NTNU – Trondheim
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The effects of risk preferences on investments and trade in the natural gas market

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Oppgavens (foreløpige) tittel	
The effects of risk preferences on investments and trade in the natural gas market	

Oppgavetekst/Problembeskrivelse

The purpose is to develop a stochastic equilibrium model for the natural gas market that incorporates uncertainty and the effects of risk in strategic/long-term decision making.

The problem includes investment decisions in infrastructure and production capabilities and has multiple decision makers.

Main content
1. Desription of the problem
2. Formulation of model(s) for the problem
3. Implementation/Solution method(s) for the model(s)
4. Computational study
5. Discussion of results and applicability of the model(s) and results

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Preface

This is a master thesis in Managerial Economics and Operations Research (AØO) at the Department of Industrial Economics and Technology Management (IØT), at the Norwegian University of Science and Technology (NTNU). The thesis develops and solves a mixed complementarity problem for a natural gas market where the producers can exert market power and express risk averse behaviour.

Working on this thesis has been an exciting journey. The thesis builds on our project report from the Fall 2013 with a similar topic. We started the work on the project with close to no prior knowledge about market modeling or risk measures, but were excited by the opportunity to learn about these intriguing topics. The process has been challenging, but we feel like we have come a long way, and are proud to present our results in this thesis!

We wish to thank our advisors Ruud Egging and Alois Pichler for their support and enthusiasm. We are grateful for the constructive discussions and valuable feedback they have provided during the course of this work.

Trondheim, June 4, 2014

Øyvind Iversen Kalvø
Thomas Walle-Hansen

Abstract

The European gas market faces declining production, and imports are expected to increase. In the US, natural gas production has increased by one third during the last seven years due to the extraction of natural gas from shale formations. Looking to the US, countries like Poland and Ukraine are starting to invest in shale gas development. The potential from this could be large, but is characterized by uncertainties in resource estimates, economic viability and political climate with respect to hydraulic fracturing. Risk is therefore an important characteristic of the European natural gas market development.

Current models of the European natural gas market have not accounted for the impact of risk averse behavior in combination with market power and the possibility of shale gas development. Risk aversion could possibly affect investment and trade in ways current models cannot predict. For better decision support, insights in the impacts of risk preferences on investments and trade in the natural gas market are needed.

In this thesis we have developed a model for a natural gas market that accounts for market power and risk averse behavior amongst producers using the risk measure conditional value at risk. The model treats different sources of natural gas as separate resources and accounts for endogenous expansions of production capacities, pipeline capacities and natural gas reserves. The model is solved as a multi-stage stochastic mixed complementarity problem.

We have studied a case where producers are moderately risk averse, and found that shale gas development might increase the total production by 15.8% from 2015 to 2025 and account for 15.9% of the total European production. We have found that successful shale gas development might reduce Russia's market share in Ukraine by up to 44%. Under risk aversion, shale gas investments were found to be 16% lower in Poland and 1.5% lower in Ukraine compared to the investment levels in a risk neutral solution of the same problem. This indicates that modeling risk averse behavior will give important insights when studying investments in a natural gas market.

Sammendrag

Det europeiske gassmarkedet står overfor synkende produksjon, og det er forventet økt import i fremtiden. I USA har produksjon av naturgass økt med en tredjedel i løpet av de siste syv årene. Denne økningen skyldes hovedsakelig utvinning av gass fra skiferformasjoner, kalt skifergass. Land som Polen og Ukraina er i ferd med å investere i skifergassutvikling. Potensialet fra dette kan være stort, men er preget av usikkerhet i ressursanslag og økonomisk levedyktighet. Potensialet er også sterkt påvirket av den politiske holdningen til hydraulisk frakturering. Risiko er derfor et viktig aspekt å ta høyde for i modellering av den fremtidige utviklingen i det europeiske naturgassmarkedet.

I denne masteroppgaven har vi utviklet og løst et flerstegs stokastisk blandet komplementaritetsproblem for et naturgassmarked med markedsmakt og risikopreferanser blant produsenter uttrykt ved risikomålet Conditional Value at Risk. Modellen tillater flere naturgass-kilder, utvidelser av produksjonskapasiteter, rørledningskapasiteter og naturgassreserver.

Nåværende modeller av det europeiske gassmarkedet har ikke tatt høyde for virkningen av risikoavers atferd i kombinasjon med markedsmakt og mulighet for skifergassutvikling. Risikoaversjon kan muligens påvirke investeringer og handel på måter dagens modeller ikke kan forutsi. Innsikt i konsekvensene av risikopreferanser på investeringer og handel i markedet for naturgass er nødvendig for å fatte bedre beslutninger.

Vi har studert en situasjon hvor produsentene har en moderat grad av risikoaversjon og funnet at skifergass kan øke den samlede produksjonen i Europa med 15.8% fra 2015 til 2025 og utgjøre 15.9% av den totale produksjonen i 2025. Vi har funnet at vellykket skifergassutvikling kan redusere Russlands markedsandel i Ukraina med 44%. Investeringene ble funnet å være 16% lavere i Polen og 1.5% lavere i Ukraina når produsentene er risikoaverse i forhold til investeringsnivået i en risikonøytral løsning av det samme problemet. Dette indikerer at modellering med risikoavers adferd vil gi viktig innsikt når investeringer i et naturgassmarkedet skal studeres.

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"A nation that can't control its energy sources can't control its future."

- Barack Obama, President of the United States of America

1 Background and Motivation

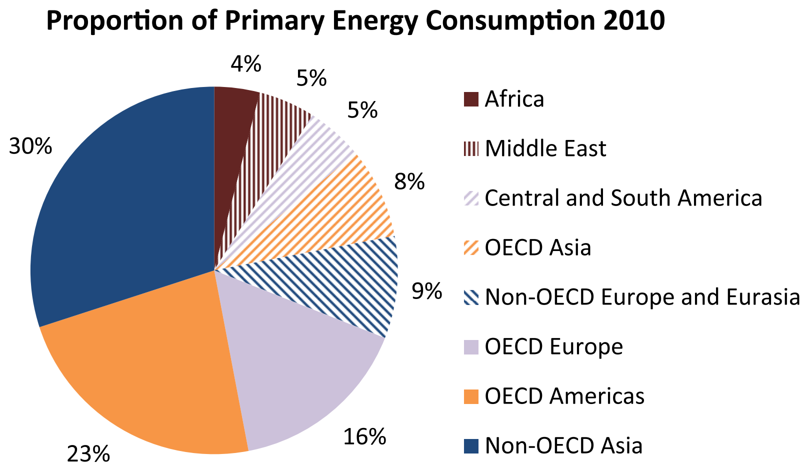
Energy is an important global topic. Energy is needed to keep us warm, to make our food and to transport us to the places we want to go. All over the world, energy is used in a many different forms; for domestic applications such as heating and lighting, industrial uses such as manufacturing, in the commercial sector for stores, offices etc., and in the transportation sector.[1] It is difficult to imagine a world without energy sources.

Energy is consumed globally. Figure 1.1 shows the world's geographical distribution of energy use in 2010, and shows that Europe, Asia and America account for more than two thirds of the world's annual energy consumption. The Energy Information Agency (EIA) projects that the growth in energy use will be 1.5% per year in the coming 30 years, reaching almost twice of today's use in 2040 [EIA, 2013a]. Most of the growth in the coming 25 years in energy consumption is expected to come from developing countries, according to British Petroleum (BP) [2014]. With its global presence and diverse uses, it can be said that energy is indeed needed to keep the world running. Energy supply and demand is therefore both an interesting and important topic to explore.

Studying energy supply and demand gives us an opportunity to understand more about how this important part of our civilization will develop in the future. This chapter presents the background and motivation for the research in this thesis. An overview of energy and natural gas as a part of the energy mix is presented, followed by aspects of the European natural gas market, the motivation for the thesis and research questions central to the work.

[1] Energy Information Agency (EIA) shows uses of energy in the United States divided in different sectors in [EIA, 2013c]

Figure 1.1: Primary Energy Consumption By Region. Energy consumption is highest in Asia, Europe and America. Source: EIA [nd]



1.1 Natural Gas as an Energy Source

Natural gas is among the most important energy sources. According to the International Energy Agency (IEA) [2013c], natural gas accounted for 25.7% of the total global primary energy supply in 2012, second only to oil.[2] Figure 1.2 illustrates the relative sizes of the different energy types in 1973 and 2012 as reported by IEA [2013c].

From Figure 1.2, we can see that the share of natural gas has increased during the past 40 years, while at the same time, total energy consumption also has increased. The role of natural gas is expected to be even greater in the future, BP [2014] expects natural gas consumption to grow at a rate of 1.9% per year from 2014 to 2035, while total energy consumption is expected to grow at a rate of 1.4% per year. Figure 1.3 shows historical and projected shares for different sources of energy as presented in BP [2014]. The figure shows a growth in the shares of gas and renewables, while coal and oil have declining shares. This suggests that natural gas might become the biggest energy source some time after 2035. As both a big and growing energy source, natural gas is interesting to study.[3]

[2]Primary energy is a term used when comparing different energy sources. The energy sources are converted to energy equivalents for comparison. See for example IEA [2013a] for an explanation.

[3]Even though BP and IEA do not agree on the relative shares between primary energy sources

Figure 1.2: Primary Energy Sources. Natural gas has become more important the last 40 years. Source: IEA [2013c]

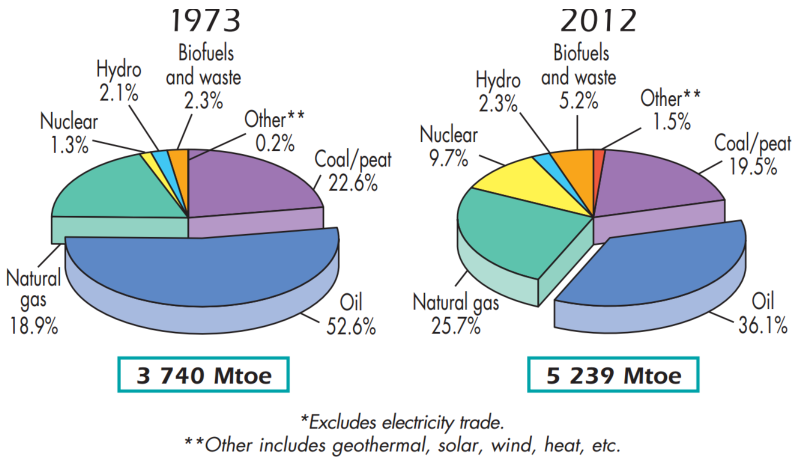
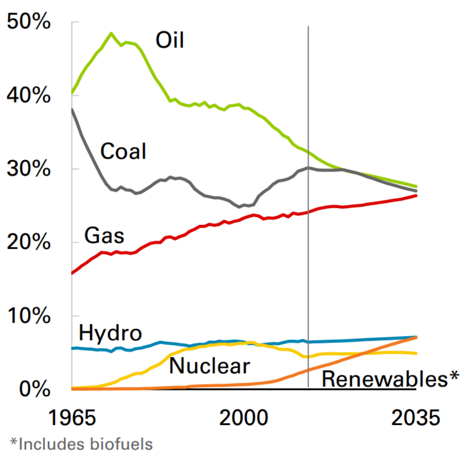


Figure 1.3: Shares of Primary Energy Sources. Gas is expected to become more important in the next 20 years. Source: BP [2014]



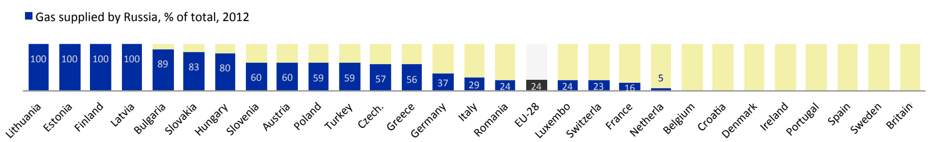
(as seen from Figures 1.2 and 1.3) they both agree that natural gas is among the top three energy sources today.

1.2 The European Gas Market

The European natural gas consumption is currently the fourth largest in the world, after being surpassed by the growing consumption in Asia and Oceania in 2009 [EIA, nd]. The dynamics of such a big market consisting of many countries and developed infrastructure makes it an interesting market to study. The size, however, is not the only aspect that makes the European natural gas market an exciting object of study. The market power held by suppliers and the need to secure natural gas supplies make the European natural gas market exciting from both an economical and political point of view.

Today, a few countries account for the majority of supplies to many European countries. Norway, Algeria and Russia supplied more than half of all natural gas in the European Union (EU) in 2007, according to the EC [2009]. In certain countries (Lithuania, Latvia, Finland and Estonia), Russia is the sole provider of natural gas, as seen in a recent briefing by the newspaper the Economist [2014]. Figure 1.4 (adapted from the Economist [2014]) shows the amount of gas supplied by Russia as percentage of total amount of gas supplied. Note that Russia supplies more than half of the gas in 13 of the 28 EU countries, and all the gas in four of them.

Figure 1.4: Amount of gas supplied by Russia as percentage of total amount of gas supplied in 2012. Russia is the sole supplier to several European countries. Adapted from the Economist [2014]



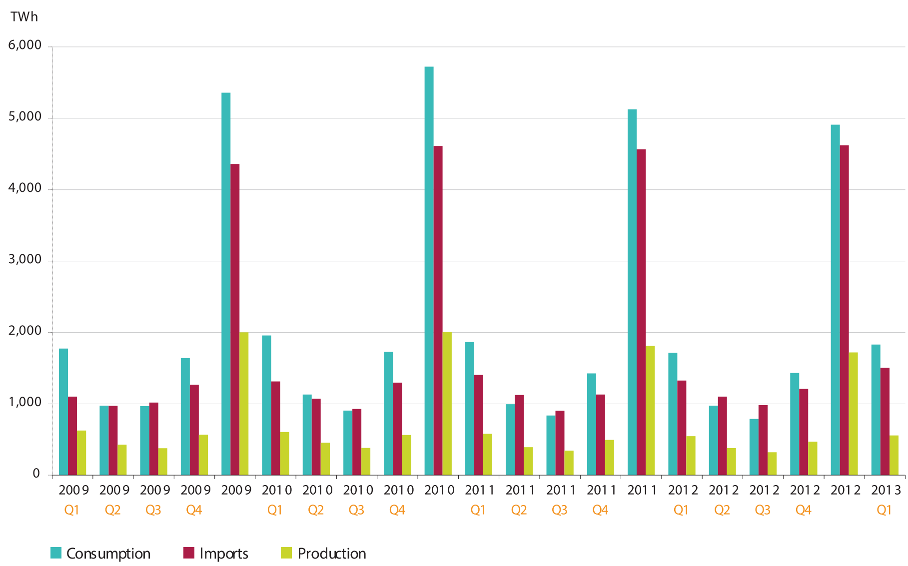
Such a situation with only one supplier or a small number of suppliers opens up for use of market power by the supplier, pushing prices up and volumes down. With a less diversified supply base, the countries also become more vulnerable to disruptions in supply. As a consequence, natural gas supply has become a political topic, and natural gas has been used as a political weapon. Most notably, Russia's actions towards Ukraine and other buyers have highlighted how natural gas supply is very much a political topic in Europe.

In 2009, Russia first cut all gas supplies to Ukraine because Ukraine did not pay for gas supplies on time, and subsequently reduced supply to Europe through Ukraine, affecting several European countries supplies [Rao, 2014; BBC, 2009].

More recently, Russia has actively displayed the use of gas supply as a political weapon against Ukraine, threatening to increase prices as consequence of Ukraine's cooperation with Europe and the EU when signing the EU integration pact [Hille et al., 2014]. As noted by the Economist [2014], this supply situation has also led Russia's president Vladimir Putin to believe that Europe will be unable to impose serious sanctions on Russia following the annexation of the Crimean peninsula.

Europe's role as a big customer of Russian gas could give a unified Europe buyer power over Russia, and this is believed to balance the power situation because Russia depends on gas revenues just as Europe depends on gas [Matlack, 2014]. Recent developments might reduce Europe's buyer power. On May 21st 2014 Russia signed a 400 bUSD gas deal with China. The contract runs for 30 years and gives Russia a new large customer of natural gas [Perlez, 2014].

Figure 1.5: EU gas consumption, production and imports in TWh. Production is decreasing faster than consumption, causing imports to increase. Source: EC [2009]



The market power of the biggest suppliers to the European natural gas market might increase in the future. Figure 1.5 shows that the production of natural gas has been declining since 2009. Rystad Energy, an energy consultancy, projects that Europe's natural gas production continue to decline in the coming years [Rystad Energy, nd]. At the same time, consumption is also declining, as can be seen in Figure 1.5. However, this decline is at a lower rate than the decline in production, which leads to higher imports. This trend is expected to continue in the future; BP [2013] estimates that Europe's natural gas imports will increase by 74% by 2030. With increased demand for imports, Algeria and Russia's market power might increase in the future as dependence on imports increases.

1.2.1 Shale Gas

One possible solution to Europe's concern for import dependence might be found in shale gas. The US has in recent years reduced their dependence on gas imports by developing shale gas [Medlock III, 2012]. Shale gas is natural gas trapped in shale formations, and is a type of unconventional gas.[4] In the last decade, technological advances in horizontal drilling and hydraulic fracturing[5] have made extraction of large shale gas volumes profitable [EIA, 2013d]. In the United States and Canada, this has led to a "Shale Gas Revolution" referring to the USA increasing domestic natural gas production and with that drastically reducing natural gas imports [Stevens, 2010]. According to EIA [2013d], the US increased its natural gas production from shale plays[6] from 2.7 to 26.9 bcf/d from January 2006 to January 2013 (Figure 1.6). In January 2013 the total US natural gas production was 67 bcf/d. Thus, shale gas has gone from being virtually non-existing to become a major gas supply source.

As a result of the developments in the US, interest in shale resources in the rest of the world have been fuelled [Weijermars and McCredie, 2011]. For Europe, this is particularly interesting because of the current reliance on gas imports. As noted in a report by Chatham House,[7] the EU has grown concerned with increasing dependence on gas imports during the last decades [Stevens, 2010]. Recently Ukraine has taken steps to start development of shale gas, by signing two 10 billion USD contracts with Chevron and Shell to start shale development [LeVine, 2013; Balmforth, 2013]. Analysts report that this can be seen as a response to Russia's dominating role as a natural gas supplier [Fernholz, 2013].

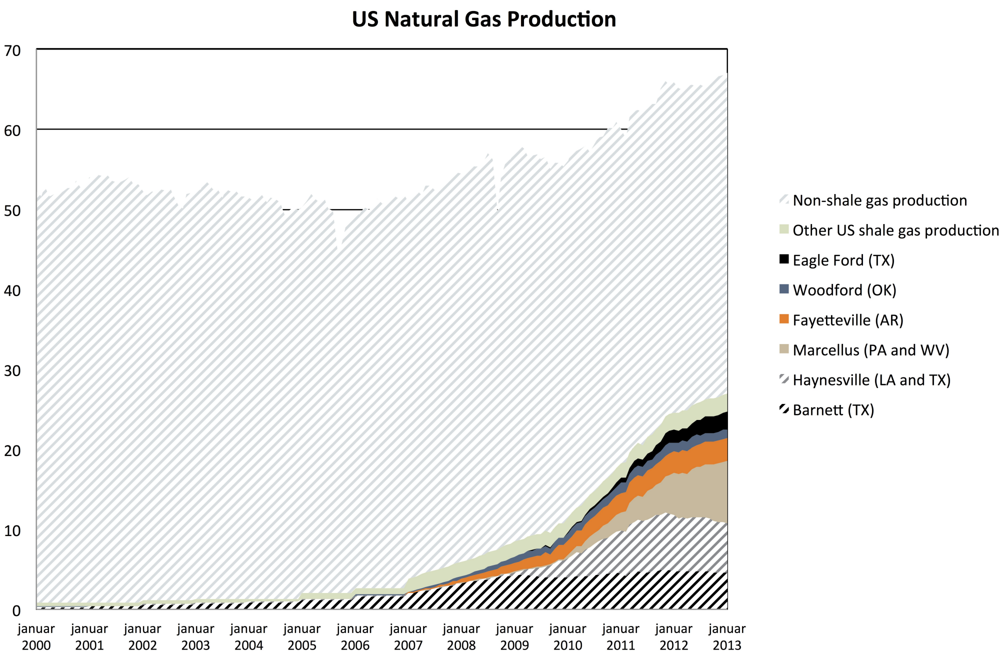
[4]There are two other types of unconventional gas: coalbed methane and tight gas. For more on unconventional gas, see IEA [2013b] and Section 1.3.

[5]Hydraulic fracturing, or fracking, is the process of pumping water, sand and chemical solutions down into the well in order to crack the sedimentary rock formations in order to extract the trapped natural gas.

[6]Shale play refers to a geological region where hydrocarbons such as ethane, methane and propane can be extracted from a shale formation.

[7]Chatham House, home of the Royal Institute of International Affairs, is a world-leading source of independent analysis

Figure 1.6: US Natural Gas Production in bcf/d. Shale gas has led to an increase in supply since 2007. Source: EIA [2013d]



Elsewhere in Europe, shale gas developments at an early stage are taking place. As of April 2014, 17 European countries have issued permits for shale gas extraction and six additional countries have allowed shale gas extraction [the Economist, 2014]. When evaluating whether or not shale gas development should be permitted one of the biggest concerns is how it affects the environment. The next section discusses some environmental concerns related to the petroleum industry.

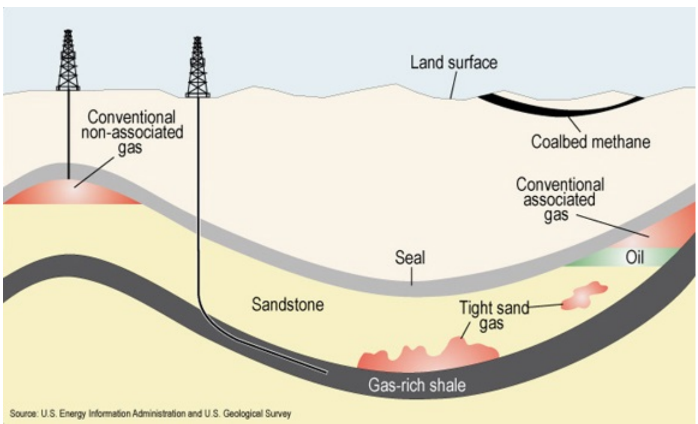
1.3 Natural Gas and Environmental Concerns

Climate change in form of global warming is among the most serious environmental concerns in today's society. Greenpeace [nda] reports that some likely negative consequences of global warming are loss of biodiversity, more extreme climate with droughts, floods and heat waves and disruption of agricultural production. In a 2013 report by the International Panel on Climate Change (IPCC), it is concluded that increases in temperatures globally is attributable to the increase in the atmospheric concentration of CO_2 since 1750 [IPCC, 2013]. As a consequence of this, measures are taken to reduce emissions of CO_2. The European Commission (EC) for example, has committed to work for reducing CO_2 emissions in EU countries by 40% by 2030, leading the United Nations (UN) general secretary to encourage other UN members to do the same [UN, 2014].

Natural gas might play a role in these reductions. Natural gas has a lower carbon content than oil and coal, the two other major energy sources. Therefore, combustion of natural gas leads to lower CO_2 emissions relative to produced energy than oil and coal.[8] Therefore, natural gas might be used where coal and oil is used today to reduce emissions while other, more sustainable sources are developed.

The key difference between conventional and unconventional natural gas is the manner, ease and cost associated with extracting the resource [Canadian Association of Petroleum Producers, nd]. The different types of gas reservoirs are illustrated in Figure 1.7.

Figure 1.7: Illustration of conventional and unconventional gas reservoirs. Extracting gas from unconventional reservoirs often requires more complicated processes such as fracking. Source: EIA [2013d]



[8]EIA shows a table of CO_2 emissions per kWh generated for oil, coal and natural gas on their website [EIA, 2014]. Here, it is shown that natural gas leads to lower CO_2 emissions per kWh generated power than any other fossil fuel. The second best, distillate oil, leads to 46% higher emissions.

Unconventional gas is subject to more environmental concerns than conventional gas due to extraction process differences. Coal bed methane requires water extraction to lower the well pressure and drive the gas from the sedimentary rock. This waste water may be contaminated and have to be disposed of in a sustainable way. Shale gas and tight gas[9] requires hydraulic fracturing to free the gas from the sedimentary rock. Fracking involves pumping large amount of water deep underground. This water is often irretrievable and might be contaminated by toxic fracking fluids. Greenpeace [ndb] states that:

> Though the oil and gas industry claims that fracking has been used safely for decades, there has been little actual study of the environmental effects of the process. In fact, companies engaged in fracking have consistently warned their investors that drilling operations, which include fracking, involve inherent risks including leaks, spills, explosions, blowouts, environmental damage, injury and death.

1.4 Uncertainty and Risk

Assessing what will happen in the future is a difficult task. Due to uncertainty about the future, for example in demand, technological advances and political climate, forecasts are often inaccurate. Therefore, decision makers often have to make irreversible decisions under uncertainty. Often, what will happen in the future decides to what extent a decision made today will have the desired outcome. In this sense we say that the decision maker is subject to risk.

Europe's shale gas potential might be game changing [Jaffe, 2010]. However, the risks associated with developing unconventional resources will probably have a significant impact on whether or not these resources will be developed. The main sources of risk in shale gas development are associated with resource potential, economic viability and political climate [Richter, 2013]. Risk in resource potential is due to the fact that volume estimates are uncertain. The risk in the economical viability is linked to the fact that development costs, demand and prices are uncertain. There is therefore a large economic risk when starting a development project, as it might not turn out to be profitable. Hydraulic fracturing is a disputed technology, and has already been banned in France and several other countries [the Economist, 2014] due to environmental concerns.

[9] Tight gas is natural gas produced from reservoir rocks (most commonly sandstone) with such low permeability that massive hydraulic fracturing is necessary to produce the well at economic rates.

Therefore shale gas developers run a political risk of shale gas being banned after irreversible investments have been made.

These risk considerations are important aspects for evaluating the commercial viability of potential investments [Gracceva and Zeniewski, 2013]. For regulators, it is important to understand how the natural gas sector might develop in the future, and how development might be affected by governmental policies. Based on these considerations, a model that assesses the effect of risk and the potential of shale gas in Europe is needed for better decision making.

1.5 Motivation

Quantitative models provide useful decision support when regulators and companies deal with an uncertain environment like the European gas market. Often, a model that can capture what will happen today and in the future decades as a result of choices made today is needed to make better decisions. Such a long term model is classified as a strategic model and takes the perspective of strategic planning in the planning framework proposed by Anthony [1965].[10]

1.5.1 The Need for Market Models

Market models are useful for a range of applications. Governments and regulators use market models to assess the impacts of different policies and regulations and to plan infrastructural expansions. Organizations and corporations use market models to predict future prices and determine production levels. Current energy market models come in a diverse set of shapes and sizes, and differ in geographical scope, energy sources, form of competition and information structure, among many things. Some models incorporate market power, while others assume perfect competition. The geographical scope ranges from global models to models of a continent or parts of a continent. A thorough description of several leading gas market models is given in Chapter 2.

[10] Anthony [1965] presents three levels of planning: strategic, tactical and operational. Strategic is long-term and concerns what will happen over several years, tactical planning is concerned with a shorter horizon, typically a year, and operational planning is about what will happen now and in the near future, typically weeks from now.

1.5.2 Research Questions and Main Contributions

This thesis develops and solves a stochastic multi-stage MCP for a natural gas network with multiple resources (types of natural gas) and endogenous expansions of capacities in the system, where the producers in the natural gas network have varying degrees of both market power and risk aversion. Different formulations are discussed, and a scheme for solving the model is presented. The main contributions are:

- Developing a stochastic multi-stage MCP for a natural gas network with multiple resources (shale gas and conventional gas), endogenous expansions of reserves and pipeline capacities, where the producers in the natural gas network have varying degrees of both market power and risk aversion.
- Developing a solution procedure for numerical solution of the model using mathematical programming.

Further, the model presented in this work will be used to study the following questions:

- To what extent does shale gas development in Ukraine and Poland have the possibility to reduce their dependence on Russian natural gas imports?
- How do risk aversion and market power affect investments and trade in a gas market?
- How does the perceived likelihood of a shale gas ban affect the investments and trade?

A numerical study will be performed to illustrate these aspects.

This chapter has introduced the subjects energy, the European natural gas market and market modeling. The purpose of the report has been presented. The rest of the report is structured as follows. Chapter 2 introduces important theoretical concepts and modeling approaches, Chapter 3 presents a stochastic multi-stage natural gas market model (first contribution) that account for risk preferences and market power among producers. Chapter 4 implements and solves a small instance of the developed model. Chapter 5 implements and studies a larger data instance, and answers the research questions posed above. Chapter 6 presents methods used for solving the problem (second contribution) and discusses the current limitations of the model. Finally, Chapter 7 gives a summary and concluding remarks on the findings of this thesis.

2 Literature Review

This chapter introduces theoretical concepts related to optimization, market modeling and modeling of risk preferences. First, game theory is presented, followed by theory on microeconomics. Some mathematical concepts related to optimization and market modeling are then introduced, followed by a review of current natural gas market models and economic modeling of shale gas. Finally, risk and energy models incorporating risk preferences are presented.

2.1 Game Theory

Game theory is the formal study of a situation where two or more players make decisions that affect their payoffs. Each player's strategy contains the actions he will take given what the other players do. A game where the players can cooperate to coordinate their actions through binding agreements is called cooperative game theory, while a game where no binding agreements are possible is called non-cooperative game theory [Tirole, 1988]. In game theory, a Nash equilibrium is a situation where none of the players have an incentive to change their strategy given what the other players are doing [Pindyck and Rubinfeld, 2013].

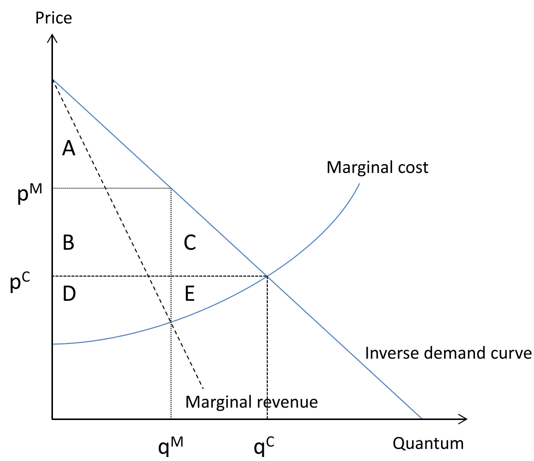
A game with only one stage where all the players act simultaneously is called a static game. A game with multiple stages where one player first makes a decision that is observable to the other players, where the other players then make decisions dependent on the first player's decision is called a dynamic game. A single game of rock-paper-scissors, for example, is a static game where both the players choose an action, and then the payoff is revealed. A game of chess is an example of a dynamic game; one player makes a move and the other player makes his move dependent on what the first player did.

Assumptions regarding information differ across different types of games. The information structure describes what information is available to the players at any time. If the players have perfect information, they know all the characteristics of the game (e.g. the marginal cost for a competitor). A situation where the players do not possess all this information is called incomplete information. Harsanyi [1967] showed how situations of incomplete information can be analysed assuming that the players are able to express their beliefs about the uncertain parameters assuming that "Each player has a subjective probability distribution over the alternative possibilities." [Harsanyi, 1967, p. 159].

2.2 Microeconomics

In microeconomics, different forms of markets and competition are studied. A market with perfect competition is a market where there are many sellers and buyers so that none of them can affect the prices in the market through their own actions alone. In such a market, producers have no market power and are said to be price takers. In a monopoly, a single producer sells a product to many buyers, and may decrease his output in order to drive prices upwards. The producer has market power in this case because he can affect prices by changing his output. Figure 2.1 shows perfect competition and monopoly prices and quantums, p^C and q^C, and p^M and q^M respectfully. Generally, p^M is higher than p^C, and q^M is lower than q^C.

Figure 2.1: Economic surpluses in a market with perfect competition and monopoly.



