally, it is the European Union itself that has produced the paper (EU, 2016) and thus makes it more unambiguous than e.g. BP, Total, Shell or Statoil prognoses.

For these reasons, this research looks at the EU future up to 2050 considered in its most recent publication (EU, 2016). For a similar approach this research will look at the whole of Europe considering the increasing interconnection between the countries rather than the end points of the pipelines, e.g., France, UK, Germany and Belgium. From this point of departure several judgements can be made. The European Union scenario recognises a domestic production decline and expects a slow increase in natural gas imports over the period to 2050.

Although renewable energy will take a larger share in the energy mix, natural gas from Norway will play a significant role (EU, 2016). European Union natural gas importers are anticipated to be dependent on Russian and Norwegian pipeline gas supply. The European Union Energy Security package clarifies that natural gas will play a crucial role in the European energy mix until 2030 and beyond (Norsk olje og gass, 2016). In the package gas is considered the cleanest of all fossil fuels and is the bridge between coal and renewables. Additionally, switching from coal to natural gas is an important contribution to the reduction of EU carbon emissions. “For the Norwegian oil and gas industry, this package is a source of optimism and gives us the confidence that we can invest further on the Norwegian shelf, knowing that there will be a market for Norwegian gas for decades to come” (Norsk olje og gass, 2016). Such predictions are in line with Petoro’s (2016) assumptions in which European Union gas market demand is expected to be in line with 2015 in which a high level of Russian gas supply will enter the European market. In addition, LNG from global capacity developments may end up on the European market resulting in dampened gas prices for 2017 and beyond.

As discussed in Section 5.4 the extent and timing of decarbonisation either involving switching from coal to gas or renewables or phasing out fossil fuels entirely is not clear. In addition, technological advances may increase the efficiency of power storage. Much will depend on policies that would support COP21, the following through on NDC commitments under COP21 and recognising natural gas as a bridging fuel because of its low CO_2 content and high efficiency compared to oil and coal.

Chapter **6**

6. Norwegian Sea Gas Infrastructure

6.1. INTRODUCTION

Chapter 1 described the history of the Norwegian Continental Shelf starting with the North Sea Sector. Through its resource management system, the NCS was gradually explored in a northern direction. In order for Norway to maintain its position of supplier of gas to the European Union, without taking into consideration the potential transit to gas as a bridging fuel, Norway needs to discover more resources to avoid a decline in future supply. White paper Meld. St. 28 (2010 - 2011) described Norway's Oil & Gas activities and future strategy (regjeringen.no, 2011). Targets should include improved field recovery rates, maintaining a high level of employment and optimisation of the resource base. Additionally, these targets would support growth in Northern Norway. The emphasis of this strategy was publicised again in 2015 as a response from Norway to a consultation on a European Union strategy for liquefied gas, natural gas and gas storage in 2015.

> Norway supports the EU goal of improved supply security and diversified gas supply sources. A well-functioning, integrated and competitive gas market with a variety of suppliers and buyers is key to enhance gas security and maintain the attraction of natural gas (Aamot, 2015).

Chapter 6 discusses the reserves present on the NCS, how they need to be expanded with additional exploration and discoveries to maintain Norway's position as preferred supplier of natural gas to Europe in Section

6.2. From the data (Gassco, 2014; Gassco, 2016; NPD, 2016d) it can be inferred that the Norwegian Sea and the Barents Sea provide the highest potential for large undiscovered resources. Section 6.3 describes the technical and operational field of the development of the first case, Norwegian Sea Gas Infrastructure (NSGI) project known as Polarled and the challenges it faces. Section 6.4 discusses the investment through a neo-classical theory lens and how it fails to optimise the resource base through a TCE lens. Section 6.5 provides data to add to the discussion of Judgments.

6.2. RESOURCES, RESERVES AND POTENTIAL

Although smaller diameter inter-field, shorter pipelines and tie-ins have been added to the Gassco portfolio (e.g. in 2015 the 22-inch 177km Valemon gas pipeline, Knarr a 12-inch 106km long pipeline and Utsira High a 16-inch 94km long line) no major trunk lines have been built in the North Sea[157] in the last 10 years (Langeled 2007). The last installed trunk-line on the NCS was Polarled located in the Norwegian Sea.

The Norwegian Sea Gas Infrastructure (NSGI) or Polarled, has been built and resembles the Barents Sea Gas Infrastructure (BSGI) which has been reported and investigated as a promising potential for opening up a new gas province. These two sectors, the Norwegian and Barents Sea, with the highest potential will be discussed. Because it is the last transmission system built on the Norwegian Continental Shelf the research starts with the Norwegian Sea Gas Infrastructure. Although it could be argued that the relatively short trunk line has no significant influence on Norway's export capacity to the EU, the system has revealed interesting issues in the light of political dispute, capacity allocation and resource management which might have set a precedent for further investment in transmission systems.

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[157] The next potential investment challenges in the North Sea (2017) are the market consultations of the binding Open Season Procedure for the Baltic Pipe Project. The Baltic Pipe (a potential new gas transmission pipeline) connecting Norway, Denmark and Poland has been identified as a European Project of Common Interest (PCI) which was detailed in Chapter 3. It is unclear if the financing of the tie-in to Europipe II will be included in the financing portfolio.

The resource portfolio on the NCS consists of oil, gas, LNG and condensate. Bearing in mind the financial value of oil compared to gas, it is arguable that oil discoveries influence decision making on gas transport systems. Absence of oil discoveries suggests no potential for associated gas synergies and reduces the incentive for natural gas transmission systems. Alternatively, oil reserves have been discovered but no timetable for transport has been identified. Gassco 2014 excluded oil discoveries such as Johan Castberg (88.10 $MMSm^3$. o. e, FID will be made in 2019), Gotha (14.6 $MMSm^3$ o.e) and Wisting (56.48 $MMSm^3$ o.e) for the latter. The overall resources on the Norwegian Continental Shelf are classed according to the NPD classification system[158] (NPD, 2011). The petroleum resources in Figure 20 show estimated recoverable resources divided into project status categories: historical production (i.e. sold), reserves, contingent resources and undiscovered resources. Sub-categories numbered from 0 to 9 have two potential states, F for First find and A for Additional find.

[158] The appendix depicts the complete table of NPD classes

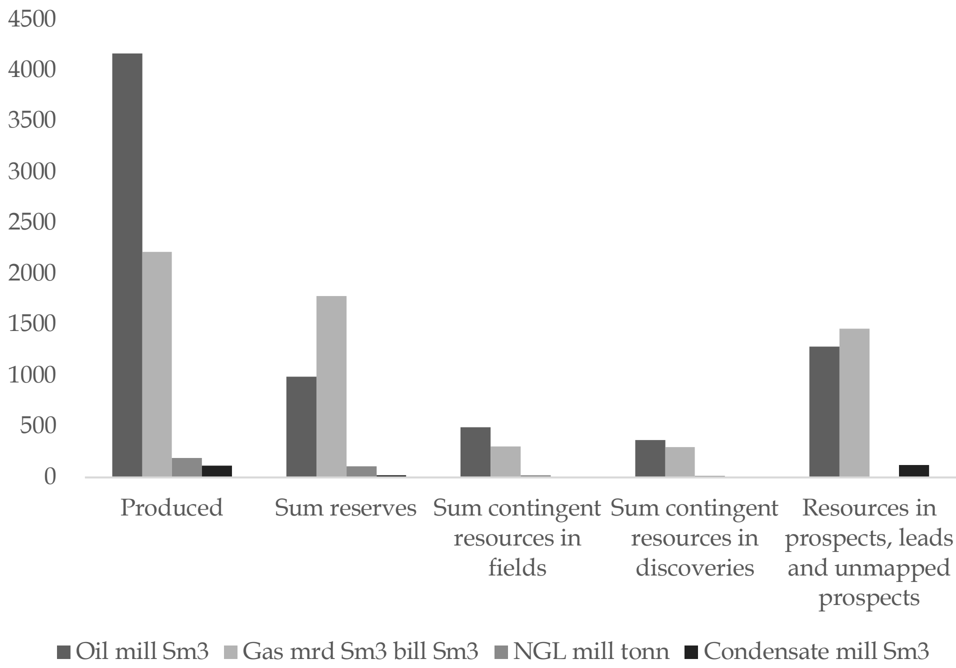

Figure 20 Resource account on the NCS in 2017.
Source: NPD, 2017

Apart from the Norwegian government's system, other resource management systems are available to identify the volumes and classify the resources, for instance the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), the Society of Petroleum Evaluation Engineers (SPEE) and the Society of Exploration Geophysicists (SEG). This Section will focus on the classification system of the NPD.

Reserves

If the volumes of reserves as depicted in Figure 20 are limited to gas only and an assumption is made that the infrastructure will remain operational despite increasing cost per bcm, and that investments will be made to increase capacity within category 3-7, Norway has enough gas to produce at a rate of 114bcm/year for another 16 years [159].

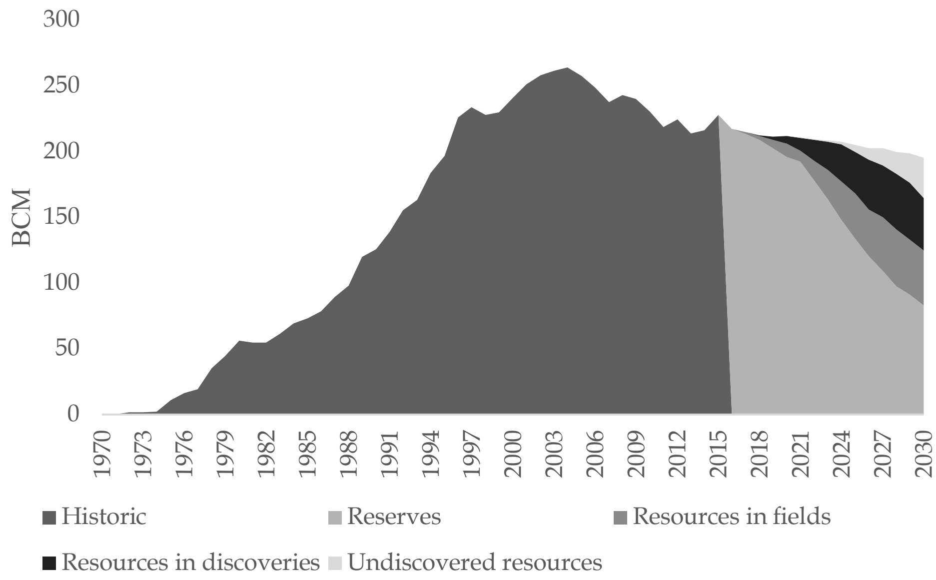

Figure 21 Historical production versus resources.
Source: Adapted from Norskpetroleum, 2017c

If Norway intents to transport natural gas volumes in the period 2017-2021[160] at the same level as in the period 2014-2016 with an average of 114 bcm/year, all reserves would be required to be put on line by 2020. Post 2020 there would be an additional requirement to connect resources in discoveries, whilst post 2024 there would be a need to tap into undiscovered resources as is depicted in Figure 21.

Overall resources have been divided into fuel type and region (North Sea, Norwegian Sea and the Barents Sea), and shown as gas volumes according to the NPD classifications. Figure 22 displays the Discovered and Produced resources, volumes of oil, gas, LNG and Condensate per region. Figure 23 will depict the Undiscovered resources.

[159] Norsk petroleum reserves in cat 1-3 @1762.9 gas in cat 4-7 @163 = 1925.9/114=16.8years. If only allowing for reserves, it is 10 years. Not taking into account increasing short run cost functions per bcm.
[160] The Shelf in 2016 (NPD, 2017, P10)

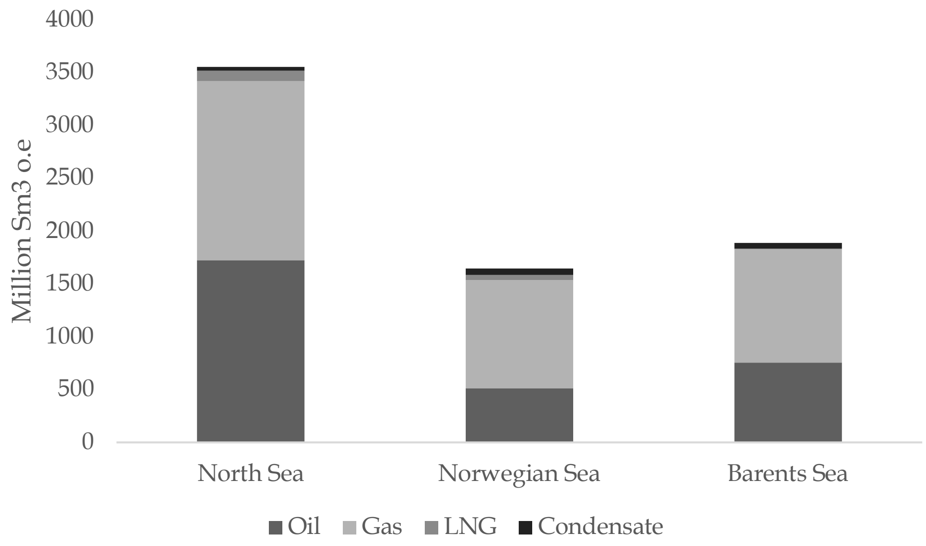

Figure 22 Total resources per region.
Source: Norskpetroleum 2017c

Data from 2017 indicates that the North Sea has the largest discovered amount of resources, approximately divided in half between oil and gas. Of all the resources depicted in Figure 22, 48% (6,863 Sm^3 o.e) has been produced and sold leaving 52% (7,421 Sm^3 o.e) in reserves and resources in prospects (Norskpetroleum, 2017c).

Determining the possibility of finding undiscovered resources depends on several factors e.g., geology, geography and resource distribution across fields. The NPD analyses the variables and characteristics with a play model[161]. The analysis returns outcomes with P95 probability for the low estimate and P5 for the high estimate, indicating a five% probability that the result will be equal to or larger than the P5 value.

[161] "A play model is a geographically and strati-graphically delimited area where a specific set of geological factors exists in order that petroleum may be provable in producible quantities. Such geological factors are reservoir rock, trap, mature source rock and migration paths, and the trap must have been formed before termination of the migration of petroleum. All discoveries and prospects within the same play model are characterised by the specific set of geological factors of the play model. The NPD addresses the uncertainty through a high and low estimate through stochastic calculation modelling based on a set of variables" (NPD, 2016b).

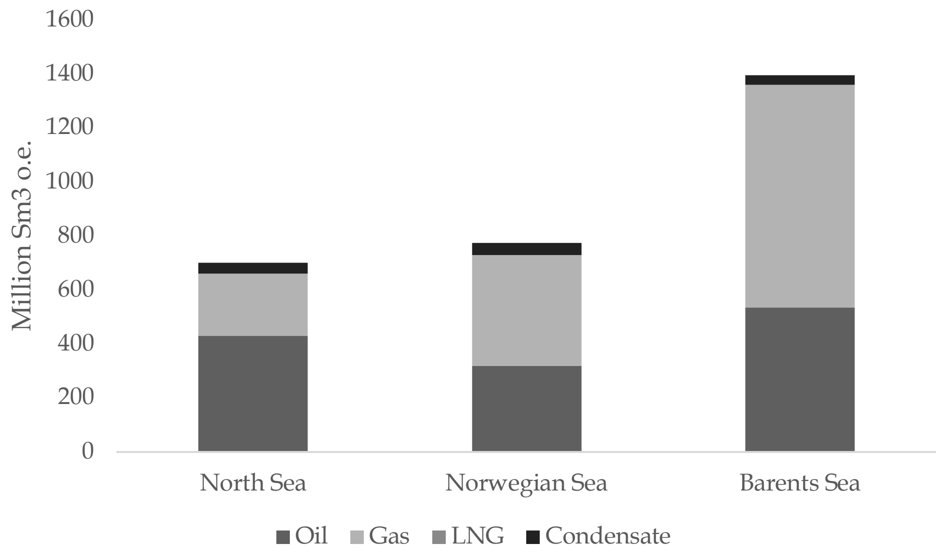

Figure 23 Undiscovered resources per region.
Source: Norskpetroleum 2017c

Data from 2017 suggests the undiscovered reserves remain highest in the Barents Sea. According to the Norwegian classification system, resources in prospects, resources in leads, and unmapped resources are quantified as undiscovered resources[162]. The total amount of undiscovered resources in the three regions adds up to 2870 MMSm^3 o.e. of which 51% is natural gas. 56% of these undiscovered resources are expected to be found in the Barents Sea (Norskpetroleum, 2017c). To revisit the discussion in Chapter 1.2, the principles of licensing on the Norwegian Continental Shelf, the total resource growth from discoveries in numbered and annual APA rounds have been approximately the same since 2000, with the Barents Sea as the largest contributor of this resource growth.