When assessing market regulations, regulators can use a principle called social welfare [Pindyck and Rubinfeld, 2013]. Social welfare is defined as the sum of the consumer surplus and the producer profit in a market. The consumer surplus is the difference between the consumers valuation of the products bought and the price they pay for it [Pindyck and Rubinfeld, 2013]. In the situation in Figure 2.1, the consumer surplus can be calculated as the area $(A + B + C)$, under perfect competition and as the area A in a monopoly. The producer profit is the area $(D + E)$ under perfect competition, and the area $(B + D)$ under a monopoly. Under a monopoly the producer uses his market power to maximize his profits at the expense of customer surplus. The area $(B + D)$ is larger than $(D+E)$. The social welfare is $(C+E)$ lower under a monopoly compared to perfect competition. This is called a dead weight loss [Pindyck and Rubinfeld, 2013]. Regulators might try to impose regulations that seek to maximize the social welfare of a system.

In an oligopoly, there are several producers who sell to the same market. Here, each producer might affect prices by adjusting his own output, but he has to take the other producers' behaviour into account when making decisions. This type of situation can be analysed by assuming that each producer knows the other producers' marginal cost. This enables them to calculate their competitor's optimal response curve, a function that describes how the producers will adjust their output given the other producers' output. A Nash equilibrium can be found in the intersection of the response curves, where no producer can do any better given what the other producers are doing [Pindyck and Rubinfeld, 2013]. In the situation in Figure 2.1, the oligopoly price will be $\in [p^C, p^M]$ and the total oligopoly quantum $\in [q^M, q^C]$.

Both in a monopoly and in an oligopoly, producers can affect prices by adjusting their output. Therefore, the producers have a higher profit relative to a situation with perfect competition and the consumers have smaller consumer surpluses. The following small example illustrates some of these concepts.

In a monopoly situation a single producer supplies a market. Assume that the market's inverse demand curve is given by $p(q) = 30 - q$. The supplier knows this curve and has to choose a quantity, q, that maximizes his profit, Π. If the producer has a per unit cost of \$4 he then wishes to maximize $\Pi = p(q)q - 4q$. By setting the $\frac{\partial \Pi}{\partial q} = 30 - 2q - 4 = 0$ (first order condition for optimality) he obtains the quantity where one more produced unit will lower Π. In this example this yields $q = 13$, $p(q) = \$17$ and a monopoly profit of \$169.

If the producer instead supplies a market with a large number of perfect competitive and identical suppliers, the producer is willing to supply while the price is higher than or equal to his marginal cost. For the market with price

$p(q) = 30 - q$ the quantity supplied by all the producers combined is then given by $30 - q = 4$. This yields $q = 26$, $p(q) = \$4$ and a profit of \$0. By a similar argument as above, it could be shown that if this market has n identical players the quantity supplied by supplier i in equilibrium follows $q_i = \frac{26}{n}$.

The Cournot model describes a situation where the producers compete on the quantity produced. The model gives quantities and prices between those of monopoly and perfect competition and yields a stable Nash-equilibrium [Pindyck and Rubinfeld, 2013]. Cournot competition is based on the assumptions that the output affects the price (they have market power), there is no collusion and that there is a fixed number of rational competitors who maximize profit based on their competitors' decisions. Assume that there are only two identical producers who are competing à la Cournot in the market where $p(q) = 30 - q$. The two producers wish to select a quantity that maximize their individual profits. Producer 1 supplies a quantity q_1 while producer 2 supplies q_2. The price is then given by $p(q_1, q_2) = 30 - (q_1 + q_2)$. Producer 1 maximizes it's profit by selecting q_1 so that $\frac{\partial \Pi_1}{\partial q_1} = \frac{\partial((30-(q_1+q_2))q_1 - 4q_1)}{\partial q_1} = 30 - 2q_1 - q_2 - 4 = 0$. This yields the optimal reaction curve $q_1 = \frac{26-q_2}{2}$. By symmetry, the optimal q_2 follows the reaction curve $q_2 = \frac{26-q_1}{2}$. This yields $q_1 = q_2 = 8.67$, $p(q) = \$12.67$ and $\Pi_1 = \Pi_2 = \$75.11$. Note that the combined profit of the two producers, in this example, is lower than the profit in the case with a single producer in the same market.

In the preceding examples an equilibrium solution was easy to find analytically. This is however not the case when we in Chapter 3 try to model a gas market with several non-identical actors who maximize their own objectives. In the following section we describe how an equilibrium solution can be found in a more general setting.

2.3 Mathematical Concepts

2.3.1 Karush Kuhn-Tucker Conditions

The Karush Kuhn-Tucker (KKT) conditions are necessary conditions for optimality of a non-linear problem. If the problem is convex, the KKT conditions are also sufficient for optimality [Lundgren et al., 2010].

The KKT conditions can be formulated as follows. Take a non-linear problem in minimization form[1] with constraints of the form $g(x) \leqslant 0$ and $h(x) = 0$:

$$\begin{aligned} \min \quad & f(x) && (2.1)\\ \text{s.t.} \quad & g_i(x) \leqslant 0 \quad \forall\, i = 1, \dots, m && (2.2)\\ & h_j(x) = 0 \quad \forall\, j = 1, \dots, l && (2.3) \end{aligned}$$

The KKT conditions of this problem are as follows:
Stationarity:

$$\nabla f(x^*) + \sum_{i=1}^{m} \mu_i \nabla g_i(x^*) + \sum_{j=1}^{l} \lambda_j \nabla h_j(x^*) = 0 \tag{2.4}$$

Primal feasibility:

$$h_j(x^*) = 0 \quad \forall\, j = 1, \dots, l \tag{2.5}$$

$$g_i(x^*) \leqslant 0 \quad \forall\, i = 1, \dots, m \tag{2.6}$$

Dual feasibility:

$$\mu_i \geqslant 0 \quad \forall\, i = 1, \dots, m \tag{2.7}$$

Complementary slackness:

$$\mu_i g_i(x^*) = 0 \quad \forall\, i = 1, \dots, m \tag{2.8}$$

A common way to rewrite the KKT conditions is by using the notation $x \perp y$ to indicate that either x or y has to be zero. The conditions become the slightly more compact by combining Equations (2.6)-(2.8):[2]

$$0 \leqslant \nabla f(x^*) + \sum_{i=1}^{m} \mu_i \nabla g_i(x^*) + \sum_{j=1}^{l} \lambda_j \nabla h_j(x^*) \perp x^* \geqslant 0 \tag{2.9}$$

$$0 \geqslant g_i(x^*) \perp \mu_i \geqslant 0 \quad \forall\, i = 1, \dots, m \tag{2.10}$$

$$h_j(x^*) = 0 \quad \forall\, j = 1, \dots, l \tag{2.11}$$

[1] A maximization problem $\max f(x)$ can be rewritten as $\min -f(x)$.

[2] Later in this thesis, $0 \leqslant -g_i(x^*) \perp \mu_i \geqslant 0 \quad \forall\, i = 1, \dots, m$ will be used instead of Equation (2.10) because the programming language GAMS does not support complementarity conditions with equations on less-than-or-equal form.

2.3.2 Complementarity Problems

A Linear Complementarity Problem (LCP) is to find x such that $0 \leqslant Ax + b \perp x \geqslant 0$ [Gabriel et al., 2012a]. By letting $Ax + b$ be replaced by a nonlinear expression, the result is a nonlinear complementarity problem (NCP). If the lower and upper bounds for the decision variables are allowed to be different from zero, a mixed complementarity problem (MCP) arises.

An MCP is a general type of mathematical problem. For the purposes of this work, it is sufficient to note that when the KKT conditions of the players in a market model are formed, the resulting set of equations form an MCP. For more on MCP and how problems can be represented as MCP's, see [Rutherford, 1995].

2.4 Gas Market Modelling

Gas market modelling can be defined as an effort to create a mathematical representation that reflects the most relevant properties of an actual gas market. Commonly, such models include sources of supply and demand spread out geographically, and a transportation network to move commodities between supply and demand regions. By some mechanism, equilibrium between supply and demand is found, and prices and quantities for commodities in the markets can be calculated.

Several approaches have been used for modelling gas markets, and they differ in multiple ways, including the perspective on competition, the objective of the mathematical program and how uncertainty is handled. Some models are highlighted here.

Gabriel and Smeers [2006] present different models that could be used for gas markets, including both models of perfect competition (system optimization) and imperfect competition. In a system optimization model, social welfare is maximized. Social welfare is calculated as the sum of the consumer surplus and the producer surplus for all producers and consumers [Pindyck and Rubinfeld, 2013]. One way of modeling imperfect competition is with an MCP. These types of MCP models are developed using microeconomic and game theoretic principles where each player's individual optimization problem is tied together by equilibrium conditions. The KKT conditions of the resulting set of problems form a complementarity problem (see Section 2.3.2). Gabriel and Smeers [2006] show how this can be done for a gas market. Gabriel and Smeers further argue that a model with perfect competition might not create the most realistic model of the natural gas market in Europe due to market power considerations.

The World Gas Model (WGM) [Egging et al., 2010] is an MCP. The WGM captures the effect of market power in a natural gas market. Each player (producer, storage operator, transmission system operator etc.) decides on quantities that maximize its profits given what the other players are doing, and thus the market is modeled as a Cournot game. The model also introduces modeling of uncertainty through stochastic programming, and [Egging, 2013] shows how such a problem can be solved efficiently using a Benders decomposition algorithm. [Gabriel et al., 2012b] use WGM to investigate the potential for a "Gas OPEC" where gas producers form a cartel. They show that a successful gas cartel will influence the natural gas market, and have significant consequences for European gas consumption.

The Integrated MARKAL-EFOM System (TIMES) model is an energy market model that models competitive markets [Loulou and Labriet, 2008]. By assuming perfect competition, maximizing the social welfare leads to the maximization of both supplier surplus and consumer surplus [Pindyck and Rubinfeld, 2013]. Loulou and Labriet [2008] point out that this can justify the concept of maximizing social welfare in settings where the profit of suppliers is of interest.

Gracceva and Zeniewski [2013] use TIMES to explore possible outcomes of shale development. In their application of TIMES, the deterministic version of the model is run for different scenarios. The results highlight the fact that different scenarios might lead to shale gas playing different roles in the world's energy mix. There exists a stochastic version of the TIMES model with an alternative objective function where a sum of expected costs and upper absolute deviation is minimized in order to capture risk aversion for the suppliers [Loulou and Labriet, 2008].

Gas mArket System for Trade Analysis in a Liberalising Europe (GASTALE) is a model of the European natural gas market including LNG imports and market power. Boots et al. [2003] present GASTALE as a static deterministic model with no possibility for investments in capacities in production or transportation and uses the model to analyse the effects of different forms of competition between the traders and producers. Lise and Hobbs [2008] build on GASTALE by separating LNG trade from pipeline transport and adding endogenous investments in expansions of transmission and storage capacities. A stochastic version with risk-neutral actors named S-GASTALE is developed in Bornaee [2012] where the Expected Value of Perfect Information (EVPI) is found to be almost 10% for a multistage model presented.

Framework of International Strategic Behaviour in Energy and Environment

(FRISBEE) is a model developed by Statistics Norway, and has a global geographical scope [Aune et al., 2010]. The model is a partial equilibrium model that does not include market power, but includes oil, coal and electricity as energy sources in addition to natural gas [Rosendahl and Sagen, 2009]. Rosendahl and Sagen [2009] argue that in a global perspective, perfect competition is an acceptable simplification because even big producers such as Russia that hold a quarter of the world's natural gas reserves only export 5% of the global production.

The ICF Gas Market Model is an Non-Linear Programming (NLP) model that describes North America with a model that spans several years and has a monthly density, thus operating on the border between tactical and strategic modeling [ICF, 2014]. The model features 110 regional markets in North America, and is used to project future developments in pipelines and other infrastructure as well as prices and production levels.

2.5 Shale Gas

So far, the academic contribution to the topic of shale gas in Europe has focused on resource estimation and economic assessment of potential shale plays. Weijermars studies five shale plays in continental Europe using an economic approach [Weijermars, 2013]. The study develops expected production curves (type curves) for the different plays, and models development of each play using a ten-year drilling campaign. Based on this and expected capital and operational expenditures, a discounted cash flow analysis is performed to evaluate the profitability of the shale plays, measured in net present value (NPV) and internal rate of return (IRR). Weijermars shows that the NPV and IRR are sensitive to small changes in expected ultimate recovery (EUR[3]) and that concepts like stochastic modelling and time value of money are crucial aspects in assessing shale play development potential. The fact that the profitability measures NPV and IRR are sensitive to the EUR highlights that uncertainty in resource potential is important when considering risk in shale gas developments.

Some authors have used stochastic modelling to assess shale play development, among them Stabell et al. [2007]; Williams-Kovacs et al. [2011]. In both these articles, the focus is on the development of tools for portfolio optimization for a single company considering several prospects. Neither of the two articles consider market implications on an aggregated level. With regards to market modelling, contributions have thus far been limited to application of general energy market models (e.g. TIMES, [Loulou and Labriet, 2008]).

[3]EUR is the amount of shale gas that will be produced over the lifespan of a well.

2.6 Risk

In many situations future outcomes are uncertain. When we write about uncertainty we mean situations where it is possible to list different outcomes and assign a probability to each of them. When uncertainty is present in such a way that it affects a decision maker's payoff, his payoff is associated with risk. In our setting risk means that the payoff is affected both by uncertainty and the decision maker's decision. Risk is therefore affected by decisions, while uncertainty is a characteristic of nature. A decision maker's attitude towards risk is known as his risk preference. To illustrate different risk preferences, let A be an investment with certain payoff x, and let B be an investment with an uncertain payoff with expected value $E[B]$. A decision maker is said to be risk averse if his utility function $u(\cdot)$ is such that: $u(A) \succeq u(B)$ when $E(B) \geqslant x$. Risk neutral investors have the same utility for both A and B given that $E(B) = x$. For a more detailed discussion, see Luenberger [1997].

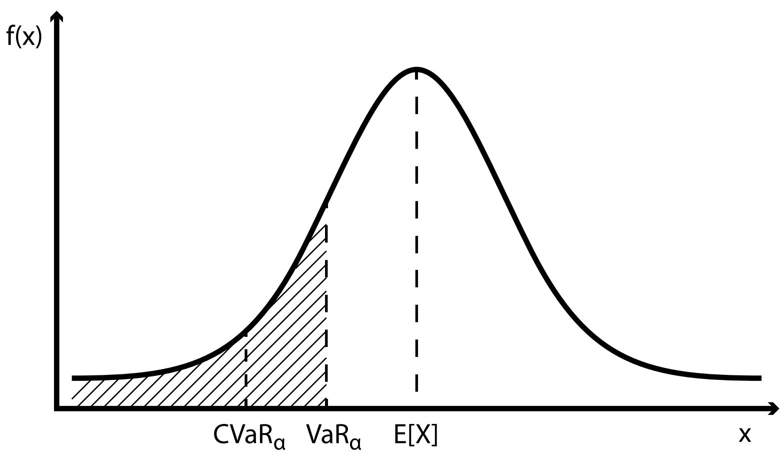
The risk associated with developing unconventional resources will probably have a significant impact on whether or not these resources will be developed. In shale gas development, the main sources of risk are, associated with resource potential, economical viability and political climate (Richter [2013], see Chapter 1). Controlling these types of risks are important aspects for evaluating the commercial viability of potential investments (see for example Gracceva and Zeniewski [2013]).

Risk measures can be used to encapsulate the risk associated with a distribution of an outcome. "A risk measure is a functional mapping of a profit (or loss) distribution to the real numbers." ([Hardy, 2006, p. 2]). In the following, some common risk measures will be introduced.

Markowitz (1952) (as cited in Krokhmal [2007]) suggested that risk could be quantified and controlled by controlling the volatility of the returns. This approach is still widely used in many areas of decision-making. However, this approach has been criticized for treating positive and negative deviations from the expected value in the same manner [Gutjahr and Pichler, 2013; Krokhmal, 2007; Quintino et al., 2013]. For an investor or a decision maker this would be unreasonable because he would want to penalize losses but not high profits. Because of this observation several downside risk measures were developed. Markowitz (1959) (as cited in Krokhmal [2007]) proposed replacing the variance with the lower semi-deviation to account for the losses only. One problem with this type of risk measure is that it does not quantify the probability of falling below a given critical value [Quintino et al., 2013].

A risk measure that solves this problem is the Value at Risk ($V@R_\alpha(X)$). V@R has for a long time been used in the insurance industry and has in the last 20 years also become increasingly popular within finance and banking [Hardy, 2006]. For a random variable X the $V@R_\alpha(X)$ at confidence level α is given as $V@R_\alpha(X) = F_X^{-1}(\alpha)$, where $F_X^{-1}(\alpha)$ is the inverse of the cumulative distribution of X [Gutjahr and Pichler, 2013]. Thus $V@R_\alpha(X)$ is the negative α-quantile of random variable X and answers the question: "With probability α, what is the minimum profit?" One problem with V@R is that it does not give information about the outcomes below the α threshold. Also, V@R does not satisfy Artzner, Delbaen and Eber (1999)'s sub-additivity axiom and is thus not a convex risk measure (as cited in Quintino et al. [2013]). The fact that it is non-convex as a function of the decision variables also makes it methodically difficult [Krokhmal, 2007]. Fortunately, the risk measure Conditional Value at Risk ($CV@R_\alpha(X)$) does not suffer from the V@R's shortcomings. $CV@R_\alpha(X)$ expresses the expected value of a random variable X given that the outcome is lower than a critical value [Hardy, 2006]. Pflug and Römisch [2007] show that $CV@R_\alpha(X)$ is concave in X.

Figure 2.2: CV@R and V@R



Based on these considerations CV@R can be used to account for the risk in the following form [Gutjahr and Pichler, 2013]:

$$CV@R_\alpha(X) = \frac{1}{\alpha}\int_0^\alpha F_y^{-1}(\nu)d\nu \tag{2.12}$$

Or, equivalently:

$$CV@R_\alpha(X) = \max_k (k - \frac{1}{\alpha} E[k - X]^+) \tag{2.13}$$

where k is the α-quantile and X is a random variable, see Figure 2.2. To illustrate how this can be used, let $h(X)$ represent a profit dependent on the random variable X. Then Equation (2.13) expresses the expected profit in the $\alpha * 100\%$ worst scenarios. If risk neutrality is assumed, $\alpha = 1$, Equation 2.13 is reduced to the the expected value, $E[X]$. Equation 2.13 is not defined for $\alpha = 0$. When $\alpha \in (0, 1)$ risk aversion CV@R is lower than E[X]. The difference is larger for low values of α (high risk aversion).

In Equation (2.13), CV@R is given as an optimization problem. The dual representation[4] of this problem is given in [Pflug and Römisch, 2007, Chapter 2]:

$$CV@R_\alpha(X) = \min\{E[XZ] : E(Z) = 1, 0 \leqslant Z \leqslant \frac{1}{\alpha}\} \tag{2.14}$$

In Equation (2.14), Z is the set of dual variables corresponding to X. The dual representation has the desirable property that it is easier to form partial derivatives of than the primal representation. This is used in Section 3.6. In addition to this, the dual representation can be used to show that $CV@R_\alpha(X)$ is concave in X, see proof in [Pflug and Römisch, 2007, Chapter 2].

The previous figure and equations present $CV@R_\alpha(X)$ with a continuous distribution of the random variable X with density $f(x)$. The following example shows how $CV@R_\alpha$ works when X is represented by a set of discrete outcomes with positive probabilities in a scenario tree.

An investor is considering an investment of 0.6$ that will give an uncertain payoff in the future. He knows that there are five different outcomes for the payoff, each with a probability of $\frac{1}{5}$. The payoff could be 0.4$, 0.8$, 1.2$, 1.6$ or 2.0$, and the expected payoff is therefore 1.2$ and the expected profit is 0.6$. Let the payoff be the random variable Y, and let the investment be I. The $CV@R_\alpha$ of his profit is:

$$CV@R_\alpha(Y - I) = \max_k (k - \frac{1}{\alpha} E[k - (Y - I)]^+) \tag{2.15}$$

[4] For more on duality, see [Lundgren et al., 2010, Chapter 6].

If the investor is risk neutral, $\alpha = 1$, CV@R$_\alpha$ is equal to the expected value, 0.6\$. If the investor is risk averse and has a value of α of 0.4, he disregards the profit in the 60% best outcomes. The only remaining outcomes are payoffs of 0.4\$ and 0.8\$, and the value of k (the best outcome amongst the considered outcomes) becomes 0.8\$ − 0.6\$ = 0.2\$. The CV@R$_\alpha$ becomes:

$$
\begin{aligned}
&0.2 - \frac{1}{0.4}\frac{1}{5}\big[(0.2 - -0.2)^+ + (0.2 - 0.2)^+ \\
&+ (0.2 - 0.6)^+ + (0.2 - 1.0)^+ + (0.2 - 1.4)^+\big] \\
&= 0.2 - \frac{1}{2}(0.4) = 0.0
\end{aligned}
$$

In this case, the CV@R$_\alpha$ of the investors profit is 0, and he will be indifferent between investing and not investing.

If the investor is risk averse and has a value of α of 0.5, k becomes 0.6\$ and the CV@R$_\alpha$ becomes 0.12\$ by a similar computation as above. In this case the investment is worthwhile for the risk averse investor.

If the investor has a value of α of 0.55, the quantile does not change because the 50% worst outcomes and the 55% worst outcomes are the same outcomes when there are five outcomes with the same probabilities. This means that when analysing the effects of increased risk aversion, the number of scenarios needs to be large in order for small changes in the value of α to have any effect. When there are n scenarios, increments of α of more than $\frac{1}{n}$ are the smallest increments that will be guaranteed to change which outcomes the investor regards.

2.7 Energy Models Incorporating Risk Preferences

Although it is most common to assume risk neutrality in energy market models, there have been a few attempts at using risk measures in market modeling.

Cabero et al. [2010] present a stochastic model for an electricity market where each producer has a risk neutral objective. Risk preferences are considered in the model by including a constraint that sets a lower bound on CV@R$_\alpha$. The model is an LCP, and the work is based on [Cabero, 2007], where KKT conditions for the model are presented. A similar application of including a lower bound on CV@R$_\alpha$ is found in Werner et al. [2014], which is a model for strategic planning in the LNG market. The model is a stochastic multistage mixed-integer linear problem, including investments in infrastructure and vessels.

A drawback of the method used in these models is that when a lower bound on $\mathrm{CV@R}_\alpha$ is to be imposed, it is first necessary to find a suitable lower bound. This requires either experience with the problem at hand in order to find a good value, or multiple iterations to adjust the bound on $\mathrm{CV@R}_\alpha$ to a reasonable level.

In this chapter current literature on gas market modelling and shale gas research has been reviewed. The findings indicate that shale gas has not been modelled in a market setting using stochastic optimization and risk preferences. TIMES [Loulou and Labriet, 2008] has been used for shale gas modeling, but does not account for market power. FRISBEE [Aune et al., 2010] suffers under the same shortcoming as TIMES. [ICF, 2014] includes shale gas production, but the geographical scope is limited to North America. WGM [Egging et al., 2010] and S-GASTALE [Bornaee, 2012] model market power and uncertainty, but do not account for risk preferences. Shale gas development is highly associated with risk, in particular with regards to reserves. A stochastic market model that includes shale gas and accounts for risk preferences could therefore give new insights to the field of natural gas market modeling. Taking this into account, the following chapter develops the natural gas market model used in this work.

3 Model

This chapter develops a multi-resource stochastic mixed complementarity problem for a natural gas market that accounts for market power and risk averse behaviour amongst producers. The starting point for the model is [Egging, 2013], but the producers and traders are combined into one set of actors as in [Egging and Huppmann, 2012]. The main differences in this model are that that it allows for several resources, and that the producers are allowed to be risk averse.

Overview

The situation is modeled as a non-cooperative static game over several stages. The uncertainty is handled à la Harsanyi [1967] by assuming that the actors are able to express their beliefs about the future by several outcomes from a probability distribution. It is therefore a game of imperfect information. The producers are risk averse, and maximize the CV@R of their profits.

Actors

The producer has the opportunity to expand the production capacity for the resources, as well as expansions in available reserves, thus representing the option of developing shale gas. A restriction is added on production capacity expansion and reserves expansion to represent limited budgets. Producers can have production in one or more country nodes. Similarly, the Transmission System Operator (TSO) has the option of expanding pipeline capacities, subject to a budget limit. The market is modeled as a network of country nodes where each country node has its own inverse demand curve.

Market Power and Competition

The gas market is characterized by relatively few producers with varying degrees of market power. The presented model represents the market as an oligopoly, and the producers compete on quantities. Each player individually maximizes his profits. The model allows for different levels of market power for each player, ranging from perfect competition to competition à la Cournot.

Uncertainty

Reserves expansions are treated as random variables. Thus, there is uncertainty in how large the realised reserves from the expansions invested in will be. Other variables that could have been treated as random variables include demand, expansion costs and political climate regarding bans or licenses for developing shale gas. However, we want to analyse the risk associated with shale gas development. Demand does not distinguish between shale gas and conventional gas. Making demand uncertain therefore does not capture the risk associated with shale gas development. Costs associated with developing shale gas are definitely not certain, and could therefore have been treated as random variables. However, we argue that the historical cost data from the US can be assumed to give a reasonable indication of the cost levels for shale gas development in Europe. The analogy between costs is assumed to be more accurate than comparisons between resource potential because cost depends on the cost of input factors with known prices such as labor and materials where data is readily available, while resources depend on unexplored geology. Political climate is highly relevant for future development, and will here be captured through what-if analysis in regard to bans.

Risk Aversion

The producers in the natural gas industry face uncertainty and can be risk averse. The model allows for risk preferences through a risk measure that will be implemented based on [Gutjahr and Pichler, 2013]. The risk measure CV@R will be used in the objective function of the producers. By using CV@R in the objective, the feasible region does not change when the value of the degree of risk aversion, α_p, is changed. CV@R also has other favorable properties that other risk measures lack, see Section 2.6 and for example [Krokhmal, 2007], [Sarykalin et al., 2008] and [Pflug and Römisch, 2007, Chapter 2].

The rest of this chapter is structured as follows. First, the natural gas supply chain is presented. Then, the modeling of the different parts of the supply chain is presented and discussed together with the resulting mathematical problems.

Following this, KKT conditions will be derived in order to be able to reformulate the model as an MCP.

3.1 Nomenclature

The nomenclature for the model is presented here. The reader can refer back to this when reading the equations for the mathematical model presented below.

3.1.1 Indices and Sets

Set	**Explanation**
$a \in A$	arcs between two country nodes
$n \in N$	country nodes (e.g. NOR, NED, POL, ESP)
$p \in P$	producers (e.g. NOR, NED, POL)
$r \in R$	resource types (shale, conventional gas)
$s \in S$	stages in the model
$u \in U$	nodes in the scenario tree
$a^+(n)$	inward arcs to country node n
$a^-(n)$	outward arcs from country node n
$u(s) \in U$	set of scenario tree nodes that belong to stage s
$n(p) \subset N$	country nodes where producer p can produce
$n^+(a)$	end node of arc a
$n^-(a)$	start node of arc a
$u^- \in U$	direct predecessor node of u in the scenario tree
$b(u, u') \in U$	direct successor from u that is in $\mathrm{pred}(u') \cup u'$
$\mathrm{pred}(u) \in U$	predecessor nodes in the scenario tree
$\mathrm{succ}(u) \in U$	successor nodes in the scenario tree
$E \subset U$	scenario tree nodes in the last stage
$m(u) \subset E$	end nodes succeeding from u. In the last stage $m(u) = u$

Explanation of Sets

Several sets are used in the model formulations. Some are needed for the model itself, and some are needed for the KKT conditions that will be developed later in this chapter.

Figure 3.1 shows the predecessors of scenario tree node u3 for a simple tree. Predecessor nodes $pred(u)$ is the set of nodes in the scenario tree that precedes u.

Figure 3.1: Predecessor nodes of u3

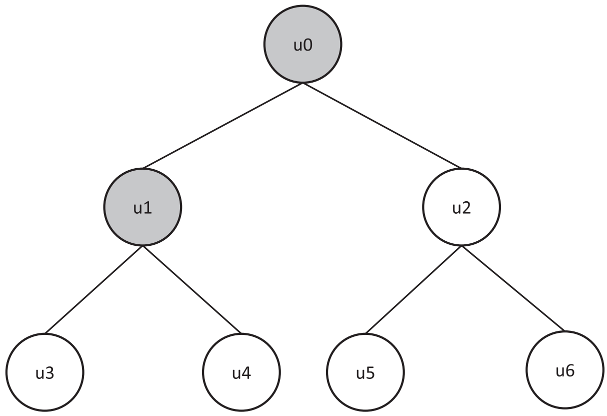


Figure 3.2 shows the successors of scenario tree node u2 for a simple tree. Successor nodes $succ(u)$ is the set nodes in the scenario tree that succeeds u.

Figure 3.2: Successor nodes of u2

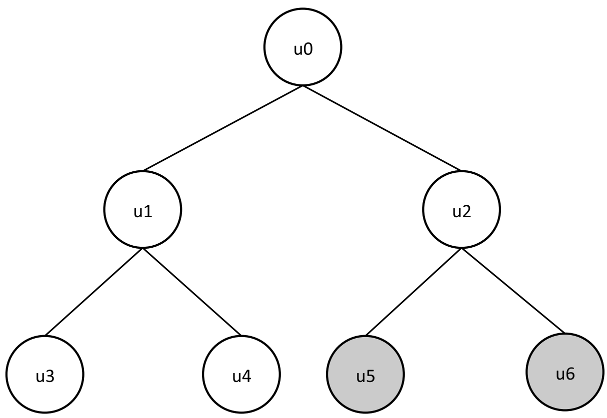


Figure 3.3 illustrates the set $m(u)$ for u1. This set is defined as the end nodes that succeed from node u. When u is itself an end node, $m(u) = u$.

Figure 3.3: Endnodes $m(u)$ for (u1)=(u3,u4)

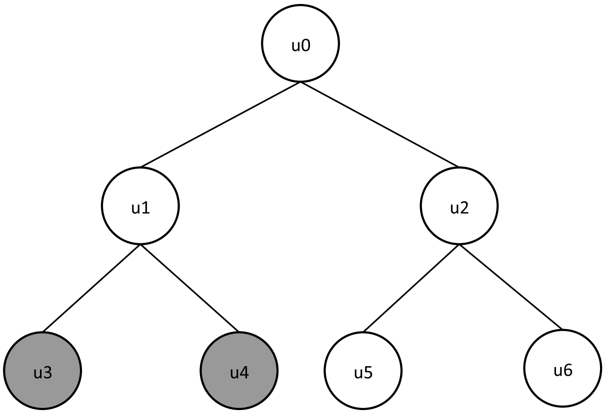


Figure 3.4 illustrates u^- for u5. u^- is defined as the empty set $\varnothing$ when u does not have predecessor.

Figure 3.4: Direct predecessor u^- for u5

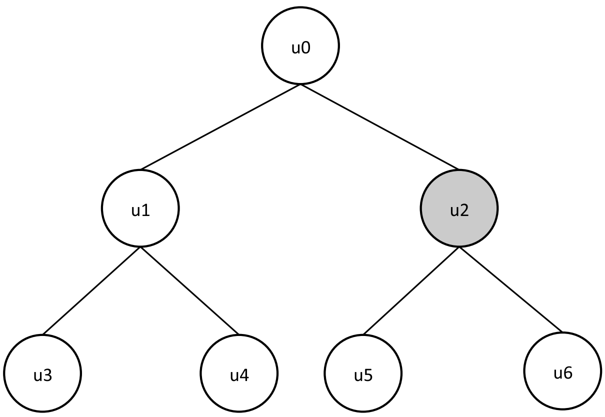
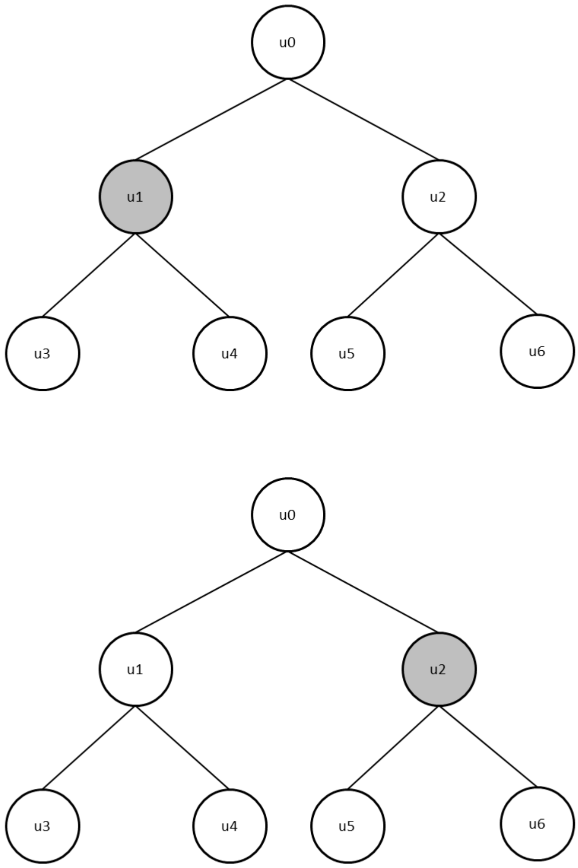


Figure 3.5 illustrates $\mathtt{b}(u, u')$ for (u0,u3) (top) and for (u0,u2) (bottom). $\mathtt{b}(u, u')$ is the direct successor from u that is in $\mathtt{pred}(u')$.