[162] See Appendix Section 2 Resource classes

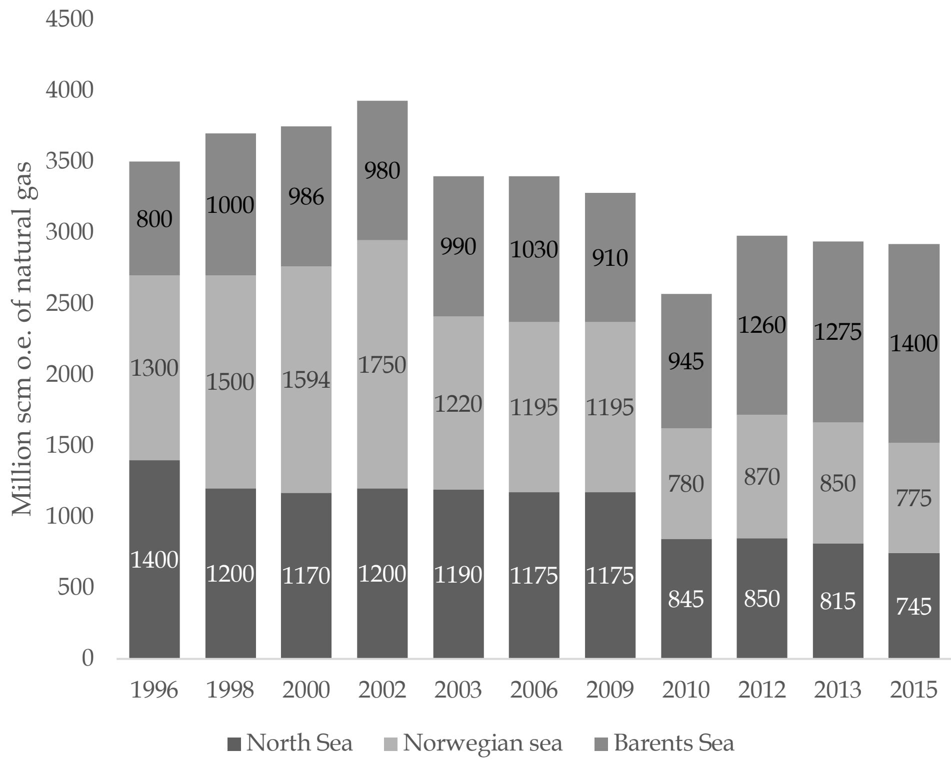

Figure 24 total recoverable undiscovered resources.
Source: NPD 2016a

The variables change, and new information based on assessments has an impact on recoverable undiscovered resources[163]. For instance, the reduction in 2010 resulted from downgraded expectations of gas discoveries in both the North Sea and Norwegian Sea, whilst the upgrade in 2012 was a result of Jan Mayen being included in the estimates for the Barents Sea and Norwegian Sea. Figure 23 indicates that there is a decline in recoverable gas resources and data has been adjusted downwards accordingly. Another trend that can be deduced from Figure 23 is that both the North Sea and

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[163] Undiscovered Resources category 8-9 "These are potential, undiscovered quantities of petroleum. No drilling has been undertaken" (NPD, 2011o)

Norwegian Sea have reduced volumes of undiscovered resources, while the Barents Sea has increased year on year (except 2009).

6.3. DESCRIPTION OF THE PROJECT

The Polarled pipeline, previously called The Norwegian Sea Gas Infrastructure (NSGI), started like the BSGI with a Gassco concept study. The project consisted of an (approximately) 482km, 36-inch subsea pipeline from the Aasta Hansteen field to Nyhamna and will be connected with the Langeled pipeline to the United Kingdom. Partners are Statoil, Petoro, OMV, Shell, TOTAL, RWE Dea, ConocoPhillips, Edison, Cape Omega and Wintershall. The ownership was built upon expected delivery of gas volumes.

One of the main objectives of installing the Polarled pipeline was to create flexibility and optimal utilisation of the already existing transmission system operated by Gassco. In addition, the policy impact assessment for Polarled indicated stable product quality, market flexibility and better regularity of export (Jenssen, et al., 2015). It was thus suggested by Gassco's modelling in 2012, that Polarled should be oversized by 25% and merge with the Gassled network prior to commissioning in 2016 (Oxera, 2015). In the PDO and PIO the pipeline allowed for capacity expansion and has six tie-in points for connections with a 30km 18-inch spur to the Kristin platform, preparations for tie-in of Linnorm (via Draugen), Zidane (via Heidrun), potential spurs 60 and 173 and a link with the Åsgard Transport system to Kårstø north of Stavanger (Statoil, 2014; Gassco, 2017).

Figure 25 Polarled pipeline
Source: Adapted from Norskpetroleum 2017c

The operational start of the Polarled pipeline in 2017 introduced the connection of the Norwegian Sea as a new province by crossing the Arctic Circle, supplying Norwegian natural gas to the markets in continental Europe and the UK and will strengthen Norway's position as long-term energy supplier. Statoil transferred the operatorship for the Polarled Joint Venture to Gassco on 1 May 2017 thus, making Gassco responsible for the Polarled pipeline operations and the Nyhamna Expansion Project on behalf of the Polarled JV (Gassco, 2017d).

6.4. ANALYSIS

The analysis uses the Transaction Cost Economic characteristics as set out by (Williamson, 1998) Asset specificity, Uncertainty and Frequency.

Asset specificity

The Polarled pipeline could be characterised as asset specific considering the location and dependability of multiple shareholders identified pre-building and installation of the project. The connection between Aasta Hansteen and Nyhamna was front end engineered and designed for additional tie-ins along this route. The Åsgard Transport pipeline from the Åsgard field, Norne, Heidrun, Draugen and Kristin fields in the Norwegian Sea to Kårstø north of Stavanger lies relatively close to (~110km) East of Polarled but is operating at full capacity until 2020. After 2020 it could be argued that Polarled will become limited asset specific considering the option to tie-in to Åsgard, making it more prone to ex-post hazards from a TCE perspective. Reflecting on 6 types of asset specificity as set out by (Williamson, 1998), the output of the production process cannot be easily transferred before 2020, leaving Polarled as the only viable option available to transport gas to Nyhamna and further into the "Dry Gas area[164]".

Uncertainty

Investment choices for the stakeholders in the offshore transmission system are driven by return on investment. Chapter 3 touched upon the change in tariffs during 2014 and the court case which could be argued as an example of regulatory uncertainty. The argument discussed in this section concerns the effect (lack of) transparency in processes and incomplete information potentially have on uncertainty in transmission system investments. What are the consequences if the Norwegian government would alter the timely sequence of delivering information, and or implement regulatory changes? Considering that no rectification on tariffs or taxes in a contracted form has been made, these consequential disturbances could have an impact on future investments in additional transmission system expansion further North. From a TCE perspective, uncertainty incentivises a decrease in contract length, whilst specific assets tend to increase the formality of the governance structure. In the case of Polarled the adaptation to further investment and field development (including the tie-ins) have been inter alia, the result of the adapting oil field service market. Reduced

[164] Area D consists of Langeled, Zeepipe, Norpipe, Statpipe, Franpipe, Europipe, Vesterled and Sage.

construction cost and services, due to the 2014 credit crunch and the fall in oil and gas prices, resulted in lower CAPEX. However, the combination of asset-specificity and regulatory uncertainty could not prevent a hold-up problem.

Chapter 3 discussed the change in tariffs and court case during 2014 which could be argued as an example of regulatory uncertainty. The table below depicts the different tariffs applicable for the different regions and shows the difference in tariffs between 2014 and 2017 indicating the price cut initiated by the government.

Area	**Unit**	**2014 K-Tariff**	**Unit**	**2017 K-Tariff, Post 2014**
A	NOK14/Sm^3	0.0683333	NOK17/Sm^3	0.0074091
B	NOK14/Sm^3	0.0434848	NOK17/Sm^3	0.0047149
C-Extraction	NOK14/Sm^3	0.1242424	NOK17/Sm^3	0.0134711
Entry				
Kollsnes	NOK14/Sm^3	0.0239788	NOK17/Sm^3	0
Kårstø	NOK14/Sm^3	0.0301909	NOK17/Sm^3	0
Nyhamna	NOK14/Sm^3	-	NOK17/Sm^3	0
Oseberg	NOK14/Sm^3	0.0301909	NOK17/Sm^3	0
Other	NOK14/Sm^3	0.0053424	NOK17/Sm^3	0
D-exit	NOK14/Sm^3	0.0692030	NOK17/Sm^3	0.0095645
F	NOK14/Sm^3	0.0745455	NOK17/Sm^3	0.0808264
G	NOK14/Sm^3	0.0185121	NOK17/Sm^3	0.0200719
BN	NOK14/Sm^3	0.0434848	NOK17/Sm^3	0.0471488
I	NOK14/Sm^3	0.0503182	NOK17/Sm^3	0.0545579

Table 6-1 Tariff old and new.
Source: Gassco 2014; Gassco, 2017

As depicted in Table 6-1, the majority of exit tariffs have been reduced by 90% (D- exit =88% s.t. (D=min)) whilst entry had been reduced to 0 (=100%). The reduction in tariffs in 2014 by the Norwegian government resulted in regulatory unrest. In addition, the reduction had a direct impact on the Internal Rate of Return (IRR), affecting the earlier agreed 7% return on investment before tax and pre-development stage (future) projects.

Combined with the 2014 change in tax build-up[165], smaller projects, i.e., smaller volumes of natural gas or an aggregate of small producers, are particularly vulnerable. Figure 25 depicts the impact and sensitivity to higher cost of capital required to build infrastructure with a high sunk cost part and the implications for an E&P company (Thema Consulting Group, 2013).

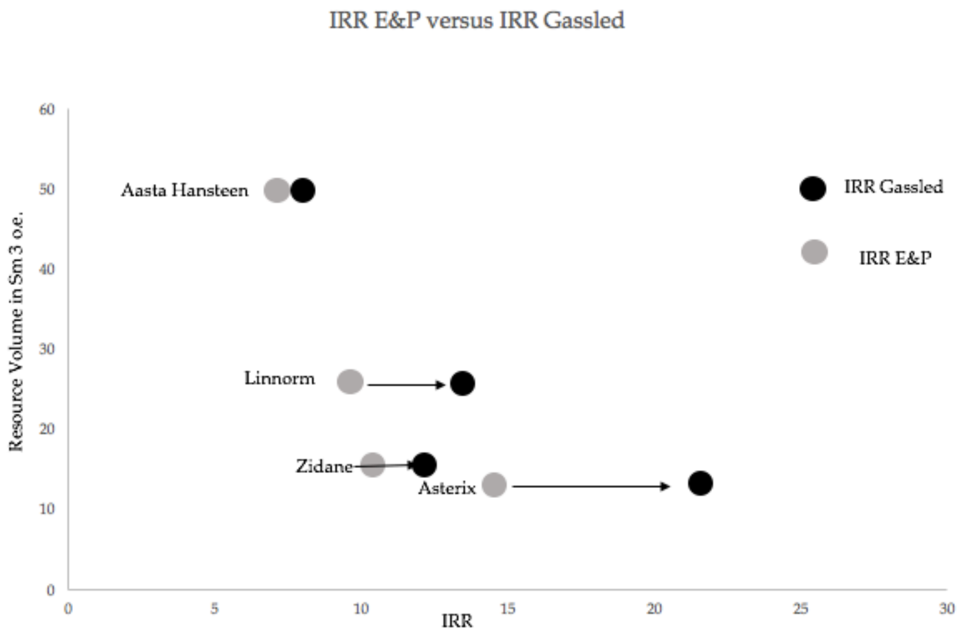

Figure 26 IRR E&P vs Gassled
Source: adapted from Pöyry, 2013

[165] See Table 4-2

Figure 26 displays the difference in IRR by comparing E&P companies owning and investing in the Polarled pipeline and investment companies (e.g., Silex, Njord and Infragas) owning and investing in the Polarled transmission systems. There is a significant difference in returns on field development, favourable for E&P owner-investors compared to investment companies, specifically, for the smaller fields e.g., Zidane, Linnorm and Asterix, which demonstrates the impact of a transmission system on field development (Thema Consulting Group, 2013). The four non-E&P Norwegian companies[166] not having field and gas resources, believed that the tariff reduction inflicted a loss of future revenues estimated at NOK15BN (Regjeringen, 2017c).

Bonds issued by Njord Gas were downgraded from A- to BBB by S&P (Njord Gas Infrastructure AS, 2015). Standard and Poor commented “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 Gas Infrastructure AS, 2015).

The change in tariffs as a regulatory measure further reduced interest in investment by Gassled owners in other infrastructures and transmission systems. E.g., Njord suggested that if tariffs had not been cut, Njord would probably have bought a stake in the 480-km Polarled pipeline. Infragas CEO Knud Noerve indicated a similar stance, saying: "When it comes to investments outside of Gassled, it is not something we're looking at for the moment […] That's because of the uncertainty created" (Reuters, 2016). In addition, the reputational damage it has done to the Norwegian government, renowned as offering a stable and predictable investment environment (Bloomberg, 2016).

[166] Njord Gas Infrastructure AS (Njord), Solveig Gas Norway AS (Solveig), Silex Gas Norway AS (Silex) and Infragas Norway AS (Infragas)

The uncertainty of behaviour in the Principal and Agent relationship resulted in what could be considered an example of a hold-up problem in Transaction Cost Economics. Whilst transacting parties enter into relationships to mitigate these and other contractual hazards, nevertheless they cannot do so perfectly (Joskow, 2002). Gassled has made the investment in the transmission system and was now dependent on the regulator to make a return on investment, i.e., "locked in" by the regulator and government. As a result, Gassled owners delayed further investments in the expansion of the transmission system.

Contrary to Gassled's position, the Norwegian Ministry argued differently. The government is entitled to change tariffs, through legal authority provided by the Petroleum Activities Act and Petroleum Activities Regulations. "There is no basis for requiring clearer legal authority than this" (Regjeringen, 2017c). The court found that although

> certain criticism of the authorities is warranted for not having clarified the basis for the calculation of returns in Gassled sooner and for not having established a system for registering and publishing the return achieved at all times (Regjeringen, 2017c, p. 4)

the Ministry has not failed to fulfil its duty to provide guidance. Thus, the appeal from the Gassled owners was rejected in the court case. The State's main interest has always been efficient resource management of petroleum resources with a long-term perspective for the benefit of Norwegian society as a whole (NPD, 2015c). The government intends to obtain a high socio-economic profitability through ensuring the maximum recovery of natural resources; "as much as possible is recovered of the resources in fields in operation, that discoveries are developed and that undiscovered resources are discovered" (Regjeringen, 2017c). To achieve this objective cost has to be kept low, E&P incentivised, TPA to the transmission system allowed and profits taken out of the fields and not from the transmission system (Regjeringen.no, 2011). This concept was reiterated throughout multiple governmental publications, e.g., Proposition to the Storting No 102 (1980–81), Report to the Storting No 46 (1986–87) and Report to the Storting No 28 (2010–2011). It could thus be argued that there appears to be a one-sided uncertainty or misinterpretation of regulations. A clear insight on revenues and transmission was needed to come to the appropriate rate of return of 7% agreed upon during the Zeepipe construction and delivery in 1987 (Regjeringen, 2017c).

A sufficient rate of return to incentivise investments

The intention of the Polarled pipeline was to develop all the fields south of Aasta Hansteen on the route to Nyhamna, all supporting the investment in the transmission system. The volumes from these fields were required to provide optimal capacity and revenues from tariffs. Due to reduced project profitability in Linnorm and Kristin, Statoil farmed down[167] its interest in Aasta Hansteen, the Asterix fields and Polarled pipeline and decided not to develop the fields (Statoil, 2014). Although Zidane's owner RWE Dea stated that the Kristin field decision would not affect the development, Zidane[168] is still on hold (Taraldsen, 2014). This had a significant impact on the initially designed PDO and PIO. Aasta Hansteen was now accountable for 100% of the volume throughput whilst only being 64% owner in Polarled (Hammer, 2015). Aasta Hansteen is in turn dependent on Polarled and vice versa. Without Polarled, Aasta Hansteen's gas does not go to market and will not be enough volume for Polarled to be realized (Taraldsen, 2014). The investment decision proved to be one of uncertainty when not enough commercially viable resources were available for the project to commence.

[167] Statoil farmed down a 24% stake in its Aasta Hansteen Field development project, a 19% stake in the Asterix Field and a 13.2% stake in the Polarled pipeline.
[168] Since 2016 called Dvalin

	Aasta Hansteen Owners	Polarled Joint Venture
Statoil	51%	37.0760%
Wintershall	24%	13.2550%
Petoro		11.9460%
OMV	15%	9.0730%
Shell		9.0190%
Total		5.1100%
DEA Norge		4.7910%
ConocoPhillips	5%	4.4520%
CapeOmega		2.8820%
Edison International S. p. a		2.3960%

Table 6-2 Ownership Polarled-Aasta Hansteen
Source: Wintershall, 2017: Gassco, 2017; Statoil, 2017; OMV, 2017

Underutilisation

In order for the Aasta Hansteen owners to recover revenues sufficient to cover the cost of overall throughput, which is now covered by only ~65% of the Polarled owners[169], would require tariffs to increase[170]by ~55%. The Aasta Hansteen owners would lean towards tariffs as set out in the initial modelling done by Gassco, which allowed for overcapacity in the range of 25% throughput. Furthermore, the operator's motive was to merge Polarled into the Gassled pool. However, due to the tariff reduction, Njord (inter alia) a Gassled partner has said that it has no interest in acquiring Polarled. In contrast to the Aasta Hansteen owners Petoro and the remaining owners of the Polarled transmission system argue for the "standard" 7% return on transmission systems (Oxera, 2015).

[169] Aasta Hansteen owners that are additionally in Polarled, Statoil, Wintershall, OMV and RWE
[170] 37.3%+13.3%+9.07%+4.79% = 64.46% 100/64.46~55%

Of the Gassled owners 51% are involved in gas production and subsequent transmission leaving 49% of owners not involved in production and therefore lacking the potential need for transportation. The owners that are O&G companies have dual interests as investor and as shipper. In the former capacity, the 51% share owners will benefit from high tariffs whilst in the latter case as an owner/shipper they prefer low tariffs. This could add to the issue of underinvestment in the transmission system. Furthermore, the government has different incentives compared to 50% of Gassled, leaving the four firms that bought Gassled stakes in 2010 and 2011 from ExxonMobil, Total, Statoil and Royal Dutch Shell with a rejected NOK15BN tariff dispute based on regulatory tariff changes. It could be argued that the governmental approach is focussed on low tariffs, deduced from the tariff reduction discussed in Section 3.3. The tariffs discussed in that Section suggest that the government's intentions are focussed on transmission systems as part of field development to transport resources to end users. Gassled identifies this as a sunk cost with relatively low returns from an investors' perspective potentially with a short recovery period due to the gas market flux.

Apart from Gassled's challenges with tariffs, the change in taxation build-up[171] , which is arguably an incentive to take profits from the field, resulted in reduced investment in resource management directly connected to Polarled. Shell delayed its Linnorm field in the Norwegian Sea, which would have produced about 100,000 barrels of oil equivalents per day. Statoil cancelled The Kristin Gas Export Project (KGEP)[172] in 2014, a pipeline connection between the Kristin field and Polarled. The KPEG partners terminated the project based on unsustainable project economics, increased costs and volume risk (Statoil, 2014). Other fields in the vicinity of Polarled which are put on hold to a potential later date are Asterix and Snefrid Nord.