Figure 3.5: $\mathtt{b}(u, u')$: direct successor from u that is in $\mathtt{pred}(u') \cup u'$ shown for (u0,u3)=u1 (top) and (u0,u2)=u2 (bottom)



3.1.2 Parameters

Parameter	Unit	Explanation
α_p	[-]	risk aversion parameter in $CV@R_{p\alpha_p}$ for producer p
B^P_{pu}	[bUSD]	budget for expansions for producer p in scenario tree node u
B^{TSO}_u	[bUSD]	budget for expansions of arc capacity for the TSO in u
CAP^{A0}_a	[bcf/d]	initial flow rate capacity on arc a
CAP^{P0}_{prn}	[bcf/d]	initial production capacity for p in n for resource r
C^{LP}_{prn}	$[bUSD/(bcf/d)]$	linear production cost for p in n for resource r
C^{QP}_{prn}	$[bUSD/(bcf/d)^2]$	quadratic production cost for p in n for resource r
C^F_a	[bUSD]	operational cost term for TSO
$C^{\Delta A}_a$	$[\frac{bUSD}{bcf/d}]$	cost per unit of arc flow rate capacity expansion on a
$C^{\Delta P}_{prn}$	$[\frac{bUSD}{bcf/d}]$	cost per unit of production capacity expansion in p of resource r in country node n
$C^{\Delta R}_{prn}$	$[\frac{bUSD}{bcf}]$	cost per unit of reserves expansion in resource r for producer p in country node n
D_u	[d]	number of days in a stage
$\Delta R_{prnu}(\xi)$	[bcf]	realised reserve expansion, for resource r, in country node n, in scenario node u
δ_{pn}	[-]	market power parameter for producer p in country node (market) n
γ_u	[-]	discount factor for scenario tree node u
INT_{nu}	$[\frac{bUSD}{bcf}]$	intercept of inverse demand curve in scenario tree node u, country node n
$Pr(u)$	[-]	probability for scenario tree node u
R^{P0}_{prn}	[bcf]	reserves of resource r available for producer p in country node n initially
SLP_{nu}	$[\frac{bUSD/bcf}{bcf/d}]$	slope of inverse demand curve in scenario tree node u, node n

Where bUSD is billion US Dollars, bcf is billion cubic feet and d denotes days.

3.1.3 Variables

Variable	Unit	Explanation
e^A_{au}	[bcf/d]	arc flow rate capacity expansion invested in by TSO on arc a in scenario tree node u
e^P_{prnu}	[bcf/d]	production capacity expansion invested in, in scenario tree node u for resource r by p in country node n
e^R_{prnu}	[bcf]	expansion of reserves of type r invested in by producer p in country node n in scenario tree node u
f_{pau}	[bcf/d]	arc flow rate on arc a for producer p, in scenario tree node u
k_p	[-]	quantile related to α_p in $CV@R_{p\alpha_p}$ for producer p
π_{nu}	[bUSD/bcf]	price from the inverse demand function in node n in u
q_{prnu}	[bcf/d]	production rate of r produced by p in node n in scenario tree node u
q^S_{pnu}	[bcf/d]	gas rate sold by p in scenario tree node u, to country node n
s_{au}	[bcf/d]	sold arc flow rate by TSO on a in scenario tree node u
y_{pu}	[-]	variable for linearization of $CV@R_{p\alpha_p}$
z_{pu}	[-]	variable for dual representation of $CV@R_{p\alpha_p}$

All these variables are nonnegative except k_p, which is free. Non-negativity restrictions are not written explicitly in the following model.

3.1.4 Dual Variables

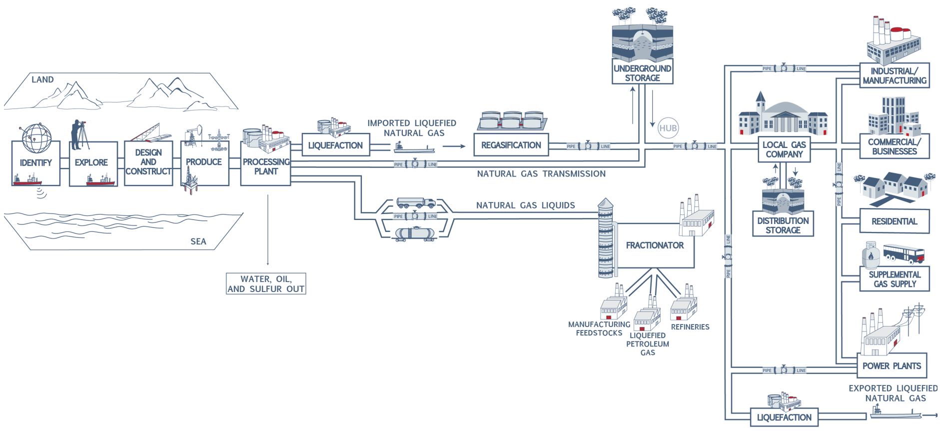
Variable	Sign	Unit	Explanation
π^M_{nu}	free	[bUSD/bcf]	duals to the sales market clearing constraints
τ_{au}	free	[bUSD/bcf]	duals to the arc flow market clearing constraints
λ^P_{prnu}	non-negative	[bUSD/bcf/d]	duals to the producer's capacity constraints
$\lambda^T_{a,u}$	non-negative	[bUSD/bcf/d]	duals to TSO arc expansion constraints
ϕ^P_{pnu}	non-negative	[bUSD/bcf/d]	duals to the producer's mass balance restriction
μ^P_{pu}	non-negative	[-]	duals to the producer's budget restriction
μ^T_u	non-negative	[-]	duals to TSO budget constraint
ρ^P_{prnu}	non-negative	[bUSD/bcf]	duals to the producer's reserve constraint
σ_{pu}	non-negative	[-]	duals to the linearization constraint

Throughout this chapter the corresponding dual variable is given in parenthesis to the right of the constraints.

3.2 The Natural Gas Supply Chain

The natural gas supply chain can be divided into activities upstream and downstream. Upstream refers to the processes from exploration to development of production to production. Downstream processes are what happens after production. Figure 3.6 illustrates the natural gas supply chain. First, natural gas is located and produced in the upstream part of the supply chain. Following this, it is processed and then transported to either liquefaction into LNG, storage or consumption by one of several sectors (downstream processes). The following sections look at production and exploration, transportation and demand and consumption in the natural gas supply chain and present the modeling of the entire system.

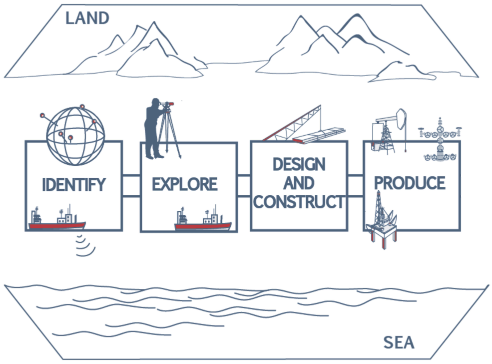
Figure 3.6: The natural gas supply chain. Source: American Petroleum Institute



3.3 Production

Exploration and production (E&P) is performed by oil and gas companies such as Total, Chevron, Shell, Statoil and BP and their suppliers. There are four major steps in exploration and production, as shown in Figure 3.7, adapted from

Figure 3.7: Steps in Exploration & Production. Source: American Petroleum Institute



the website of the American Petroleum Institute. The first stage is to identify natural gas resources using geological data and seismic surveys. On land, this is done by truck, while ships are used for seaborne surveys. The second stage, exploration, is carried out in promising areas by drilling exploration wells to further assess the amount of gas available for extraction. Drilling an exploration well typically takes a little less than a month. After this, the well has to be tested. The results of this could be that very little gas is found, or the amounts found could be as expected or sometimes substantially higher than expected. If the exploration wells are successful, stage three is started, as plans to build production facilities and plans to start production are made.

The construction or development of a field consists of drilling several production wells and building production facilities. A number of well sites are identified, and a drilling schedule is made to plan the drilling of production wells. A suitable size of processing facilities is also constructed at this stage. For shale gas development, an extra stage follows after drilling. Big pumps are used to pump, water, sand and chemicals down in the well in order to fracture the shale rock containing the gas so that the gas flows freely from the shale and up to the ground [EIA, 2013d]. This extra step increases development time and capital expenditures for shale gas development.

For onshore natural gas, the time between the first exploration well is drilled and the production starts often range around two to three years. For offshore projects, the lead time is often more than three times longer because offshore projects require big production facilities to be placed on the seabed or on platforms, which takes time to plan and execute.

The fourth stage is production. When production starts, production rate is typically planned to first build up to a plateau and then produce at approximately that level for as long as there is gas left that is profitable to extract. During the late years of production in a field, production rates will typically decline as the pressure in the reservoir decreases.

Following the upstream parts of the natural gas supply chain are the downstream processes. Processing removes any unwanted substances such as sulphur, water, oil and CO_2 from the gas. Natural gas liquids (mainly butane, propane and heptane) are separated out and sold separately. Next, the gas is either transported by pipe or liquefied to LNG and transported by ship and regasified again. After this, the gas is either stored or sold for use to different sectors. The producer can sell its produced gas either by long-term contracts or to the spot market. Currently, the volume of spot marketed gas is increasing in Europe, and long-term contracts are being linked to spot prices [EC, 2013].

3.3.1 Producer

In this model, production is modeled in the following way: a producer p is an actor that produces natural gas in one or more country nodes n and sells the gas to different country nodes n. A producer can deliver gas to a country node n by transporting gas, for a cost, τ_{au}, consisting of a base cost plus a congestion fee, through a gas pipeline network. The producer wants to maximize his profit given a preference towards risk. This risk preference is expressed through the $CV@R_{p\alpha_p}$, meaning that producer p maximizes the profits in the $\alpha_p * 100\%$ worst scenarios.

3.3.2 Assumptions

- The producer selects production, transportation and sales rates for a period at a time, taking future periods into account.
- The producer sells all the gas directly to the consuming country, and pays for transportation in the pipeline network to transport the gas to market.
- The producer has a risk preference that can be described by CV@R.
- Expansions of production capacities and reserves are possible in a continuous range of values. In reality, expansions are stepwise. Continuous values are needed because the MCP solvers needed for this kind of equilibrium problem cannot handle integer variables.

- The producers have imperfect information, meaning that they know the probability tree, but not which tree node they and their competitors will end up in.
- There are no losses in transportation.
- There is no option of storing gas for later periods.
- A field comes on stream five years after the decision of exploring the field has been made, regardless of location and whether or not it is a shale gas field or a conventional field.
- Production facilities take five years to build and set into operation.
- Production costs are quadratic.
- Processing costs are assumed to be included in production costs.
- The role of trading natural gas is merged with the producer, so that the producers decide sales volume to end markets instead of traders.

3.3.3 The Producers' Problem

The producer is concerned with maximizing the CV@R of his profit, subject to the technical limitations he faces. The next sections present the building blocks of his objective and the constraints he has to respect.

In order to maximize the CV@R of the profits, the producers make the following decisions for each country node n in each scenario tree node, u:

- production rate of resource r, in country node n, in scenario tree node u, q_{prnu}
- sales rate to country node n, in scenario tree node u, q^S_{pnu}
- investments in reserves expansion for resource r, in country node n, in scenario tree node u, e^R_{prnu}
- investments in production capacity expansion for resource r, in country node n, in scenario tree node u, e^P_{prnu}

In addition, the producer decides the arc flow capacity bought from the TSO, f_{pau}, for each arc a and scenario tree node u.

3.3.3.1 Expected Profit

The producer's profit is the discounted sum of his revenues from sales minus operational costs (transportation and production costs) and capital expenditures (costs of exploration and development). The producer's expected profit, $\mathrm{E}[\mathrm{profit}_p]$, can be calculated as:

$$\begin{aligned}
&\mathrm{E}[\mathrm{profit}_p] \\
&= \sum_{u \in U} \Pr(u) \Bigg[\gamma_u \Bigg(\sum_{n \in N} D_u q^S_{pnu} \\
&\quad \Bigg(\delta_{pn} (\mathrm{INT}_{nu} - \mathrm{SLP}_{nu} \sum_{p' \in P} q^S_{p'nu}) + (1 - \delta_{pn}) \pi^M_{nu} \Bigg) \\
&- \sum_{n \in N, a \in a^+(n)} D_u \tau_{au} f_{pau} \qquad (3.1) \\
&- \sum_{r \in R, n(p) \in N} \Big(e^P_{prnu} C^{\Delta P}_{prn} + e^R_{prnu} C^{\Delta R}_{prn} + D_u (C^{LP}_{prn} q_{prnu} + C^{QP}_{prn} (q_{prnu})^2) \Big) \Bigg) \Bigg]
\end{aligned}$$

Using the notation from Section 2.6, X would correspond to the terms inside the square brackets in Equation (3.1). Note that Equation (3.1) is linear except for the two squared terms with a negative sign in front of them. This means that the expression for the profit (and thus the expected value) is concave.

If the producer wants to produce a low amount of gas from a well, the pressure is typically high enough to get the desired gas flow without great effort. When the producer wants to increase production, however, costs increase. This is because more effort has to be put in to increase flow by increasing workload on pumps, compressors and processing facilities. These increasing production costs are assumed to follow the shape of a quadratic function. The production cost function is $\mathrm{Cost} = C^{LP}_{prn} q_{prnu} + C^{QP}_{prn} (q_{prnu})^2$.

The costs of expansions of reserves and production capacities are assumed to be linear. In reality, the fixed costs associated with acquiring drilling rigs or constructing facilities would give decreasing costs per unit of expansion, but the model assumes that these costs are linear. Depending on choice of input parameters, this will either make small expansions less expensive than in reality or make big expansions more expensive than in reality.

As discussed in Chapter 2, some of the producers in the natural gas market may exert market power. Therefore, the price term in the producer's expected profit function (Eq. (3.1)) is composed by a weight between the inverse demand curve and the competitive price, where $\delta_{pn} \in [0, 1]$ expresses the weight between pure Cournot competition ($\delta_{pn} = 1$) and competitive market price ($\delta_{pn} = 0$). Thus, a higher δ_{pn} implies greater market power.

3.3.3.2 Objective

The objective for a risk neutral producer would be to maximize Equation (3.1). This is similar to what is done in [Egging et al., 2010]. Here however, the producers are assumed to have varying degrees of risk aversion expressed through α_p. Therefore, they might want to control the downside risk by making optimal decisions in the $\alpha_p * 100\%$ worst outcomes. This approach adds the decision variable k_p for each producer p (see Section 2.6).[1]

The producer's objective is given by:

$$\begin{aligned}
&\max_{\substack{q_{prnu},\, q^S_{pnu},\, e^P_{prnu}\\ e^R_{prnu},\, f_{pau}}} \mathrm{CV@R}_{p\alpha_p}\left(\mathrm{profit}_p(q_{prnu},\, q^S_{pnu},\, e^P_{prnu},\, e^R_{prnu},\, f_{pau})\right)\\
&\qquad = \max_{\substack{q_{prnu},\, q^S_{pnu},\, e^P_{prnu}\\ e^R_{prnu},\, f_{pau}}} \max_{k_p} \left(k_p - \frac{1}{\alpha_p} E[k_p - \mathrm{profit}_p]^+\right) \qquad (3.2)
\end{aligned}$$

Here, profit_p is the term inside the brackets in Equation (3.1). The producers' objective expresses the risk adjusted expected profit. The value of $\mathrm{CV@R}_{p\alpha_p}$ is the expected profit given that the profits are lower than the lower α_p-quantile of the profit distribution. To calculate the expected profit for a given optimal solution of Equation (3.2), Equation (3.1) has to be evaluated with the optimal decisions. This is useful for comparing profits for different levels of risk aversion. It should also be noted that for $\alpha_p = 1$ Equation (3.2) is equal to Equation (3.1). When $\alpha_p = 0$, Equation (3.2) is not defined.

3.3.3.3 Production Constraints

When the producer develops a field, a certain production capacity is selected and built. The production rate in a field cannot exceed this capacity unless the

[1] k_p is not a variable the producer explicitly decides, but an implicit decision that is a consequence of the other decision variables. It is a decision variable in the mathematical model.

facilities have been expanded in previous time periods. Equation (3.3) describes this relation.

$$q_{prnu} \leqslant CAP^{P0}_{prn} + \sum_{u' \in pred(u)} e^{P}_{prnu'} \quad \forall\, p, r, n, u \qquad (\lambda^{P}_{prnu}) \tag{3.3}$$

The production rate of each resource type r, by p in country node n and scenario tree node u, must be less than or equal to the initial maximum production rate (CAP^{P0}_{prn}), plus the capacity invested in (e^{P}_{prnu}), in all preceding scenario tree nodes.

Here, expansion in production capacity is allowed to be a continuous amount. In reality, capacity expansions are only available in steps. Here, however, we keep the variables continuous by allowing the producer to expand in fractions of these steps. When a solution from the model is obtained, very small expansions might be regarded as marginal projects that might not have been realized in reality.

3.3.3.4 Mass Balance Constraints

The producer is responsible for transporting the gas to the market. As the gas has to flow through the existing pipelines, the amount a producer sends into a country plus the amount it produces there must equal the amount is sends out of the country plus the amount it sells there.

$$\sum_{r \in R} q_{prnu} + \sum_{a \in a^{+}(n)} f_{pau} - q^{S}_{pnu} - \sum_{a \in a^{-}(n)} f_{pau} = 0 \quad \forall\, p, n, u \quad (\phi^{P}_{pnu}) \tag{3.4}$$

Equation (3.4) states that for every node n, each producer's production rate in that node plus the producer's total inflow rate to n must equal the producer's sales rate to the node n plus the producer's total outflow rate from n, for every resource r and scenario tree node u.

3.3.3.5 Expansion Constraints

The producer produces natural gas from its reserves. The cumulative production in a field cannot exceed the reserves in that field. However, the reserves can be expanded through exploration. The costs of exploration of natural gas and construction of production facilities have to be within the limits of the capital available to the producer. These two relations are described in the following constraints:

$$\sum_{u' \in pred(u)} D_{u'} q_{prnu'} + D_u q_{prnu} \leqslant R^{P0}_{prn} + \sum_{u' \in pred(u)} \Delta R_{prnu'}(\xi) e^{R}_{prnu'-} + \Delta R_{prnu}(\xi) e^{R}_{prnu-} \quad \forall\, p, r, n, u \qquad (\rho^{P}_{prnu}) \tag{3.5}$$

$$\sum_{r \in R, n(p) \in N} \left(C^{\Delta P}_{prn} e^{P}_{prnu} + C^{\Delta R}_{prn} e^{R}_{prnu} \right) \leqslant B^{P}_{pu} \quad \forall\, p, u \qquad (\mu^{P}_{pu}) \tag{3.6}$$

Equation (3.5) states that the total produced quantity of each resource type for each producer in each node n and each scenario tree node u, must be less than or equal to the original reserves plus the stochastically determined reserve expansions invested in, in previous time periods. Equation (3.6) states that for each time period and scenario, a producer can only incur costs related to expansions of reserves and production capacity within a budget limit.

Figure 3.8: Illustration of Constraint (3.5)

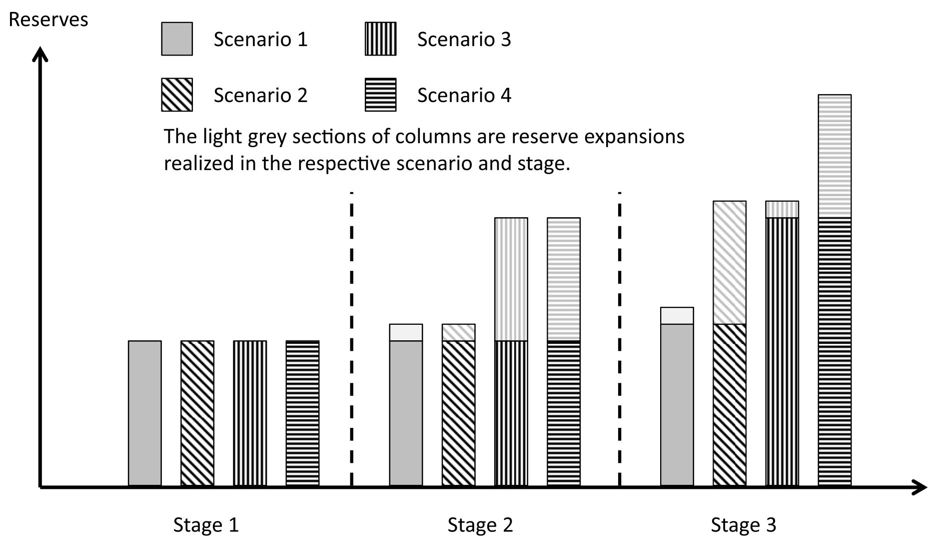
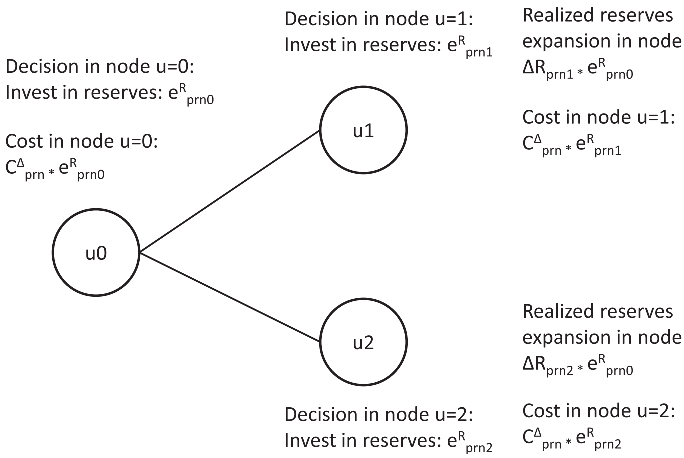


Figure 3.8 illustrates Equation (3.5) over three time periods for one resource type and the scenario tree in Figure 3.1. For each different scenario, the increase in the limit per unit of reserves expansion invested in will be different.

Figure 3.9: Illustration of reserve expansion cost and payoff timing



The timing of investments in reserves, costs of these investments and reserve expansions from investments are illustrated in Figure 3.9 for the first two stages in the scenario tree in Figure 3.1. Costs are incurred at time t (node u0) and reserves are expanded at time $t + 1$ (node u1 and u2).

All the constraints in the producers' problems are linear. In combination with the concave objective functions, this leads to convex problems for the producers.

3.4 Natural Gas Pipelines

Figure 3.10 illustrates the natural gas pipelines in Europe. After the natural gas is produced and input to the transmission pipelines, the TSO is responsible for gas transportation from the producers and delivery to marketers, storage operators and local distribution companies. Legislation regulating the ownership, operation and revenue scheme of the transmission network differs from country to country. In the past it was common that the TSO sold gas to end customers and/or participated in production related activities. Due to the large infrastructure investments required for effective transmission, the TSO often forms a natural monopoly on transport. The monopoly gave the TSO a market position that was sub-optimal from a socioeconomic point of view. To counter this effect the European Commission made legislation aimed at functional and ownership unbundling.[2] In Europe this process started in the late 1990's [Egging, 2010].

Figure 3.10: Natural gas pipelines in Europe. Source: IEA

The pipelines in Figure 3.10 are in reality operated by many different TSOs. In this model it is assumed that all pipelines are operated by a single TSO. There are no storage operators in the model and gas is sold by producers to end customers. In Figure 3.10 it can be seen that there are two types of pipelines, one for L-gas (yellow pipes) and one for H-gas (blue and red pipes).[3] To reduce the network complexity it is assumed that all gas has the same calorific value, that no more than one pipe goes from one country to another and transmission losses are ignored.

The TSO revenues should be such that the TSO has an incentive for necessary expansions and reliable operations, while at the same time prohibiting

[2]Process of making sure that the TSO is independent in regards to organisation, ownership and decision making from activities not related to transportation and distribution.

[3]H-gas (high calorific gas) consists of 87-99% methane. L-gas (low calorific gas) consists of 80-87% methane and higher quantities of nitrogen and carbon dioxide. L-gas is cheaper than H-gas because its energy content is lower. The calorific value of L-gas is between eight and ten kilowatt hours per cubic meter, while the range for H-gas is between ten and twelve kilowatt hours [WINGAS, nd].

the extraction of monopoly profit. To achieve this, regulatory intervention is needed. In Europe this is done differently in various countries [Ruester et al., 2012]. Typically, the TSO revenues are comprised of two factors; a fixed tariff aimed at recovering costs and a congestion fee resulting from saturation of the pipelines. In our model we assume full Third Party Access[4] and that the unbundling is fully implemented. The TSO then allocates transportation based on the producers demand and the revenue scheme is the same for all pipes.

When market dynamics change, capacity expansions are needed in order to maintain an effective network. Due to the physical nature of the pipes, these expansions will happen in steps in reality. In order to keep the model convex, so that the resulting MCP is solvable, we assume that continuous expansions are possible.

3.4.1 Assumptions

- The TSO is a regulated player.
- There is one TSO who operates the entire pipeline network.
- The operational costs are linear.
- It is possible to invest in a continuous range of pipeline expansions.
- Congestion pricing is used for the natural gas pipelines.
- There are no losses in transportation.
- There is no storage.
- Full Third Party Access.
- The many smaller natural gas pipelines that might exist between two countries are modeled as one aggregated pipe.

3.4.2 The Transmission System Operator's Problem

The TSO is concerned with maximizing revenues from transportation and congestion less the cost of operation and expansion. The TSO therefore maximises the expected profit over all scenarios by deciding on arc capacities expansions of each arc a, in scenario tree node u, e^A_{au} and the flow rate on each arc a in each scenario tree node u, s_{au}.

[4]No discrimination among pipeline users.

3.4.2.1 Objective

$$\begin{aligned}\max_{e^A_{au}, s_{au}} \quad & \mathrm{E}[\mathrm{profit}_{tso}] \\ = \sum_{a\in A, u\in U} & \Pr(u)\gamma_u \left(s_{au} D_u[\tau_{au} - C^F_a] - C^{\Delta A}_a e^A_{au}\right)\end{aligned} \tag{3.7}$$

Note that the price of transport, τ_{au} is not a decision variable for the TSO, but a price given by the dual to the market clearing constraint (Eq. (3.11)). In this implementation τ_{au} represents two things; one part that covers the TSO's cost of operation and one part representing congestion fees. When there is no congestion there will be no expansions, and τ_{au} equals the cost of operation. Without congestion the TSO will have zero profit. When pipes are congested the part of τ_{au} that represent congestion fees is larger than zero and gives the TSO an investment incentive. Note that this part of τ_{au} is not actually payed to the TSO, put provides a mechanism for efficient allocation of scarce capacity. For more on congestion fees see [Gabriel et al., 2012a, Chapter 9].

3.4.2.2 Constraints

In reality pipeline capacities are dependent on flows and pressure differences in neighbouring pipes. This can be modeled with nonlinear equations, but this greatly complicates the MCP. More importantly, the technical modeling of pipe flows is not needed for the strategic research questions of this work. We therefore ignore pressure differences, in line with the recommendations by Gabriel et al. [2012a]. The flow rates sold by the TSO are then constrained by the pipe flow rate capacities. Since the model allows for expansions, the flow rate capacities may increase over time. This situation is modeled by Eq. (3.8).

$$s_{au} \leqslant CAP^{A0}_a + \sum_{u'\in \mathrm{pred}(u)} e^A_{au'}, \quad \forall\, a, u \quad (\lambda^T_{a,u}) \tag{3.8}$$

Eq. (3.8) makes sure that the sold arc flow rate in scenario tree node u is less than or equal to the initial flow rate capacity plus flow rate capacity invested in in all preceding scenario tree nodes.

The expansions of the flow rate capacities are constrained by the TSO budget. This is modeled in Eq. (3.9).

$$\sum_{a \in A} C_a^{\Delta A} e_{au}^A \leqslant B_u^{TSO} \quad \forall u \qquad (\mu_u^T) \tag{3.9}$$

All the constraints in the TSO's problem are linear. In combination with the linear objective function (in the TSO's decision variables), this leads to a linear problem for the TSO.

3.5 End Users

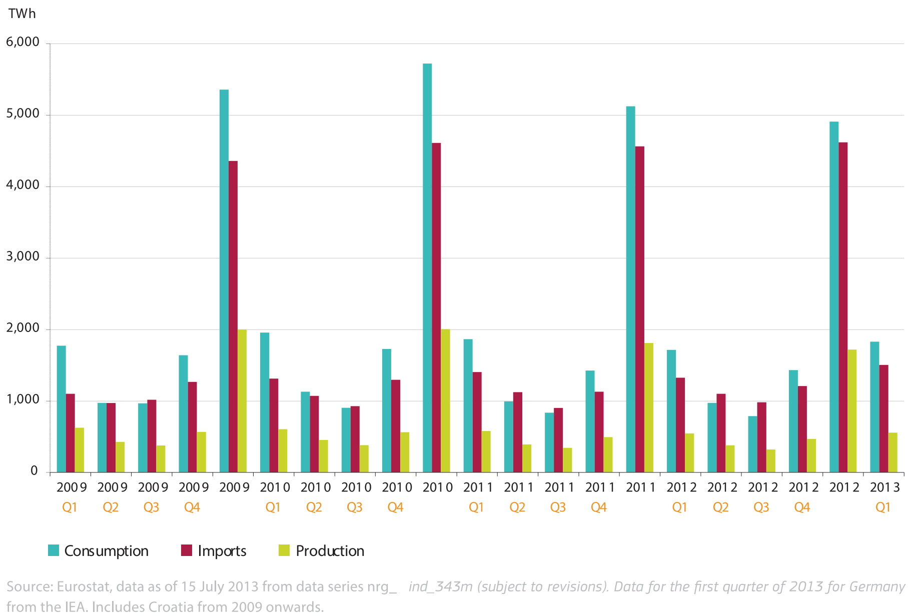
Natural gas consumption can be split in four main sectors: industrial, residential and commercial, electricity generation and transport. In the industrial section, natural gas is used for heating, cooking and as a feedstock for creating other chemicals. In the residential and commercial sector, natural gas commonly is used for heating and cooking. In electricity generation, natural gas is combusted in order to drive generators for electricity. Natural gas is used in the transportation section, mostly for heavy duty vehicles and vessels [NGSA, nd].

In some of these sectors, demand for natural gas is seasonal. This is especially true for the residential and commercial sector, where the temperature affects how much gas is needed for heating. In the winter, natural gas demand is therefore much higher than in the summer. Figure 3.11 shows the natural gas consumption in the EU from 2009 to 2013. The consumption (the blue series) is much higher in the first and last quarters, the winter months, than in the second and third quarters. Since it is more efficient for the production to be more stable throughout the year than demand is, gas is supplied in a steady stream by producers and an inventory of stored gas is built during the spring and summer for use in the winter months.

3.5.1 Consumers

In this model, the consumers are modeled as one combined demand sector in each country. The demand is also deseasonalized so that each period of the model has one level of demand. The demand is represented as an inverse demand curve for each country that represents the relationship between price and demand, namely that there should be some price sensitivity such that a higher price leads to lower demand.

Figure 3.11: EU gas consumption, production and imports in TWh. Source: EC



3.5.2 Assumptions

- The demand in the different sectors are aggregated in the model.
- Demand can be represented by a linear inverse demand curve.
- Demand is independent of seasons.
- There is no storage of gas by the consumers.

3.5.3 Market Clearing in the Natural Gas Market

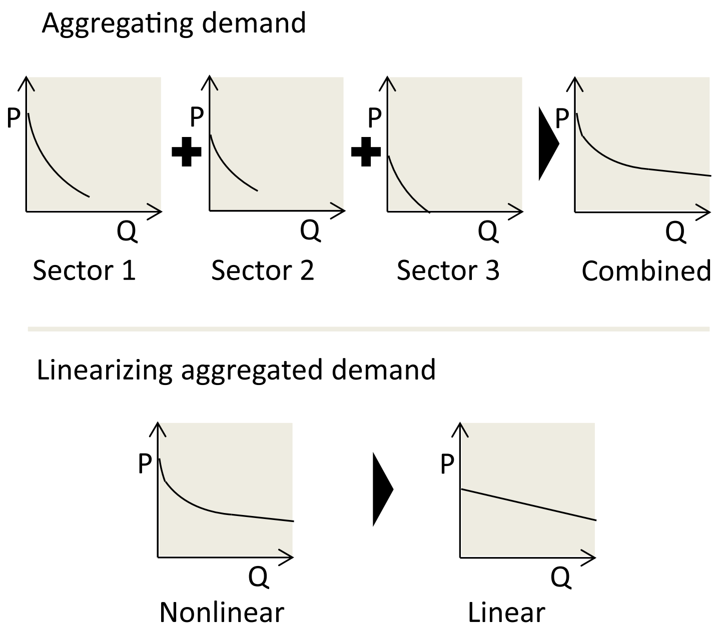
The inverse demand function in country node n in scenario tree node u expresses the relation between price and sold gas flow. As the total demand is the sum of the demand in each sector, the inverse demand function can be found by summing the inverse demand functions horizontally as shown in Figure 3.12. The resulting function is then approximated by a linear function.

$$\pi_{nu} = INT_u - SLP_u \sum_{p \in P} q^S_{pnu} \quad \forall\, n, u \qquad (\pi^M_{nu}) \tag{3.10}$$

Equation (3.10) clears the market between consumers and gas-selling producers.

The aggregation of the different sectors into one inverse demand function means that the model is not concerned with which sector buys the gas. The aggregation is illustrated in Figure 3.12. The demand functions are summed horizontally to form one demand function. However, it is possible to split the sold gas into the separate sectors after solving the model. What is lost, however, are price differences between the sectors.

Figure 3.12: Illustration of demand curve aggregation



The inverse demand function used in the model is linearized as shown in Figure 3.12. Clearly, such a demand function is not an optimal description of demand, as the slope of the inverse demand curve (the amount the price changes when the quantity sold changes) should be different at different quantity levels. Consumers might be willing to pay much less for the second unit of natural gas as the first, but the difference in valuation between the hundredth and the hundred-and-first unit might not be as big.[5] Therefore, other forms of inverse demand functions might be suggested. However, the lack of information available on price elasticities in different ranges of sold quantities makes estimating the parameters of such curves less likely to give significantly better modeling of natural gas demand. Therefore, the linear inverse demand function is used.

3.5.4 Market Clearing in the Pipeline Transportation Market

The sales of flow capacity to all producers must match the amount of flow on the given pipeline for all pipelines and time periods. Therefore, this flow constraint must hold for each arc a:

$$s_{au} - \sum_{p \in P} f_{pau} = 0 \quad \forall\, a, u \qquad (\tau_{au}) \tag{3.11}$$

Equation (3.11) ensures that the flow rate sold by the TSO on each arc equals the sum of the producers' flow rates on the given arc and thus clears the market for transportation of natural gas.

This part of Chapter 3 has presented a model formulation for a natural gas market. The model has multiple objectives, one for each actor. It is therefore not possible to solve it as an ordinary optimization problem, because these need to have one single objective. One way of finding a solution to such a multi-objective model is to reformulate it as an MCP.

Another option is to assume perfect competition. In this case, the solution can be found by maximizing the social welfare (see Gabriel and Smeers [2006]). However, market power cannot be captured in a model maximizing social welfare.[6] Therefore, this approach is not used.

The next part of this chapter develops the MCP for the presented model.

[5] It is possible to get the slope approximately right in a small domain of the inverse demand function, making the linear inverse function a first order approximation of the true inverse demand function in a given point.

[6] It is possible to add a markup for the producers to model market power in a social welfare maximization model, but with this approach geographical diversification is not captured, see [Egging, 2010].

3.6 MCP Formulation

In this section, an MCP formulation of the problem is derived using KKT conditions.[7] Before the KKT conditions are derived, the model is put in standard form (see Section 2.3.1), which means that the objective is minimized and the constraints are of the form $g(x) \leqslant 0$ and $h(x) = 0$. This is easily achieved by changing signs of some of the expressions in the previously presented model.

All the constraints in the model presented are linear. The profit of the producers are concave, differentiable functions, and the profit function for the TSO is linear. Therefore, the problem is convex and the solution to the KKT conditions of the presented model gives a solution that is guaranteed to be optimal.

3.6.1 Deriving KKT Conditions with CV@R

When the KKT conditions for the producers' problems are formed, special attention has to be paid to the producers' stationarity conditions. This is because the partial derivatives of $CV@R_{p\alpha_p}$ have to be derived for the stationarity conditions. Deriving the partial derivatives of the $CV@R_{p\alpha_p}$ is complicated by the fact that only the positive part of the term in brackets in Equation (3.2) adds to the objective. Therefore, the partial derivatives of $CV@R_{p\alpha_p}$ should be zero for the scenarios where the term in brackets in Equation (3.2) is negative (the scenarios where the profits are above the quantile k_p). Two methods for dealing with this are presented and discussed.

3.6.1.1 Partial Derivatives of $CV@R_{p\alpha_p}$ Using Auxiliary Variables

To find the appropriate partial derivatives using auxiliary variables, we start with the partial derivatives of Equation (3.1) (If Equation (3.1) was the objective, the producer would be risk neutral and would therefore consider all scenarios). In this case, the producer's objective would have been to minimize the following:

[7] When taking partial derivatives with respect to variables that appear in constraints and equations in several scenario tree nodes, special care has to be taken. An explanation of this with an example is given in Appendix B.

$$
\begin{aligned}
& -\mathrm{E}[\mathrm{profit}_p] \\
&= -\sum_{u \in U} \Pr(u) \Bigg[\gamma_u \Bigg(\sum_{n \in N} D_u q^S_{pnu} \\
&\quad \Bigg(\delta_{pn} (\mathrm{INT}_{nu} - \mathrm{SLP}_{nu} \sum_{p' \in P} q^S_{p'nu}) + (1 - \delta_{pn}) \pi^M_{nu} \Bigg) \\
&\quad - \sum_{n \in N, a \in a^+(n)} D_u \tau_{au} f_{pau} \qquad (3.12) \\
&\quad - \sum_{r \in R, n(p) \in N} \Big(e^P_{prnu} C^{\Delta P}_{prn} + e^R_{prnu} C^{\Delta R}_{prn} + D_u (C^{LP}_{prn} q_{prnu} + C^{QP}_{prn} (q_{prnu})^2) \Big) \Bigg) \Bigg]
\end{aligned}
$$

The partial derivatives of Equation 3.13 is as follows:

$$
\begin{aligned}
\frac{\partial \mathrm{E}[\mathrm{profit}_p]}{\partial q_{prnu}} &= \Pr(u) \gamma_u D_u (C^{LP}_{prn} + 2 C^{QP}_{prn} q_{prnu}) && \forall \quad p, r, n, u \qquad (3.13) \\
\frac{\partial \mathrm{E}[\mathrm{profit}_p]}{\partial q^S_{pnu}} &= -\Pr(u) \gamma_u D_u \delta_{pn} \\
&\qquad \Bigg(\mathrm{INT}_{nu} - \mathrm{SLP}_{nu} (\sum_{p' \in P} q^S_{p'nu} + q^S_{pnu}) \Bigg) && \forall \quad p, n, u \qquad (3.14) \\
\frac{\partial \mathrm{E}[\mathrm{profit}_p]}{\partial e^P_{prnu}} &= \Pr(u) \gamma_u C^{\Delta P}_{prn} && \forall \quad p, r, n, u \qquad (3.15) \\
\frac{\partial \mathrm{E}[\mathrm{profit}_p]}{\partial e^R_{prnu}} &= \Pr(u) \gamma_u C^{\Delta R}_{prn} && \forall \quad p, r, n, u \qquad (3.16) \\
\frac{\partial \mathrm{E}[\mathrm{profit}_p]}{\partial f_{pau}} &= \Pr(u) \gamma_u D_u \tau_{au} && \forall \quad p, a, u \qquad (3.17) \\
\frac{\partial \mathrm{E}[\mathrm{profit}_p]}{\partial k_p} &= 0 && \forall \quad p, a, u \qquad (3.18)
\end{aligned}
$$

To ensure that only the outcomes in the $\alpha * 100\%$ worst scenarios affect the producer's decisions, the following steps are taken.

Let z_{pu} be defined as:

$$z_{pu} = \begin{cases} \frac{1}{\alpha_p} & \text{if } profit_{pu} < k_p \\ 0 & \text{if } profit_{pu} > k_p \\ z_{pu}(\cdot) & \text{if } profit_{pu} = k_p \end{cases} \tag{3.19}$$

Where $z_{pu}(\cdot)$ is defined implicitly through the equation:

$$\sum_{u \in u(s)} Pr(u) z_{pu} = 1 \quad \forall \quad s \in S \tag{3.20}$$

The z_{pu} are part of the dual representation of CV@R (see Section 2.6, [Pflug and Römisch, 2007]). These are used to form the partial derivatives for $CV@R_{p\alpha_p}$. The z_{pu} variables make sure that the partial derivative is zero for the scenarios where the profit is larger than the quantile k_p. This makes sure that the outcomes in the scenarios that we want to disregard (the $(1-\alpha) * 100\%$ best scenarios) do not affect the optimal decisions.

The partial derivatives of the $CV@R_{p\alpha_p}$ in the directions q_{prnu} and q^S_{pnu}, are given by the following equation:

$$\frac{\partial CV@R_{p\alpha_p}(profit_p)}{\partial q_{prnu}} = z_{pu}\left(\frac{\partial E[profit_p]}{\partial q_{prnu}}\right) \tag{3.21}$$

$$\frac{\partial CV@R_{p\alpha_p}(profit_p)}{\partial q^S_{pnu}} = z_{pu}\left(\frac{\partial E[profit_p]}{\partial q^S_{pnu}}\right) \tag{3.22}$$

The partial derivatives in other directions have a similar form. Finally, this yields the following stationarity conditions for the producers:

$$z_{pu}\left[Pr(u)\gamma_u D_u(C^{LP}_{prn}+2C^{QP}_{prn}q_{prnu})\right]+\lambda^P_{prnu}-\phi^P_{pnu}$$
$$+(D_u\rho^P_{prnu}+\sum_{u'\in succ(u)} D_{u'}\rho^P_{prnu'})=0 \quad \forall \quad p,r,n,u \tag{3.23}$$

$$-z_{pu}\left[Pr(u)\gamma_u D_u\delta_{pn}\right.$$
$$\left.\left(INT_{nu}-SLP_{nu}(\sum_{p'\in P} q^S_{p'nu}+q^S_{pnu})\right)\right]+\phi^P_{pnu}=0 \quad \forall \quad p,n,u \tag{3.24}$$

$$z_{pu}\left[Pr(u)\gamma_u C^{\Delta P}_{prn}\right]-\sum_{u'\in succ(u)}\lambda^P_{prnu}$$
$$+C^{\Delta P}_{prn}\mu^P_{pu}=0 \quad \forall \quad p,r,n,u \tag{3.25}$$

$$z_{pu}\left[Pr(u)\gamma_u C^{\Delta R}_{prn}\right]+C^{\Delta R}_{prn}\mu^P_{pu}$$
$$-\sum_{u'\in succ(u)}\Delta R_{prn,b(u,u')}\rho^P_{prnu'}=0 \quad \forall \quad p,r,n,u \tag{3.26}$$

$$z_{pu}\left[Pr(u)\gamma_u D_u\tau_{au}\right]-\phi^P_{pn^+(a)u}$$
$$+\phi^P_{pn^-(a)u}=0 \quad \forall \quad p,a,u \tag{3.27}$$

3.6.1.2 Partial Derivatives of $CV@R_{p\alpha_p}(profit_p)$ Using Linearization

Another approach is to linearize the $CV@R_{p\alpha_p}(profit_p)$ expression and then take the partial derivatives of the resulting expressions. Recall the producers' objective:

$$\max_{\substack{q_{prnu},\, q^S_{pnu},\, e^P_{prnu}\\ e^R_{prnu},\, f_{pau},}} CV@R_{p\alpha_p}(profit_p)$$
$$=\max_{\substack{q_{prnu},\, q^S_{pnu},\, e^P_{prnu}\\ e^R_{prnu},\, f_{pau},}} \max_{k_p}\left(k_p-\frac{1}{\alpha_p}E[k_p-profit_p]^+\right) \tag{3.28}$$

This could be reformulated as:

$$\min_{\substack{q_{prnu},\, q^S_{pnu},\, e^P_{prnu} \\ e^R_{prnu},\, f_{pau},\, k_p,\, y_{pu}}} -CV@R_{p\alpha_p}(profit_p) = -k_p + \frac{1}{\alpha_p}\sum_{u\in E} Pr(u)y_{pu} \tag{3.29}$$

s.t.

$$k_p - X_{pu} - y_{pu} \leqslant 0 \quad \forall\, p, u \in E \qquad (\sigma_{pu}) \tag{3.30}$$

Here, X_{pu}, defined for all p and $u \in E$ is the discounted profit for producer p along the path from the first node in the scenario tree to node u. y_{pu} is non-negative.

For example, following the scenario tree in Figure 3.4 for a producer p:

$$X_{p,'u3'} = profit_{p,'u3'} + profit_{p,'u1'} + profit_{p,'u0'} \tag{3.31}$$

Where $profit_{pu}$ is:

$$\begin{aligned}\gamma_u \Bigg[\sum_{n\in N} D_u q^S_{pnu} \Bigg(\delta_{pn}(INT_{nu} - SLP_{nu} \sum_{p'\in P} q^S_{p'nu}) + (1-\delta_{pn})\pi^M_{nu} \Bigg) \\ - \sum_{n\in N, a\in a^+(n)} D_u \tau_{au} f_{pau} \\ - \sum_{r\in R, n(p)\in N} \Bigg(e^P_{prnu} C^{\Delta P}_{prn} + e^R_{prnu} C^{\Delta R}_{prn} + D_u (C^{LP}_{prn} q_{prnu} + C^{QP}_{prn}(q_{prnu})^2) \Bigg) \Bigg]\end{aligned} \tag{3.32}$$

With the linearized producer objectives (Equation (3.29) and (3.30)) the producers' stationarity conditions can be expressed as follows (see Section 2.3.1):

$$-1 + \sum_{u \in E} \sigma_{pu} = 0 \quad \forall \quad p \tag{3.33}$$

$$\frac{1}{\alpha_p} \Pr(u) - \sigma_{pu} = 0 \quad \forall \quad p, u \in E \tag{3.34}$$

$$\gamma_u D_u (C^{PL}_{prn} + 2C^{PQ}_{prn} q_{prnu}) \sum_{u' \in m(u)} \sigma_{pu'} + \lambda^P_{prnu} - \phi^P_{nu}$$

$$+\rho^P_{prnu} D_u + \sum_{u' \in succ(u)} D_{u'} \rho^P_{prnu'} = 0 \quad \forall \quad p, r, n, u \tag{3.35}$$

$$-\gamma_u D_u \left[\delta_{pn} \left(INT_{nu} - SLP_{nu} \left(\sum_{p' \in P} q^S_{p'nu} + q^S_{pnu} \right) \right) + (1 - \delta_{pn}) \pi^M_{pnu} \right] \sum_{u' \in m(u)} \sigma_{pu'}$$

$$+\phi^P_{pnu} = 0 \quad \forall \quad p, n, u \tag{3.36}$$

$$\gamma_u C^{\Delta P}_{prn} \sum_{u' \in m(u)} \sigma_{pu'} - \sum_{u' \in succ(u)} \lambda^P_{prnu'} + \mu^P_{pu} C^{\Delta P}_{prn} = 0 \quad \forall \quad p, r, n, u \tag{3.37}$$

$$\gamma_u C^{\Delta R}_{prn} \sum_{u' \in m(u)} \sigma_{pu'} - \sum_{u' \in succ(u)} \Delta R_{prn, b(u,u')} \rho^P_{prnu'}$$

$$+\mu^P_{pu} C^{\Delta R}_{prn} = 0 \quad \forall \quad p, r, n, u \tag{3.38}$$

$$\gamma_u D_u \tau_{au} \sum_{u' \in m(u)} \sigma_{pu'} - \phi^P_{pn^+(a)u} + \phi^P_{pn^-(a)u} = 0 \quad \forall \quad p, a, u \tag{3.39}$$

3.6.1.3 Discussion of Methods for Partial Derivatives

The two proposed methods for calculating the partial derivatives both give the partial derivatives without too much effort.

The method with the auxiliary variables utilizes the principles of CV@R to say that the partial derivatives can only be non-zero when the outcome is in the critical quantile. Implementations of this formulation requires the values of z_{pu} in Equation (3.19) to be calculated during the solution process, because it is dependent on k_p and $\mathtt{profit}_{pu}$. This situation might require a master-sub-structure to the solution procedure, where the master problem updates z_{pu} and the sub-problem finds a solution that the master-problem uses to update z_{pu}. An obvious issue with this approach is convergence, as z_{pu} is defined in such a way that it might alternate between 0 and $\frac{1}{\alpha_p}$ between iterations. This means that convergence might be difficult to prove.

The method where CV@R is linearized is based on basic optimization techniques for linearizing expressions, and gives a set of stationarity conditions where some of the terms are bilinear[8] because a dual variable is multiplied by

[8] A bilinear function is a function where variables are multiplied, for instance $f(x, y) = xy$.

a primal variable. One implication of this is that a solution method that uses derivatives of these bilinear expressions might have difficulties if their starting point is zero (see Chapter 6). Therefore, implementations of this method might need to state starting points different from zero for some of the decision variables. Fortunately, this is easily achieved in most optimization languages, for example by starting from a previous solution. From this discussion, we conclude that there are fewer difficulties with implementation of the method with linearizing CV@R than with using auxiliary variables. Therefore, the linearization is used for the rest of this report and for the implementation of the model. Note that even though CV@R is linearized, the model still accounts for market power and increasing marginal costs through a quadratic cost function. The next section gives the entire set of KKT conditions for the natural gas model. Equation (3.41) - (3.57) are the equations that will be implemented to solve the problem.

3.6.2 KKT Conditions

3.6.2.1 KKT Conditions for the Producers

$$0 \leqslant -1 + \sum_{u \in E} \sigma_{pu} \perp k_p \geqslant 0 \quad \forall \quad p \tag{3.40}$$

$$0 \leqslant \frac{1}{\alpha_p} Pr(u) - \sigma_{pu} \perp y_{pu} \geqslant 0 \quad \forall \quad p, u \in E \tag{3.41}$$

$$\begin{aligned} 0 \leqslant \gamma_u D_u (C^{PL}_{prn} + 2C^{PQ}_{prn} q_{prnu}) \sum_{u' \in m(u)} \sigma_{pu'} + \lambda^P_{prnu} - \phi^P_{nu} \\ + \rho^P_{prnu} D_u + \sum_{u' \in succ(u)} D_{u'} \rho^P_{prnu'} \perp q_{prnu} \geqslant 0 \quad \forall \quad p, r, n, u \end{aligned} \tag{3.42}$$

$$\begin{aligned} 0 \leqslant -\gamma_u D_u \Bigg[\delta_{pn} \Bigg(INT_{nu} - SLP_{nu} (\sum_{p' \in P} q^S_{p'nu} + q^S_{pnu}) \Bigg) \\ + (1 - \delta_{pn}) \pi^M_{pnu} \Bigg] \sum_{u' \in m(u)} \sigma_{pu'} \\ + \phi^P_{pnu} \perp q^S_{pnu} \geqslant 0 \quad \forall \quad p, n, u \end{aligned} \tag{3.43}$$

$$\begin{aligned} 0 \leqslant \gamma_u C^{\Delta P}_{prn} \sum_{u' \in m(u)} \sigma_{pu'} - \sum_{u' \in succ(u)} \lambda^P_{prnu'} \\ + \mu^P_{pu} C^{\Delta P}_{prn} \perp e^P_{prnu} \geqslant 0 \quad \forall \quad p, r, n, u \end{aligned} \tag{3.44}$$

$$\begin{aligned} 0 \leqslant \gamma_u C^{\Delta R}_{prn} \sum_{u' \in m(u)} \sigma_{pu'} - \sum_{u' \in succ(u)} \Delta R_{prn, b(u,u')} \rho^P_{prnu'} \\ + \mu^P_{pu} C^{\Delta R}_{prn} \perp e^R_{prnu} \geqslant 0 \quad \forall \quad p, r, n, u \end{aligned} \tag{3.45}$$

$$0 \leqslant \gamma_u D_u \tau_{au} \sum_{u' \in m(u)} \sigma_{pu'} - \phi^P_{pn^+(a)u} + \phi^P_{pn^-(a)u} \perp f_{pau} \geqslant 0 \quad \forall \quad p, a, u \tag{3.46}$$

$$0 \leqslant y_{pu} - k_p + X_{pu} \perp \sigma_{pu} \geqslant 0 \quad \forall \quad p, u \in E \tag{3.47}$$

$$0 \leqslant CAP^{P0}_{prn} + \sum_{u' \in pred(u)} e^P_{prnu'} - q_{prnu} \perp \lambda^P_{prnu} \geqslant 0 \quad \forall \quad p, r, n, u \tag{3.48}$$

$$\sum_{r \in R} q_{prnu} + \sum_{a \in a^+(n)} f_{pau} - q^S_{pnu} - \sum_{a \in a^-(n)} f_{pau} = 0 \quad \phi^P_{pnu} \quad free \quad \forall \quad p, n, u \tag{3.49}$$

$$0 \leqslant B^P_{pu} - \sum_{r \in R, n(p) \in N} \left(C^{\Delta P}_{prn} e^P_{prnu} + C^{\Delta R}_{prn} e^R_{prnu} \right) \perp \mu^P_{pu} \geqslant 0 \quad \forall \quad p, u \tag{3.50}$$

$$\begin{aligned} 0 \leqslant R^{P0}_{prn} - \sum_{u' \in pred(u)} D_{u'} q_{prnu'} - D_u q_{prnu} \\ + \sum_{u' \in pred(u)} \Delta R_{prnu'}(\xi) e^R_{prnu'-} + \Delta R_{prnu}(\xi) e^R_{prnu-} \perp \rho^P_{prnu} \geqslant 0 \quad \forall \quad p, r, n, u \end{aligned} \tag{3.51}$$

3.6.2.2 KKT Conditions for the TSO

$$0 \leqslant Pr(u)\gamma_u C_a^{\Delta A} - \sum_{u' \in succ(u)} \lambda_{au'}^T + C_a^{\Delta A} \mu_u^T \perp e_{au}^A \geqslant 0 \quad \forall \quad a, u \tag{3.52}$$

$$0 \leqslant -Pr(u)\gamma_u D_u(\tau_{au} - C_a^F) + \lambda_{au}^T \perp s_{au} \geqslant 0 \quad \forall \quad a, u \tag{3.53}$$

$$0 \leqslant CAP_a^{A0} - s_{au} + \sum_{u' \in pred(u)} e_{au'}^A \perp \lambda_{au}^T \geqslant 0 \quad \forall \quad a, u \tag{3.54}$$

$$0 \leqslant B_u^{TSO} - \sum_{a \in A} C_a^{\Delta A} e_{au}^A \perp \mu_u^T \geqslant 0 \quad \forall \quad u \tag{3.55}$$

3.6.2.3 KKT Conditions for Market Clearing

$$INT_{nu} - SLP_{nu} \sum_{p \in P} q_{pnu}^S - \pi_{nu} = 0 \quad \pi_{nu}^M \; free \quad \forall \quad n, u \tag{3.56}$$

$$s_{au} - \sum_{p \in P} f_{pau} = 0 \quad \tau_{au} \; free \quad \forall \quad a, u \tag{3.57}$$

This chapter has presented a multi-stage stochastic model with multiple producers for the natural gas market with expansions in reserves, production and transportation capacity and competitive markets where the producers can express risk averse behaviour. Further, the KKT conditions for the mathematical problem have been derived, forming an MCP and thereby making the problem solvable. In the following two chapters, the model is first verified with a small example, followed by a numerical study of a larger scale model.

4 Model Testing and Preliminary Study

This chapter implements and solves a small instance of the model developed in Chapter 3. The purpose of this is twofold. The first goal is to verify the model with respect to risk preferences and competition. Risk preferences and competition are particularly important aspects that set this model apart from other natural gas models, and are therefore important to verify. The second goal is to study the effects of risk preferences and market power on investments and trade in a gas market, a research question posed in Chapter 1.

4.1 Test Case Setup

The developed model describes a natural gas market where each actor maximizes their objectives as presented in Chapter 3 while constrained by player-specific and market-wide restrictions. In this chapter, a test case is studied. The test case characteristics are:

- There are two producers, `P_NOR` with production in Norway and `P_NED` with production in the Netherlands.
- Both producers can invest and expand both their resources and production rate capabilities, but only in the country node where they are situated.
- The producers start with both reserves and production capacity in the first stage.
- There is one demand node, `NED`, in the network situated in the Netherlands.
- Consumers are represented through an estimated inverse demand curve.

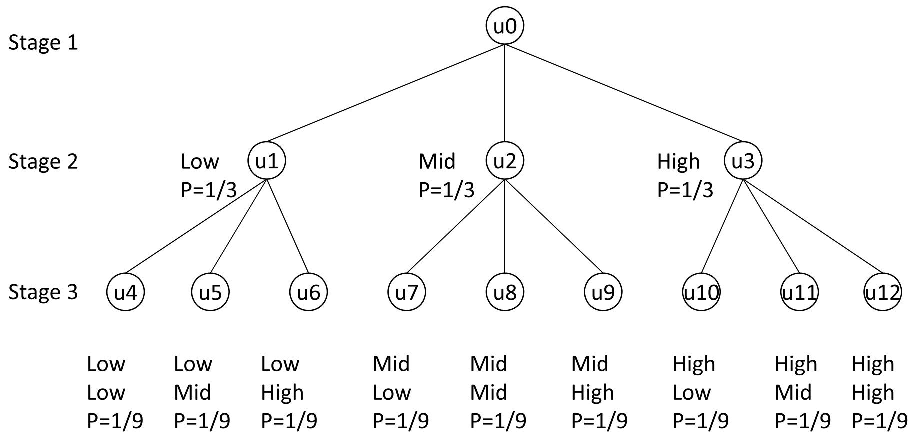
- The TSO operated flow network consists of a single directed pipe from Norway to the Netherlands.
- Input parameters are based on estimates from Rystad Energy AS. See Section 5.1 for more info on the input parameters.

The scenario tree models different outcomes of shale gas reserves expansion. In each stage, there can be either a much lower amount of shale gas than expected, an amount in the middle that is slightly lower than the expected amount or a much higher amount than expected. This is chosen to get a distribution that is skewed to the right, a simple three-point approximation of a lognormal distribution as proposed by Demirmen [2007]. The values have been scaled so that the expected realization of reserves expansion is one bcf per bcf invested in. The three different outcomes have the same probabilities, $\frac{1}{3}$, for each branch. This gives each node in the second stage a probability of $\frac{1}{3}$ and each node in the third stage a probability of $\frac{1}{3} * \frac{1}{3} = \frac{1}{9}$. We do not possess the expertise required to set realistic probabilities of the shale gas realizations and have therefore chosen to let each scenario tree nodes in each stage be equally likely as the others in the same stage. A more realistic modeling might be possible based on experience from working with shale gas reservoirs. It is assumed that the amounts of shale gas found are perfectly correlated between Norway and the Netherlands, while there is no correlation between the findings in two different stages. There are three stages, and the different scenarios can be designated by for example "Low low" for the scenario where a low amount of shale gas is found in both stage two and three. Figure 4.1 shows both the probabilities and outcomes in the scenario tree.

A complete listing of the input data used in this chapter is found in Appendix A. The problem is implemented and solved using the programming language GAMS. For more information on the implementation see Section 5.1.

To analyse the situation we compare solutions for different levels of risk aversion, α_p, and for different levels of market power, δ_{pn}, while keeping other data inputs constant. By using a relatively small model with realistic data inputs, two things are achieved. First, a small model makes it easier to isolate the effects of different levels of market power and risk aversion. Second, getting a visual overview of the results of a small model is easier than with a large model.

Figure 4.1: Scenario tree



4.2 Verification and Results

Based on economic theory, there are several concepts that a model with risk aversion and market power is expected to fulfill. We call these concepts the verification criteria. The ones we focus on are listed below.

- Lower market power leads to lower prices, higher sales rates and lower expected producer profits. This is based on the concepts in Section 2.2.
- Risk aversion leads to lower investments. When a risk averse producer is considering investing in something that has an uncertain outcome, he will regard the uncertain outcome as less valuable than the expected outcome, and therefore invest less than a risk neutral actor, who regards the uncertain outcome as just as valuable as the expected outcome.
- The $\mathrm{CV@R}_{p\alpha_p}$ of the producers' profits is a decreasing function of increasing risk aversion. Increasing risk aversion means that the producer will include fewer of the good scenarios when calculating $\mathrm{CV@R}_{p\alpha_p}$ (see Section 2.6), thus causing $\mathrm{CV@R}_{p\alpha_p}$ to decrease when risk aversion increases.

These criteria will be investigated in the following. If these criteria are not met, the model is very likely to be incorrect, and will have to be improved so that it operates as intended. If these criteria are met, the model appears to be working correctly.[1]

4.2.1 The Effects of Risk Aversion and Market Power on Investments and Trade in a Gas Market

This section studies the effects of different levels of risk aversion and market power in a small gas market, with focus on investments and trade.

4.2.1.1 Two Risk Neutral Producers

As a benchmark, we first look at a situation when both producers are risk neutral, $\alpha_p = 1$. We compare solutions where P_NOR and P_NED compete à la Cournot, perfect competition, and a solution where P_NOR and P_NED both have moderate market power. The different combinations of market power and risk aversion are shown in Table 4.1. To represent a moderate level of market power exertion, a value of 0.6 is chosen for the market power parameter δ_{pn}. This is slightly closer to Cournot than perfect competition.

Table 4.1: Level of risk aversion, α_p, and market power, δ_{pn}, for three competitive settings.

	α_p	δ_{pn}
Perfect Competition	1.0	0.0
Moderate Market Power	1.0	0.6
Full Cournot	1.0	1.0

Note that when $\alpha_p = 1$, $\mathrm{CV@R}_{p\alpha_p}(\mathtt{profit}_p) = \mathtt{E}[\mathtt{profit}_p]$. The optimal objective values for the different actors and economic surpluses for the three cases are listed in Table 4.2. When producer market power increase, producer profits increase, while social welfare and consumer surpluses decrease. In the moderate market power case P_NOR's profit is 93 bUSD. This is 15% lower than under full Cournot competition. For P_NED the profit is also 15% lower in the moderate market power case. Due to quadratic costs the profits are larger than zero in the perfect competition case as well. According to the basic economic theory presented in Section 2.2 this is as expected. The TSO has zero profits in all of the three cases since the pipeline never gets congested.

[1] In principle it is not possible to prove that a model gives a correct representation of the real world. Falsification is always possible, so this is the verification approach chosen.

Table 4.2: Optimal Economic surpluses [bUSD] for different actors in various forms of competition.