[171] Ibid Table 4-3, In 2017 the "Ordinary" company tax rate is 24 %, and the "Special" tax rate is 54 % resulting in a marginal tax rate of 78 %. In 2016 the taxation rates were 25 % and 53 %. An additional feature is introduced to safeguard normal returns from the special tax. This comes in the form of a deduction called uplift. In 2016 the total uplift was 22 %.

[172] KGEP partners (Statoil 53.4%, Petoro 35.6% and GdF 11%)

Zidane, initially put on hold for 3 years has become economically viable after shedding 20% of the 2017 $1.23BN estimated cost.

The regulatory uncertainty also influenced the development of some significant oil reserves. Possibly the most notable was the delay of the Johan Castberg ($11.3BN) oil field in the Barents Sea by Statoil in 2015. The change in ordinary and special tax would increase cost for a barrel of oil produced at Johan Castberg by $7, significantly constraining project profitability. It has taken Statoil 2 years to resubmit a Plan for Development and Operation (PDO) for the field based on a substantial reduction in cost and increase in oil price.

Frequency in Transaction

Frequency is a pertinent dimension, in that recurrent transactions may support the setup costs of specialized governance and have better reputation effect properties (Williamson, 1998). In the context of offshore transmission systems, the frequency of contractual transactions compared to spot market trading is low. To develop a specialised structure to capture excessive cost appears not effective. However, if a contract is recurrent, albeit at the same frequency as offshore pipelines are contracted, good reputation becomes relevant. Market contracting, if supported by good reputation effects, thus becomes part of the comparative contractual calculus (Williamson & Tadelis, 2010).

Although the decision (PDO and PIO) to develop Polarled was already made and the gas directives partially implemented, mid-process alteration of tariffs[173], demonstrated its importance in the overall arrangement of the implementation through all 4 levels of the TCE framework. The Plan to Develop and Operate (PDO) and Engineering Procurement and Construction (EPC) contract were agreed upon on ex-ante tariff reduction resulting in unfavourable investment conditions ex-post.

[173] See Table 2-1 i.e., Level 2 as depicted in the Williamson framework

Furthermore, the changes of regulations through the EU gas directives and implementation at the national level could arguably be seen as very frequent compared to the 10-20 years of the original TCE framework. In addition, the frequent change of tariffs in comparison to long term contracts could be considered a higher frequency. Reputation has been affected by the changing tariffs within the Norwegian gas market, ergo, it became part of the comparative contractual calculus.

6.5. CONCLUSION

The Chapter started with the exploration of Norway's natural resources and reserves. The largest segment of undiscovered resources and available reserves is divided between the Norwegian Sea Sector and the Barents Sea Sector. This Chapter focussed on the last trunk line to be installed in the Norwegian Sector, Polarled. Aggregating findings from Chapter 2, TCE and Principal-Agent theory, from Chapter 3 Supra-national regulations, from Chapter 4 National regulations and applying these findings on the Polarled case, several judgements can be made. Reflecting back the supranational regulations have had limited to no influence on the decision-making of Polarled. Investment decisions were made post implementation of the gas directives. Furthermore, the gas directives might have been more beneficial for organising the tariffs and transmission system rather than disadvantageous. National regulations played a significant role in the investment in Polarled and the further development of the surrounding fields with the potential to tie-in to Polarled.

The potential for underinvestment was supported by statements from Njord Gas Infrastructure and Infragas (combined owners of 45% of Gassled) indicating that had the tariffs not been cut, Gassled would probably have bought a stake in the 480-km Polarled pipeline. However, due to the uncertainty created there is no incentive to invest in Gassled (Reuters, 2016b). It was appropriate for the government to reduce the tariffs according to the outcome of the court case in which the Gassled owners lost their appeal against Norwegian's state tariff reduction. The question remains if the rate of return now applicable to Gassled owners is sufficient to incentivise an investment. As mentioned in this Chapter, the government does not deny the offshore transmission owners a return, but it is limited to 7% pre-tax based on calculations prepared by and for the ministry. The key driver was and is to take profits from the field, rather than from the transmission system. The alterations of Norwegian taxes, in combination with low 2014-2017 oil and gas prices has provided no incentive for field development with tie-in points on the Polarled trunk line.

Observations

Although Gassco is not the end-decider on transmission system development - this is left to the transmission system owners Gassled as identified in this Chapter - it has a significant influence on infrastructure projects. It is Gassco's responsibility to evaluate development with a focus on optimal transportation for all Norway's resources. Oil & Gas companies and third-party investors might be reluctant to invest in a region without an infrastructure, whereas transmission system investors might be reluctant to invest without sufficient volumes to guarantee optimal throughput.

With Polarled, Gassco had allocated overcapacity at additional cost, adding to the investment incentive already present on the Norwegian Continental Shelf. Another observation that can be made is that the underutilisation of approximately 50% was not taken into consideration by Gassco when expanding the transmission system with 25% overcapacity. Nor was the effect it would have on returns for the field and pipeline owners taken into account.

To answer this judgement, a Norwegian regulatory mechanism designed to mitigate the potential performance barriers was explored. Transmission system investors have encountered several limiting barriers to invest further in the Norwegian transmission system. The case study provided evidence of uncertainty in the efficiency of the transmission system, significant cost, ex-post increased risk and changes in tax and tariffs. Furthermore, increasing cost factors through faster depreciation rates of assets and or shorter payback periods, are unfavourable factors influencing uncertainty and the performance barriers. These factors pose a substantial ex-post hazard that may result in a hold-up. Regulatory intervention could reduce investment uncertainties. In the case of Polarled the regulation discouraged investment in the fields through changes in taxation. This in turn led to underutilisation of the transmission system. To prevent "hold up" related to specific assets, natural gas contracts were, on average, longer than in typical non-regulated markets (Williamson & Tadelis, 2010).

Another factor to take into consideration is the coordination between other parts of the value chain. The coordination between the asset owners and vertical integration where applicable provides insights, information and efficiency. The intention of Polarled, when designed, was to facilitate a certain amount of overcapacity potentially to supply the transmission system with additional gas ex-post decline in the North Sea and to avoid overbooking on Åsgard Transport.

Furthermore, the discussion on Asset specificity of Polarled and Åsgard could lead to an interesting revised definition if transporting gas from multiple fields, like Polarled and Åsgard post 2020 could create an incentive to transport gas from one rather than another system, thus becoming limited asset specific or asset diverse. Asset-specific investments and efficiency are both key principles of TCE as discussed in Section 2.2. Production optimisation and capacity utilisation of the transmission system are key factors determining investment returns. As discussed in this Chapter an asset specific investment i.e., Polarled on advice from Gassco should arguably be efficient. The upfront investment in Polarled created a bargaining position from a governmental perspective in favour of the pipeline owners, the latter expecting a specific form of economic governance. The Norwegian governance in the Polarled case adapted policies relating to tariffs and taxes at the cost of investors and field development resulting in postponement of fields.

The return required to cover the investment in Polarled and future Gassled infrastructure rests on a cost-return function. Tariffs as a function of regulation determine prices and returns for the investors. Consequently, reduction of tariffs increases the cost-return ratio. It could thus be argued that to an extent Norwegian regulation affected the investments negatively, potentially to the point where no investments will be made.

7. Barents Sea Gas Infrastructure

7.1. INTRODUCTION

This Chapter investigates the potential of the Barents Sea Gas Infrastructure, discovered and undiscovered resources in the Barents Sea, and whether natural gas resources, gas prices, cost (CAPEX-OPEX) and financial challenges warrant investment in the Barents Sea Gas infrastructure.

Chapter 7 discusses the second case on the NCS, the Barents Sea Gas Infrastructure(BSGI). Section 7.1 describes the resource base and how the Gassco 2014 report sets out scenarios to develop the region with a transmission system. These findings support the argument to further investigate the case of the BSGI and apply data, solutions and methods from Chapter 2 and 3. Furthermore, Section 7.2 defines the principles of how fluid dynamics and pipeline engineering provide additional information on various additional options next to the two proposed 32-inch and 42-inch pipeline options discussed in the Gassco Barents Sea Gas Infrastructure. Optimal calculations are explained in Section 7.3. Gassco makes use of simulation software which makes use of the Benedict-Webb-Ruben-Starling (BWRS) equation of state. The Colebrook-White friction factor correlation is also used by Gassco, and Gassco makes use of the Gassopt model for short-medium and long-term simulations which makes use of the Weymouth equation (Rømo, 2009). Certain assumptions regarding the BSGI will be made and introduced in Section 7.4. Justification is based on data provided

(Gassco, 2014; NPD, 2017c). Section 7.5 provides data for judgements which will support answering the research question and the sub-questions.

Barents Sea potential

Since the 2011 White Paper and 2014 Gassco report[174] exploration has continued and provided new insights from the drilling of wells and finds. Although the ratio of discoveries to exploration has not improved significantly there is an increasing trend in drilling activity resulting in more discoveries. The exploration of the Northern province has increased in the 22nd and 23rd licensing-round. Evidence that the emphasis is on the northern province is demonstrated by the 24th licencing round. In March 2017, the MPE announced a public consultation on a proposal to explore 102 blocks, of which 9 were in the Norwegian Sea in addition, but 93 in the Barents Sea (Regjeringen.no, 2017b). The increase in drilling activity in the Barents Sea has resulted in more discoveries in the last 4-year segment from 2012-2015 with sizes of 10-50 Scm o.e.

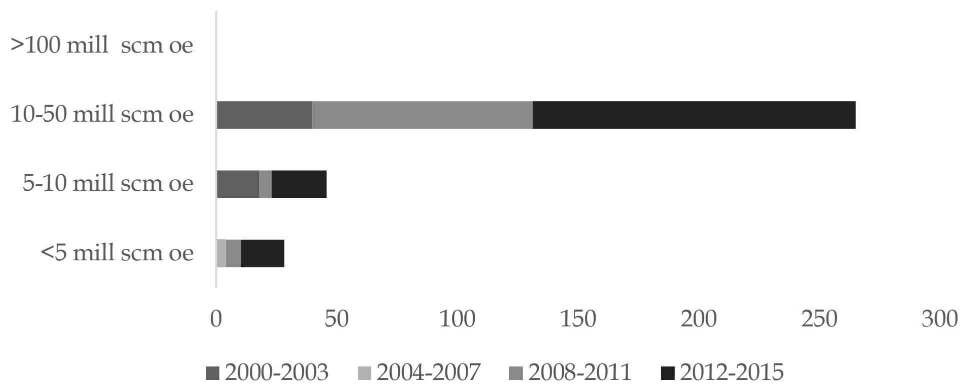

Figure 27 Resource discoveries in 4-year periods (2000-2015)
Source: Norskpetroleum, 2017c

Figure 27 depicts the accumulated resource growth over the period 2000-2015. One significant gas discovery has been made in the Barents Sea – the

[174] (Gassco, 2014; Regjeringen.no, 2011)

Snøhvit field (1984)[175]. Snøhvit is now operational but has experienced significant setbacks during engineering, construction, as well as production. The licensing rounds have consistent accumulated resources, but growth in the Barents Sea has been stagnating since 2008. The success rate has been volatile year on year, with an average success rate around 45%.

An increase in reserves is needed to meet the fundamentals for a viable offshore transmission system investment. Figure 28 depicts expected aggregated gas resources in the Barents Sea. The largest amount is “undiscovered”, whilst only 41bcm of gas is produced, predominantly by Snøhvit, and transported as LNG.

Scenarios for 2017 to 2020 prospects

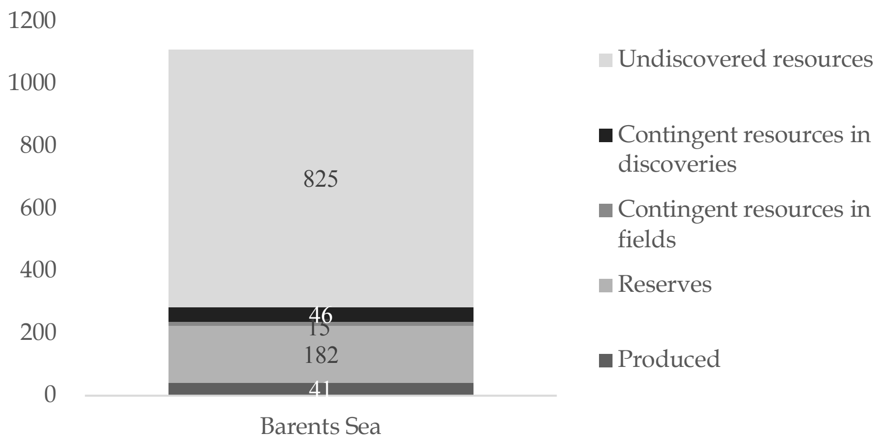

Figure 28 Barents Sea Natural Gas Resources.
Source: Norskpetroleum, 2017d

A higher level of drilling activity based on an increase in licenses in the Barents Sea should provide a more precise geographical picture, resulting in an increased growth of discoveries. A significant factor that has an influence on investment in infrastructure in the Barents Sea is the size of the finds. As depicted in figure 27 there has been an increase in finds, however these

[175] Goliat (2000) and Johan Castberg (2014) Johan Castberg is an oilfield with combined finds from 2011-2014, Goliat consists of oil and gas.

consist of relatively small discoveries, i.e., small deposits. Although small deposits are individually less financially viable for development and do not warrant an offshore trunk-line, small discoveries may benefit from a transmission system and become profitable by the inclusion of a flow line tying into the transmission system.

Scenarios for undiscovered resources

Based on the data presented in Section 6.2 Resources and Reserves, there are a plenitude of scenarios possible. Gassco, the Norwegian operator starts with 5 scenarios, A to E and proposes three outcomes, C&D, E and A&B. All scenarios depart from a 200 BCM[176] discovery base case.

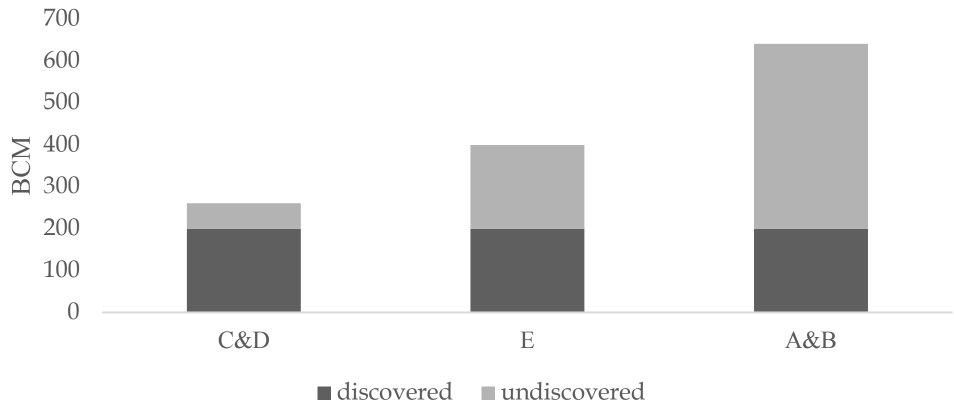

Figure 29 Gassco Scenario A-E 2013-2017.
Source: Gassco, 2014

Scenario C&D assumes 60BCM of undiscovered gas, scenario E 200BCM and Scenario A&B 440BCM. The five scenarios were selected from Monte Carlo simulations to reflect appropriate overall characteristics. The variables taken into account are resource size, prospects[177] timing of discoveries, number of discoveries (several small in A and C, or a few larger fields in B and D), size

[176] NPD's view, as depicted in figure 28, is that the figure should be 243 BCM
[177] Prospects: p5=a high resource outcome, p50=a median scenario, p95=a low resource outcome

of the largest discovery, production characteristics (low/high energy and poor/good quality) and distance between discoveries (Gassco, 2014a).

Comparing the data from 2017 that has been proven and categorized by the NPD with the data from Gassco's reference Scenarios indicates that the forecast in the Gassco 2014 report have not been met. The actual discoveries in the Barents Sea accumulated from Year 2014 till April 2017 have amounted to one 5F and two 7F discoveries totalling 45.5 Mm o.e. as displayed in table 7-1 (last three items).

Field	Year	Volume	Medium	Code	Status
7120/12-2 (Alke Sør)	1981	12.92	GAS	5F	Production likely, but unclarified
7121/5-2 (Snøhvit Beta)	1986	2.8	GAS	7F	Production not evaluated
7122/6-1 (Tornerose)	1987	3.87	GAS	4F	Production in clarification phase
7220/8-1 JOHAN CASTBERG	2011	10.89598	GAS	7F	Production in clarification phase
7120/1-3 (Gohta)	2013	14.625	OIL/GAS	5F	Production likely, but unclarified
7120/1-3 (Gohta)	2013	6.22	OIL/GAS	7F	Production likely, but unclarified

7220/11-1 (Alta)	2014	26.396	OIL/GAS	5F	Production likely, but unclarified
7220/11-1 (Alta)	2014	9.7	OIL/GAS	7F	Production likely, but unclarified
7220/6-2 R	2016	6.5	OIL/GAS	7F	Production not evaluated
Total	2017	93.921			

Table 7-1 Barents Sea fields, West- Central.
Source Norskpetroleum, 2017d

As depicted in table 7-1, there appears to be a discrepancy between the estimates of proved reserves and the required volumes. Accumulated 1981-2017 findings lean towards Gassco Scenario C&D (93.21BCM versus 60BCM), and more closely from the date the Gassco report 2014 was published 60BCM (see figure 28) compared to 42.6BCM (year 2014-2017), with several small finds on multiple locations, however lack the expected doubling of the resource base in Norway's Barents Sea sector as predicted in the Gassco report (Gassco, 2014a).

7.2. TRANSMISSION SYSTEMS

The BSGI report discussed three possible transmission systems as potential options; a 32-inch diameter Pipeline, a 42-inch diameter pipeline and LNG. Although LNG might be considered as a viable option, it is outside the scope of this research based because

1) LNG gains significant financial advantages over pipelines over long distances e.g., 2,500Km upwards, however this benefit reduces over shorter distances.