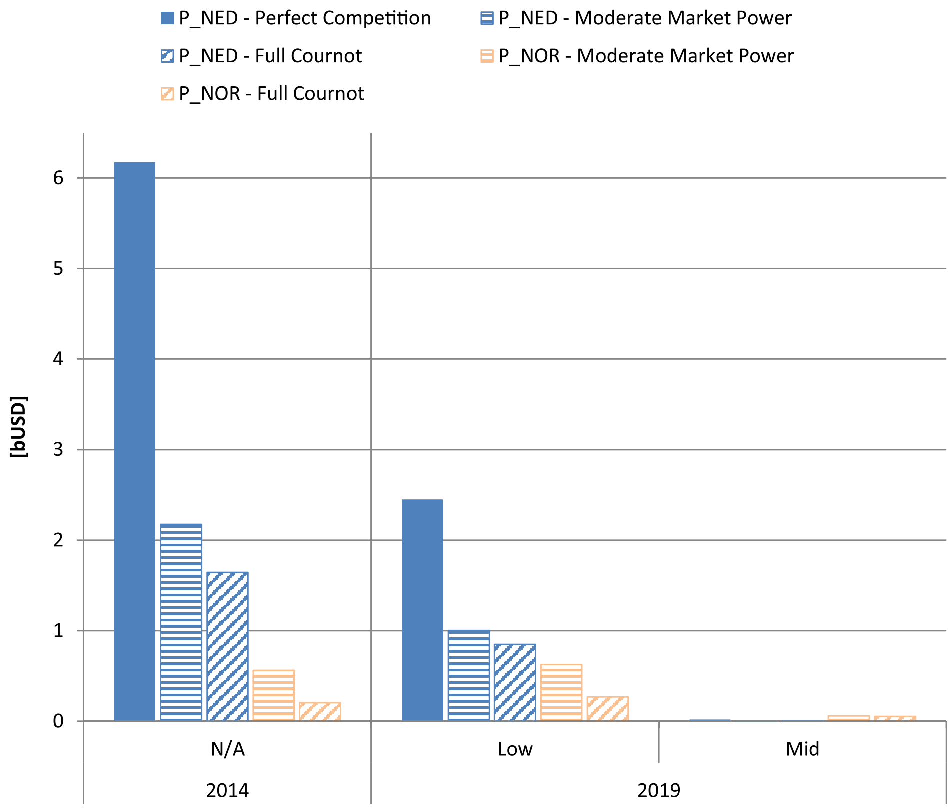
Actor	Attribute	Perfect Competition	Moderate Market Power	Full Cournot
P_NOR	Expected Profit	42.51	92.98	108.91
P_NED	Expected Profit	30.85	94.60	110.94
TSO	Expected Profit	0.00	0.00	0.00
Consumers	Expected Surplus	379.49	238.93	184.32
System	Expected Social Welfare	452.85	426.50	404.17

Investments

Figure 4.2 illustrates the levels of investments in the three cases. With the given input data, the production capacity is so high that investments in capacity expansions are not needed. Therefore, all investments are in expansions of reserves. The general trend in Figure 4.2 is that lower market power leads to higher investments by `P_NED`. Under moderate market, `P_NED` invests 2.2 bUSD in the first stage, 35% of the investments they make under perfect competition. Under full Cournot competition, `P_NED` invest 1.6 bUSD in the first stage, 25% of the perfect competition investments level. Under perfect competition, `P_NED` uses it's cost advantage in production costs to capture the entire market from stage 2 and onwards. Therefore, it is not worthwhile for `P_NOR` to invest in expansions, and all expansions therefore occur in the Netherlands in the perfect competition case. When both producers have moderate market power, prices are higher than `P_NOR`'s marginal cost, and both producers will therefore take a share of the market. This is in accordance with the theory presented in Section 2.2. Therefore, they both invest in reserves expansions, though at a lower level than under perfect competition because they can achieve increased prices at lower sales rates and therefore need less gas to market. When they both behave as full Cournot players, the investments are even lower, down from a total of 6.7 bUSD in the first stage for the two players combined to 1.8 bUSD, a 73% decrease from perfect competition case.

Another effect observed in Figure 4.2 is that the total investments are quite high in the first stage (2014), and lower in the following stage (2019). This can be explained as follows. If the producers find themselves in the scenario tree node where they find only a small amount of shale gas, they need to invest again in order to have enough natural gas to sell in the following period. If they find

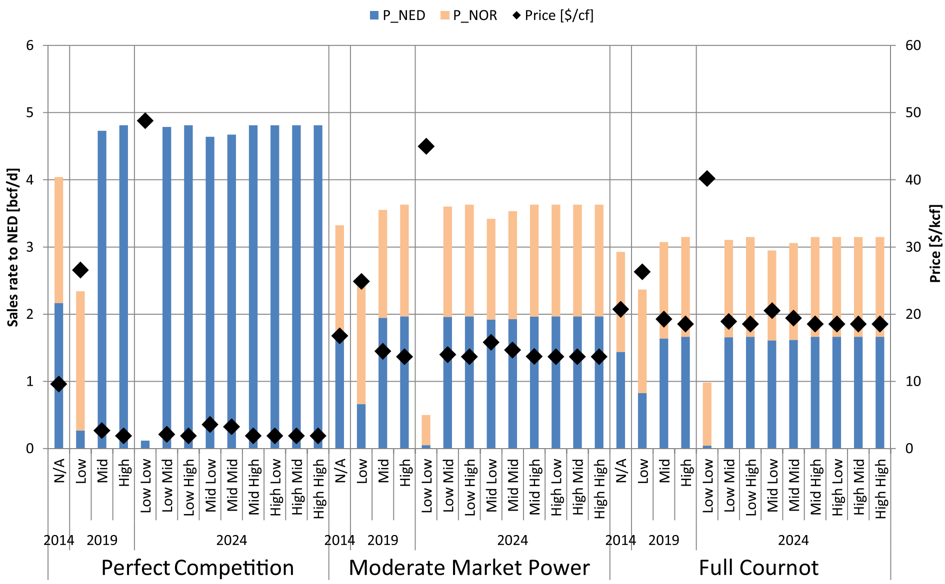
Figure 4.2: Investments with risk neutrality and various forms of competition



themselves in the scenario tree node where a moderate amount of shale gas is found, only a small amount of shale gas reserves expansions is needed for the next stage. In the scenario where a high amount of shale gas is found, reserves are plentiful and no further investments in expansions are needed.

The investment behaviour is found to be as expected for the two natural gas producers. In the second stage of the model, the horizon is just one more stage in the future, spanning from 2019 to 2024. In reality however, the horizon would be just as long in the second stage as in the first stage. This would cause investments in late stages to be greater than in our results. Specifically, investments might have been seen in the scenario tree nodes where a moderate or high amount of shale gas is found, and also in the last stage (2024, not shown). In a bigger study aimed at more realistic modelling of a natural gas market, extra stages can be added to the scenario tree to give a stronger incentive for investments in later stages. For example, if the investments in 2024 are of interest, stages for 2029 and 2034 could be added. This would give producers reason to plan for the future from 2024, and give a more realistic picture of investments in 2024. Poor representation of investments in the last stage is a shortcoming of the scenario tree chosen as input in this test case.

Figure 4.3: Prices and sales rates with risk neutrality and various forms of competition



Trade

Figure 4.3 illustrates the producers' sales rates and prices in the equilibrium solutions of the three risk neutral cases. It can be seen from the figure that the sales rates are higher in the perfect competition case than in the two cases with market power. In the perfect competition case the average total sales rate is 4.2 bcf/d. This is 45% higher than in the full Cournot case, where the average total sales rate is 2.9 bcf/d. Higher sales rates when market power is lower was expected from the first criterion in the start of this chapter, indicating that the model operates as intended with respect to market power. Figure 4.3 further shows that the average price in each stage is higher when the sales rates are lower (caused by a higher value of δ_{pn}).

It is interesting to study the scenario wherein the reserve expansion realization is the lowest. Here, the producers have a low amount of reserves. There is therefore a supply deficit that leads to a steep increase in prices. The relative price increase is largest in the perfect competition case and especially in the third stage where `P_NOR` has depleted its reserves. In this scenario tree node, the price increase is 409% compared to the first stage. Such a price increase could be observed in reality, but would be moderated because when prices increase, consumers switch to natural gas substitutes. This leads to lower demand and a moderation of the price increase. This is especially true in the long run, because natural gas dependent equipment could be replaced by equipment that uses other energy sources.

An interesting implication of increased market power is that the producer's incentive for holding back the sales rates (and thus not depleting reserves) makes the society better off in bad scenarios. In a world where the worst scenario plays out, the social welfare (calculated as the social welfare in scenario tree nodes $u0 + u1 + u4$) is 6.7% lower under perfect competition, where the social welfare is 312 bUSD, than when both producers have full market power, where the social welfare is 333 bUSD. To counter this, a policy maker might encourage producers to have certain levels of reserves available or encourage storage of natural gas for use in such situations.

4.2.1.2 One Risk Averse Producer

To study the effects of risk averse behavior, we now look at a variation of the test case used above. In this variation, `P_NOR` is assumed risk neutral while `P_NED` is assumed risk averse. The value of α_p for `P_NED` is 0.6. This represents a high level of risk aversion where the producer disregards the 40% best scenarios when making decisions. Both the producers have full market power and are therefore competing à la Cournot. The setting is presented in Table 4.3.

Figure 4.4 compares the investments made when `P_NED` is risk averse and `P_NOR` is risk neutral, to the investments made when both producers are risk neutral. The expected result, as hypothesized by the second criterion in the start of this chapter, is that investments decrease when risk aversion increases. The results show that the first stage investment made by the risk averse `P_NED` is 0.24 bUSD (15%) lower than in the risk neutral case. Thus we see that the model operates as intended with respect to this aspect. `P_NOR` responds to

Table 4.3: Risk preferences and market power setup when one producer is assumed risk averse.

Producer	α_p	δ_{pn}
P_NOR	1.0	1.0
P_NED	0.6	1.0

P_NED's lower investments by investing 0.12 bUSD (59%) more compared to the case where both producers are risk neutral. This shift of investments allows P_NOR to supply a larger share of the market and therefore capture more of the profits. P_NOR's profit is 3% higher when P_NED is risk averse. The investment shift can be seen in Figure 4.4.

Figure 4.4: Investments with risk neutrality vs. one risk averse and one risk neutral producer under Cournot competition.

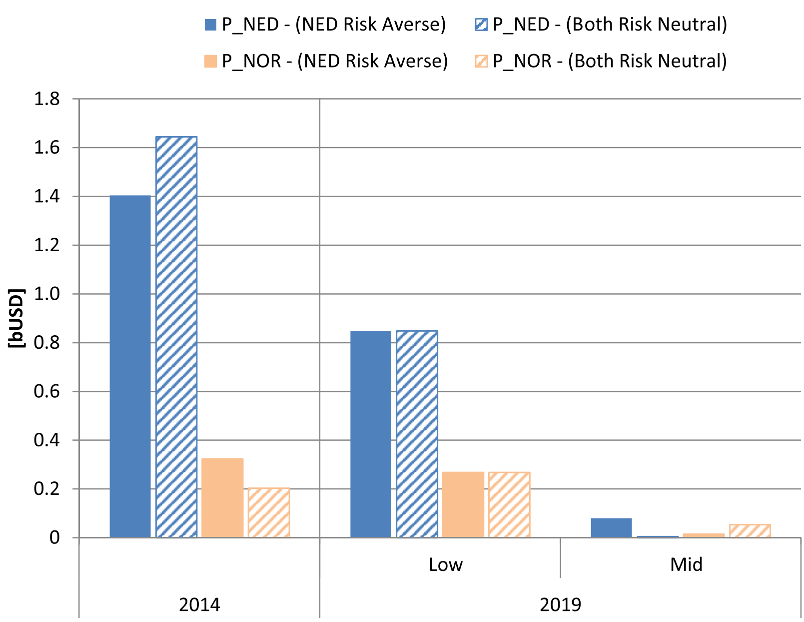
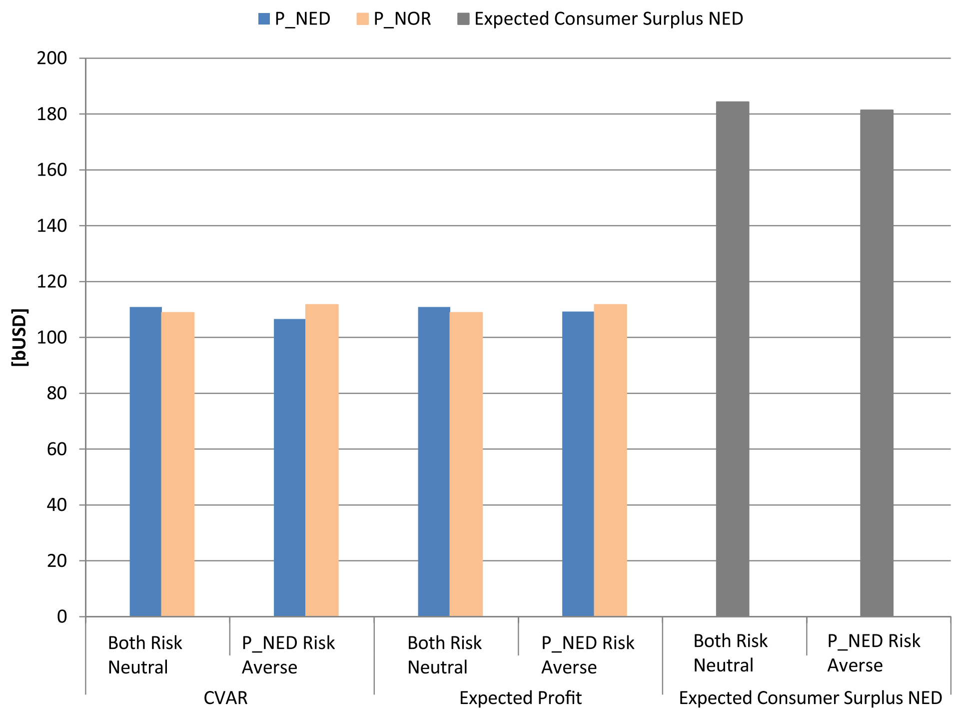


Figure 4.5 gives $\mathrm{CV@R}_{p\alpha_p}$, expected profits and consumer surplus when P_NED is risk averse and P_NOR is risk neutral and compares them to values of the same variables when both producers are risk neutral. The competition form is full Cournot for both combinations of risk aversion. It is evident that P_NOR's expected profit increases, while P_NED's expected profit and $\mathrm{CV@R}_{p\alpha_p}$ decreases. Consumer surplus decreases by 1.6% and social welfare also decreases by approximately 1% when P_NED becomes risk averse.

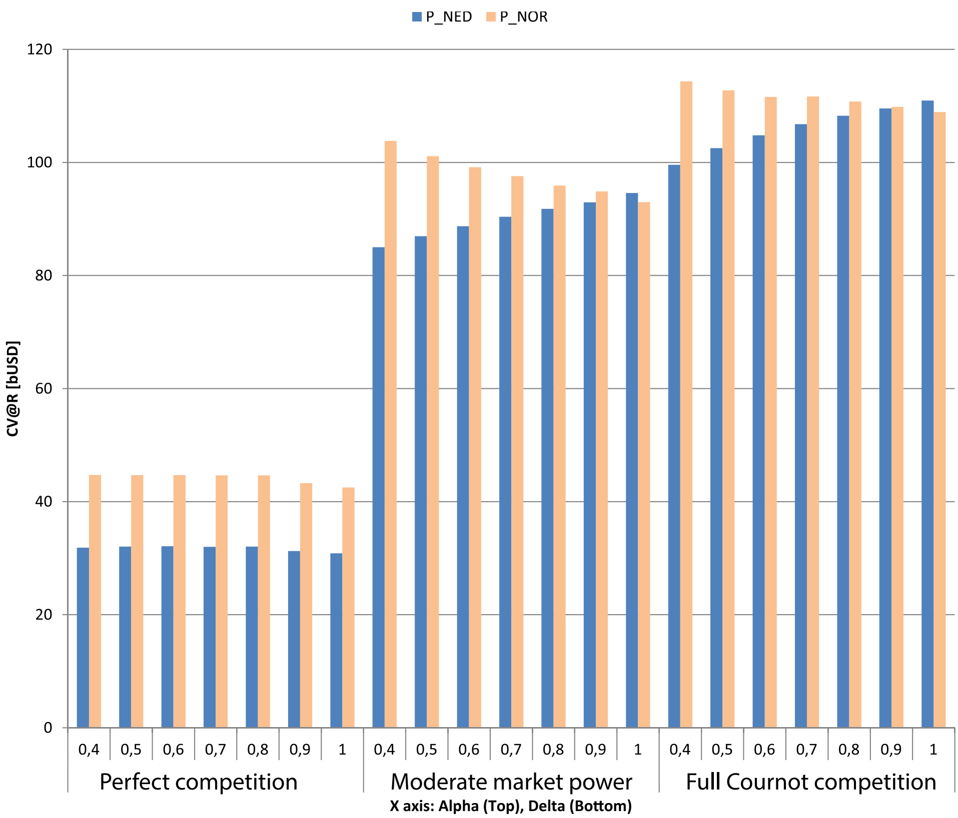
Figure 4.5: CV@R, expected profits and consumer surplus with risk neutrality vs. one risk averse and one risk neutral producer



4.2.1.3 Overall Trends

The previous cases have illustrated different combinations of risk aversion and market power. Many more are possible, but we do not analyse every one of them in detail. To show some overall trends Figure 4.6 gives the optimal $CV@R_{p\alpha_p}$ values for the two producers for a few different value combinations of $\alpha_{P_{NED}}$ and δ_{pn}.

Figure 4.6: CV@R as a function of α_{P_NED} for δ_{pn} 0, 0.6 and 1. `P_NOR` is risk neutral ($\alpha_{P\_NOR} = 1$).



The main insight from Figure 4.6 is that, as expected from the third criterion, $CV@R_{p\alpha_p}$ appears to be falling when α_p is lowered.

In the full Cournot and the Moderate market power cases, $\mathrm{E}[\mathrm{profit}_{P\_NOR}]$ increases and $CV@R_{P\_NED\alpha_{NED}}$ decreases when `P_NED`'s risk aversion increases (lower value of α_{P_NED}). This can be explained as follows. `P_NED` invest less when their risk aversion is higher. This leads to lower reserves for `P_NED`. As a consequence, `P_NED` is not able to produce and sell as much natural gas. This gives P_NOR the opportunity to supply a larger part of the market and increase its expected profit.

Under full Cournot competition, P_NED's $CV@R_{p\alpha_p}$ is 111 bUSD when they are risk neutral, and 100 bUSD when they are very risk averse ($\alpha_{P\_NED} = 0.4$). When P_NED is risk neutral, P_NOR's expected profit is 109 bUSD, and it is 114 bUSD, 5% higher, when P_NED is very risk averse.

Under moderate market power, P_NED's $CV@R_{p\alpha_p}$ is 95 bUSD when they are risk neutral, and 85 bUSD when they are very risk averse ($\alpha_{P\_NED} = 0.4$). When P_NED is risk neutral, P_NOR's expected profit is 93 bUSD, and it is 104 bUSD, 12% higher, when P_NED is very risk averse.

In the perfect competition case the trend is a little different. Here, both producers get higher profits when P_NED is more risk averse. P_NED's $CV@R_{p\alpha_p}$ is 31 bUSD when they are risk neutral, and 32 bUSD when they are very risk averse ($\alpha_{P\_NED} = 0.4$). When P_NED is risk neutral, P_NOR's expected profit is 43 bUSD, and it is 45 bUSD, 5% higher, when P_NED is very risk averse.

The following provides an explanation of this. As we have noted earlier, in this case P_NED takes the entire market from the second stage and onwards except in the scenario tree node where the producers find a low amount of shale gas in the second and third stage. However, when P_NED is risk averse they invest less. P_NOR still does not invest and this leads to a shortage in the risk averse cases. The investments are lower and the shortage is bigger when P_NED is more risk averse. This in turn leads to lower sales rates than they would have been if investments were at the risk neutral level. This means that both producers get a higher price and larger profits, while the consumer surplus and social welfare decrease.

4.3 Summary of Findings

This chapter has tested that the model behaves as expected and studied how risk aversion and market power affects investments and trade in a natural gas market. The verification criteria were met by the results:

- Lower market power leads to lower prices, higher sales rates and lower expected producer profits. In the first stage prices are 54% lower, the total sales rate is 38% higher and producer profits are 67% lower with perfect competition than with full Cournot competition.
- Risk aversion leads to 15% lower first stage investments by the risk averse actor compared to investments when both producers are risk neutral. This

lowers the expected consumer surplus by 1.6% due to lower production and sales rates.

- The $\mathtt{CV@R}_{p\alpha_p}$ of the producer P_NED's profits decrease from 111 bUSD to 107 bUSD when comparing the risk neutral to the risk averse case with a value of $\alpha_p = 0.6$.

In the scenarios where a low amount of shale gas is found market power might make consumers better off. The reason for this is as follows. Market power creates an incentive for producers to hold back on sales, which in turn leads to more reserves left for later stages. Therefore, their reserves might not be depleted in scenarios where very low amounts of new resources become available. This means that they are able to sell more natural gas even when they only find very small amounts of gas. This leads to higher consumer surplus in later periods compared to the perfect competition case.

Under Cournot competition and under moderate levels of market power, the expected profit of the risk neutral producer increases by 5% under Cournot competition and 12% under moderate market power as the expected profit of the risk averse producer decreases, as is seen in Figure 4.6. Under perfect competition we have found that both producers get higher profits when one producer is more risk averse. This is because lower investments creates a shortage in some scenario tree nodes and pushes prices up from the perfect competitive level.

From this chapter we conclude that the model appears to be working as expected. In the next chapter we will implement and analyse a larger data instance.

5 Computational Results and Analysis

In this chapter we use the developed model to answer and discuss the research questions presented in Chapter 1. The developed model is intended to describe a general natural gas market, and many different topics can be analyzed using the results from the model, including infrastructure developments, exploration strategies for producers and regional price differences. The scope of this chapter is to shed light on the research questions posed in Chapter 1:

- To what extent does shale gas development in Ukraine and Poland have the possibility to reduce their dependence on Russian natural gas imports?
- How does risk aversion and market power affect investments and trade in a gas market?
- How does the perceived likelihood of a shale gas ban affect the investments and trade?

The last question has already been treated in Chapter 4. Therefore, the two first questions will be given priority.

This chapter is structured as follows. In the first section, the implementation of the presented model is discussed. First, implementation in the programming system General Algebraic Modeling System (GAMS) is presented. Second, an overview of collection and calibration of data inputs is given. The second section looks at different results from the model. First, a general overview of the results is given. Second, the impact of shale gas developments and risk preferences is assessed. Third, the effects of the perceived likelihood of a shale gas ban in Ukraine and Poland is studied.

5.1 Implementation

When the model is implemented, several aspects have to be considered. The mathematical model has to be implemented in a suitable programming language, data inputs have to be selected and calibrated, and a scenario tree has to be developed. These aspects are treated in the following.

5.1.1 Implementation in GAMS

To solve the problem, the model has been implemented in the modeling system GAMS. All constraints, functions, variables and parameters from the model formulation in Chapter 3 are included in the GAMS code. GAMS does not distinguish between lower case and capital letters. Therefore certain names differ between the mathematical model and the code.

The problem is coded in several files. The input data, model equations, solution procedures and post solve calculations are separated. The problem is then run from a main file. The separation allows for easy transitions between different data sets. The code is available in Appendix C and in the attached .zip archive.

To solve the problem, the PATH solver is used. It solves MCPs by using a modified Newton-search [GAMS-Development-Corporation, nd]. In addition, the NLP solver CONOPT is occasionally used in order to find an initial point from which PATH starts its procedures from. For more details on this, see Chapter 6.

5.1.2 Data Input

Data collection and calibration are important tasks in developing a model that realistically represents the European natural gas market. The process of collection and calibration is an iterative process. It starts with collection of data for the coefficients and parameters of the model. After this, the data are put into the model without any adjustments. The results from the model then typically highlights certain aspects of the data that could be calibrated in order to create results that reflect the current situation in the natural gas market in the first stage of the model. The data inputs are then adjusted, and the model is run again. This is repeated until an acceptable picture of the current situation is reflected in the first stage results of the model. Data of this kind can never represent reality perfectly, and the results are affected by the input data chosen. However, we feel confident in the data from Rystad Energy AS and our calibration.

5.1.2.1 Data Collection

The model presented in Chapter 3 contains a great number of parameters. Data regarding cost of development and production of shale gas and conventional gas, potential resources of natural gas, natural gas demand and production and transportation capacities are needed to run the model. Most of the data have been provided by the energy consultancy Rystad Energy AS, and are available in their proprietary database of upstream oil and gas activity called uCube. Demand data and pipeline capacities are based on publicly available sources. The data inputs are presented in Tables 5.1 to 5.10.

Table 5.1: Misc. parameters

Attribute	**Value**	**Unit**
D_u	1825	days
Discount factor	5%	per year
B_u^{TSO}	1	bUSD

The model has stages of five years (1825 days) and an annual discount factor of 5%.

5.1.2.2 Data Input for the Producers

The model is set up to give a sufficiently realistic picture of the European natural gas market to get meaningful results for analysis, while at the same time keeping the problem size low enough to be solvable. By including the biggest producers in Europe, the model captures 88% (24 bcf/d) of the production in Europe in 2014. The producers are represented as national producers, with one producer in each country. The producers included are Norway, the Netherlands, the UK, Russia, Poland and Ukraine. Since the focus of this work is the European gas market, the producer in Russia, P_RUS, is modeled as an exogenous supply source. In order to account for the European supply portion of P_RUS's production, the production is capped at the current export level and there is no Russian domestic market or investment opportunities. This is done in order to represent `P_RUS`'s exports to Europe only.[1] With this aggregation of the real world situation (where there are several producers in each country) the number of suppliers are lower, and the sales should therefore come closer to the monopoly quantities than with more suppliers. This can be remedied by adjusting the market power parameter down.

Market Power

The presented model allows the modeler to set a market power parameter for each producer in each market. The real levels of market power are hard to assess because it is difficult to prove the exertion of market power with the available information. In order to determine the producers' market power, the following approach is used: For each country (market), the number of suppliers is determined by looking at imports to that country as of today. The level of market power is then determined by the number of suppliers. Many suppliers suggest low market power for each supplier, while few suppliers suggests high market power for the suppliers in that market. Using this proxy for determining market power, all the producers supplying to a market are assumed to have the same level of market power in the same market. In reality different producers could have different levels of market power in a market. This is not captured by the model, and leads to results where the most powerful suppliers, such as Russia, get a smaller advantage than what they have in reality.

In order to make the number of possible levels of market power manageable, increments of $\frac{1}{5}$ are used when setting the market power parameters. Table 5.2 lists the levels of market power in each market. Ukraine has few suppliers (mainly Russia), and suppliers therefore have a high level of market power in Ukraine. The UK and Germany on the other hand have a larger set of suppliers and suppliers therefore have less market power. The Netherlands and Poland fall in between Ukraine and UK with respect to the amount of market power given to suppliers.

Reserves Investments

According to EIA [2013b], the three European countries with the largest shale gas reserves are Ukraine, Poland and France. Shale gas development is banned in France [the Economist, 2014] while Poland and Ukraine has some of Europe's most favorable infrastructure and largest public support for shale gas development. Other European countries have much lower shale resources. The input data therefore only allow for shale gas investments in Ukraine and Poland. In

[1] Theoretically, Russia could decide to sell all its gas to Europe, but this is not seen as likely. Their production is therefore capped at their export level.

Table 5.2: Levels of market power in each market.

Country	**Market power, δ_{pn}**
Ukraine	1.0
United Kingdom	0.2
Germany	0.2
Netherlands	0.6
Poland	0.8

the solutions studied here, investments in reserves can only be made in nodes where producer p already is present. For example, the producer P_UKR is the only producer who can invest in reserves in country node UKR (Ukraine). In reality producers are able to invest in several countries, but this is not needed in order to study how shale gas development could take place on a national level. If the producers were allowed to invest in several countries, the amount of shale gas developed in a country could be calculated by adding the different producers' investments in the given country. In this case, producers who are risk averse would be expected to invest less in shale gas in a country than risk neutral producers.

Risk Preferences

The problem is solved for two different cases of risk preferences (see Table 5.3): a risk averse situation where α_p is 0.85 for P_UKR and P_POL and a risk neutral setting where all the actors are risk neutral. Lower values of α_p, representng higher degrees of risk aversion, could also have been used. However, the current limitations of the model limits the value of α_p to $[0.85, 1]$. For more on α_p-value limitations see Chapter 6. As seen in Chapter 4, a value of α_p of 0.85 is sufficient to have a significant impact on the solution. If lower values of α_p had been possible, the impacts of risk aversion on the solution would have been larger.

Table 5.3: Risk preferences in two cases.

Case	α_p (p=P_UKR and P_POL)
Risk averse (RA)	0.85
Risk neutral (RN)	1.00

Today, 80% of Ukraine's and 59% of Poland's natural gas consumption is covered by Russian imports. Since Poland and Ukraine also have the largest available shale gas resources they are the most interesting with respect to the risk associated with shale gas development. We therefore focus on them in particular and let α_{UKR} and α_{POL} vary over the two cases. This enables comparisons between the results in the two settings so that it is possible to study the effects of different risk preferences. The rest of the actors are assumed risk neutral.[2]

The remaining parameters for the producers are based on data from Rystad Energy AS, and are presented in Table 5.4-5.7.

Table 5.4: Budgets in bUSD and initial reserves in bcf for producers.

Producers	B^{P}_{pu} [bUSD]	R^{P0}_{conv} [bcf]	R^{P0}_{shale} [bcf]
P_NOR	60.0	72075	0
P_NED	10.8	39539	63
P_POL	3.7	3655	498
P_UKR	16.0	11930	166
P_RUS	0.0	200000	0
P_UK	7.7	15768	0

Table 5.5: Initial capacities in bcf/d for producers.

Producers	CAP^{P0}_{conv} [bcf/d]	CAP^{P0}_{shale} [bcf/d]
P_NOR	10.3	0
P_NED	7.6	0
P_POL	0.5	0
P_UKR	0.8	0
P_RUS	20.0	0
P_UK	4.2	0

[2]The model allows for letting more actors be risk averse. Letting the other producers be risk averse, however, will not make big differences when studying a situation where only P_POL and P_UKR are making risky investments.

Table 5.6: Linear and quadratic cost function coefficients C^L: $[bUSD/(bcf/d)]$ C^Q: $[bUSD/(bcf/d)^2]$

Producers	C^L_{conv}	C^Q_{conv}	C^L_{shale}	C^Q_{shale}
P_NOR	0.0027	0.002	-	0.002
P_NED	0.0019	0.002	0.0018	0.002
P_POL	0.0016	0.006	0.0015	0.006
P_UKR	0.0016	0.020	0.0015	0.002
P_RUS	0.0020	0.002	-	0.002
P_UK	0.0052	0.002	-	0.002

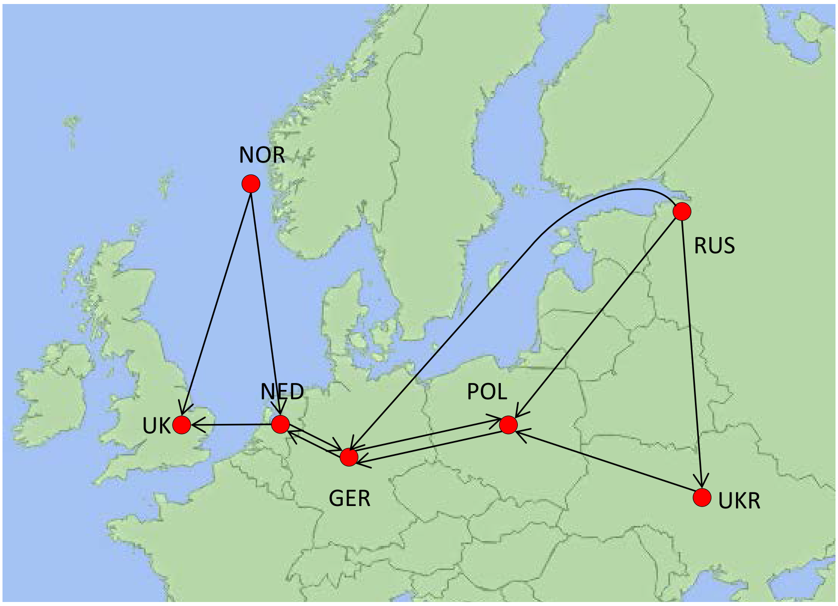
Table 5.7: Costs of expansions for producers, [bUSD/(bcf/d)]

Producers	$C^{\Delta R}_{conv}$	$C^{\Delta R}_{shale}$	$C^{\Delta P}_{conv}$	$C^{\Delta P}_{shale}$
P_NOR	0.00029	-	0.0028	-
P_NED	0.00029	0.0230	0.0013	0.003
P_POL	0.00230	0.0053	0.0035	0.022
P_UKR	0.00090	0.0030	0.0043	0.014
P_RUS	-	-	0.0018	-
P_UK	0.00073	-	0.0033	-

5.1.2.3 Data Input for the Transmission System Operator

As stated in Chapter 3, the model aggregates pipes so that at most one pipe transports gas from one country to another. For the country nodes included, pipes are needed between several markets in order to let the natural gas flow from producers to markets. Figure 5.1 illustrates the pipeline network and the country nodes in the model.