2) LNG has a higher cost profile and is technically more complicated. Whilst both transport methods would suffer financial losses if production

falls, ramping up production is less costly in a pipeline case than for LNG. Furthermore, considering Ledesma et al. s' (2014) statement that investors prefer proven systems, LNG might not be a viable option taking into account the inefficiencies and setbacks in the case of Snøhvit. In addition, setting up another LNG train at Snøhvit would be challenging and expensive from an engineering perspective. Moreover, it would lack the flexibility an extra, or larger compressor on a pipeline would bring. This leaves the alternative of a greenfield LNG transmission system with Snøhvit as reference case.

From a TCE perspective an LNG investment appears to have several benefits over the pipeline option, LNG reduces asset specificity. Although the investment is still irreversible LNG and more specifically FLNG is less locational specific. Furthermore, there is no requirement to build the facility for one specific supplier or end-user. Alternatively, FLNG could be towed to another location or country and operate for a different supplier or client. A similar approach could be taken for an LNG terminal. A significant downside of LNG and FLNG in the Barents Sea Case are high costs, marginal use (based on Snøhvit's record), and less flexibility in volume/production compared to pipelines.

	CAPEX	Price Output	Revenue/ Day	Increase in Output	CAPEX 2 NOKMM
Pipeline	45 M^3/D	8 mbtu	95,350,500	27 M^3/d	6,000
LNG	12 mtpa	10 mbtu	119,188,125	7.3 mtpa	109,500

Table 7-2 Cost comparison on flexibility.
Source: Author's own calculations adapted from Gassco 2014

Table 7-2 depicts the cost differences in flexible delivery for an increase of 27M^3/Day for a 42-inch Pipeline compared to an equal amount of flexible output in LNG. The additional cost of flexibility is significant (Gassco, 2014a). Other methods of gas transmission are recognised but are outside of the scope of this research due to lack of empirical evidence of their success. E.g., Compressed Nitrogen Gas (CNG) or Gas to Liquid (GTL) have not demonstrated cost benefits and operational capabilities in or outside of Norway in scalable volumes. The same judgement has been made for the option to transform natural gas to electricity for transport to the end market. It is clear that a capital investment of this proportion requires risk containment and elimination of uncertainties through proven cost-effective technology, a substantial amount of resources and documented "long-term" contracts. An investing party takes into consideration price, time, volume, risk and capacity.

To support the discussion on transportation of natural gas through pipelines, the transportability and requirements of the supporting system, a concise description of theories of gas mechanics and dynamics will be presented. The related discussion supports the choice of a 42-inch pipeline as a viable solution for the BSGI and a basis[178] for the cost of such as system.

Although a transmission system consists of a myriad of pipelines, nodes, valves, templates, compressors, treatment facilities and end terminals, the components that will be discussed consist of pipeline, compressor and the product natural gas. The basis for the calculations serves as an explanatory foundation to arrive at a judgement on the potentially added value of an increase or decrease in pipe diameter; e.g., the Gassco report considers two pipeline diameters, 32-inch and 42-inch. Economies of scale will play a significant part in the functionality of transporting natural gas. Increasing a pipe diameter has the potential to increase the economies of scale but increasing the diameter and or pipeline length also increases friction between gas and the pipeline inner wall resulting in a reduction in gas pressure between entry and exit point. An increase in the number of

[178] Calculating a complete offshore pipeline system is extremely complex and mathematically modelled by computer programmes. It is out of the scope of this research. Gassco makes use of the Gassopt model to derive conclusions from the data available on the Norwegian offshore transmission system. For an in-depth explanation (Rømo, 2009).

compressors or in the horsepower of a compressor increases pressure and throughput. The interaction between these variables is mathematically calculated in optimisation programmes. Gassco, the pipeline operator makes use of a Gassopt model.

In gas flow formulae, diameter, inlet pressure and temperature are the key design parameters, which have implications on capacity and thus economies of scale in trunk-lines. In order to obtain economies of scale a trade-off between diameter, volume and pressure has to be considered. With an increase in length there will be a decrease in pressure.

Gassco uses several definitions for pipeline transport capacity, e.g., hydraulic, technical and committable capacity. The hydraulic capacity is calculated maximum physical throughput using maximum inlet pressure and minimum outlet pressure. Available Technical Capacity accounts for limitations in system boundary conditions, e.g., caused by limited inlet pressure due to dependency on other pipelines. A fuel factor is also deducted to account for metering errors and fuel gas consumption in either compressors or heating stations. The committable capacity is the capacity that is available for stable deliveries. Operational flexibility of 1 or 2% is usually deducted from the available technical capacity to ensure that small operational disturbances do not lead to loss of delivered gas (Langelandsvik, et al., 2009).

Furthermore, when calculating capacity, a distinction is made between an existing pipeline and a study for a proposed pipeline. For an existing pipeline, extending the maximum capacity is limited to an increase in compressor power, whilst a new build pipeline still has the option to increase diameter in addition to an increase in compressor power. When a new pipeline is planned, it is designed to meet a transport capacity need. This means that after finding the optimal route from the supply point to the delivery point and the length of this route, the diameter is chosen such that the requested capacity is obtained. This is performed using a pipeline simulator with all design data as input and typically makes use of an equation of state[179]. Gassco simulation software makes use of the Benedict-Webb-Ruben-Starling (BWRS) equation of state in addition to the Colebrook-White friction factor correlation. For short-medium and long-term simulations Gassco makes use of the Gassopt model, which makes use of the Weymouth equation (Rømo, 2009). After the pipeline is commissioned and operational, a capacity test is performed to find the hydraulic roughness in a real test of the pipeline (Langelandsvik, et al., 2009). With the planning of a new pipeline consideration is given to the cost factor as a function of capacity. An increase in diameter results in more throughput and less cost, both factors of economies of scale.

The desire of the operator to have additional capacity is plausible, it provides manoeuvrability with capacity and the option of additional throughput increases revenue. Furthermore, from a resource development perspective, in this case the Norwegian government, it provides the option to tie-in additional fields when planning transport capacity in the long term including small deposits.

Economies of scale and subadditivity have been validated through calculation of the cost components of the Norwegian dry gas area. Two methods will be applied, one considering investment as a ratio to capacity and the second method demonstrating the influences of diameter on capacity throughput. The cost of eight dry gas pipelines is compared in order to identify economies of scale and trends in investment over capacity. If a pipeline grows in capacity, its costs increase less than linearly while throughput increases exponentially" (IEA cited in (Dahl, 2001).

As displayed in Table 7.3, prices of Norwegian offshore pipelines have fallen, and economies of scale have grown in the period 1977-2015. In the table, a ratio of investment to capacity has been calculated over an indicative 12-year period[180] in the last column of the table and indicates that

[179]A semi-empirical functional relationship between pressure, volume and temperature of a pure substance.

[180]Remaining period for the Gassled owners on the duration of the license period to 2028.

overall cost has declined over time and annual total capacity has increased. Several technological factors have not been taken into consideration in the calculation e.g., wall thickness to diameter ratio, the learning curve following the crossing of the Norwegian trench for further infrastructures and the various depth considerations.

Pipeline year	length in km	Diameter in inch	ATC* in Msm3 /d	From	To	Annual max through put	In 2016 BN NOK	Investment /capacity NOK/BN MAX/12Y
Norpipe 1977	443	36	32	Ekofisk	Emden	11.68	32.508	0.23193493
Vesterled 1978	361	32	39	Heimdal	St. Fergus	14.23	39.744	0.23266596
Zeepipe 1993	814	40	42	Sleipner	Zeebrugge	15.33	16.524	0.08982387
Europipe I 1995	620	40	46	Draupner E	Dornum	16.79	26.244	0.13025610
Franpipe 1998	840	42	55	Draupner E	Dunkerque	20.07	12.312	0.05110834
Europipe II 1999	658	42	71	Kårstø	Dornum	25.91	11.772	0.03785452
Langeled 2007	534	44	72	Sleipner	Easington	26.28	9.288	0.02945205

Sage 2015	94	16	5	Edvard Grieg	St. Fergus	1.825	1.728	0.07890411

Table 7-3 Eight pipelines cost calculations
Source: Author's own calculations

Additional economies[181] of scale can be derived from compressor power consumption which increases less than linearly as delivery pressure increases. This further supports the argument that the flexibility of an increase in compressor capacity might be financially more attractive than e.g., LNG or a smaller diameter pipeline with a limited pressure capacity. In line with the BSGI report, arguably the 42-inch pipeline is the practical option in 4 out of the 5 Scenarios and will be used for this research as the investment option.

Revisiting Project Finance as Functional Model

Chapter 4 set out the principles of financing oil and gas operations. From a historical perspective "on balance sheet capital" was raised for field development on the Norwegian Continental Shelf which included the offshore pipelines segment to transport the resources to the end-user. Whilst the balance sheet financing principle still has a place in the Norwegian gas sector, the division of the transmission system from fields requires a different finance approach for offshore pipelines. From Chapter 6 it was made clear that the Gassled owners[182] found limited incentives to invest in the Norwegian transmission system. Additionally, the final report to the European Commission Directorate-General for Energy indicated the improvement of the regulatory environment to be the most important factor in the financing of energy infrastructure projects, according to the experts of

[181] Another method to calculate economies of scale in pipeline systems is displayed in the appendix Section 4
[182] (Silex, 2013), (Njord Gas Infrastructure AS, 2015)

32 TSOs and 15 financing institutions (EC DG for Energy, 2011). Key issues included regulatory remuneration and regulatory stability.

In the period from 2014-2017 no alterations in the regulatory structure have been made to support infrastructure investments on the Norwegian Continental Shelf. For this reason, an assumption is made that there will be no incentive from the regulators, national and supranational to alter 2017 regulations to support infrastructure investments on the NCS. Furthermore, exemptions from parts of the energy packages, e.g., TPA, have not been taken into consideration[183]. The BSGI report identified the potential need for alternative investment models' due to the significant CAPEX, likelihood of multiple licenses needed to aggregate the investment and the substantial size of the marginal resources needed in order to maximise value (Gassco, 2014a). Financial options besides "on the balance sheet" as explained in Chapter 4, identified Project Finance as a viable alternative. Project finance provides vehicles to deal with the factors described in the BSGI report and is in line with the theoretical foundation of Transaction Cost Economics. In addition to theory, empirical evidence suggests that Project Finance is a common model for large gas infrastructure investments such as LNG projects (Ledesma, et al., 2014). Although costlier to set up than on the balance sheet investments, it provides the option to obtain more capital from a broader investor base. Other factors that support this approach are the government's desire to separate the oil companies from the infrastructure. Off-balance sheet financing supports the division of oil field and transmission system. Furthermore, it separates the asset from the investor/investment, whilst optimising the risk characteristics for each of the investor types.

[183] Justification in the next section revisiting regulations.

7.3. BSGI PROJECT ASSUMPTIONS

This section will set out the assumptions needed to come to a judgement on potential investment decisions on the BSGI. The calculations made in this section are to identify the potential of attracting investors, following the absence of the Gassled owners' willingness to invest. To commence the project, alternative investors would need to be satisfied with the conditions current in 2016-2017. To arrive at a judgement on an investment, the section is set out in transmission system cost factors, financial modelling and results.

Assumptions on volumes in Barents Sea Central and West

The 45 Mcm^3/day capacity in Figure 30 has been derived from the Gassco (2014) Barents Sea Report and represents the throughput associated with the proposed 42-inch pipeline for the BSGI as discussed in Section 7.2. The resource volumes in Figure 30 are 243 BCM of which 93.9 BCM is based on undeveloped existing fields and discoveries. For completeness, Gassco's reference scenario adds 100BCM from undiscovered resources and 14.5 BCM from Snøhvit[184].

[184] (this volume will be transported through the pipeline instead of the Melkøya /LNG route).

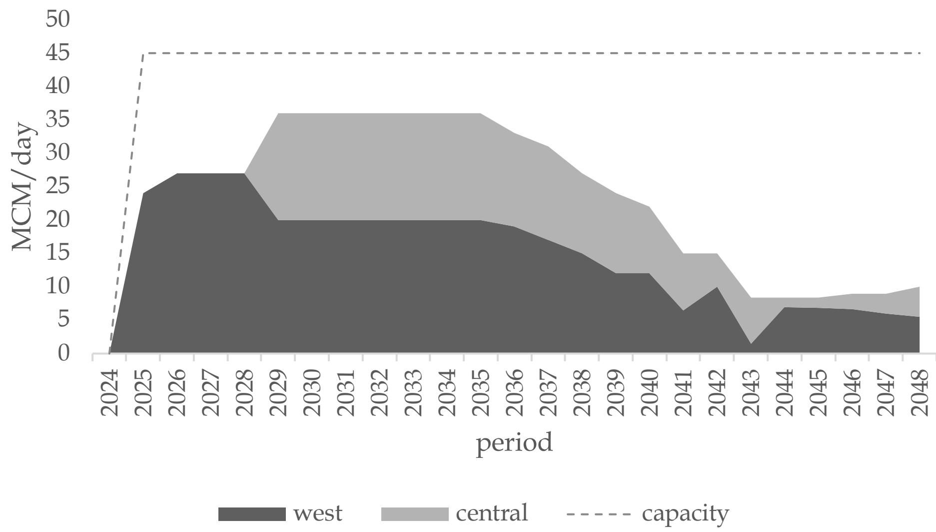

Figure 30 Capacity vs Production in the Barents Sea.
Source: Gassco, 2014a

The optimal capacity, based on 45 Msm3 a day over a 25-year lifespan would require a volume of 402 BCM at 98% utilisation rate or 321BCM over a 20-year span at 98% utilisation rate of the transmission system. A publication from the NPD of April 2017 suggests a record year for the Eastern Barents Sea. The resources increased from 50% to nearly 65% of the total undiscovered resources on the Norwegian shelf (NPD, 2017a). These figures will not be taken into consideration for this research until Statoil has drilled wildcats in 2018 to confirm the potential discoveries. Thus far, Korpfjell drilling in August 2017 has been disappointing (Statoil, 2017).

CAPEX

Several assumptions have been made to obtain the CAPEX for a 42-inch pipeline supporting the BSGI. Data for these assumptions derived from the Gassco Report, NPD and MPE.[185] The Gassco report additionally discussed the flexibility of upscaling through compressor capacity increase

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[185] (Gassco, 2014; MPE, 2016; Norskpetroleum, 2017f).

from 45 MMSm^3 at the price of NOK72BN to 72 MSm^3 at the cost of NOK 78BN.

OPEX

An identical approach of ratio to capacity, as depicted in Table 7.3, has been applied to arrive at anticipated OPEX. Data has been adapted from Gassco's cost estimate model (Gassco, 2014a).

A 1,000km length of 42-inch pipeline from the Haltenbank to the Barents Sea with an average daily transmission capacity of 45Msm^3/day results in an annual throughput of 16.4BCM. The CAPEX is estimated at NOK72BN. The investment over capacity in NOK per year over a period of 25 years provides a ratio of 0.06667.

To put 16.4BCM per year in perspective, Troll which accounts for ~30% of Norway's gas export produced 31.86BCM in 2016.

Capital Structure

Investments in the Oil and Gas industries have been influenced across the entire value chain by declining oil prices post the 2008 financial crisis which resulted in reduced cash flows and profits for IOCs an NOCs. Oil and gas companies took various measures to maintain the level of dividend shareholders were accustomed to. Inter alia, a significant reduction in CAPEX in project investments. Additionally, there has been a reduction in the debt to equity (D/E) ratio, allowing for larger debt at low interest rates. Pre-2008 D/E ratios for the oil and gas majors were between 0.20 and 0.60. Post 2014 a shift towards 0.45 to 080 was displayed (Y-Chart, 2017). Pipeline investments were leaning towards the .70-.82 bandwidth pre-2008 period (Pierru, 2013).

Pipeline	Year	Country	Country Risk	Investment in US$MM	Debt Ratio
Cheyenne Plains	2005	US	0	435	.80
Dolphin Energy	2005	Oman	2	4800	.72
Atlantic Cross Island	2005	Trinidad	2	336	.80
Southern Light	2008	US	0	2429	.71
Elba Express	2009	US	0	578	.35
Fayetteville Express	2009	US	0	1340	.82
Ruby	2010	US	0	2910	.52
Nord Stream Phase 1	2010	Russia	4	7535	.71
AccuGas	2010	Nigeria	6	250	.24
Nord Stream Phase 2	2011	Russia	4	4790	.71

Table 7-4 Debt ratio historical pipelines
Source: adapted from Pierru, 2013

Debt

In a Project Finance construction, financial institutions and banks require substantial cash flows to compensate for the lack of asset ownership resulting in more risk for the Project Company. Where in the past long contractual arrangements between seller and buyer covered the revenue stream, the move away from 20-year contracts to e.g. 5-year contracts, results in debt volumes becoming dependent on committed volumes to market (DNB, 2015). To further the research and provide data to come to a judgement an assumption will be made that the BSGI will obtain a Debt Ratio of 0.71, taking the Gassco risk profile[186]into consideration (Gassco, 2014a).

Although LIBOR has been considered as interest rate determinant, the Norwegian Interest rate has been preferred due to the LIBOR Scandal (CFR, 2016). The interest rate applicable is set in accordance with the

[186] Risk profile see Section 4.3

Norwegian Interbank Borrowing Rate (NIBOR) lending profiles and spread. LIBOR is based on the estimated rate of interest that is charged between banks in the London interbank market. The rate is calculated for a variety of currencies and loan maturities based on a bank submission process administered by the Intercontinental Exchange. Another reason for applying the Nibor[187] is that the Nibor panel banks base their quotes on a US dollar rate that reflects the price of unsecured interbank loans in USD. Before the financial crisis, the banks used the US dollar Libor rate as a basis for their Nibor quotes. During the financial crisis, it was widely claimed that Libor underestimated the actual US dollar rate facing banks in the interbank market, and the Nibor panel banks decided to switch to a US dollar rate as the basis for Nibor. For the purpose of this research the NIBOR will be applied with a spread of 100 and 345 based on DNB indications (DNB, 2015) and (Norges Bank, 2017). It provides the foundation of the debt build-up that comes with the investment in the BSGI transport system.

Debt and interest build-up

Total debt outstanding (MNOK)	51,120
NIBOR rate (%)	1.33%
Margin (bps)	222
Interest rate (%)	3.55%
Repayment period (years)	15

Table 7-5 Interest build-up.
Source: Adapted from Hammer 2015

Bearing in mind the consequences of Basel III on Project Finance portfolios and the 2008 financial crisis the debt is build-up of 71% of NOK72BN as a maximum debt ceiling with a ten-year Nibor rate and an average margin of 222 base points derived from (Norges Bank, 2017).

187 The term "-ibor rates" refers to the benchmark rates e.g., Libor, Euribor, Stibor, Cibor and NIBOR for Norway

Equity

One of the outcomes of the Gassco report concerned the entry of new but smaller O&G companies into exploration as well as transmission (Gassco, 2014a). These smaller companies (compared to e.g. Shell, Statoil), have constraints on raising finance and will typically look for equity, JV combinations or joint structures, including farm-out agreements. As a result of this diversity a need for collaboration between more companies and licensees becomes more pressing in order to be more cost effective, competitive and attractive to investors. Clew (2016) described independent companies as more innovative in making use of financing structures e.g. securing finance against working capital. Equity plays a significant part in the capital structure considering the capability of offsetting a high return due to the higher risk. Equity holders will be remunerated after the debt is paid.

Hybrid

In the scenario depicted by Gassco's assumptions there are still gas resources left post-debt servicing. It could be argued that the volumes left are less risk prone resulting in lower returns. The low return features do not meet the high return requirements of the O&G companies in the exploration segment. Based on owner interviews, Hammer (2015) described the risk return for the BSGI to be in the range of 18%-20%. For the gap between debt and the high yield returns of the O&G equity the Project Finance model allows for a hybrid investment i.e., through mezzanine capital. The hybrid capital applied consists of capital returns and dividend. The dividend differs from "standard" dividend because it is not a tax-deductible dividend, not being on the balance sheet of the company. The hybrid capital instrument is assumed at 20% of the required CAPEX. Given that there are some contractually committed volumes left to partly service the required dividends and the potential value of the warrant structure, the infrastructure fund would require a ROI of approximately 10% with a 10-year period (Pedersen & Georgsen, interview, 19.03.15 cited in Hammer, 2015).

Parameters

Revisiting taxation as set out in Chapter 4, in 2017 the "Ordinary" company tax rate equalled 24 %, and the "Special" tax rate 54 %, resulting in a marginal tax rate of 78 %. The general investment phasing profile is set at: 15%, 20%, 30%, 20%, 15%, adapted fromGassco, 2014a.

7.4. ANALYSIS

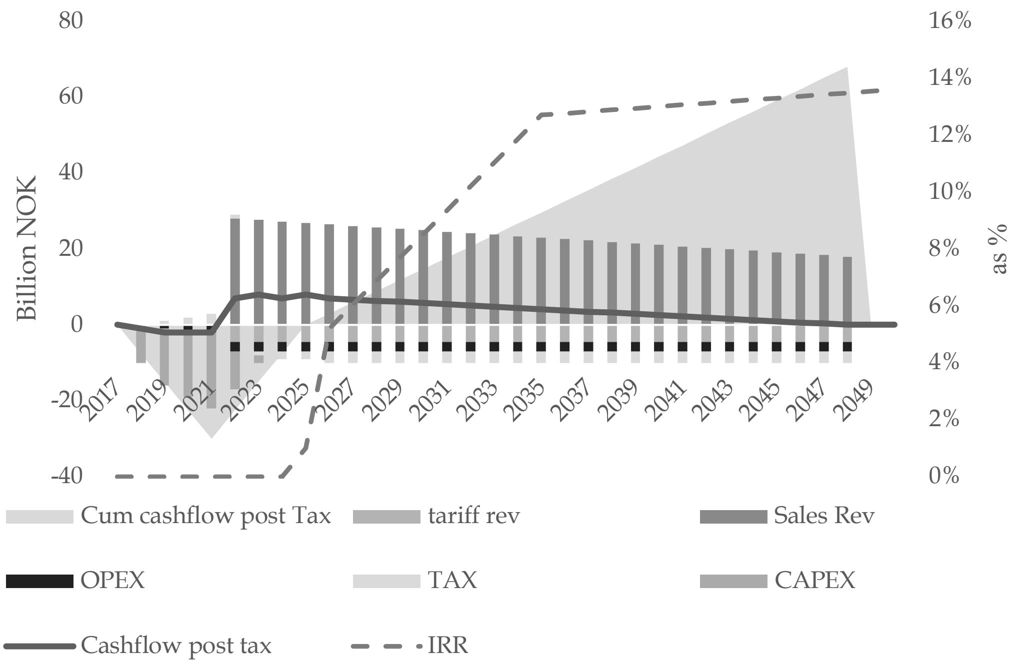

Figure 31 Cash flows from investment in pipeline to 2050
Source: Author's own calculations adapted from Gassco, 2014a

IRR

Staying with the assumptions that sufficient resources are available and put on stream as discussed in the BSGI-E case at 45 Ms^3/day (Gassco, 2014) Figure 31 illustrates that the cash flows in the reference throughput scenario are sufficient to service the dividends to the mezzanine capital. As the figure illustrates the guaranteed cash flows will not be sufficient to cover the dividends required to provide the infrastructure investors the 10%

return. Hence, there is significantly more risk associated with owning the mezzanine capital than debt, and consequently the infrastructure funds must be compensated by higher returns and potential upside. The model assumes a 13.6% IRR with a post-tax return of 7%.

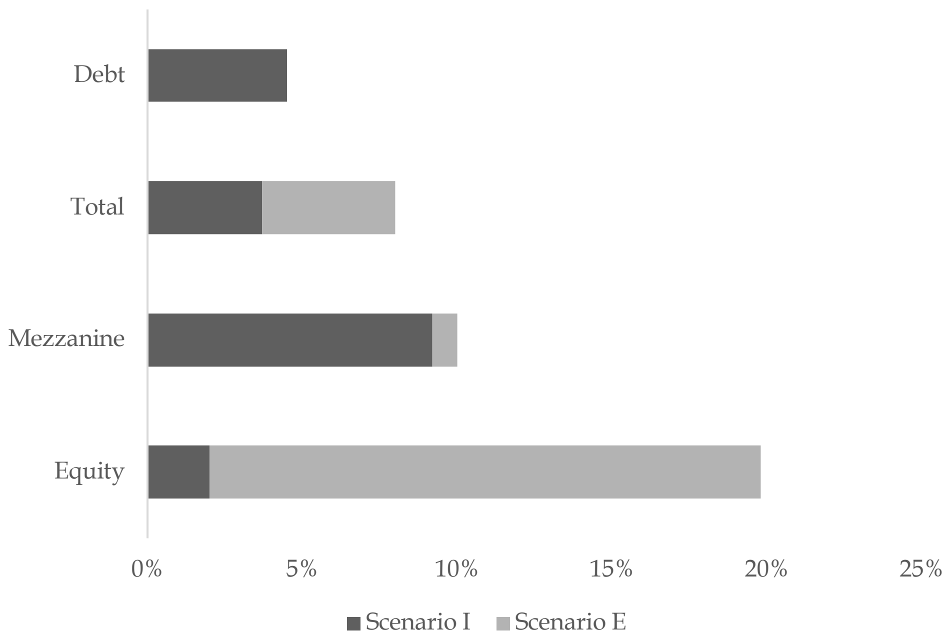

Figure 32 IRR based on Scenario I and Gassco E Scenario
Source: Adapted from Gassco, 2014

Figure 32 depicts the resources found and the resources needed to meet reference Scenario E, indicating that in order to meet the financial returns, significant amounts of natural gas need to be put on stream to capture this return on investment.

A project IRR of 10 % is substantial for offshore pipeline projects of this character. In a PF structure with significant leverage, a required rate of return of 10% suggests the project is associated with substantial risk for a commercial bank issuing debt (Hammer, 2015). In comparison to other pipelines on the NCS depicted in Figure 33 the BGSI IRR is higher, based on assumptions, whilst historical data suggests that other transmission systems are running on a lower IRR. The other projects were however of different nature at a time when there was less volatility of cash flows. Furthermore, these transmission systems were built on significant larger finds of gas in established areas closer to market.

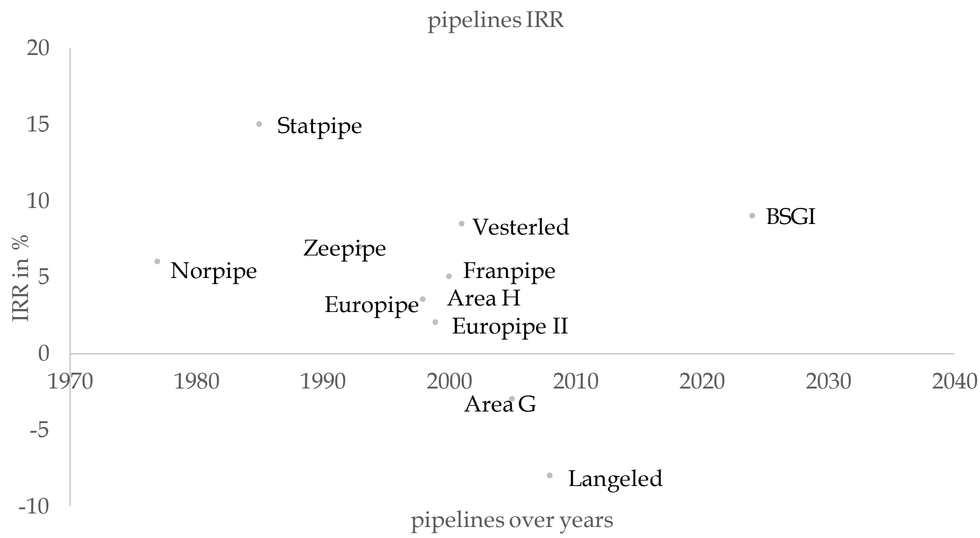

Figure 33 pipeline IRR over years 1970-2040
Source: Njord 2015

NPV

The NPV is dependent on the annual throughput times the set tariff. A distinction should be made that the price of gas and its volatility has no direct effect on the tariff and thus, on the volatility of revenues for the investors. It could however be argued that a lower price could incentivise greater demand and a higher price a reduction in demand. The low prices from 2014 to 2017 however indicate that the correlation of low price and higher demand and high price and low demand is not necessarily a fixed rule. Figure 34 demonstrates that in Scenario I, the NPV of the volume of gas defined in the Barents Sea is not sufficient in relation to the total NPV line once the tax benefits are offset with the end of loans. Scenario E is Gassco's Barents Sea Gas Infrastructure Scenario E, the modest Scenario between high and low (Gassco, 2014a).

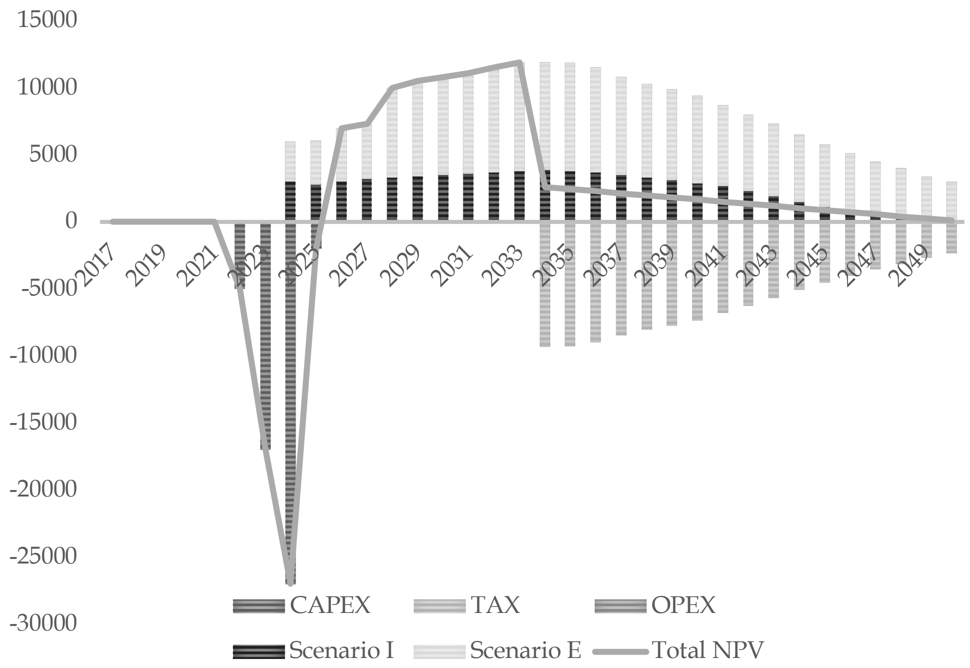

Figure 34 NPV Scenario I and Gassco Scenario E
Source: Adapted from Gassco 2014

In Section 1.4, the MPE has historically set the tariffs so that the pipeline projects yielded a return of 7% based on indicative throughput. Hammer (2015) stated that the Gassled owners suggested the required IRR for the BSGI should be in the region of 10%, which would have been in line with the pre-tariff reduction of 2013. Gassled's return as a whole for the period ex-ante 2013 amounted to 10.7% (Regjeringen, 2017c). In addition to increased regulatory risk, the higher required return comes as a result of more uncertainty related to throughput compared to other pipeline projects on the NCS. The O&G companies' option to make contractual commitments to secure debt repayments, although quite possible, has not been discussed. The management of the natural resources through national and supra-national regulation, will need to provide clear communication of incentives and rewards and be open to potentially new investment forms.

Collaboration will be required to optimise the balance of investment, cost and economic efficiency.

7.5. CONCLUSION

Chapter 7 has investigated the potential of the Barents Sea and in particular the Barents Sea Gas Infrastructure and its natural gas resources. The discoveries up to mid-2017 do not justify the BSGI investment, unless "a giant" is found. Although the Troll field with 1,764BCM was called "A Giant", volumes required to justify a BSGI investment would have to be 285-320BCM[188], which is approximately the size of the Johan Sverdrup field (298BCM) or Ormen Lange (317BCM). The resources discovered in the Barents Sea are spread and are not of substantial size to justify an offshore pipeline system.

Asset specificity

Economies of scale are a key factor in the decision whether to aim for a 42-inch trunk line. Of the various formulae, available to assess the value of throughput, it was suggested that the methodology used by Gassco e.g., the Weymouth principles[189] are best suited for large diameter high pressure pipelines. The 2014 to 2017 exploration portfolio in Gassco's Scenario E was expected to double the natural gas resource base in the Barents Sea, but there is evidence suggesting (Norskpetroleum, 2017b) no substantial increase in resources. The volumes discussed in this Chapter are based on a potential scenario as laid down by Gassco's report (Gassco, 2014a). Calculations have demonstrated that the base case, determined by discovered resources do not justify any pipeline system considering the cost of NOK72BN required to transport a diversified resource base.

[188] Chapter 8 provides a calculation to arrive at this volume
[189] Section 8.7 in the Appendix provides evidence and calculation examples to justify the statement

Uncertainty

The region is still in its infancy and would benefit from further investigation through wildcats and exploratory services to map the actual amounts of gas available, and their location to optimise the transportation route of a collecting pipeline. The Barents Sea holds the largest amount of undiscovered resources on the Norwegian Continental Shelf with the largest amount of fossil fuel to be found as gas (Norskpetroleum, 2017c). With finds announced in April 2017, in addition to the increased concentration on this area in licensing round 22, (with 72 licences of the 86 in the Barents Sea) and in the significant number of blocks in the area in the 23rd and 24th rounds, indicates that the government's intentions are clearly focussed on the region. Notwithstanding the 2017 finds and a step up in exploration, the discoveries were of marginal to small size and only a small amount has been deemed commercially viable in 2017. No discovery on its own has warranted the development of the infrastructure (Gassco, 2014a). The smaller scattered finds will not become commercially viable without a transmission system in place. Thus, the majority of the known potential of natural gas resources, discovered and unproven in 2017 in the Barents Sea, are expected to remain undeveloped.

Furthermore, for the Barents Sea Pipeline Developers to commence construction, besides the needed currently lacking natural gas resources, the cost of engineering procurement and construction would have to be significantly reduced given low 2014-2017 gas prices. Historically over the period from 1996 to 2016 gas prices[190]have fluctuated between $2 and $10/MMbtu. From 2014-2016 European import prices fluctuated between $5-$8/MMbtu, with average 2017 gas prices between $5.5/MMbtu (German border price) and $5.8/MMbtu (TTF) (EU, 2017b). It is expected that prices of $6-$8MMbtu are needed to remunerate 2017 delivery costs of large

[190] See Chapter 5, Figure 19 Natural gas prices in $/MMbtu across five main gas regions.

volumes of gas from new offshore pipeline gas (Stern, 2017d). Considering Norway to be at the high end of this price range it remains uncompetitive to invest in a greenfield Barents Sea offshore pipeline assuming a 20-year asset life based on gas prices.

Frequency in Transaction

Data provided by the field operators indicates it is unlikely the BSGI will be driven by an individual license due to the expected resource base and the high CAPEX needed (Gassco, 2014a), so that collaboration across licenses will be needed. From a Transaction Cost Economics perspective, focussed on supporting an investment of this size, the frequency of contractual transactions compared to spot market trading is low. Developing a specialised structure to capture excessive (recurring) costs does not appear to be effective.

8. Summary and conclusions

8.1. RESEARCH MOTIVATION AND PROBLEM DEFINITION

Norway's position as supplier of natural gas to the European Union is under pressure from multiple sides, through liberalisation of the natural gas market, supranational and national regulations, market dependencies and its national resource management. While the European Union, the largest market for Norwegian natural gas, has not decided on the future role of natural gas and Norway's position in it, Norway claims to have sufficient gas especially in the Barents Sea to `continue to be a trusted supplier of gas to the European Union. However, it would require confirmation of an offtake commitment.

Against this background, this research has come to five conclusions regarding Norway's capability to maintain economically viable, operationally and technically efficient natural gas transportation to Europe under the European and Norwegian regulatory regimes.

First, as shown throughout the research, Norway can supply the EU with natural gas in a technically efficient operation. However, compared to LNG and Russian piped gas, cost is a limiting factor for Norway, especially when considering the construction of greenfield offshore gas pipeline systems such as the Barents Sea Gas Infrastructure.