Figure 5.1: Pipelines in the model.



The capacities of the pipelines (see Table 5.8) have been chosen based on the current sales rates of producers split on markets.[3] For producing countries that only have pipelines for flow out of the country, this works very well. For example from Norway, the production rate from Norway is split on continental Europe and the UK, and the capacities of the pipelines to continental Europe and the UK are set based on these rates. For countries with both ingoing and outgoing pipes, such as the Netherlands, the capacities are set such that the sales of the country and other countries sending gas through the country are able to flow. For the pipeline from the Netherlands to Germany, for instance, the sales rate of both Norway and the Netherlands to Germany are included when setting the pipeline capacity.

[3]Current sales rates of producers splits on markets are obtained from Rystad Energy AS.

Table 5.8: Pipeline capacities, operational costs and expansion costs

Pipeline	CAP^{A0} [bcf/d]	C^F_a [bUSD/bcf/d]	$C^{\Delta A}$ [bUSD/(bcf/d)]
NOR_UK	2.20	0.0010	1.5
NOR_NED	8.10	0.0010	2.0
NED_UK	3.00	0.0010	1.2
NED_GER	3.00	0.0005	1.0
GER_NED	2.00	0.0005	1.0
POL_GER	0.10	0.0005	1.0
GER_POL	0.50	0.0005	1.0
RUS_POL	5.40	0.0005	1.0
RUS_UKR	5.40	0.0005	1.0
RUS_GER	5.40	0.0010	2.0
UKR_POL	1.00	0.0005	1.0

5.1.2.4 Data Input for the Markets

The markets included are the Netherlands, Germany, the UK, Poland and Ukraine. By selecting these markets, 50% of the consumption in the EU plus the entire demand of the Ukrainian market is covered in the model. For each of these markets, a linear inverse demand function is formed by finding an intercept and a slope for each stage. The intercepts and slopes are found by using a reference price and sales rate and assuming a price elasticity. Since the model aggregates different demand sectors into one inverse demand curve per country, the price elasticity has to be chosen so that it is a reasonably good fit for several sectors. Liu [2004] studies price elasticities of natural gas in Organisation for Economic Co-operation and Development (OECD) countries. Liu finds long-term price elasticities of -0.36 for the residential sector and values of -0.25 for the industrial sector. We do not have estimates for the price elasticities for the commercial and transportation sectors, but assume that they are closer to the industrial sector than the residential sector. This is based on the observation that, just like the industrial sector, the two sectors are dominated by corporations. We therefore assume a price elasticity of -0.25 for the aggregated inverse demand function.[4]

[4] Values of price elasticities for natural gas differ greatly between different models and sources. For example, Egging [2010] uses values between -0.25 and -0.75.

The following relations are used, where ϵ is price elasticity (see Pindyck and Rubinfeld [2013]):

$$SLP = \frac{P^{ref}}{Q^{ref}} * \frac{1}{-\epsilon} \tag{5.1}$$

$$INT = P^{ref} + SLP * Q^{ref} \tag{5.2}$$

For the Netherlands for example, with a reference price of 0.01 bUSD per bcf and a reference demand of 4.74 bcf/d, the slope becomes 0.008 (rounded to 0.01 in the data set), and the intercept becomes 0.05. Demand data were gathered from [CIA, 2012].

To capture the expected growth in demand, the intercepts of the future periods are adjusted by a growth factor found from EIA [nd] by taking the expected demand for the given stage and dividing it by the 2015 estimated demand. The intercept for stage two (2020) is then found by multiplying the intercept of stage one by the growth factor. Intercepts and slopes are found in Tables 5.9 and 5.10.

Table 5.9: Intersects of the inverse demand curve.

		INT	
Countries	**2015**	**2020**	**2025**
NED	0.050	0.052	0.053
POL	0.034	0.035	0.036
UKR	0.060	0.062	0.063
UK	0.090	0.093	0.095
GER	0.085	0.088	0.090

5.1.3 Scenario Tree

In a stochastic model, different scenarios are needed in order to model the uncertainty. As discussed in Chapter 1 and 3, the main sources of uncertainty relevant for the research questions are uncertainty in resource estimates and shale gas legislation. Therefore, the scenario tree needs to reflect these two aspects.

Table 5.10: Slopes of the inverse demand curve.

Countries	**SLP**
NED	0.010
POL	0.015
UKR	0.010
UK	0.010
GER	0.010

When a producer decides to develop shale gas resources, he decides how much to invest in shale gas. The outcome of the investment is uncertain, as there can be a large amount or a small amount of shale gas in the ground. This uncertainty is captured by letting each stage have two distinct outcomes for each producer: one outcome where a low amount of shale gas is found relative to expectation and one where a high amount of shale gas is found relative to expectation. In the next stage, the producers face the same uncertain situation, which is modeled by the same two possible outcomes.

Our initial idea was to have three outcomes with respect to the amount of shale gas found (low, medium, high) as in Chapter 4. However, in combination with modeling a shale gas ban (described in the Section 5.1.3.1), this made the scenario tree very large. Therefore, two outcomes (low, high) were used. To capture the effects of risk preferences, two distinctly different outcomes for shale gas exploration is sufficient. This allows for capturing the effects of risk preferences while at the same keeping the scenario tree at a solvable size. As in Chapter 4, the two outcomes are chosen to be equally likely,[5] with the low outcome giving 0.2 times the expected findings and the high outcome giving 1.8 times the expected findings. It is very difficult to model the probability distribution of shale gas resources in unexplored areas because few studies have been done and development is at a very early stage. However, these two outcomes reflect possible results of exploring a prospective natural gas reservoir and serve the purpose of capturing the uncertainty. Before drilling, the seismic surveys show that there is gas, but there might not be much, giving just 20% of the expected volumes. On the other hand, it might be that there is more gas than one was able to prove using seismic surveys, giving almost twice the expected amount. The chosen values have an expectation of 1 cf per cf invested in, and therefore give a good representation of the expectation. However, extreme events (tail values) where a lot of shale gas (or none) is found

[5]The argumentation for this is given in Section 4.1.

are lost using this estimate of the distribution.

Another option could have been to model the outcomes of shale gas exploration after a probability distribution assumed to fit well with natural gas reservoirs. Demirmen [2007] suggests that a lognormal distribution would be a good fit for petroleum reservoirs. However, approximating a distribution requires more knowledge about the actual probability distribution of shale gas resources for the effort to be worthwhile. Available estimates for shale gas resources in Europe are typically one-point estimates as in EIA [2013b]. Also, more outcomes would be required to approximate the distribution. This would make the scenario tree significantly bigger and make the problem harder to solve.

5.1.3.1 Modeling a Shale Gas Ban in the Scenario Tree

The current situation regarding shale gas legislation is uncertain. As presented in Chapter 1, several European countries have banned shale gas production while others have not. This situation has led us to investigate the impacts of the perceived likelihood of a shale gas ban. In order to capture the possibility of a shale gas ban in the scenario tree, a branching is added from the first stage, where one branch reflects the situation where shale is legal and the other branch reflects a shale gas ban. Once a decision on legislation is made between the first and the second stage (2015-2020), we assume that the legislation will not change over the model horizon (until 2025). The probability of such an event is difficult to estimate, but signals by the Ukrainian government by signing deals with oil companies for shale exploration and Poland's current proposal to cut taxes on shale gas suggest that a ban is not very likely [Wasilewski, 2014]. Based on this, the probability is set to 5%. If the probability is in fact lower, shale gas investments will look less attractive in the model than in the real world, and vice versa if the probability of a ban is higher in reality. The model is also solved for 25% probability of shale gas ban to study the effects of different perceptions of the likelihood of a shale gas ban.

In scenario tree nodes where there is a ban in effect, already producing shale reserves are allowed to continue production until the reserves are depleted. This can be interpreted as a situation where no new production licenses are issued. In reality regulators might also close down existing production of shale gas when a ban issued. This could be modeled by adding a restriction on the quantity of shale gas produced. Such a constraint could be:

$$q_{prnu} \leqslant b_{prnu} \quad \forall \quad p, n, u = bannode,\ r = shale \tag{5.3}$$

b_{prnu}, the bound on the produced amount for shale gas, would be zero for the scenario tree nodes where a shale gas ban is in effect. The constraint above would not exist for the scenario tree nodes where there is no shale gas ban. In scenario tree nodes without ban Equation (3.3) (repeated below) would constrain the production rate.

$$q_{prnu} \leqslant CAP^{P0}_{prn} + \sum_{u' \in pred(u)} e^{P}_{prnu} \tag{5.4}$$

This would however increase the size of the problem, and the realized reserves expansions parameters are therefore used to model the shale gas ban instead. This is done by setting the realized reserves, ΔR_{prnu}, to 0 in the scenario tree nodes where a ban is in effect. Ban on production from existing shale gas fields is not accounted for in the model. However, there exists very little shale gas production in Europe today, so this model shortcoming will not affect the produced volumes significantly.

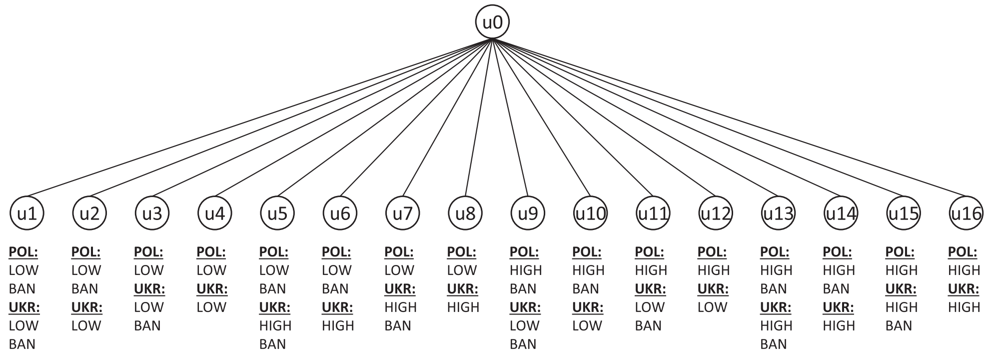
5.1.3.2 Reducing the Scenario Tree Size

Given that the scenario tree includes both different shale gas legislation and different amounts of shale gas found, the scenario tree grows quite quickly. For a situation with only two producers, there are 16 combinations going from stage one to stage two. Figure 5.2 shows this for the two producers Ukraine (`UKR`) and Poland (`POL`). "HIGH" refers to a large amount of shale gas found, and "LOW" refers to a low amount. "BAN" indicates that shale gas is banned in the respective country from that stage and onwards. As a great number of nodes in the scenario tree increase the problem size, we want to reduce the tree size. In order to do this, the following observation is used.

In nodes `u1`, `u5`, `u9` and `u13`, there is a ban in both Ukraine and Poland. This means that the amount of shale gas found is irrelevant. These four nodes are therefore combined into a single node where the amount of shale gas found is set to zero. This has the same effect as a ban. Likewise, the same can be done for the nodes where there is a ban in one country and the findings in the other country ("HIGH" or "LOW") are the same. This happens in the pairs `u3-u7`, `u6-u14`, `u11-u15`. These pairs can each be combined into one node each. In this way, the 16 nodes are reduced to nine. In the next stage, the same logic is applied, reducing the number of nodes in the third stage from 36 to 25.

The scenario tree used in the numerical study is presented in Figure 5.3. The node numbers do not match the numbers above and in Figure 5.2 because of

Figure 5.2: Small Scenario Tree



the reductions made. The scenario tree shows which elements are treated as uncertain in the numerical study: the amount of shale gas found in Ukraine and Poland and whether or not shale gas is banned in the two countries. The figure shows the outcome in each stage for each of the 25 scenarios.

In summary, there are 25 scenarios and 35 scenario tree nodes over 3 stages. Note that the number of scenarios is large enough to see a difference in $\mathsf{CV@R}$ when α_p is reduced by increments of more than $\frac{1}{25}$. This is discussed in Section 2.6 and is sufficient for the purpose of our analysis where we are comparing $\alpha_p = 0.85$ to $\alpha_p = 1$.

There is perfect correlation between stages with respect to bans on shale gas production, while the amount of reserves found is assumed to be independent both between stages and producers. Independence between producers is reasonable because they are situated in different countries. Independence between stages within a country is less realistic. The reason for this is the following. If a large amount of shale gas is found in the first period, the shale formation probably contains a high amount of extractable shale gas. Findings would therefore be more likely to be high in later periods since the same formation could be targeted. Estimating the correlation, however, is very difficult because very little information exists that could support an estimation of the correlation.

The probabilities of each scenario tree node is given in Figure 5.4, and are calculated in the following way. For each scenario tree node, the probability of the corresponding shale gas reserves event (low, high) and the probability of the corresponding shale gas ban event (ban, no ban) are multiplied to form the scenario tree node probability. For example, $\mathsf{Pr}(\mathsf{u11})$ is the product of the probability of a ban in Ukraine ($\frac{1}{20}$) times the probability of a low amount of shale gas in Poland in 2020 ($\frac{1}{2}$) and a low amount of shale gas in Poland in 2025 ($\frac{1}{2}$). Therefore, $\mathtt{Pr}(\mathtt{u11}) = \frac{1}{20}\frac{1}{2}\frac{1}{2} = 0.0125$. In Figure 5.4, the probabilities are rounded to three decimals, and their values do therefore not sum to 1 (in the figure). In each stage, $\mathtt{Pr}(\mathtt{u})$ gives the probability of ending in node $\mathtt{u}$. For example, the probability of coming to node u3 in stage two is 0.024, while the probability of ending in node u13 is 0.012, and the probability of ending in node u13 when standing in u3 ($\mathtt{Pr}[\mathtt{u13}|\mathtt{u3}]$) is 0.5.

Figure 5.3: Three Stage scenario tree with outcomes.

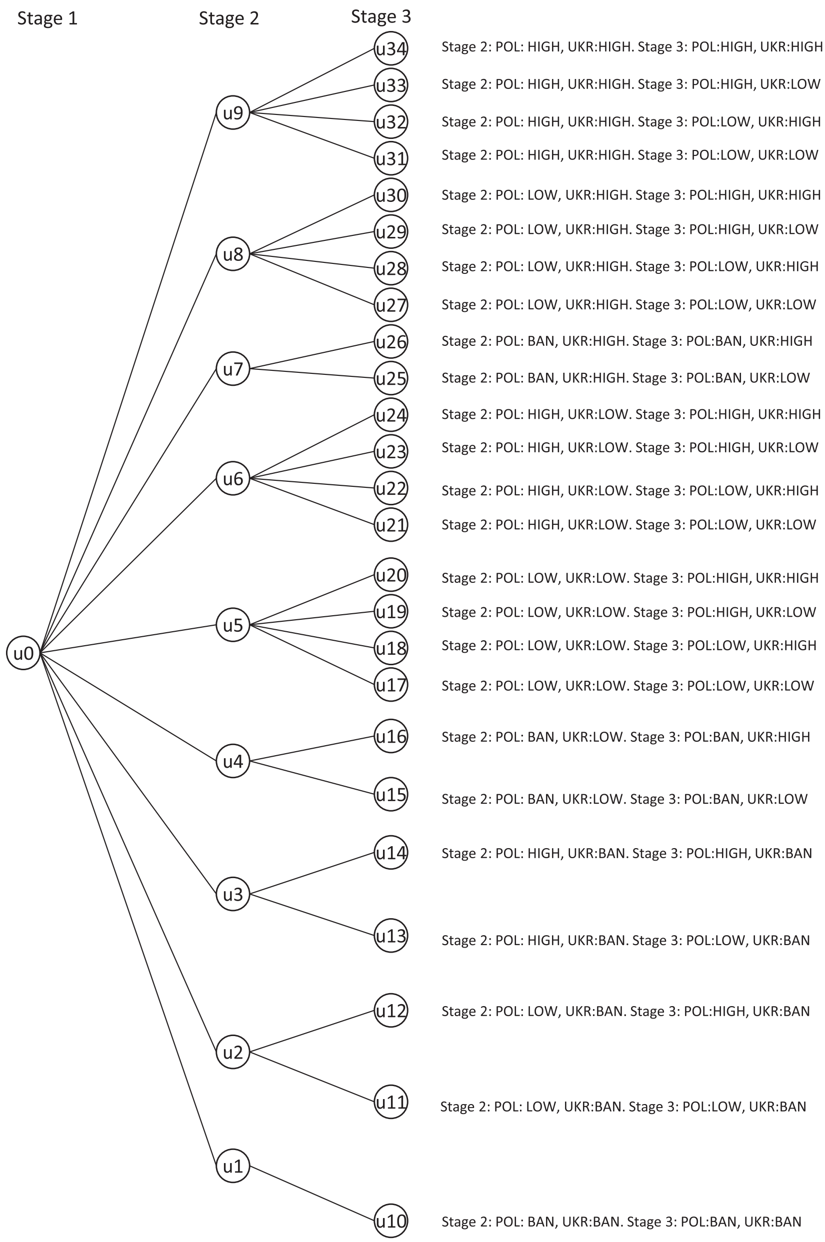
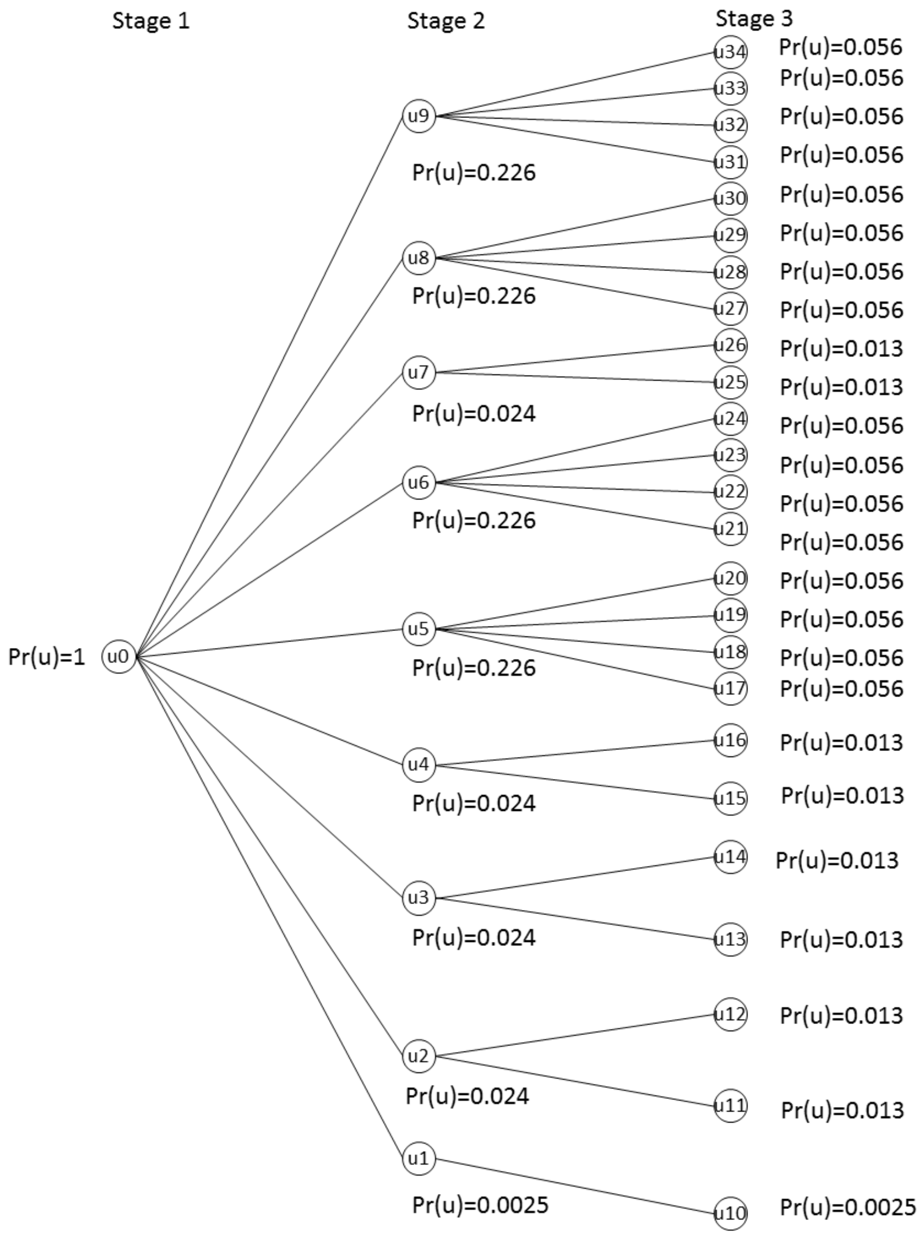


Figure 5.4: Three stage scenario tree with probabilities rounded to three decimals.



5.2 Results and Discussion

In the following we present and analyze solutions of the large scale model. The discussion is divided in three parts. First, we look at the solution of a case where the level of risk aversion is such that α_p is 0.85 for the two producers P_UKR and P_POL and the probability of a ban is 5%. This case is called the *"Risk Aversion Case" (RA Case)*. Second, we compare the RA case to a risk neutral solution of the same problem to isolate the effect of risk aversion on shale gas development. Third, we investigate the effects of the perceived likelihood of a ban on shale gas exploration.

5.2.1 Solution of the RA Case

The model makes several decisions for all the actors of the system. The model looks at a situation of the European natural gas market where there is a possibility for the two risk averse producers P_UKR and P_POL to explore shale gas resources. The costs of producing a given quantity of shale gas is lower than the cost of producing the same quantity of conventional gas for both producers (see Table 5.6). Therefore, it would be expected that an economically rational and risk neutral actor would prefer shale gas to conventional gas and therefore invest in shale gas development.[6] This should also lead to changes in the producers' trade balances, as P_UKR and P_POL might be able to supply shale gas to markets. This could reduce Russia's role as a dominating supplier to Ukraine and Poland. The following investigates how these hypotheses play out in the natural gas market by looking at production, sales, prices and investments.

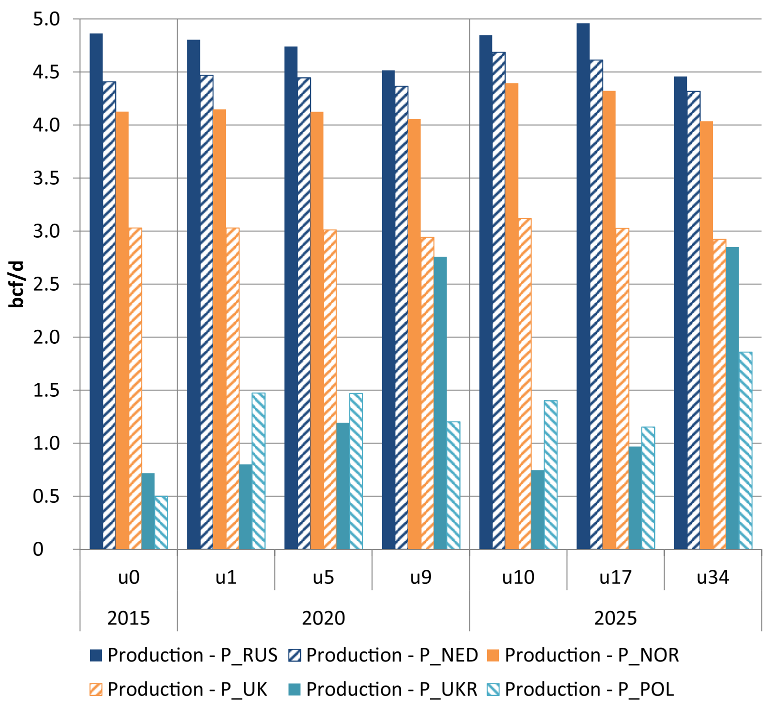
5.2.1.1 Increasing Supply with Shale Gas

The European natural gas system has four major producers: Russia (not in Europe, but an important supplier), Norway, the Netherlands and the UK. Ukraine and Poland are relatively small producers, but might increase their production significantly by developing shale gas. Figure 5.5 shows the development of production for each country in three paths in the scenario tree. The scenario where shale gas exploration is banned in Poland and Ukraine in 2020, the "ban" path, is u0-u1-u10. The scenario where both P_UKR and P_POL find

[6] Note that the quadratic costs can make it optimal to produce a mix of the two resources. If they produce both shale and conventional gas, the quantities of each resource will be such that the marginal cost for the two are the same, given that there are no shortages.

lower amounts of shale than expected in 2020 and 2025, the "low" path, is u0-u5-u34 and the scenario where both `P_UKR` and `P_POL` find higher amounts of shale than expected in 2020 and 2025, the "high" path, is u0-u9-u34. There are 25 different scenarios in the third stage and therefore 25 different paths that could have been presented. To make the comparisons manageable, three paths are chosen. We have chosen to highlight these three because they illustrate the span of different scenarios, with respect to shale gas bans and the amount of shale gas found.

Figure 5.5: Production from 2015 to 2025 for different producers.



The results show that Russia, the Netherlands and Norway are the largest producers in 2015 with shares of the production of 28%, 25% and 24%, respectively.[7] They remain the biggest producers throughout 2025 regardless of scenario.

[7] In reality, the relative production levels are different. Our model only includes the proportion of Norwegian exports that supplied to the markets in the model in 2014 and therefore appears lower in the results than in reality.

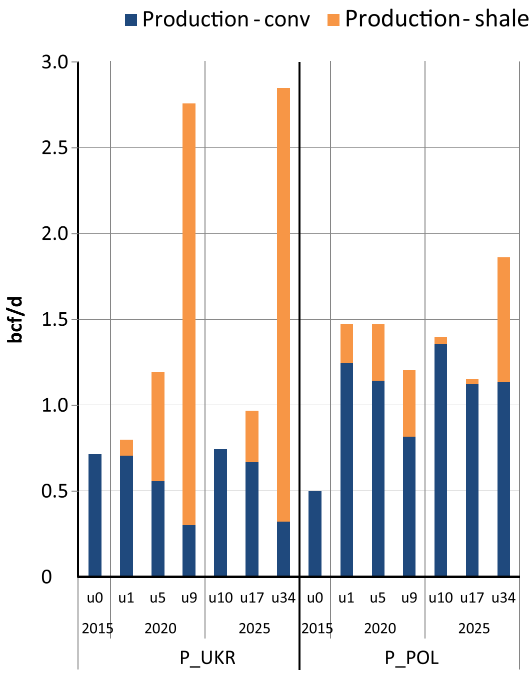
In the scenario where shale gas is banned, the production among the four biggest producers increases by 3.7% (16.2 to 17.0 bcf/d) from 2015 to 2025. Here, P_NED shows the greatest increase in production with an increase of 6.3% (4.1 to 4.4 bcf/d) from 2015 to 2025 (compare u10 to u0 in Figure 5.5).

In the scenario where shale gas exploration gives a low amount of shale gas in Poland and Ukraine, the increase in production for the four biggest producers is 3.0% from 2015 to 2025 (compare u17 to u0 in Figure 5.5). The increase is lower than from u1 to u10 where shale gas is banned. The reason for this is the following. When a low amount of shale gas is found by P_UKR and P_POL, they increase their total production by 74% from 2015 to 2025, and take shares of the market that otherwise would have been supplied by the four largest producers. The increased production by P_UKR and P_POL also increase the total quantum supplied, by all producers, with 7.9% (17.4 to 19.0 bcf/d) from 2015 to 2025 (u0 to u17).

In the scenario where a high amount of shale gas is found in 2020 and 2025, total production increases by 15.8% (17.6 to 20.4 bcf/d) from 2015 to 2025 (compare u34 to u0 in Figure 5.5). This increase is driven by increases in production by P_UKR and P_POL, and is slightly offset by a decrease in the four biggest producers production levels. The four biggest producers' total production is 4.3% lower in 2025 compared to 2015 in this scenario. Russia faces the biggest decrease in this scenario, with an 8.4% reduction. Successful development of shale gas harms Russian production most due to the fact that Russia has to compete with domestic shale gas in both Ukraine and Poland. In this scenario, shale gas production is 3.3 bcf/d and represents 15.9% of the total production by 2025, underlining the potential impact of shale gas in the European natural gas market as a means to increase supply.

From 2015 to 2025, P_UKR and P_POL increase their production by investing in expansions in a mix of shale gas and conventional gas. Figure 5.6 shows P_UKR's and P_POL's production split on shale gas and conventional gas. P_UKR increases its production by developing shale gas only. In the scenario where they find a high amount of shale gas in both 2020 and 2025, they increase their total production rate from 0.7 bcf/d to 2.8 bcf/d, an increase of 298%. In the scenario where they find a low amount of shale gas in 2020 and 2025, they increase their total production by 35% from 2015 to 2025. When there is a ban on shale gas exploration, P_UKR is not capable of increasing its production, and produces all its initial shale gas reserves by 2020. This shows that shale gas development might have a very large impact on the total production of natural gas in Ukraine. In the light of this potential, it seems reasonable that the Ukrainian governments is interested in signing deals for shale gas development with major petroleum producers.

Figure 5.6: Detailed Production for P_UKR and P_POL. Successful shale gas developments increases production greatly.



At the current production levels, the marginal cost of producing shale gas is lower than the cost of producing conventional gas. Therefore production of conventional gas is reduced at the expense of shale gas when P_UKR finds shale gas. The reduction of conventional gas production is 0.05 bcf/d from 2015 to the scenario tree node in 2025 where a low amount of shale gas is found. The reduction is 0.4 bcf/d from 2015 to the scenario tree node in 2025 where a high amount of shale gas is found. This can be seen in Figure 5.6. A profit maximizing producer will increase shale gas production to the point where the marginal costs of shale gas production and conventional gas production are equal. The reason for the lower reduction of conventional gas production in the scenario where a low amount of shale gas is found is because in the scenario where a low amount is found, the shale gas reserves are not large enough to replace as much of the conventional production as when a high amount of shale gas is found.

P_POL increases its production rate by developing both shale gas and conventional gas. The production of conventional gas is more than doubled from the 2015 level of 0.5 bcf/d by 2025. In the scenario where there is a ban on shale gas exploration the increase is 171% (to 1.3 bcf/d). When there is found high or low amounts of shale gas, the increase is 125% and 127% (to 1.1 bcf/d for both), respectively. In the scenario where shale gas exploration is banned, the existing shale gas reserves are depleted by 2025. When a high amount of shale gas is found in 2020 and 2025, shale gas production reaches 0.73 bcf/d in 2025.

So far we have seen that shale gas development can significantly increase production in Ukraine and Poland. This might increase the European production of natural gas by as much as 15.8% by 2025. The next section will focus on prices.

5.2.1.2 Downwards Pressure on Prices from Shale Gas Supply

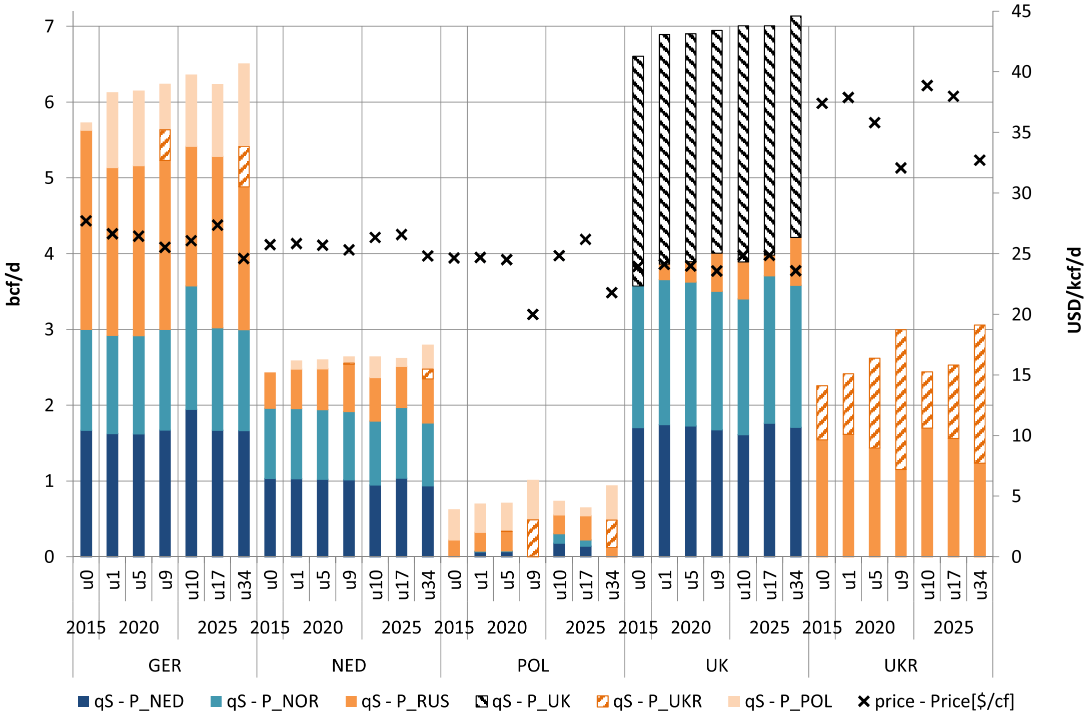
When the production increases, more gas also has to be sold at some point in time. As storage is not included in the model, the increased production in a period will give increased sales in the same period. Where the increase in sales takes place, however, is not clear without further investigation.