The second conclusion is that the implementation of the European regulatory framework i.e., the gas directives, was agreed at a time when there was a pressing need, from the Norwegian point of view, to coordinate the diverse offshore structures and tariffs into a single Norwegian offshore transmission system. In addition, it coincided with the EU Commission's concerns about the Norwegian system for delivery of gas (Regjeringen, 2017c). Although the implementation of the gas directives does not provide sufficient incentives for new investments in offshore pipeline export infrastructure on the Norwegian Continental Shelf, the changes in regulations and tariffs support the cost-efficient resource management needed to produce gas for export at prices that can match natural gas hub prices.

The third conclusion, albeit somewhat obvious considering it has been documented on several occasions (e.g., the Royal Decree and the Petroleum Activities Act), yet misinterpreted by pipeline investors, Norway's national policies and regulations do not support the commercial viability of investments in offshore pipelines and infrastructures. The emphasis of Norwegian laws and regulations has always been on taking profits from the fields rather than from the infrastructure. Allowing for a higher than the predetermined 7% before tax return on pipeline investment would have represented a breach of the principle that the return shall primarily be taken from the field (Regjeringen, 2017c).

The fourth conclusion refers to the previous conclusion on ROI. The cost characteristics and regulations that are important for the Barents Sea decision makers are based on the expected CAPEX, and transportable volumes, taking into consideration that increasing the return of 7% would be breaking an important principle. The NOK72BN CAPEX is significant and would require 17-19 years to recover based on volumes around 285BCM, of which (according to 2017 estimates) 42BCM are still to be discovered.

The fifth and final conclusion of this research is that the EU gas directives, although important in a Norwegian context, have a minor role to play for Barents Sea decision makers compared to Norwegian national regulations.

This research is motivated by the uncertainty as to whether Norway is able to provide the European Union with natural gas for "many years to come", taking into consideration world natural gas prices and an ageing Norwegian infrastructure. In addition, the European Union has falling domestic natural gas production, a significant gap in infrastructure investments in transmission systems and an increasing obligation to comply with COP21 commitments. These factors provide support for additional reforms in the European gas market for which Norway is the second largest supplier; and also, in government policies and regulations in Norway where the oil and gas industry make up 22% of GDP and 67% of exports.

8.2. THEORETICAL CONSIDERATIONS

This research applied three economic viewpoints to investigate these concerns:

1) The neo-classical approach which is the foundation of European Union and Norwegian gas regulation;
2) Transaction Cost Economics for its alternative view on gas regulation and application to investments in offshore natural gas transmission systems through capturing deficiencies in contractual agreements; and finally,
3) The Principal-Agent theory for its ability to identify issues between the Norwegian government as Principal and Gassco, Gassled and Petoro as agents.

Neo-Classical Theory

Concluding that there cannot be a perfect natural gas market in Europe, European Union regulatory intervention is intended to obtain a perfectly competitive[191]natural gas market with a perfect price equal to marginal cost. Regulatory intervention in itself suggests market failure, assuming that a perfect market would not require regulatory involvement. Built on theoretical assumptions and comparison with the gas directives, the

[191] Appendix for detailed explanation of monopoly regulation.

separation of ownership i.e., unbundling of the competitive sector from the transmission monopoly, occurred in Norway with the abolition of the GFU. For the purpose of unbundling vertically integrated entities Directives 2003/55/EC, 2003/54/EC and 2009/73/EC resulted in ownership unbundling. Whilst measures were taken to avoid unfair incentives for vertically integrated firms to over-invest in transmission systems, the rulings promoted non-discriminatory investments in the infrastructure and allowed for new entrants and transparency in the market. Whether or not the non-discriminatory investment incentives implemented by the directives are efficient and effective is subjective. Each member state is free to implement the regulations individually, particularly in relation to resource development and offshore infrastructure, as is the case of Norway for which Gassco is the operator (TSO) and Gassled the owner. The extent to which the unbundling has been efficient was analysed by Growitsch & Stronzik (2014), whose study of 18 EU countries over 19 years revealed no indication of a price-decreasing effect of ownership unbundling. "However, the breaking-up of formerly vertically integrated TSOs resulted in reduced end-user prices" (Growitsch & Stronzik, 2014). From a regulatory perspective, it appears that further separation would not provide more efficiency i.e., additional unbundling could result in diminishing economic benefits.

Returning to the economic foundation in which the State's interest is to maximise social welfare, it could be argued that charging no tariffs would be optimal. However, to allow investors and transmission system owners a fair return a minimum recovery of cost plus a profit would be required. Due to the difference between investors, e.g., transmission system owners that own parts or shares of the system and natural resources, the transmission cost and tariff are financially internalised providing an advantage to sell more gas. A homogeneous tariff function for all the transmission systems with different cost functions would suggest inefficiency. Transaction cost economics bridges the intermediate period by capturing deficiencies in contractual agreements.

Transaction Cost Economics (TCE)

With the application of the TCE model, determining factors became apparent. Furthermore, it provided an understanding of the link between neoclassical theories and practice in the natural gas market. The model provided a mechanism to divide levels of regulation and implication on each level. Whilst this model provided additional insights it had some drawbacks in regard to motivation for changes by a regulator or government. In the case of tariff reduction and taxation in the Norwegian context it could be argued that both incentives measures (tariff reduction and taxation) are counterproductive, whilst no clear benefit could be derived from the framework. Furthermore, given how the market moved through technological inventions and regulatory changes between 2003 and 2009 on an EU level, and between 2013 and 2015 in Norway, the adapted Williamson model, shown in Chapter 2 Table 2-1, presents time bands of 10-20 years. Conversely in the case of Norway, from 1971 until 2017 the general consensus is that there has been no significant change of natural resources policy, and thus 20-30 years seems within the scope of the Williamson framework. Although it could be argued that in Norway there is an intention to reduce reliance on oil and gas revenue, no action or significant change has been taken on any of the four levels of the regulatory framework.

It is not the purpose of this thesis to evaluate the appropriateness of regulations but several findings from TCE analysis provide insights on supra- and national regulations. Chapter 2 described the fundamentals of TCE and its limitations. The foundation of its governance rests on 3 factors asset specificity, uncertainty, frequency of transaction. Asset specificity is potentially the most influential factor in the Norwegian transmission system context considering that without it, competition would be a common outcome. Buyers would turn to other suppliers and set up a new contract with the next seller of natural gas. There is no incentive to continue a contract with a specific seller. A form of governance is required taking into account the multitude of governance forms, the differences in the spot price market for natural gas, and vertical integration. Within the uncertainty factor due to incomplete contracts, opportunism from either side results in ex-post contractual hazards. TCE has demonstrated regulatory opportunism albeit in a less dominant way than before the outcome of the court case between Gassled and the Norwegian Government. The Norwegian ministry as regulator of Gassled could have reasonably expected to be accountable for the publication of information regarding the return on investment made in the offshore pipeline system. Providing this information would have indicated exact earnings by the Gassled owners and consequently not have resulted in unannounced changes of tariffs. The government has however emphasised its rights to alter tariffs in laws, regulations and white papers. Whilst the principle of regulatory opportunism resulted in the regulator pressuring Gassled, this was not so in the Polarled case and with the Barents Sea Gas Infrastructure. The description of Polarled in chapter 6 depicts a situation where ex post hazards are not removed and investors in Aasta Hansteen are disadvantaged or deprived of appropriate revenue streams. In the case of BSGI, the setting was provided to invest on the basis of criteria given by the Gassco report (Gassco, 2014a). The situation is still not attractive to investors, due to high cost, an uncertain return period for the investment and the 7% return on investment before tax, not meeting investors requirements.

Not all situations are appropriate for a Transaction Cost Economic approach. Arguably if asset specificity, uncertainty, frequency of transaction is not met, then ex-ante contract alterations or e.g., perfect competition as market function could resolve incomplete contracts if such a contract form is applicable. The investments in Polarled and BSGI are asset specific due to sunk cost, subadditivity, location and frequency of change, making the projects vulnerable to ex-post hazards as has been demonstrated in both cases.

Principal-Agent Theory

Norway as a gas exporter appears locked into a long run relationship with the main importer (EU), the infrastructure owner Gassled and the TSO Gassco. Arguably bargaining over the resource rent could be perceived as a multi-principal-multi-agent situation. Norway as a gas exporting country has an additional principal-agent relationship with Statoil the National Oil Company, which is tasked with the maximisation of the resources for exporting purposes and thus maximisation of social welfare. Together with Petoro "the other" agent of the Norwegian government, both have a significant influence on production and operating sharing agreements on the continental shelf, functioning as principal in the relationship with international oil companies. A substantial dissimilarity between an IOC and a NOC is the financial investment horizon, where the NOC may be partially on the national political economic agenda for which a long-term perspective is normal and lower short term returns in revenue would meet social welfare.

That there is asymmetric information between the principals and the agents can be deduced from the fact that before the tariff reduction, the oil major Statoil sold its share in Gassled. A robust governance structure and clear communication on future strategies reduces principal-agent problems. This would include reduction of uncertainty for the asset owners, identification of risks and through discussion, a requirement for strategic planning.

The relationship between the Norwegian government and Gassled has come under tension due to the tariff change in which the government concluded that the Gassled owners were earning more than 7% pre-tax and thus reduced the tariffs. The Norwegian court favoured the government's position over the pipeline owners. Whilst Gassled's focus is based on maximising profit at minimum cost, the role which the regulator (i.e. the government) has given itself, is to maximise social welfare and optimal resource development, which creates an undesirable tension resulting in another principal agent problem. The government incentive is to reduce cost in order to develop as much of its resource base as possible, whilst Gassled owners as investors want the highest possible return on investment. It could be argued that the fall in gas prices post-2014 made it clear that unless Norwegian gas costs could be significantly reduced then the resource base in the north would remain largely undeveloped.

8.3. CASE STUDIES

Regulatory frameworks and anticipated European hub prices need to incentivise investments required to meet European Union gas demand. However, the Barents Sea Gas Infrastructure is costly and currently anticipated gas prices do not meet the requirements. To explain this statement the next three subsections will discuss regulations, investment and gas prices and provide a generalised observation from the Polarled and the Barents Sea Gas Infrastructure cases.

Regulations

One of the characteristics of the EU regulations is the "one size fits all" format for all EEA countries. No two of the countries are the same. Each of the member state's regulators has a different interpretation and implementation of the regulations. The first differentiator is the incentive of the regulation. From an EU perspective, this is security of supply, competition and sustainability. In the configuration of the European Union and Norway, history has demonstrated that adapting to these incentives was not a smooth transition. Planning of ownership change based on rulings in 2001 was not initiated on a voluntary basis but was rather the result of formal anti-trust proceedings initiated by the Directorate-General Competition. From a Norwegian perspective the implementation of the gas directive, although coinciding with the anti-trust proceeding came at a convenient time in which multiple pipeline owners with multiple tariffs were required to be aggregated into one uniform transmission system to become more efficient and thus competitive. From a principal-agent perspective the best interest of the EU did not necessarily match the interest of the Norwegian government, which was selling gas on Norwegian terms. However, the Norwegian government wanted a large-scale market for its gas and the European Union was quite willing to provide that market. This resulted in a transition to EU legislation on the NCS as national laws were adapted. As a consequence, the supra-national regulator will encounter asymmetric information exchanges and take actions that may not be to the best interest of Norwegian society. This allows for additional arguments regarding regulatory opportunism and regulatory failure. Reflecting on the discussion on TCE and neo-classical theory regarding the EU targets, it could be argued that the EU framework does not meet the set target of perfect competition.

Investments

The EU framework based on neo-classical economic principles has imperfections as discussed from a theoretical perspective in Section 8.2. Furthermore, in Chapter 3 the discussion of the development of financial instruments designed to attract additional private investment through "the Juncker Plan" supports the TCE fundamentals and confirms reduced interest in investments.

Bearing in mind the lead times for long term projects and the backlog of these projects, Norwegian investments have declined:[192] by ~23% from 2014 to 2015; by another 6% from 2015 to 2016. For the years 2017 and 2018 declines of ~6% and 8% are expected before an 8% uptick to return to 2017 levels according to Petoro. An estimated reduction of $50 BN in CAPEX and E&P should be anticipated between 2016 and 2020.

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[192] Taking into account all investment forms, e.g., concept studies, brownfield expansion, greenfield and E&P (Petoro, 2016 ; Petoro 2017)

To distinguish the dampening effect the supra-national natural gas regulatory framework has had on investments, from the impact of the fall of fossil fuel prices is difficult to determine. The same position is taken on the implications of supra-national financial regulations and the effect they have on potential investments on the Norwegian Continental Shelf. While both may be valid topics, the arguments are out of the scope of this research.

Revisiting Natural Gas Prices

Predicting natural gas prices is a complex matter and not in the scope of this research. Nevertheless, in order to discuss investments required to meet European Union gas demand, a view must be taken on anticipated hub prices because of their significant impact. Grounded on historical data, whilst referencing to the gas market as set out in Chapter 5, several judgements will be made centred on various predictions made by Energy Institutes and data providers e.g., BP, EIA and IEA. The average gas prices over the past 20 years and the years post 2013 are shown in table 8-1.

$/MMbtu	Japan LNG	Germany	UK, NBP	US BN
Average 20 years	8,42	6,39	5,68	4,47
2014-2016	12,44	7,78	7,53	3,28

Table 8-1 Long-term gas price assumption
Source: Adapted from BP, 2017

In the first three quarters of 2017 the prices of natural gas have fluctuated between $4-$6MMbtu, Russian gas has been moving in the same price range. In a gas oversupply scenario, spot prices are likely to remain at a similar level with average 2017 gas prices between $5.5MMbtu (German border price) and $5.8MMbtu (TTF) (EU, 2017b).

Polarled and BSGI

It is expected that prices of \$6-\$8MMbtu are needed to remunerate 2017 delivery costs of large volumes of gas from new offshore pipeline gas (Stern, 2017d). Considering Norway to be at the high end of the \$6-\$8MMbtu price range it remains unprofitable to invest in a greenfield Barents Sea offshore pipeline assuming a 20-year asset life based on expected gas prices.

From an offshore pipeline owner's perspective, supporting the transmission of natural gas resources from the Barents Sea through the BSGI, several factors are relevant to consider. Gassco's annual reports from the period 2011 to 2016 depict requirements based on gross revenues and maximum throughput. Table 8.2 shows the gross revenue Gassled received from Gassco from tariffs, and the volumes transported for this revenue. The volumes required to recover the investment of NOK 72BN depicts a high, low and average scenario based on 16.4BCM maximum throughput obtainable from the BSGI[193].

Period 2011- 2016	High	Low	Average 11- 16
Year	2016	2012	
Gross revenue in MMNOK x 1,000	27.377.312	24.696.780	26.194.239
BCM	108,6	107,6	103,7
Gross Revenue/BCM	252.093.112	229.523.978	252.994.511
Volume required (BCM)	286	312	285
Years to recover NOK72BN CAPEX	17,42	19,13	17,41

Table 8-2 Volumes required to recover investment
Source: Gassco 2011-2016 annual reports, author's own calculations

[193] E.g., 27.377.312/108,6=NOK 252.093.112 per BCM in 2016. NOK72BN/252.093.112=286/16.4BCM Max throughput=17,42years

Based on 2016-2017 data, it is difficult to predict natural gas requirements post 2030[194]and long-term security of supply. The postponement and cancelation of the development of various fields and transmission systems may have an impact on the steady flow of Norwegian gas to the EU. Furthermore, the Oil & Gas industry has cut back its investment plans, in Norway but also globally. As a result, further activity linked to development of new production capacity on the Norwegian Shelf is expected to stabilise at a lower level than before 2014 (Petoro, 2016). The fields that are coming on line, and the continuous drilling on the NCS suggest that the incentives to explore are still viable. However, considering the cases of Polarled and BSGI, in addition to Johan Castberg, this thesis has found that the viability of development and production is limited by the return on investment. Minor fields can achieve viability with smaller and thus cheaper connections tying into existing systems at a fraction of the cost of installing a trunk line. However due to the lack of major offshore pipelines in the Barents Sea this is not an option. Natural depletion of the fields could result in underinvestment and underutilisation of transmission systems and field development leading to reduced volumes available from the NCS to the European market. The impact can be deduced from a sliding scale depending on the interaction of future demand, discoveries and gas price.

BCM/BN	2020	2025	2030	2040
MAX	110	96	93	91
MIN	87	78	59	41

Table 8-3 pipeline estimates
Source: Gassco, 2016

[194] If usage of fossil fuels would be restricted to e.g., 2030 and pipeline investors would have to recover the investment in 13 years (2017-2030), the maximum cost of the offshore of the pipeline would have to equal or be less than NOK54BN. This assumption would imply a reduced asset life by ~50% from 25 to 13 years and a 25% reduction (NOK18BN) in engineering, procurement, construction and installation cost. These developments impact long term supply of natural gas from Norway.

The supply potentials shown in Table 8-3 (derived from NPD, Gassco and MPE data) define a possible range of Norwegian gas exports to Europe via pipeline ranging from 110-91 BCM in a high demand scenario to 87-41 BCM in a low demand scenario.[195] Comparing the data from 8-3 with table 8-2 it appears that an investment in the BSGI is not economically viable. If assuming the low-end scenario, the implications would suggest that Norway would reduce investments, resulting in reduced revenues and a higher OPEX per BCM in the existing offshore pipeline system. To what extent this will be commercially feasible depends on future gas prices.

As discussed in Chapters 3 and 6 there is room for improved efficiency, however, tax benefits are substantially more accommodating for oil and gas companies in offshore facilities, than in onshore investments. Furthermore, the intention of the change in Norwegian offshore taxes was to stimulate E&P activity, more specifically with the opening of acreage in the Barents Sea in the later licensing rounds in 2016-2017. Norway's aim is to develop resources and fields in order to justify an offshore gas transportation system. There appears to be no incentive to invest in additional transmission systems. The smaller tie-ins (e.g., Valemon, Utsira) have been absorbed by the field owners in joint ventures and are operated by Gassco.