Figure 5.7 displays the development of both sales and wholesale prices for natural gas in each demand country. The stacked columns show sales split on producers and are plotted on the primary axis (left hand side). The x-marks show prices and are plotted on the secondary (right hand side) axis. The figure shows a trend of growing sales from 2015 to 2025. This is caused by an increase in demand that is met by increased production by the producers. The prices are found to be quite similar in Germany, the Netherlands, Poland and the UK, and substantially higher in Ukraine. Further, each country is supplied by at least two producers.

The highest changes in prices are seen in Poland and Ukraine. In Poland, the prices are quite stable in the scenarios where shale gas exploration is banned and where low amounts of shale gas are found in both 2020 and 2025. In the scenario where a high amount of shale gas is found, however, prices decrease by 19% (25 to 20 USD/kcf) in 2020 and by 12% (25 to 22 USD/kcf) in 2025 relative to 2015 prices.

In Ukraine, prices go up in the scenario where there is a ban on shale gas exploration, and down in the scenarios where shale gas exploration is allowed. When shale gas is banned, `P_UKR` is not able to increase sales to Ukraine at the same rate as demand is growing because they have no big increase in shale gas production. Therefore, prices increase. In the scenario where a low amount of shale gas is found in 2020 and 2025, prices are a little lower than they would

Figure 5.7: Sales and prices. High shale gas findings lead to lower prices in Ukraine and Poland.



have been if shale gas had been banned because P_UKR increases its shale gas production and sells more to Ukraine. In the scenario where a high amount of shale gas is found in 2020 and 2025, P_UKR increases sales to Ukraine, causing total sales to Ukraine to increase by 35.3% and prices to go down by 12.5% compared to 2015. In this scenario, P_UKR takes market shares in several markets in both 2020 and 2025. In 2020, P_UKR sells 0.4 bcf/d to Germany, 0.02 bcf/d to the Netherlands, 0.5 bcf/d to Poland and 1.8 bcf/d to the Ukrainian market. In Ukraine, this reduces Russia's dominating role by shrinking their market share from 68% in 2015 to 38% in 2020. In 2025, P_UKR's sales are approximately the same as in 2020, with the exception of the Netherlands, where the sales rate increase to 0.1 bcf/d, from zero in 2015.

The scenario where a high amount of shale gas is found in Poland and Ukraine in 2020 and 2025 shows that successful shale gas development can push down gas prices in Europe. In this scenario, volume weighted average prices decrease by 6.6% from 2015 to 2025. This is good for the consumers because higher quantities at lower prices will increase the consumer surpluses. The total European consumer surplus is 4.4% higher in the scenario where a high amount of shale gas is found compared to the scenario where there is a ban on shale gas development. The findings therefore indicate that regulators who wish to increase the consumer surpluses could do this by encouraging shale gas development.

5.2.1.3 Trade-offs Between Reserves Investments

The producers have the option of investing in expansions of reserves and production capacity, both are needed in order to increase the production of natural gas. Both conventional gas and shale gas production face increasing marginal costs. The best option for a producer in such a situation would be to produce a mix of the two types in order to keep the costs as low as possible for the production rate desired. The investments of `P_UKR` and `P_POL` should reflect this desire.

Table 5.11: Reserves quantities invested in by producers in bcf.

	Stage	**2015**	**2020**		
Producer	**Scenario**	**u0**	**u1**	**u5**	**u9**
P_UK	Conventional Reserves	0.0	980.9	778.7	458.6
P_UKR	Shale Reserves	4959.1	0.0	2730.5	0.0
P_POL	Conventional Reserves	482.2	1608.5	1000.7	424.0
P_POL	Shale Reserves	486.2	0	263.9	363.1

Table 5.11 shows the quantities the producers try to expand reserves by through investing in reserves expansions in 2015 and in the three highlighted scenarios in 2020. The reserves expansions in shale gas in 2015 are larger than investments in conventional gas in both `P_UKR` and `P_POL`. In the first stage `P_UKR` try to expand their shale gas reserves with 4959.1 bcf. `P_POL` try to expand their shale gas reserves with 486.2 bcf and their conventional gas reserves by 482.3 bcf. In the scenario where there is a ban on shale gas exploration (u1), `P_POL` shifts completely over to conventional gas, while `P_UKR` does not find investing in conventional gas profitable and does not invest. In the scenario where a low amount of shale gas was found in 2020, `P_UKR` invests in shale gas once more.

The lower level of investments by P_UKR in 2020 in this scenario compared to 2015 is due to the fact that the horizon does not go any longer than 2025, and there is therefore no use in having too much reserves in 2025, while having too much reserves in 2020 simply means that you can invest less in 2020. However, this is more costly than delaying parts of the investment to 2020 because of discounting. The overinvestment is seen in P_UKR in the scenario where a high amount of shale gas is found in 2020. Here, P_UKR's reserves have become so big that there is no need to invest in further reserves expansions. In reality, one would have investments in 2025 as well, but due to the fact that the model horizon ends in 2025, the producers have no incentive for investments in the third stage. In Chapter 4, adding extra stages is presented as a way to describe investments behavior in 2025 more realistically.

P_UK invests in conventional gas reserves in 2020, because P_UK depletes it's reserves after the first ten years and needs to expand them in order to be able to produce enough gas in 2025. The amount depends on which scenario they find themselves in. In the scenario where there is a ban on shale gas exploration, P_UK has to invest in 981 bcf. In the scenario where both P_UKR and P_POL have found low amounts of shale gas, P_UK's investments are lower because in this case P_UKR and P_POL are able to supply gas to P_UK's potential markets, decreasing the amount that P_UK can gain from expanding reserves. In the scenario where P_UKR and P_POL find high amounts of shale gas, P_UK's investments are down to 459 bcf.

5.2.1.4 Expanding Pipelines to Germany

Investments in pipeline capacity expansions made by the TSO are shown in Table 5.12. In 2015, the pipeline between Poland and Germany is congested. It is therefore expanded by 1 bcf/d in 2015. This expansion facilitates exports from P_POL and P_UKR (via Poland) to Germany and the Netherlands in 2020.

Table 5.12: Investments in pipeline capacity [bcf/d]

Stage	**2015**	**2020**		
Scenario	u0	u1	u5	u9
NED_GER	0	0.88	0.25	0.00
POL_GER	1	0.12	0.63	0.97
UKR_POL	0	0.00	0.12	0.03

In 2020, the investments depend on which scenario occurs. In the shale gas ban scenario, the pipeline from the Netherlands to Germany is expanded by 0.88 bcf/d. This lets P_NOR and P_NED sell more gas to Germany (note the increase in sales from P_NOR and P_NED to Germany in u10 in 2025 compared to u1 in 2020 in Figure 5.7). In the the scenario where a high amount of shale gas has been found in both Ukraine and Poland in 2020, the pipeline from Poland to Germany is expanded once more, allowing both P_UKR and P_POL to sell more to the German, British and Dutch markets. In the scenario where a low amount of shale gas is found in Ukraine and Poland, both the pipeline between the Netherlands and Germany and the pipeline between Poland and Germany are expanded. However, the expansion is twice as big for the latter. Since the TSO has a limited expansion budget, there is a tradeoff between expanding different pipes, and the most congested pipeline will get the biggest expansion.

These findings suggest that if shale gas development is successful in Poland and Ukraine, new pipeline capacity from these countries to big consumption regions such as Germany might become profitable. However, actual investments in pipelines will depend on political will as well as economic viability. Therefore, this finding has to be viewed in a bigger context: the countries that a proposed pipeline is flowing through will have to agree on investments and regulations for such a project to be realized. Also, since the model allows for continuous values of pipeline capacities, the size of the expansions found in the results have to be compared to existing and proposed pipelines. If the expansion is much smaller than any projects found, the expansion is seen as marginal and is not likely to be built. The proposed expansions are smaller than many real cross border pipelines, but there are some pipelines either under planning or existing in the range of the proposed expansions. For instance, Balticconnector between Finland and Estonia, WEDAL between Germany and Belgium and Tyra West F3 between Denmark and the Netherlands all have capacities in the range of 0.2-1.0 bcf/d. In light of these observations, it would not be reasonable to think that the smallest expansions in Table 5.12 would be built in reality, but the bigger ones (greater than 0.25 bcf/d) appear possible.

5.2.2 The Impact of Risk Preferences on Shale Gas Development

The purpose of this section is to study the effects of risk preferences on shale gas development in the European gas market. In order to do this, we compare the RA Case to a risk neutral solution of the same problem. The risk neutral solution will from now on be called the RN Case. Since it is assumed in the RA case that only P_POL and P_UKR are risk averse these two producers will be the focus of the analysis.

5.2.2.1 First Stage Investments

In Chapter 4 we saw that higher risk aversion leads to lower shale gas investments in the first stage. As can be seen in Table 5.13 and Table 5.14 this is still the case in the large scale implementation. P_POL's shale gas reserves investments are 16% lower, and P_UKR's shale gas reserves investments are 1.5% lower in the RA case compared to the RN case. The table shows that P_POL in addition shifts its reserves investment mix from 69% Shale in the RN Case to 50% in the RA Case. This is to be expected as the risk averse producers make decisions which are better suited for the bad scenarios where shale gas resource expansions are less profitable. Note that risk aversion seems to have a bigger impact on investment decisions when there is a less risky alternative present.

Table 5.13: Comparison of first stage investments [bcf] for the RN and RA case

Producer	Case	Conventional	Shale	Total	% Shale
P_UKR	RN		5033	5033	100 %
P_UKR	RA		4959	4959	100 %
P_POL	RN	266	580	846	69 %
P_POL	RA	482	486	968	50 %

Table 5.14: Difference in first stage investments in the RA case compared to the RN Case.

	Case	Conventional	Shale	Total
P_UKR	RA	0.0 %	-1.5 %	-1.5 %
P_POL	RA	81.4 %	-16.2 %	14.5 %

Table 5.14 shows that P_POL's total investments are 14% higher in the RA case compared to the RN case, due to 81% higher conventional investments and 16% lower shale gas investments. This is a direct consequence of risk aversion and is explained as follows. P_POL's risk aversion affects the tradeoff between risky shale and more expensive conventional gas. In the RA case P_POL finds it better to pay more for guaranteed conventional gas than to pay less for shale gas even though the investments should yield the same amount of gas in expectation. In addition, when P_POL in the RA case makes decisions better suited for bad outcomes it makes sense to increase the total quantity. By doing so they hedge against the possibility that they find very little shale or there is a ban by

still being able to sell conventional gas at a lower profit. In this way accounting for risk aversion can describe and account for a more realistic investment behaviour.

5.2.2.2 Robustness of Expected Profit when Risk Aversion Affects the Optimal Decisions

$\mathrm{CV@R}_{p\alpha_p}$ and expected profits for P_POL and P_UKR for the two cases are listed in Table 5.15. As one would expect, the $\mathrm{CV@R}_{p\alpha_p}$ is lower in the RA Case than in the RN case. The $\mathrm{CV@R}_{p\alpha_p}$ is 5% lower for P_UKR and 4% lower for P_POL in the RA case compared to the RN case.

Table 5.15: CV@R and Expected profit in the RN and the RA case

Case	**Producer**	$\mathrm{CV@R}_{p\alpha_p}$ **[USD]**	**Expected Profit [USD]**
RN	P_UKR	124.90	124.90
RA	P_UKR	119.16	124.90
RN	P_POL	60.58	60.58
RA	P_POL	57.95	60.20

It is interesting to find that the expected profits are only slightly affected by the increased risk aversion. P_UKR's expected profit is unchanged between the cases while P_POL experiences 0.6% lower expected profit. Between the two cases, Poland changes its action the most, and therefore experiences the biggest drop, but Table 5.15 clearly shows that risk aversion does not affect the expected profits by a large amount, even if investments are shifted. The reason for this is explained in the following.

The total sales rates and prices in the different markets are not changed much between the cases. If the individual producer in addition has the same sales rate in all markets in the RA and in the RN case the producers' expected profits should therefore not change much either.

P_POL's expected profit is not affected significantly by the increased risk aversion in the RA case even though investments are different. The reason for this is as follows. In the scenarios where shale gas is banned or shale gas findings are low, the increased conventional investments makes P_POL able to sell more conventional gas (and have higher profits) than in the RN case. This is especially notable in the second stage in the scenario where shale gas exploration is banned (u10) where P_POL increases sales rates by 4.4% compared to the RN case. In the scenarios where shale gas findings are high, P_POL can sell a mix of conventional gas and shale gas at a cost that is only a little higher than in the RN case. The combination of these two effects therefore only reduces the overall expected profit by a fraction between the cases.

P_UKR's expected profit is not affected significantly by the increased risk aversion in the RA case even though investments are slightly lower. In the RA case P_UKR invest 1.5% less in shale gas reserves than in the RN case. This results in very small corrections in sales rates and production in the different scenario tree nodes. In the second stage the biggest change happens in the scenario where both P_POL and P_UKR find high amounts of shale gas (u9), where the sales rate is lowered by 1%. In the third stage the biggest reduction is 3% and happens in the scenario where shale gas is banned in Poland and findings are high in Ukraine (u26). In some scenarios P_UKR gets slightly higher sales rate in the RA case because of a reduction in P_POL's shale gas production. This happens because in these scenarios P_POL has invested in less shale gas when they are risk averse than in the RN case. Therefore, P_UKR gains more from high shale gas findings relative to the RN case. However, the sum of these changes is so small that the overall expected profit appears to be unchanged.

5.2.3 The Impact of Government Policies on Shale Gas Development

Currently, shale gas is banned in several European countries, while others have allowed shale gas production, and yet others have issued production permits [the Economist, 2014]. The decisions of governments differ with their motives: some want to promote energy independence and welcomes shale gas, while others are more concerned with environmental concerns and have banned it. The producers who want to develop shale gas are at the mercy of the governments in the countries they wish to operate. When the producers face the possibility of a ban in the future, they might be hesitant about investing too much in shale gas developments in case shale gas exploration is banned so that their investment is wasted. Does the perceived likelihood of a shale gas ban affect production, sales or prices in the natural gas market?

5.2.3.1 Perceived Likelihood of a Shale Gas Ban

In the results presented above, the probability of a shale gas ban in Poland and Ukraine is 5%. For the purpose of this analysis, two additional cases of the model are solved. The new results are used together with the results from the

RA case and the RN case to investigate the effects of the perceived likelihood of a shale gas ban. The two new cases are set up as follows:

- A Risk Averse, High Ban Probability case where risk preferences are as in the case presented above and the probability of a ban is 25%.
- A Risk Neutral, High Ban Probability case where all actors are risk neutral and the probability of a ban is 25%.

These four cases allow for comparison of the effects of a higher probability for a shale gas ban with and without risk aversion, which gives the possibility of assessing the impact of risk preferences in this setting.

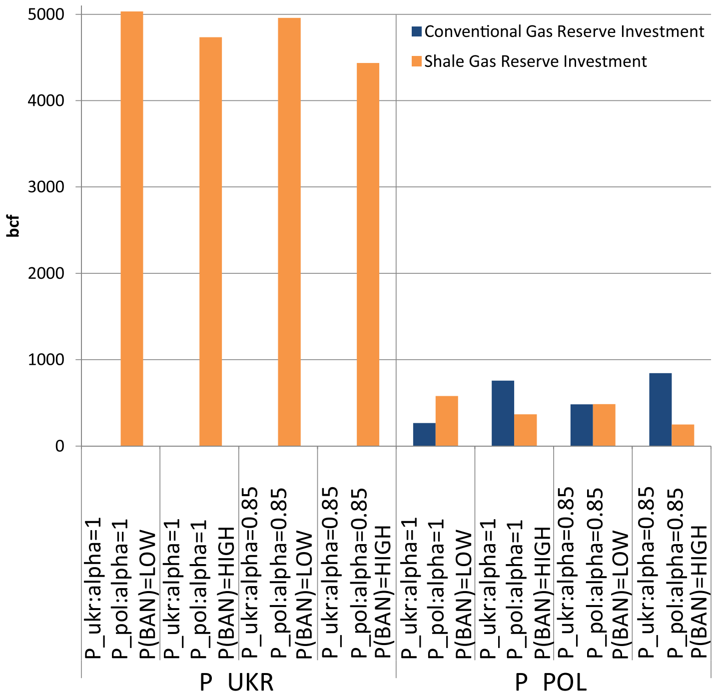
5.2.3.2 Reduced Investments in Shale Gas

As expected, a higher perceived likelihood of a shale gas ban leads to lower investments. Figure 5.8 shows the first stage investments in shale gas and conventional gas reserves expansions for `P_UKR` and `P_POL` in the four different cases.[8] By comparing the investments for the same risk preferences, it becomes evident that shale gas investments are lower in the first stage when the perceived likelihood of a shale gas ban is higher. When `P_UKR` and `P_POL` are risk neutral, reserves expansion investments decrease by 6.0% (5033 to 4734 bcf) and 36.7% (580 to 367 bcf), respectively. When they are risk averse, the investments decrease even more: by 10.5% (4959 to 4437 bcf) and 48.7% (486 to 249 bcf).

Risk aversion amplifies the effect of the perceived likelihood of a shale gas ban. Policy makers who wish to facilitate investments in shale gas development, should therefore try to reduce the degree of risk aversion among the producers as well as the perceived likelihood of a shale gas ban. This could be done by offering risk sharing, by letting losses on exploration be applicable for tax deduction, similarly to the Norwegian petroleum tax model. This would make the producers less afraid of not recouping their shale gas exploration expenses because they would be able to deduct the losses from later profits. However, such a tax model leads to lower income for the government that has to be compensated for elsewhere. One option would be to increase tax rates on petroleum profits, but this might discourage investors.

[8] By comparing first stage investments and not investments in general, we are able to isolate the effects of the perceived likelihood of a ban, that is, how the producers think the scenario tree is best represented, regardless of what the actual probability of a ban (as seen by the government). When we later compare production in the second stage, we can then do so for the scenarios where shale gas is not banned. This holds because conditional on that there is no ban on shale gas ban, the two scenario trees are the same.

Figure 5.8: First stage investments in the different cases of ban probability and risk aversion.



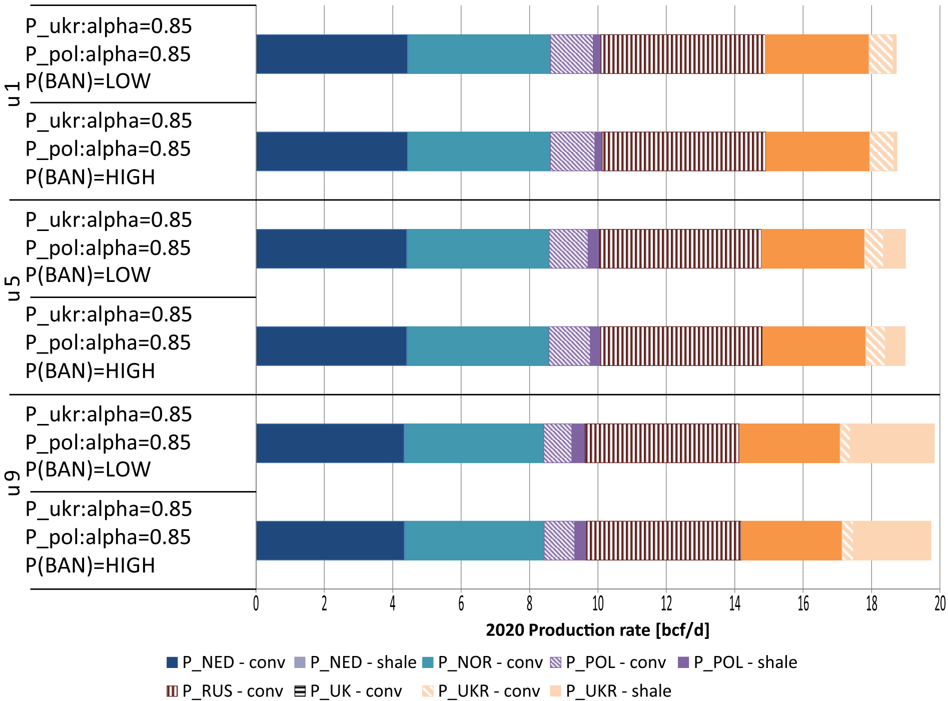
P_POL increases the level of investments in conventional gas reserve expansions when the probability of a shale gas ban is seen as high. P_UKR does not do this because the marginal cost of producing conventional gas is already so high that they produce at a rate that will not deplete their resources by 2025.

5.2.3.3 Lower Production - Lower Sales?

The investments are found to be lower when the perceived likelihood of a shale gas ban is higher. With lower investments in shale gas reserves, the producers are able to produce less shale gas.

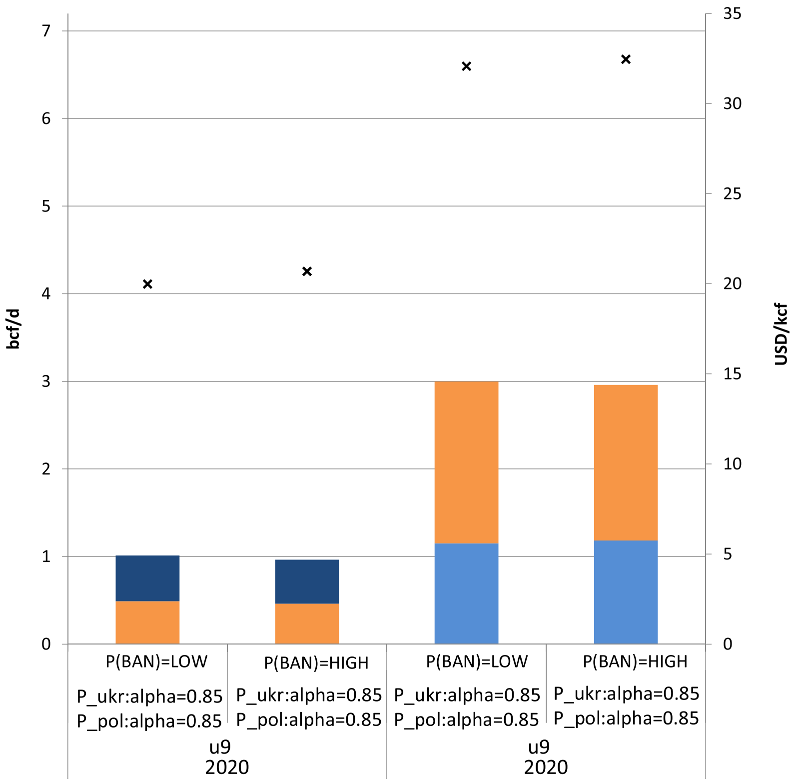
The lower production of shale gas when the perceived likelihood of a ban is higher is offset by increased production of conventional gas. Therefore, the impact on total production is attenuated. The decrease in total production when the perceived likelihood of a shale gas ban is higher is less than 0.1 bcf/d

Figure 5.9: Total 2020 production rate in selected scenarios



for all the producers combined when P_UKR and P_POL are risk averse (less than 1% decrease). The effect is smaller when the producers are all risk neutral. Figure 5.9 illustrates the production rates in 2020 in the three scenarios used in Section 5.2.1 for the two cases where P_UKR and P_POL are risk averse. When there is a shale gas ban, P_POL is able to produce more conventional gas if they believed the probability was 25% because in that case they invested more in conventional reserves expansions in 2015. In the scenario where there is no ban and a low amount of shale gas is found in both Poland and Ukraine, P_POL is able to produce more if they believed the probability of a ban was 25% because in the case where shale gas findings are low, a higher proportion of conventional gas reserves investments in 2015 gives them the opportunity to produce more natural gas than if they invested mostly in shale gas. In the same scenario, P_UKR is able to produce 0.04 bcf/d (4%) less if they believed that the probability of a shale gas ban was 25% because this leads them to invest in less shale gas reserves expansions in 2015 out of fear of a ban. The largest effect is seen in the scenario where a high amount of shale gas is found in both Ukraine and Poland in 2020. Here, P_UKR's production is reduced by 6% if they believed the probability of a shale gas ban was 25% and invested accordingly in 2015. The other producers, however, see larger production rates when this happens, because competition from P_UKR is less fierce.

Figure 5.10: 2020 sales rate in Ukraine and Poland



The slight decrease in total production rates pushes volume weighted average prices in 2020 up by a mere 0.5% in the scenario where a high amount of shale gas is found. By taking a closer look, however, we find that some markets see bigger changes. The sales to Poland decrease by 0.05 bcf/d, increasing prices by 3.6% to 21 USD/kcf. Sales to Ukraine decreases by 0.04 bcf/d, increasing prices by 1.2% to 32 USD/kcf. This is illustrated in Figure 5.10, which shows the sales to Ukraine and Poland and the prices in these markets in 2020 in the scenario where a high amount of shale gas is found.

5.2.3.4 Suggestions for Policy

We find that the perceived likelihood of a shale gas ban has clear effects on investments in shale gas reserves. However, due to the fact that there is production capacity available for conventional gas, the impacts on total production and sales prices are small.

The impact could be larger in a situation where conventional gas is not an option or when producers of conventional gas do not have enough capacity to satisfy demand. In these situations, investments in shale gas could be necessary to supply enough gas in the future. Sub-optimal (too low) investments in these situations could decrease the consumer surplus and social welfare by pushing sales down and prices up.[9] In such a situation, governments and regulators could do the following to signal that a ban on shale gas is unlikely if they want to encourage investments:

- Issue long-term permits for shale gas exploration. This will make the producers certain that they will be able to produce shale gas for a long enough time to recoup their investments. A drawback of this is that it reduces the flexibility of the government in case it wants to stop shale gas production due to environmental concerns in the future.
- If they believe that supply security is more important than environmental concerns, this could be signaled. This signal might reduce the perceived likelihood of a shale gas ban, but the signal is not guaranteed to be credible because there is no risk sharing between the government and the corporations. Furthermore, a change of government could render old promises and signals useless.
- Take ownership in shale gas development by creating national shale gas companies or joint ventures with natural gas producers. This could show other producers that the government and corporations share the risk and encourage others to start shale gas development.

This could reduce the perceived likelihood of a shale gas ban and encourage investments by producers.

[9] The producers could increase their profits in this case, recall that the monopoly quantity is lower than the Cournot quantity. However, there will be a dead weight loss because consumer surpluses decrease more than producer profits increase.

5.3 Summary of Findings

In this chapter the developed model has been applied to analyze a portion of the European gas market. Outcomes from a equilibrium solution that account for market power, risk aversion and uncertainty have been analyzed and compared to a risk neutral solution of the same problem. An investigation of how different probabilities of a shale gas ban affect the outcome has also been undertaken.

Shale gas investments in Ukraine and Poland can be profitable and might reduce Russia's market share in Ukraine from 68% in 2015 to as low as 40% in 2025. In Poland, successful shale gas development can reduce Russia's market share down to 13% in 2025. Further, shale gas developments can increase the total European production of natural gas by 2.8 bcf/d, and might reduce natural gas prices in Poland by 12% to 22 USD/kcf and Ukraine by 13% to 33 USD/kcf in 2025.

The perceived likelihood of a shale gas ban affects the investments made in Ukraine and Poland, lowering shale gas exploration by up to 49% in Poland and 11% in Ukraine when the perceived likelihood goes from 5% to 25%. This effect is larger for a risk averse actor than a risk neutral one. This leads to a lower production of shale gas in the future, but increased production of conventional gas makes up for low investments in shale, with the result that sales rates and prices are not severely affected by the increased fear of a ban on shale gas exploration.

If policy makers wish to facilitate investments in shale gas development, they should try to lower the perceived likelihood of a shale gas ban and reduce the degree of risk aversion among the producers. The first can be achieved by issuing long-term licences, clearly communicating the commitments to not enforce either moratoriums or bans on shale gas exploration or starting joint ventures with producers. The second is a more difficult undertaking, but one option might be to offer a risk sharing by letting losses on exploration be applicable for tax deduction and putting a higher tax on profits instead, similarly to the Norwegian petroleum tax model.

A comparison of a risk neutral solution to a solution where `P_POL` and `P_UKR` exhibit risk averse behaviour shows that `P_POL`'s and `P_UKR`'s risk aversion leads to lower investments in shale gas in the first stage. Shale gas investments are lowered by 16% in Poland by `P_POL`. This is offset by increased investments in conventional gas reserves. `P_UKR` only invest 1.5% less in the first stage compared to the risk neutral case. Due to the hedging with conventional gas exploration by `P_POL` and the fact that changes by `P_UKR` are small, the expected profits are not noticeably smaller in the risk averse solution, even though $\mathrm{CV@R_p}$ is reduced by 4-5%. Also, Russian imports are only slightly affected by higher risk aversion. For the profit maximizing producers, risk aversion seems to be of less importance. However, we have shown that risk aversion alters the decisions on investments and that shale gas in itself could be an effective way to reduce Russian imports. Therefore, modeling with risk aversion gives a better picture of how investments in shale gas would play out in the real world.

6 Solution Procedures and Model Limitations

The previous two chapters have studied equilibrium solutions for several data instances. However, the inclusion of risk aversion complicates the structure of the problem greatly, and the standard solution procedures in PATH is not able to find solutions for all our data instances. Therefore special solution procedures have been developed for solving the problem. The procedures developed for solving the presented model, the second contribution of this thesis listed in Chapter 1, are given in this chapter. In addition, numerical limitations of the model are discussed.

The model developed in Chapter 3 is an MCP, and is solved with the PATH solver. The model includes bilinear terms as a consequence of the inclusion of CV@R in the objective. For instances where all the actors are risk neutral, the solver finds solutions without difficulties. However, when risk aversion increases, finding optimal solutions becomes increasingly more difficult. For the instances presented in Chapter 5, the standard solution procedures of PATH was unable to find a solution when risk aversion increased so that $\alpha_p \leqslant 0.94$ for the producers `P_UKR` and `P_POL`. Therefore, special solution procedures were developed for solving the problem. Two approaches were used, starting from a different initial point and changing the solver settings. Both these approaches are explained in the following.

6.1 Changing the Initial Point

PATH is a stabilized Newton method for solving MCPs. When PATH solves an MCP, it works in three general steps. First, it uses a first-order approximation, in the current point, to linearize the problem. Second, it finds a search direction by generating a path. Third, it does a search along the generated path to find a new point [Dirkse and Ferris, 1995]. This is repeated until a convergence criterion for the equilibrium solution is met, and the problem is solved, or PATH terminates without finding an equilibrium solution.