Government reduction of transmission tariffs was aimed at increasing production and transportation of gas through the introduction of competition, the modifications of national policies and the move to hub-based pricing may have had a positive competitive effect considering that the volumes of exported gas have gone up from ~107BCM in 2014 to ~115BCM in 2016. To what extent this is a result of policy changes or market demand remains uncertain. The fact that Norway has the ability to manage its resources in a short-term gas market suggests the regulations meet this requirement. Conversely, from a theoretical perspective the regulations on a

[195] LNG from Snøhvit has been excluded, Norwegian LNG exports are part of the LNG potentials and are not taken into consideration for the purpose of this research. Annual export capacity was around 21.5 MsM3 in 2016

national level still have not excluded market failure, whether in terms of incomplete information, inefficiencies, uncertainty or lack of competition. The aim should be to provide pre-conditions that eliminate market failure corrections ex-post investment or ex-post project execution. Furthermore, the research has identified insufficient documentation of measures to avoid regulatory opportunism in Norwegian regulation and the EU gas directives. The cost associated with regulatory opportunism, if it can be documented, could lead to a reduction of intervention through policy changes.

8.4. AN UNCHANGING SUPPLY OF GAS

According to the NPD and Petoro, oil and gas production on the NCS will continue to remain constant and Norway will maintain its position as a reliable supplier of fossil fuels to the EU. However new discoveries are needed to maintain production levels around 90-100 BCM for the period 2020-2040. With a reduction in revenues due to lower oil and gas prices, the Norwegian coffers needed filling from the Pension fund in 2016 for the first time in its history. This indicates that Norway would need to sell more gas for less revenue, as has been the case since 2014. In order to sell more, it would require more resources to maintain the predicted production horizon.

Falling domestic production rates in the United Kingdom and the Netherlands have contributed to a higher level of imports. Germany absorbed 41% of Norway's gas supply and the United Kingdom 30% in 2016. The United Kingdom also received 20% of its gas import from the Netherlands. This has caused significant issues in the Groningen province where reduced production ordered by the council of State will have knock on effects on supplies to the United Kingdom, Germany and Belgium.

The fact that Norway has made a reduction in investments has not resulted in a reduction in developments or production. The government granted Statoil permission to increase output from the Troll or Gullfaks fields to 33BCM for a year from October 2017 using additional gas technology to extend the field lives, indicating that the government is managing its resources. Updated technologies in drilling and increased efficiency in gas development have resulted in cost reduction and an increase in drilling completion. The government could stimulate activity and take the role of coordinator again in the form of what was known as the NORSOK (Norwegian shelf competitive position) cooperation. Technically there are restrictions to increasing production (just as with the Troll field), but the government has capabilities to increase other fields accordingly.

Although the Barents Sea has been advocated by the Government, Gassco and Statoil as the location which will enable a major increase in future production, thus far the 2017 results have only located reserves in the Kayak, Blåmann and Gemini fields. The much anticipated Korpfjell[196] has not delivered commercially viable results. As discussed in Chapter 7 the potential resources in the Barents Sea would first need to be discovered in accumulations significant enough to create required cooperation between various field owners and transmission system owners to justify another trunk-line. This will require a major investment in cooperation and standardisation. National regulations, and to lesser extent supra-national regulations, would need to anticipate investors' needs and the lessons learned from Polarled in relation to field development, resource allocation and contract guarantees to minimize uncertainties.

Based on the low investments in the Polarled fields with a trunk-line already in place, only a significant find will result in the building of BSGI unless risks are rewarded with a higher return over a shorter period. The choice to explore and develop fields near existing resources in the North Sea is thus more viable, considering this would allow for optimal usage of the existing mature offshore pipeline system.

[196] Korpfjell field was a prospect with a BN-barrel potential. However, the result on 29.08.2017 was a non-commercial gas discovery.

8.5. RECOMMENDATIONS ON FURTHER RESEARCH

Further research on the influence of regulation

Environmental regulation may result in a move away from fossil fuels, even if natural gas will function as a bridging fuel. Furthermore, the transition to a more sustainable environment in the case of Norway, as a substantial supplier of natural resources yet strong advocate of environmental policies, will have implications. An analysis of the social welfare of Norway vis a vis reduced income and the country's willingness to move away from oil and gas revenues would be extremely useful. This research could be taken as a point of departure for an analysis of resource management and regulation.

Further research on the potential for alternative usage of the infrastructure

The research investigated the Norwegian offshore transmission system, transporting natural gas. It furthermore discussed investment options in the transmission system. The research approach might be of value to investigate alternative usage of offshore transmission systems, more specifically transportation of hydrogen from decarbonised natural gas.

Further research related to economic theory

Natural gas pipelines have been identified as resources that exhibit public goods characteristics. In the case of Norway, which exports nearly all its gas, there is the question whether gas and transmission pipelines can be considered public goods if they do not serve a very high percentage of the population of a country.

Further research on the influence of technological advances

Calculating a complete offshore pipeline system is extremely complex. Mathematically modelling a programme in the form of, for instance "a digital twin", to optimise the complete natural gas chain might support balancing and more efficient management of natural resources.

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Appendix

1) PIPELINE CALCULATIONS

Pipeline cost and material selection

(Cherney, 1949), (Yépez, 2008), and (Massol, 2011) depart from a theoretical linear function where the pipeline wall thickness is a ratio from the diameter, however do not incorporate material selection. In gas transmission trunk lines 50-55% of the project cost is the weight of the steel used for the transmission lines. If this[197] is applied to a 40” trunk line with a length of 1000 km with the option to build with either X-70 steel or X-80 steel this could make a difference of $24MM. Besides the diameter and length of a pipeline is the grade or material choice relevant for the product as well as cost factor. E.g. The Europipe II offshore pipeline from Norway to Germany which was built in 1996, is the first pipeline using X-80 grade steel. Figure 35 shows the pipeline transportation cost for a 1000-km pipeline depending on capacity and steel grade. The transportation cost for such a distance can be reduced by 20% using X-100 instead of > X-70. For 20 BCM per year and 1000-km distance the pipeline transportation cost is $0.47/MMbtu using X-70 and $ 0.8/MMbtu with X-100 (IEA, 2011). For purposes of fluid and gas dynamics assumptions will be made in accordance with NORSOK M001 (NORSOK, 2002) recommendations on minimal requirements of Pipeline systems shall be in accordance with DNV OS-F101 “The material selection

[197] See Appendix for example calculation on X-70 and X-80

for pipeline systems for processed gas shall be Carbon-Manganese steel[198]" (Det Norske Veritas, 2010).

2) NPD RESOURCE CLASSES AND PROJECT STATUS CATEGORIES

The NPD has categorised recoverable resources[199] in:

Reserves category 1-3

- Reserves are characterized by the following: - it is petroleum (fossil fuel in all its forms) that has been discovered, e.g., through test drilling
- These volumes can be recovered both technically and commercially
- If these reserves are not already developed and in operation, a plan for development and operation (PDO) is agreed upon (Gassco, 2014)

Contingent Resources category 4-7

- This is petroleum that has been discovered, normally by drilling However, it is currently not considered commercially recoverable, for example due to small volumes, low oil prices, or technical challenges

Undiscovered Resources category 8-9

- These are potential, undiscovered quantities of petroleum. No drilling has been undertaken (NPD, 2011)

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[198] Carbon-Manganese Steels have its manganese content in carbon steels increased for the purpose of increasing depth of hardening and improving strength and toughness

[199] A detailed table is provided in the appendix

Total recoverable Petroleum resources

Undiscovered Discovered

Resource Class	Project Status Category		
	Category		Description
Historical production	0		Sold and delivered petroleum
	1	F A	Reserves in Production
	2	F A	Reserves with an approved plan for development and operation
Reserves	3	F A	Reserves which the licensees have decided to recover
	4	F A	Resources in the planning phase
	5	F A	Resources whose recovery is likely, but not clarified
Contingent Resources	6		Resources whose recovery is not very likely
	7	F A	Resources that have not been evaluated
	8		Resources in prospects
Undiscovered Resources	9		Resources in leads, and unmapped resources

Table Appendix-0-1 Resource classification. Source NPD.

3) A CONSIDERATIONS ON CAPACITY CALCULATION

Capacity calculation

In order to calculate the requirements to transport a certain volume of gas, several parameters will be discussed which have an influence on the construction of an infrastructure and the costs that are involved. The decisions about the to be transported volume of gas and investment are assumed to be taken separately with the estimate of output assumed to be made prior to the investment decision. This assumption is consistent with industrial practice because, in many cases, the flow of gas is an outcome of exogenous negotiations between a natural gas producer and a group of buyers (Massol, 2011). Calculating the flow and pressure needed to transport an amount of gas, optimal investments and infrastructures are dependent on the properties of the gas and the pressure drop due to friction of gas on the inner wall of the pipeline. The properties of gas, e.g., viscosity, gravity and compressibility respond differently to pressure and temperature. Friction can be calculated using the General Flow Equation or Weymouth, Panhandle A & B equations. Several friction and transmission factors are available such as the American Gas Association (AGA) and Colebrook-White. No data is available indicating which model has preference or is more adequate.

Hudkins (2009) investigates the accuracy of nine flow equations and the respective range of error. The produced errors, according to Hudkins, could be pointed to utilisation of the equations outside the intended pipeline environment. "This error could directly affect theoretical optimal pipeline diameter and cause it to be significantly different from the actual optimal pipe diameter" (Carroll & Hudkins, 2009).

Equation Name	Range of Error
Panhandle	3.5 – 10%
Colebrook	2.4 – 10%
Modified-Colebrook	1.0 – 8.8%
AGA	0.2 – 15%
Weymouth	39 – 59%
IGT	7.6 – 17%
Spitzglass	88 – 147%
Mueller	13 – 20%
Fritzsche	40 – 52%

Table Appendix-0-2 Equations and range of error.
Source (Mokhatab Saeid, 2007)

Considering the functionality of the Gassopt model in addition to extensive usage in the industry will the General flow equation with the Colebrook white friction factor and the Weymouth equation be used for possible calculations on ex-post and ex -ante transmission systems and will be compared.

General flow equation

The general flow equation will be

$$Q = 5.747 \times 10^{-4} F \left(\frac{T_b}{P_b}\right) + \left[\frac{P_i^2 - P_d^2}{G T_f L Z}\right]^{0.5} D2.5$$

$$Q = 5.747 \times 10^{-4} F \left(\frac{T_b}{P_b}\right) + \left[\frac{P_i^2 - E^s P_d^2}{G T_f L_e Z}\right]^{0.5} D2.5$$

for which, $L_e = \frac{L(e^s - 1)}{s}\ for\ s = 0.06846\ \left(\frac{H^2 - H^1}{TFZ}\right)$

the distinctive difference between the two flow equations being the incorporation of elevation alternatively assumption of equal level for the purpose of example.

$\sqrt{1/f} = 4\ log\left(\frac{3.7d}{k}\right)$

- *Q=Quantity in Ms*^{3}
- *C=Constant parameter*
- *T_b=Temperature base*
- *P_b= Pressure base*
- *d=diameter in mm*
- *Root 1/f= flow factor*

The Weymouth equation

The purpose of discussing the following equations is to establish a general accepted means to calculate the requirements to transport gas from point A to point B. The equation is applied to gas flows at high pressures because of its accuracy under these specific circumstances. The equation defines the relationship between the flow and the pressure drop due to friction through a horizontal pipeline segment defined as:

$$Q=\frac{C_0}{\sqrt{l}} D^{\frac{8}{3}} \sqrt{\left(\frac{P1}{P2}\right)^2 -1}$$

- *Q =quantity*
- *D =diameter*
- *L = length*
- *P1 =pressure at beginning*
- *P2 =pressure at end point*
- *C_0 = exogenous constant parameter*

Flow in pipelines is indicated inter alia by a Reynolds number.

> Reynolds developed a dimensionless number that may be considered as the ratio of the dynamic forces of mass flow to the shear stress due to viscosity. If the Reynolds number is less than 2000, flow may be considered laminar. If it is above 4000, the flow is turbulent. In the zone between 2000 and 4000 the flow is partially turbulent, however cannot be predicted by the Reynolds number (Gas Processors Suppliers Association, 2004, p. 456).

The flow is affected by friction in gas flows with low and high Reynolds numbers.

Colebrook White

This equation is $\frac{1}{\sqrt{f}} = -2log_{10}\left[\frac{e}{3.7D} + \frac{2.51}{R_{e}\sqrt{f}}\right] for\ R_e > 4000$

Modified Colebrook White

This modified equation takes into consideration $\frac{1}{\sqrt{f}} = -2log_{10}\left[\frac{e}{3.7D} + \frac{2.825}{R_{e}\sqrt{f}}\right]$

Gas compressibility

Gas is compressible. A distinction must be made between isothermal gas compressibility (Mokhatab Saeid, 2007) which is generally used to determine the compressible properties of a reservoir on one hand and the gas deviation factor Z or super-compressibility on the other hand. The latter will be further discussed in this Section.

Two particularly difficult tasks are how to calculate the given gas' deviation from an ideal gas (specified as the Z-factor), and how to calculate the friction occurring between the gas molecules and the pipeline wall (specified by the friction factor).

4) COMPRESSOR POWER

Another important field of interest is to clarify compressor power requirements needed for transporting the natural gas in the transmission system. The variable costs are directly linked to the fuel consumption in the compressor drive motors. Such motors are either gas turbines or electric motors. These relationships will also clarify marginal costs of transportation as being the marginal cost function, defined as the derivative of the variable cost function.

In order to calculate the compressor power, the compressor's suction pressure and delivery pressures must be defined.

Gas from the well has natural pressure. To what extent this is sufficient to transport it to the next station, whether end terminal or compression station, is dependent on several factors. However, once gas is being treated and the separations process has commenced the pressure is not sufficient for gas to be transported and requires compression. Gas driven turbines have been the main instrument for this task although however, since 2007 Norway has investigated the option for electric shore power. Until now two platforms run on sustainable (predominant hydroelectricity) shore power, Valhall and Troll A with Martin Linge and Ula to follow. The turbine or shore power operates the compressor which compresses and pumps the gas to the next point. Different types of compressors[200] e.g. centrifugal, reciprocating, blade and axial compressor from different manufactures come with different operation characteristics. With the choice of compressor and its performance comes a power output and cost. Nørstebø, Rømo, & Hellemo (2010) modelled compressor performance and demonstrated that "differences between the estimated linearized power consumption and the post-calculated theoretical power consumption lie between 1% and 11%. The resulting pressure and flow values deviate up to 12% and 66% respectively

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[200] (Gas Processors Suppliers Association, 2004) provides in depth explanation of the various types and functions and the required auxilary equipment.

from the user defined pressure and flow values in these cases". This outcome supports (Langelandsvik, et al., 2009) method to ex-post calculate real power consumption based on empirical data and allow for deviation in consumption in ex-ante calculation in the front-end engineering.

To transport gas from A to B a compressor(s) might be required. Depending on the pipeline diameter and the volumes to be transported, variation in compressor power needs to be calculated. To follow Massol (2011) the definition of compressor power required to transport gas from A to B, i.e. inlet pressure of P_0 to a predefined outlet pressure of P_1 Yépez, (2008) equation for power is applied as BN =horsepower per Million cubic feet of gas R =pressure ratio P1/P2 ≥ 1 with C_1 = Positive dimensionless constant parameters and β = Positive dimensionless constant parameters (β < 1. 4)

$$BN = C_1 . (R^{\beta} - 1) Q$$

Calculating economies of scale in a pipeline

Another method of demonstrating economies of scale is by looking at changes in diameter compared to a throughput of a set amount of gas through a fixed length of pipeline. Taking the Weymouth equation and compressibility of gas into consideration[201] the following example as displayed in Figure 30 illustrates that with a smaller diameter of pipe more compression power is required to accomplish the same throughput. More compression power requires a bigger compressor or more compressors raising the variable operating cost.

[201] In the hypothetical example, a natural gas subsea pipeline transports 30 Million m3/day of gas from an offshore platform to a compressor station site 100 km away. The pipeline is buried along a flat terrain. The delivery pressure desired at the end of the pipeline is a minimum of 5500 kPa. assuming a pipeline efficiency of 0.95. The gas gravity is 0.65, and the gas temperature is 18°C with a base temperature = 15°C and base pressure 101 kPa. The gas compressibility factor Z = 0.92.

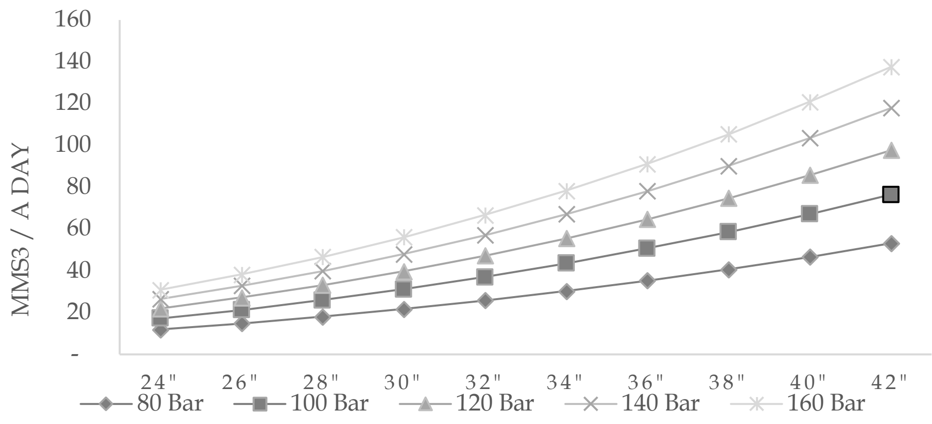

Figure 35 Inlet pressures for different pipes transporting gas
Source: Author's own calculations

The red baseline is set at 30 Million m3/day[202]. It requires 160 Bar of pressure for a 24-inch pipeline to meet the 30 MMs^3 of throughput, whilst at half the pressure, 80 Bar, it can make use of a 38-inch.

5) PUBLIC AND PRIVATE OWNERSHIP

Build, operate, and transfer (BOT)

> The public administration delegates planning and realisation of the project to the private party together with operating management of the facility for a given period of time. During this period, the private party is entitled to retain all receipts generated by the operation but is not the owner of the structure concerned. The facility will then be transferred to the public administration at the end of the concession agreement without any payment being due to the private party involved (Yescombe, 2007, p. 8).

[202] For the example, standard pipe x-70 and diameters have been used rather than exotic alloys or one-off made diameters. The rounding has been upward to meet the demand.

Build, operate, and own (BOO)

> The private party owns the assets. Ownership is not transferred at the end of the concession agreement. Therefore, the residual value of the project is exploited entirely by the private sector. (Gatti, 2008, p.7)

build, own, operate, and transfer (BOOT)

The private party owns the assets. At the end of the concession term the works are transferred to the public administration, and in this case a payment for them can be established.

Design, build, finance, and operate (DBFO)

The public administration pays an annual toll to the private concession holder based on the volume of throughput the transmission system and the service levels. The end user does not actually pay a toll to the operator. The final cost of construction is factored into the e.g., national budget and so is paid for by citizens through taxes (Gatti, 2008).

6) CREDIT RATINGS

	Investment Grade	Rating
Highest grade		
S&P	The issuer's capacity to meet its financial obligation is extremely strong	AAA
Moody's	These obligations are judged to be of the highest quality, with minimal credit risk	Aaa
Fitch	Highest credit quality, denotes the lowest expectation of credit risk. Exceptionally strong capacity to payment of financial commitments	AAA
High Grade		
S&P	The issuer's capacity to meet its financial obligation is very strong, differing from the highest-rated obligation only to a small degree	AA+ AA AA-
Moody's	These obligations are judged to be of high quality and are subject to very low credit risk	Aa1 Aa2 Aa3
Fitch	Very high credit quality, denotes expectations of very low credit risk. Very strong capacity to payment of financial commitments	AA+ AA AA-
Upper Medium Grade		
S&P	The issuer's capacity to meet its financial commitments. However, it is more susceptible to the adverse effect of changes and circumstances and economic conditions than higher grade obligations.	A+ A A-

Moody's	Obligations rated "A" are considered upper medium grade and are subject to low credit risk.	A1 A2 A3
Fitch	High credit quality, denotes expectations of low credit risk. Strong capacity to payment of financial commitments	A+ A A-
Lower Medium Grade		
S&P	Exhibits adequate protection parameters. Adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the issuer to meet its financial commitments.	BBB+ BBB BBB-
Moody's	These obligations are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics.	Baa1 Baa2 Baa3
Fitch	Good credit quality, denotes that there are currently expectations of low credit risk. The capacity for payment of financial commitments so considered adequate but adverse changes in circumstances and economic conditions are more likely to impair this capacity.	BBB+ BBB BBB-
Speculative Grade		
S&P	Less vulnerable to non-payment than other speculative issues, However, the issuer faces major ongoing uncertainties or exposures to adverse business, financial or economic conditions which could lead to inadequate capacity to meet its financial commitment.	BB+ BB BB-

Moody's	These obligations are judged to have speculative elements and are subject to substantial risk.	Ba1 Ba2 Ba3
Fitch	Speculative, there is a possibility of credit risk developing, particularly as a result of adverse business, financial or economic or market changes	BB+ BB BB-

Table Appendix-0-3 Credit ratings

7) NOK EXCHANGE RATE 1960-2017

22/9/2017
Exchange rates

Land	**EU** Euro	**UK** Pound	**USA** Dollar
NOK per:	1 EUR	1 GBP	1 USD
2016	9,2899	11,3725	8,3987
2015	8,9530	12,3415	8,0739
2014	8,3534	10,3690	6,3019
2013	7,8087	9,1968	5,8768
2012	7,4744	9,2199	5,8210
2011	7,7926	8,9841	5,6074
2010	8,0068	9,3402	6,0453
2009	8,7285	9,8052	6,2817
2008	8,2194	10,3304	5,6361
2007	8,0153	11,7237	5,8600
2006	8,0510	11,8141	6,4180
2005	8,0073	11,7111	6,4450
2004	8,3715	12,3401	6,7372
2003	8,0039	11,5670	7,0824
2002	7,5073	11,9461	7,9702
2001	8,0492	12,9414	8,9879
2000	8,1109	13,3129	8,8058
1999	8,3101	12,6252	7,8047
1998		12,5007	7,5465
1997		11,5958	7,0788
1996		10,0795	6,4543

1995	9,9997	6,3369
1994	10,7954	7,0521
1993	10,6625	7,1060
1992	10,9326	6,2060
1991	11,4365	6,4889
1990	11,1504	6,2544
1989	11,3077	6,9078
1988	11,5960	6,5262
1987	11,0262	6,7355
1986	10,8504	7,3974
1985	11,0775	8,5856
1984	10,8714	8,1694
1983	11,0686	7,3018
1982	11,2798	6,4729
1981	11,5770	5,7461
1980	11,4936	4,9394
1979	10,7464	5,0640
1978	10,0548	5,2417
1977	9,2955	5,3232
1976	9,8722	5,4565
1975	11,5733	5,2283
1974	12,9240	5,5257
1973	14,0883	5,7518
1972	16,4775	6,5895
1971	17,1527	7,0185
1970	17,1145	7,1434
1969	17,0899	7,1534
1968	17,1113	7,1500
1967	19,6513	7,1567
1966	19,9805	7,1533
1965	19,9933	7,1567
1964	19,9916	7,1608
1963	20,0225	7,1542
1962	20,0407	7,1401
1961	20,0208	7,145
1960	20,0292	7,136

Table Appendix-0-4 Currency conversion
Source (Norges Bank, 2017)

8) CONVERSION TABLE

1-barrel oil ≈ 159 litres

1 Scm oil ≈ 6.29 barrels

1 tonne oil ≈ 1.18 Scm oil

1 Scm oil ≈ 0.85 tonne oil

1 Scm gas = 35.315 Scf gas

9) FINANCIAL EQUATIONS

The Net Present Value (NPV) criterion

"One should invest if the present value of the expected future cash flow from an investment is larger than the cost of the investment" (Pindyck & Rubinfeld, 2012)

$$NPV = \sum_{t=1}^{n} \frac{(R_t - C_t)}{(1+i)^t} - I_0$$

the net present value is described as the sum of all present values in a discrete time period (*T*) submitted to an interest rate (*R*) in which the cost of capital (*C*) to finance the investment (*I*) will be deducted from the rate of return and taking the initial investment into account.

IRR, Internal Rate of Return

Alternatively, in order to find the discount rate for which the NPV = 0 (or, costs equal benefits). This rate is known as the internal rate of return (IRR) the higher the return rat is the more profitable the investment must be to capitalise on the investment.

$$\sum_{t=1}^{n} \frac{(R_t - C_t)}{(1+i)^t} = I_0 \qquad IRR$$

Both methods have the option to make use of the (WACC) to obtain the cost of capital.

Cost of Capital

Capital related expenses will be accounted for through Weighted Average Cost of Capital (WACC)[203]. This may prove an important factor assuming different types of owners of the transmission system have the same return function, proportionally the same cost, and potentially can only differentiate in the cost of capital employed, leveraged proportion in its portfolio or discount periods.

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

The cost of capital is build up from the equity (*E*) times the rate of equity (R_E) in addition to the portion (*V*) of debt (*D*) times the rate of debt (R_D).

10) SUMMARY EU REGULATIONS

The European union, in relation to natural gas and the IEM, is build up out of 6 institutions. These institutions are responsible for European gas regulations and legislation. The six institutions are, The European Commission; The Council of Ministers; The European Parliament; The European Court of Justice; The Economic and Social Committee; The Committee of Regions; and The Court of Auditors and will be concisely discussed.

1. The European Commission consists of representatives of each EU country/member state (27) with the interest of the EU as main incentive. From a natural gas perspective, Directorate- Generals (DG) are allocated to Competition, Energy and Transport, Environment, and Internal Market and Services (Nello., 2005) cited in (Spanjer, 2006).

203 For this example, tax shield has been left out of the equation $\mathrm{WACC} = \left(\frac{\mathrm{E}}{\mathrm{V}}\right) * \mathrm{R_E} + \left(\frac{\mathrm{D}}{\mathrm{V}}\right) * \mathrm{R_D} * (1 - Tc)$

2. The European Council, contains members of states and governments of each of the member states.
3. The Council of ministers made up out of ministers of each of the member states is considered the main deciding authority. Members are appointed, and decisions are made by votes.
4. The European Parliament legislative power is equal to that of the Council, in addition is the only elected council.
5. The European Court of Justice comprises of one judge of each of the Member States, additionally eight Advocates-General.
6. Relevant parties and councils in relation to natural gas, are e.g., CEER, ACER, OGPI, GIE and EFET. The aforesaid councils, bodies and or associations represent EU stakeholders, institutions, regulators, competition authorities, supporting EU decisions on regulations relevant for the natural gas value chain. Other stakeholders are national regulators, producers, shippers in a national boy or association representing national needs in relation to gas value chain issues. Approving and implementing a regulation such as e.g., the gas directives requires uniformity from all parties to be able to approve a regulation, bearing in mind all stakeholders interests.

Gas Directives

In this research, a directive is an agreement on a uniform EU desire to implement and execute the common objective as set out in the EU agreement for each member state. It leaves room for each member state to implement this objective as deemed appropriate allowing for national regulation to meet the requirements set out in the directive.

From a Norwegian perspective as resource owner and exploiter pre-gas directives, the upstream was regulated by the GFU (de facto monopoly) the midstream was regulated by the GFU and the Downstream was regulated and controlled by national monopolies (Gasunie, Distrigaz, SNAM, BG and Gaz de France) in Belgium, France, The United Kingdom, The Netherlands and Germany in accordance with EU, 1995 The Directive 91/296/EEC on the transit of natural gas through grids. The Official Journal of The European Communities provides the complete list of European high-pressure transmission grids (EU, 1995).

It could be argued that despite fluctuations in gas prices throughout history, the demand side (buyers) had a reason to improve security of supply at an "acceptable" price[204], not all buyers were appreciative on pricing. In the GFU period, services to the end users were bundled e.g., explore, produce, sale, and offshore transportation. Furthermore, the seller owned the gas all the way through the system from production until final sale to the wholesale market, thus offering security of supply and a high level of nomination rights for the buyer. (MPE, 2001) This process supported efficiency and optimised assets. The GFU / FU system, SDFI ownership and Statoil, all under the control of the MPE, represented the NGF and were national policy instruments making it possible to achieve lower costs through economies of scope, better resource management and a strengthened market position for Norwegian gas production and its sale (Austvik., 2011).

First Gas directive

The first energy package was adopted in 1998 and transposed in 2000. The main objectives of the first directive concerned obligations related to connection and supply of connected (captive) customers; gas quality; safety; security and diversification of gas supply; interconnections and new gas infrastructure; development and operation of underground gas storage; gas balancing; marketing of gas; price equalisation; sustainability; energy saving; research and development in the gas sector and the "small fields policy". (EU, 1998)

[204] The high prices and the strategic importance of energy in economic and political affairs have raised questions about how the liberalization of energy-markets may increase economic efficiency, and thus stimulate growth, when at the same time energy security needs to be taken into consideration (Stern, 2002) (EU, 2006) (Finon, 2008)

The second Directive

The Second Energy Package was adopted in 2003, its directives to be transposed into national law by Member States by 2004, with some provisions entering into force only in 2007. Industrial and domestic consumers were now free to choose their own gas and electricity suppliers from a wider range of competitors. proposed changes regarding the market opening, TPA and unbundling provisions (Spanjer, 2006) ultimately leading the latest round of EU energy market legislation (EU, 2003).

Third Gas Directive

In April 2009, a Third Energy Package[205] seeking to further liberalise the internal electricity and gas markets was adopted, amending the second package and providing the cornerstone for the implementation of the internal energy market. The third package, which has been enacted to improve the functioning of the internal energy market and resolve structural problems. It covers five main areas:

- Unbundling energy suppliers from network operators
- Strengthening the independence of regulators
- Establishment of the Agency for the Cooperation of Energy Regulators (ACER)
- Cross-border cooperation between transmission system operators and the creation of European Networks for Transmission System Operators
- Increased transparency in retail markets to benefit consumers (EU, 1998)

[205] (Yfimava, 2013) provides comprehensive work on the third energy package and Gas target model

With the establishment of ACER came its work the Gas Target Model (GTM). Following the 18th Madrid Forum in 2011, the Council of European Energy Regulators (CEER) developed a vision for the European gas market the Gas Target Model (ACER, 2015).

Gas Target Model (2011)

The GTM was set up for short-term (2014) implementation of internal gas markets and a long-term vision of the gas market to 2020 and its 2016-2017 review to extend this to 2025 and the Internal Energy Market[206] (IEM). ACER pursued the GTM which is a framework to ensure efficient markets, strongly building on access issues and gas demand and supply considerations. In addition, implementation of the third energy package which included:

> provide investment signals in both gas production and in gas network infrastructure, including transmission and storage, in order to meet the demands of European gas consumers […] shippers to access the gas infrastructure are basic requirements for competition to develop and for the network to be used efficiently (ACER, 2015).

GTM2 (2014)

The function of Gas Target Model 2 is to ensure that a flexible regulatory framework for gas wholesale markets and identify appropriate measures to develop hub liquidity and improved tools for market integration (ACER, 2015).

[206] Five key objectives for the Internal Energy Market (IEM) by 2025:
1) Establishing liquid, competitive and integrated wholesale energy market
2) Enhancing Europe's security of supply and channelling the external element of IEM
3)Moving to a low carbon society with increased renewables and smart, flexible responsive energy supply
4) Developing a functioning retail market that benefits consumers
5) Building stakeholder dialogue, cooperation and new governance arrangements

Four Network Codes

The implementation of the Third Energy Package with respect to gas markets is consistent with the evolution envisaged in the GTM, and covers matters such as the full unbundling of network operators, the establishment of congestion management procedures (CMP) and the development of Network Codes (NCs), e.g. for capacity allocation mechanisms in gas transmission systems (CAM NC), gas balancing (Balancing NC), interoperability and data exchange (Interoperability NC) and tariff structure harmonisation (Tariff NC). For European energy regulators, the implementation of the Third Energy Package, as well as the continuing development and implementation of the Framework Guidelines and binding Network Codes, remain key priorities.

Interoperability NC

The network code on interoperability aligns the complex technical procedures used by network operators within the EU, and possibly with network operators in the Energy Community and other countries neighbouring the EU[207].

Balancing NC

The Network Code on Gas Balancing of Transmission Networks sets out gas balancing rules including the responsibilities of transmission system operators and users. This network code[208] was applied 1 October 2015.

Capacity Allocation Management NC

The Network Code on Capacity Allocation Mechanisms[209] in Gas Transmission Systems requires gas grid operators to use harmonised

[207] Commission Regulation establishing a Network Code on interoperability and data exchange rules (703/2015/EU)
[208] Commission Regulation establishing a Network Code on Gas Balancing of Transmission Networks (312/2014/EU)
[209] Commission Regulation establishing a Network Code on Capacity Allocation Mechanisms in Gas

auctions when selling access to pipelines. These auctions sell the same product at the same time and according to the same rules across the EU (applied November 2015).

Congestion Management Procedures (CMP)

The European Commission's rules on congestion management procedures[210] aim to reduce congestion in gas pipelines. They require companies to make use of their reserved capacity or risk losing it. Unused capacity is placed back on the market.

Transmission Tariff Structures NC

The network code on harmonised transmission tariff structures[211] for gas enhances tariff transparency and tariff coherency by harmonising basic principles and definitions used in tariff calculation, and via a mandatory comparison of national tariff-setting methodologies against a benchmark methodology. It also stipulates publication requirements for information on tariffs and revenues of transmission system operators.

EU Regulations table

1987	Single European Act (OJ L 169/1)
1988	The Internal Energy Market' (COM (88) 238)
1990	price Transparency Directive (90/377/EEC) (Finon & Locatelli, 2008)
1991	Gas Transit Directive (91/296/EEC)

Transmission Systems (984/2013/EU)

210 Commission Decision (EU) 2015/715/EU amending Annex I to Regulation (EC) 715/2009 on conditions for access to the natural gas transmission networks
Commission Decision on conditions for access to the natural gas transmission networks [2012/490/EU]

211 Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas. Regulation on Conditions for Access to the Natural Gas Transmission Networks (715/2009/EC).

1994	Hydrocarbons Directive (94/22/EC)
1998	First Gas Directive (98/30/EC)
2000	Gas market opening begins
2003	Second Gas (2003/ 55/EC) Directive
2004	European Regulators Group for Electricity and Gas (ERGEG) established.
2005	Market opening following the second Directives begins
2005	Regulation (1775/2005) on conditions for the access to natural gas transmission networks
2007	Publication of Energy Package and final report on the energy Sector Inquiry (SEC (2006 1724)
2007	Full gas and electricity market opening
2009	P6_TC1-COD (2007)0197 Position of the European Parliament adopted at first reading on 18 June 2008 with a view to the adoption of Regulation (EC) No …/2008 of the European Parliament and of the Council on establishing an Agency for the Cooperation of Energy Regulators
2009	Third Gas Package
2010	The European energy directives, specifically security of supply Regulation
2011	Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT).
2011	COMMISSION IMPLEMENTING REGULATION (EU) No 1348/2014 on data reporting implementing Article 8(2) and Article 8(6) of Regulation (EU) No 1227/2011 of the European

	Parliament and of the Council on wholesale energy market integrity and transparency (implementing acts)
2013	Commission Regulation (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009 of the European Parliament and of the Council Text with EEA relevance
2014	Commission Implementing Regulation (EU) No 1348/2014 of 17 December 2014 on data reporting implementing Article 8(2) and Article 8(6) of Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency Text with EEA relevance
2014	EN Official Journal of the European Union L 91/15 COMMISSION REGULATION (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks Text with EEA relevance
2014	Directive 2014/65/EU of the European Parliament and of the Council Of 15 May 2014 On Markets in Financial Instruments and Amending Directive 2002/92/EC And Directive 2011/61/EU (Recast)
2016	Published: 2016-06-30 EU law COMMISSION REGULATION (EU) …/… establishing a network code on harmonised transmission tariff structures for gas
2016	COMMISSION REGULATION (EU) No …/.. establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and repealing Commission Regulation (EU) No 984/2013

2017	Commission Implementing Decision (EU) 2017/89 of 17 January 2017 on the establishment of the annual priority lists for 2017 for the development of network codes and guidelines (Text with EEA relevance.)

Table Appendix-0-5 EU Regulations and Directives 1987-2010