In two of the KKT conditions for the model, Equations (3.42) and (3.43) repeated below, there are terms where a primal variable is multiplied by a dual variable (q_{prnu}, σ_{pu} and q^S_{pnu}, σ_{pu}). When PATH starts the solution in the point zero (All variables and dual variables zero. This is the default starting point for PATH.), the initial point contains different information on this bilinear relationship than when starting in a non-zero point. Specifically, when two multiplied variables are zero, the effect of changing either one of them depends on whether or not the other variable is changed. For example, if the variable q_{prnu} is changed, the effect of this depends on whether the dual σ_{pu} below remains zero, or not. Therefore, we believe that the second step of the PATH procedure, finding a good search direction, should be more difficult when starting in the point zero because the impact of the bilinear terms are represented more poorly than in a non-zero starting point.

$$\begin{aligned} 0 \leqslant \gamma_u D_u (C^{PL}_{prn} + 2C^{PQ}_{prn} q_{prnu}) \sum_{u' \in m(u)} \sigma_{pu'} + \lambda^P_{prnu} - \phi^P_{nu} & \\ + \rho^P_{prnu} D_u + \sum_{u' \in succ(u)} D_{u'} \rho^P_{prnu'} \perp q_{prnu} \geqslant 0 \quad \forall \quad p, r, n, u & \qquad (6.1) \end{aligned}$$

$$\begin{aligned} 0 \leqslant -\gamma_u D_u \Bigg[\delta_{pn} \Bigg(INT_{nu} - SLP_{nu} \big(\sum_{p' \in P} q^S_{p'nu} + q^S_{pnu} \big) \Bigg) & \\ + (1 - \delta_{pn}) \pi^M_{pnu} \Bigg] \sum_{u' \in m(u)} \sigma_{pu'} + \phi^P_{pnu} \perp q^S_{pnu} \geqslant 0 \quad \forall \quad p, n, u & \qquad (6.2) \end{aligned}$$

A numerical example of a non-zero starting point in Equation (6.1) is given later in this section.

6.1.1 Algorithm for Solution via Proximal Solutions

Based on the hypothesis that a good starting point should improve the solution procedure, a new solution approach was developed. The main principle behind the algorithm is outlined in Algorithm 1. First, the problem is initialized as usual by setting all parameters to their respective values, and defining equations and variables. Next, the model is attempted to be solved using different methods for finding a good starting point. In Algorithm 1, `method(i)` refers to the different methods, with `i` ranging from 1 to 9. All the methods are different variations of first finding a solution that lies in the proximity of the solution to the actual problem by altering the degree of risk aversion and market power, and then solving the original problem with the proximal solution as a starting point.[1] If a method is successful in finding an equilibrium solution to the original problem, the loop is stopped and the solution is returned, along with a variable indicating which method worked.

Algorithm 1: Solving the problem using proximal solutions as initial points

```
initialization: methodNumber = 0, i = 0, flag = 1, numMethods = 9 ;
while i lessThan numMethods & flag = 1 do
    try method(i);
    if method(i) successful then
        methodNumber = i;
        flag = 0;
    end
    i = i + 1;
end
```

Since risk aversion and market power complicates the problem, it might be easier to solve the problems if the degrees of risk aversion and market power are changed in the direction of something we know is solvable. For $\alpha_p = 1 \ \forall \ p$, a risk neutral problem, we have never had any difficulties, while it seems to be harder for lower values of α_p. Therefore, it might help to start with a solution found from the same problem but with lower risk aversion. The same principle applies to market power. This idea forms the basis for the methods that are used to solve the problem. The different methods can be read in the code in Appendix C. The methods that were most successful for the problem studied in Chapter 5 are outlined below in Algorithm 2.

For the instance in Chapter 5 where $\alpha_p = 0.85$ for `P_UKR` and `P_POL`, and the probability of a ban was low, the method that solved the problem was method 2. This method works by first storing the original values of α_p, and then increasing the value of the α_p's that are less than 1 by half the distance between α_p and 1. This is essentially the same as solving the problem for a lower degree of risk aversion. If this solution is found, the values of α_p are reset to the stored values, and the proximal solution is used as an initial point for the problem with the original values for α_p.

[1] Here, proximity refers to a solution that is believed to be close to the equilibrium solution. For example, the solution obtained from a version of the problem where producers have slightly more market power.

Algorithm 2: Selected methods for solving the problem via initial points. Methods are run by the loop in Algorithm 1.

```
method 1;
solve social welfare maximization;
set solution as initial point for mcp;
solve mcp;
if optimal solution then
  | return optimal solution
end
;
method 2;
store alpha(p) as storedAlpha(p) ;
if alpha(p) is not 1 then
  | set alpha(p) = alpha(p) + 0.5 * (1 - alpha(p));
end
solve mcp;
if optimal solution from mcp then
  | reset alpha(p) to storedAlpha(p);
  | set solution as initial point for mcp;
  | solve mcp;
  | if optimal solution then
  |   | return optimal solution
  | end
end
;
method 7;
store delta(p,n) as storedDelta(p,n) ;
set alpha(p) = 1;
if delta(p,n) is not 1 then
  | set delta(p,n) = delta(p,n) + 0.25 * (1 - delta(p,n));
end
solve mcp;
if optimal solution from mcp then
  | reset delta(p,n) to storedDelta(p,n);
  | set solution as initial point for mcp;
  | solve mcp;
  | if optimal solution then
  |   | return optimal solution
  | end
end
```

In the instance where $\alpha_p = 0.85$ for `P_UKR` and `P_POL`, and the probability of a ban was high, the method that solved the problem was method 7. This method works by setting $\alpha_p = 1$ for all producers and adding $\frac{1-\delta_{pn}}{4}$ to δ_{pn}, thus making the producers risk neutral and giving them slightly more market power. This value of δ_{pn} is fairly close to the original value, and could therefore provide a good starting point. This solution is used as a starting point after resetting α_p and δ_{pn} to the stored values.

It is possible to speed up the new solution procedure by observing which methods work most often and placing them before the other methods. Currently, the methods are sorted in the following sequence: 1, 7, 8, 6, 5, 2, 3, 9, 4. This is done so because it is more efficient overall to put the most effective methods early, like 1 and 7.

The new starting points apparently make PATH's path generation and search along the path more effective. Here, we compare two starting points in order to try to understand what is going on. The approximation of `eq_qStat(P_NOR,conv,NOR,u34)` (an instance of Equation (6.1)) when starting in zero is:

```
1 eq_qStat(P_NOR,conv,NOR,u34)..  (0)*q(P_NOR,conv,NOR,u34)
2       + lambdaP(P_NOR,conv,NOR,u34) + 1825*rhoP(P_NOR,conv,NOR,u34)
3       + (20.9046007369089)*sigma(P_NOR,u34) - phi(P_NOR,NOR,u34) =G= 0 ;
4       (LHS = 0)
```

The approximation of `eq_qStat(P_NOR,conv,NOR,u34)` with a different initial point:

```
1 eq_qStat(P_NOR,conv,NOR,u34)..  (0.246539289996078)*q(P_NOR,conv,NOR,u34)
2       + lambdaP(P_NOR,conv,NOR,u34) + 1825*rhoP(P_NOR,conv,NOR,u34)
3       + (20.0470356279112)*sigma(P_NOR,u34) - phi(P_NOR,NOR,u34) =G= 0 ;
4       (LHS = 0)
```

The second approximation contains a nonzero term of 0.2465 in front of the variable `q(P_NOR,conv,NOR,u34)` in line 1. PATH therefore "sees" the effect of changing the variable, while in the first approximation, this effect is lost. We believe that this is part of the reason that starting from a proximal solution helps the solution process.

Table 6.1 presents solution times in seconds for the model when run with PATH with standard options in the column "MCP" and for Algorithm 1, presented above, in the column "NewSolve". The "-" indicates that PATH was not able to find the equilibrium solution. The algorithm solves the problem in many instances where no solution is found by PATH with standard option values.

Table 6.1: Solution time in seconds for different variations of the instance from Chapter 5.

α_p	Pr(ban) = 0.05			Pr(ban) = 0.25		
	MCP	**NewSolve**	**Method**	**MCP**	**NewSolve**	**Method**
1.00	1.9	28.3	1	1.78	14.6	1
0.95	9.5	234.5	7	-	467.7	5
0.90	-	304.5	7	-	356.6	7
0.85	-	664.3	2	-	325.6	7
0.80	-	-	-	-	-	-

In the cases where PATH with standard options is able to find an equilibrium solution, it is much faster than the developed procedure. A general solution framework might utilize this by first attempting to solve the problem for 10-15 seconds using PATH with standard options, and then starting the new solution procedure if PATH is unable to solve the problem in the 10-15 seconds. This might save time in some cases.

In the cases in Table 6.1, our procedure finds an equilibrium solution in eight out of ten cases. With the default starting point, PATH only finds an equilibrium solution in three out of ten cases. Since the new procedure is not able to find equilibrium solutions in all the cases, a second approach was tried. This approach is to change the solver settings, and is described in the next section.

6.2 Adapting Solver Settings

The settings for PATH can be set manually as option values before the PATH solver is invoked [Dirkse and Ferris, 1994]. Moreover, PATH restarts itself with new settings, if it determines that no progress is being made [Ferris and Munson, 2000]. The settings that most often give good solutions can be used in order to determine what settings are good to start with when trying to solve the problem. For example, the following restart settings were used by PATH in method 5 in the algorithm above when it led to a solution in a variation with $\alpha_p = 0.95$ for `P_UKR` and `P_POL` and high probability of a ban on shale gas:

```
Restart Log
proximal_perturbation 0
crash_method none
crash_perturb yes
nms_initial_reference_factor 2
lemke_search_type slack
proximal_perturbation 1.0000e-001
```

To utilize the fact that these settings led to a solution, we start the solution procedure for method 5 with these settings, hoping that this will help PATH find a solution more quickly. We do the same thing for the other methods. We then attempt to solve the variations of the problem with the new settings. The results are presented in column "NewSettings" in Table 6.2 together with the results without the new settings (column "NewSolve"). For the variation of the data instance that was used to find the settings (α_p is 0.95 for `P_UKR` and `P_POL` and high probability of a ban on shale gas), the solution time was cut from 468 to 395 seconds, a 15.5% decrease. However, when the settings were used for other variations, the solution time and which method solved the problem changed. For instance, for α_p is 0.90 for `P_UKR` and `P_POL` and high probability of a ban on shale gas, the method changed from 7 to 2, and the time increased from 357 to 552 seconds. Method 7 is attempted before method 2, so this implies that the new settings caused method 7 to fail. Some instances that were solvable with the standard settings using Algorithm 1 were not solvable with the new settings. Based on these findings, we conclude that changing settings based on one data instance did not help solve the problem in general. However, changing the settings is effective when solving the specific instance it is based on, and can therefore be useful when solving the same problem several times.

Table 6.2: Solution time in seconds for different variations of the instance from Chapter 5 with and without new settings for the PATH solver. M. denotes method.

	Pr(ban) = 0.05				**Pr(ban) = 0.25**			
α_p	**New solve**	**M.**	**New settings**	**M.**	**New solve**	**M.**	**New settings**	**M.**
1.00	28.3	1	21.7	1	14.6	1	14.3	1
0.95	234.5	7	188.9	7	467.7	5	395.1	5
0.90	304.5	7	522.6	2	356.6	7	552.4	2
0.85	664.3	2	-	-	325.6	7	-	-
0.80	-	-	-	-	-	-	637.8	2

6.3 Numerical Limitations

In this section, some of the models numerical limitations and the efforts made to surpass them are discussed.

6.3.1 Degrees of Risk Aversion

Table 6.1 presents the solution time for different variations of the instance used in Chapter 5. The difference between the variations is the value of α_p for `P_UKR` and `P_POL` and the probability of a shale gas ban. The table shows that solution time increases for increasing degrees of risk aversion. Only the two least risk averse variations were solvable with using the PATH solver with default option values, while the methods developed in this chapter enable us to solve for values of α_p down to 0.85.

The solution time is much longer for the developed solution procedures than for PATH with standard option values, but the new solution procedure is also able to solve more of the cases. PATH with the default initial point was only able to solve three of ten instances, while the developed solution procedure solved eight of ten. In the instances studied, very high degrees of risk aversion were not solvable when using the procedures outlined here.

When the new solution procedure is not able to find an equilibrium solution, PATH reports "Other Error". PATH does not run out of memory and the resource usage (in seconds) is the less than the limit. We speculate that the problem is related to lack of convergence. The reason for this might be that the objectives of the problems that the MCP describes are relatively flat. We speculate this based on the observation that the producers expected profits did not change much when the producers decisions changed as a consequence of different values of α_p in Chapter 5. We think that the flat objective might make it difficult for PATH to prove that it has converged to an equilibrium solution. Based on this theory, it might be possible to improve the solution procedure by adjusting the convergence tolerances in the PATH solver settings. With the limited amount of time available for this work, we did not prioritize to test this, but it might be a good way to improve the number of cases that can be solved.

6.3.2 Problem Size

The problem size seems to be a complicating factor for the solution of the problem. In Chapter 4, a model with 407 variables was solvable for values of α_p down to 0.40. With the instance in Chapter 5 with 8,316 variables, values of α_p down to 0.85 was solvable. One of the findings from Chapter 4 was that extra stages could be added to the model after the last stage in order to give a more realistic horizon for investments in the later stages. A version of the instance used in Chapter 5 with an extra stage at the end was therefore developed. This instance has four stages and 14,811 variables, and was not solvable for α_p lower than 0.95, even when using the solution methods outlined here.

6.4 Summary of Solution Procedures

This chapter has shown that solving the developed model can be facilitated by providing good initial points. An algorithm that employs different solution methods for finding these initial points and then solving the problem has been presented. The algorithm solved several instances that were not solvable with standard solution procedures. Further, the chapter has found that solution times might be improved by changing the settings for the solver PATH. This is found to reduce solution time by 15.5% in one case.

7 Conclusions

In the US, shale gas development have played a large role in reducing imports of natural gas. In the recent conflict between Russia and the Ukraine, Russia has used natural gas exports to gain political leverage. This has led to increased interest in shale gas among producers and politicians in many European countries. To provide decision support for regulators and producers of natural gas, we have therefore used our model to study how shale gas development in Europe will affect future market dynamics.

Risk preferences and risk averse behaviour are features of the human psyche. A model that wishes to describe a system governed by humans should consider including risk preferences to capture this aspect of decision making. In this thesis we have developed a multi-stage stochastic MCP for a natural gas market that accounts for several resources, market power and risk averse behaviour amongst producers. The actors in the model are producers, a TSO and end users. The different producers and the TSO have individual objective functions. Compared to other natural gas market models, our model differs by accounting for risk aversion through CV@R in the producers' objective functions in an MCP setting.

Incorporating CV@R in an MCP makes the problem harder to solve. To be able to solve large problem instances methods for finding good starting points for the MCP have been developed. The developed algorithm proves to be more efficient than PATH with standard option values, solving several instances that were not solvable with standard solution procedures. Further, we have found that solution times might be improved by changing the settings for the PATH solver. This allows some data instances that would not be solved by PATH with standard option values to be solved and reduces solution time by 16% in one of the cases we have compared.

The problem has been solved for a large portion of the European gas market from 2015 to 2025. Analysis of the solution has shown that successful shale gas developments can increase the total European production of natural gas by 15.8% from the 2015 level of 17.6 bcf/d. We have found that shale gas development might reduce natural gas prices from 2015 to 2025. In Poland prices decreased by 12% to 22 USD/kcf. Prices in Ukraine were reduced by 13% to 33 USD/kcf. For the European gas market as a whole, volume weighted average prices decrease by 6.6% from 2015 to 2025 when shale gas exploration in Poland and Ukraine is successful. This is good for the consumers because higher quantities at lower prices will increase the consumer surpluses. The total European consumer surplus is 4.4% higher in the scenario where a high amount of shale gas is found compared to the scenario where there is a ban on shale gas development. Further, shale gas development in Ukraine and Poland can be profitable and might reduce Russian producers' market shares by 44% in Ukraine and by 64% in Poland. Successful shale gas development can therefore increase Europe's security of supply.

Whether this shale gas development will take place or not depends on several factors outside the scope of the developed model. There has to be political will, producers have to be willing to invest, landowners will have to approve and the public opinion should not be strongly opposed to such development. One single model can therefore not describe with certainty what will happen with shale gas development in Europe, but our findings indicate that development might be economically viable.

The impact of perceived political will has been analysed by looking at the impact of the perceived likelihood of a shale gas ban. The model has shown that an increase in the probability of a shale gas ban from 5% to 25% might lower the investments by 11% in Poland and 49% in Ukraine. This corresponds to a reduction of shale gas reserves expansions by 237 bcf in Poland and 522 bcf in Ukraine. Since the perceived likelyhood of a shale gas ban affects investments, several suggestions for how policy makers, who want to encourage shale gas developments, can handle this has been presented. These include signaling, tax incentives and risk sharing through joint ventures.

We have also studied how the solution changes when the producers go from being risk neutral to being risk averse. The analysis has shown that Russian imports and the producers' expected profits are only slightly affected by higher risk aversion. In 2015, shale gas investment in Poland are 16% lower when the producer is risk averse compared to the risk neutral case. This corresponds to a lowering of shale gas reserves expansions by 94 bcf. In Ukraine, the investments are 1.5% lower in 2015 compared to the risk neutral case, a lowering of shale gas reserves expansions by 74 bcf. Due to the hedging with conventional gas exploration by the producer in Poland and the fact that investments made by the producer in Ukraine are only slightly reduced, the expected profits are not noticeably smaller in the risk averse solution, even though $CV@R_p$ is reduced by 4-5%. We have shown that risk aversion alters the decisions on investments and that shale gas in itself could be an effective way to reduce Russian imports. Therefore, modeling with risk aversion gives a better picture of how investments in shale gas could play out in the real world.

Since CV@R complicates the problem greatly and the solution is only altered slightly, there exists a trade off between a realistic representation of investment behaviour and added complexity. The inclusion of risk preferences in this type of market model is at an early stage. Possible future development of this model could take several directions. One direction could be to incorporate our CV@R approach for a larger data instance and a longer time horizon. Another direction could be to work on increasing the levels of risk aversion the model is able to solve to optimality. The last one will require further work on solution procedures to find more equilibrium solutions. We believe that a good starting point for this further work would be to have a look at the convergence tolerances in the PATH solver.

Glossary

bcf/d	Billion Cubic Feet per Day. 6
BP	British Petroleum. 1–3
CO_2	Carbon Dioxide. 8, 35
EC	European Commission. 8, 46
EIA	Energy Information Agency. 1, 8
EU	European Union. 4, 5, 8, 45, 46, 79
EVPI	Expected Value of Perfect Information. 18
FRISBEE	Framework of International Strategic Behaviour in Energy and Environment. 18
GAMS	General Algebraic Modeling System. 71
GASTALE	Gas mArket System for Trade Analysis in a Liberalising Europe. 18
IEA	International Energy Agency. 2, 3
IPCC	International Panel on Climate Change. 8
KKT	Karush Kuhn-Tucker. 15–17, 23, 27, 49, 57, F
kWh	kilo Watt hours. 8
LCP	Linear Complementarity Problem. 17, 23

LNG	Liquiefied Natural Gas. 18, 24, 33
MCP	Mixed Complementarity Problem. 11, 17, 48, 49, 57, 116
NLP	Non-Linear Programming. 19
OECD	Organisation for Economic Co-operation and Development. 79
PATH	PATH solver for complementarity problems. 107
TIMES	The Integrated MARKAL-EFOM System. 18
TSO	Transmission System Operator. 25, 41, 49, 116
TWh	Tera Watt hours. 5, 46
UN	United Nations. 8

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A Input data for the problem in Chapter 4

Units are given in Chapter 3

Miscellaneous parameters

Outcome	Low	Mid	High
$\mathrm{Pr}(u)$	$1/3$	$1/3$	$1/3$
$\Delta R_{prnu}(\xi)$	0.02	0.8	5

Attribute	Value	Unit
D_u	1825	days
Discount factor	5%	per year
B_u^{TSO}	1	bUSD

Attribute	1. Stage	2. Stage	3. Stage
γ_u	1	0.77	0.60

Market parameters

Countries	INT_{nu}	SLP_{nu}
NED	0.05	0.01
NOR	-	-

Arc parameters

Arc	CAP^{A0}_{a}	C^{F}_{a}	$C^{\Delta A}_{a}$
NOR_NED	8.90	0.001	1

Producer dependent parameters

Producers	α_p	$\delta_{p,NED}$
P_NOR	Case specific	
P_NED		

Producers	$CAP^{P0}_{p,conv,NED}$	$CAP^{P0}_{p,shale,NED}$
P_NOR	10.3	0
P_NED	7.6	0

Producers	B^{P}_{pu} [bUSD]	$R^{P0}_{p,conv,n}$	$R^{P0}_{p,shale,n}$
P_NOR	60	7207.5	0
P_NED	10.8	3953.9	63

Producers	$C^{LP}_{p,conv,n}$	$C^{QP}_{p,conv,n}$	$C^{LP}_{p,shale,n}$	$C^{QP}_{p,shale,n}$
P_NOR	0.0027	0	-	0
P_NED	0.0019	0	0.0018	0

Producers	$C^{\Delta R}_{p,conv,n}$	$C^{\Delta R}_{p,shale,n}$	$C^{\Delta P}_{p,conv,n}$	$C^{\Delta P}_{p,shale,n}$
P_NOR	0.00029	-	0.0028	-
P_NED	0.00029	0.023	0.0013	0.003

B Partial Derivatives in a Stochastic Model

When taking partial derivatives with respect to variables that appear in constraints and equations in several scenario tree nodes, special care has to be taken.

As an example, consider how the partial derivative of Equation (3.3) (repeated on the form $g_{prnu}(x) \leqslant 0$ below, see Setion 2.3.1) with respect to e^P_{prnu} would be. Let x be a vector with the variables e^P_{prnu} , q_{prnu}.

$$q_{prnu} - CAP^{P0}_{prn} - \sum_{u' \in pred(u)} e^P_{prnu'} \leqslant 0 \quad \forall\, p, r, n, u \qquad (\lambda^P_{prnu}) \tag{B.1}$$

For the purpose of simplifying the explanation, consider a situation where there is one producer p in one country node n producing one resource type r. The equation above can then be written like this:

$$q_u - CAP^{P0} - \sum_{u' \in pred(u)} e^P_{u'} \leqslant 0 \quad \forall\, u \qquad (\lambda^P_u) \tag{B.2}$$

The entire problem has the form presented in Section 2.3.1:

$$\min \quad f(x) \tag{B.3}$$

$$\text{s.t.} \qquad g_i(x) \leqslant 0 \quad \forall\, i = 1, \ldots, m \tag{B.4}$$

$$h_j(x) = 0 \quad \forall\, j = 1, \ldots, l \tag{B.5}$$

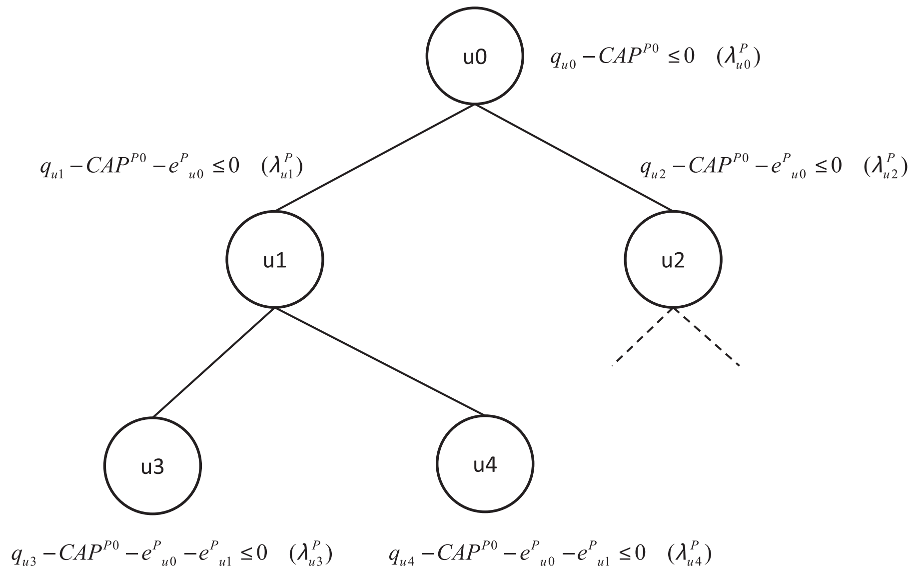
Now, say we want to find the stationarity equation for the problem with respect to e^P_{u1}. Let the objective be $f(x)$ and disregard all constraints except the set of $g_u(x)$.

The component of the stationarity condition we are interesting is:

$$\frac{\partial f(x)}{\partial e^{P}_{u1}} + \sum_{u \in U} \lambda_u \frac{\partial g_u(x)}{\partial e^{P}_{u1}} = 0 \tag{B.6}$$

The next step is to find the partial derivatives of $g_u(x)$ with respect to e^{P}_{u1}. To do this, we type up $g_u(x)$ for the nodes in the scenario tree. For this example, we use the scenario tree presented in Figure 3.1. We look at the variable e^{P}_{u1}, and therefore omit the two scenario tree nodes to the right in the third stage.

Figure B.1: Equation (B.2) illustrated for a small tree. Duals in parenthesis.



From Figure B.1, we see that the partial derivatives become -1 for all the scenario tree nodes that are successors of u1, and zero for all the other scenario tree nodes.

This yields the following:

$$\begin{aligned} &\frac{\partial f(x)}{\partial e^{P}_{u1}} + \sum_{u \in U} \lambda_u \frac{\partial g_u(x)}{\partial e^{P}_{u1}} \\ =&\frac{\partial f(x)}{\partial e^{P}_{u1}} + \sum_{u' \in succ(u1)} \lambda'_u(-1) \\ =&\,0 \end{aligned} \tag{B.7}$$

To derive the stationarity conditions and the rest of the KKT conditions in the model, the same procedure can be used.

B.1 Economic Interpretation

For an economic interpretation, let the objective function be simplified as $f(x) = \sum_{u \in U} Pr(u)(C^{\Delta P} e^P_u - m * q_u)$, where m is the margin of sales (here, the price and cost are constant). Looking at just the variable e^P_u for the left side of the tree in Figure B.2, the KKT conditions are:

$$0 \leqslant Pr(u0)C^{\Delta P} - \lambda^P_{u1} - \lambda^P_{u3} - \lambda^P_{u4} \perp e^P_{u0} \geqslant 0 \tag{B.8}$$

$$0 \leqslant Pr(u1)C^{\Delta P} - \lambda^P_{u3} - \lambda^P_{u4} \perp e^P_{u1} \geqslant 0 \tag{B.9}$$

$$0 \leqslant Pr(u3)C^{\Delta P} \perp e^P_{u3} \geqslant 0 \tag{B.10}$$

$$0 \leqslant Pr(u4)C^{\Delta P} \perp e^P_{u4} \geqslant 0 \tag{B.11}$$

The following interpretation can be made. Investments in reserve expansions in u0 will be made if the sum of the increase in the objective value by increasing the capacities in scenario tree node u1, u3 and u4 ($\lambda_{u1} + \lambda_{u3} + \lambda_{u4}$) is greater than the probability weighted cost of investments in expansion of production capacity. The same can be seen for investments in u1, except that the increased objective function value gained from increasing capacity in scenario tree node u1 (λ_{u1}) is not included. In the third stage, no investments will be made as there are no future periods where increased capacity can increase the objective function values. In mathematical term, the two last expressions do not contain λ_u's, forcing e^P_{u3} and e^P_{u4} to be zero.

C GAMS Code

The GAMS code is included bellow. The problem is coded in different files:

- Main: ties the files together and is used for file selction
- Model: includes the mathematical formulation from Chapter 3
- Solve and report: includes solution procedures and file output manipulation
- Calculations: includes post solve calculations
- Data files: Different data instances used for different cases are coded in sepperate files.

The GAMS files are available in the attached .zip archive.

C.1 Main

```
*********************************************
*NATURAL GAS MARKET MODEL *******************
*W/RISK AVERSION AND MARKET POWER************
*WRITTEN BY KALV AND WALLE—HANSEN************
*MAY 2014************************************
*********************************************

$ontext
MAIN

This file controls solution of the probem.
It uses separate files for:
— solving and settings
— calculations (via solve procedures)
```

```
— data input

UPDATED: 23.5.
$offtext

*Output the 100 first of all sets of constraints for bug searching.
option limrow=100;
$eolcom #

*Select data set.
$INCLUDE UKRRN_POLRN_LOWBAN.txt

*Include model file
$INCLUDE models.gms
Use "solve mcp..." for standard solution procedure, new_solve.gms for
    special solution procedure, new_solve_settings.gms for special
    solution procedure with specialized settings.
*solve mcp using mcp
$INCLUDE new_solve.gms
*$INCLUDE new_solve_settings.gms

********************************************
*SETTINGS FOR CONVERSION OF NLP MODEL TO MCP**
*THIS IS USED FOR CHECKING KKT CONDITIONS*****
********************************************

*$call rm -f tmpmcp.gms convert.op9
*$echo "NLP2MCP tmpmcp.gms" > convert.op9
*$echo "dict dict.txt" > convert.op9

$ontext
file coop9 / 'convert.op9' /;
putclose coop9 'NLP2MCP tmpmcp.gms'
            / 'dict dict.txt'
            /;

$call sed -n -e "s:^ *\([exbi][0-9][0-9]*\) \(.*\):s/\1/\2/g:gp" dict.txt
    | sed -n "1!G;h;$p" > mod.txt
$call sed -f mod.txt gams.gms

cvarOpt.optfile = 9;
option nlp = convert;
solve cvarOpt using nlp min cvarObj;
* test that tmpmcp.gms was created
execute '=test -e tmpmcp.gms';
abort$errorlevel 'we did not find tmpmcp.gms from convert run';

execute 'gams tmpmcp.gms lo=#GAMS.lo#';
abort$errorlevel 'tmpmcp.gms did not execute cleanly';
$offtext
```

C.2 Model

```
$ontext
MODEL

This file contains the declarations of everything needed for the model.
There are three models declared: the mcp model developed in the thesis
and two optimization models used for generating initial solutions for
the mcp.

This file is controlled by main.gms

UPDATED: 26.5.
$offtext

#CONSTANTS
parameter yearsPerStage, discountRate, branches;

set
         a       #arcs
         n       #country nodes
         p       #producers
         r       #resources
         u       #nodes in scenario tree
;
alias
         (pp,p)
         (nn,n)
         (uu,u)
         (uuu,u)
;
set
         aPlusn(n,a)    #inward arcs a to node n
         aMinusn(n,a)   #outward arcs a from node n
         nProd(p,n)     #nodes n where p has production
         nPlus(a,n)     #end node n of arc a
         nMinus(a,n)    #start node n of arc a
         pred(u,uu)     #predecessor nodes in scenario tree
         succ(u,uu)     #predecessor nodes in scenario tree
         endNodes(u)    #end nodes in scenario tree
         temp(u,uu,uuu) #temp used for making b
         b(u,uu,uuu)    #used for matching deltaR eR and rhoP in eRStat
         flag(u,uu)     #used for making b
         dirsucc(u,uu)  #direct successors uu of u
         uMinus(u,uu)   #direct predecessor uu of u
         match(u,uu)    #used for matching node u to its succeeding
                        #endnodes uu
;
Parameter
         prev(u)         #Used for matching deltaR and eR
         alpha(p)        #Risk aversion parameter
```

```
          BP(p,u)          #Producers expansion budget in scenario tree
                           #node u
          BTSO(u)          #TSO expansion budget in scenario tree node u
          CAPA0(a)         #Arc a flow rate cap
          CAPP0(p,r,n)     #Initial production rate capacity for p
                           #producing r in n
          CL(p,r,n)        #Linear production cost term for producer p r
          CQ(p,r,n)        #Quadratic production cost term for producer p r
          CF(a)            #Arc a operational cost
          CdeltaA(a)       #Cost per unit of arc capacity expansion
          CdeltaP(p,r,n)   #Cost per unit of production rate expansion
          CdeltaR(p,r,n)   #Cost per unit of reserve expansion
          D(u)             #Days in a stage
          deltaR(p,r,n,u)  #Realised reserve expansion
          delta(p,n)       #Market power parameter
          GAMMA(u)         #Discount factor in scenario tree node u
          INT(n,u)         #Intersection of inverse demand curve in country
                           #node n in scenario tree node u
          prob(u)          #Scenario tree node probabilities
          RP0(p,r,n)       #Initial Reserve for p
          SLP(n,u)         #Slope of inverse demand curve in country node n
;

#VARIABLES
positive variables
          eA(a,u)                 #capacity flow rate expansion
          eP(p,r,n,u)             #production rate cap expansion
          eR(p,r,n,u)             #reserve cap expansion
          f(p,a,u)                #flow rate for producer p on a
          q(p,r,n,u)              #production rate
          qS(p,n,u)               #sales rate
          s(a,u)                  #flow rate
          z(p,u)                  #positive part of k-f(x) in CVAR
          lambdaP(p,r,n,u)        #Dual to prodCap restriction
          rhoP(p,r,n,u)           #Dual for expRes
          muP(p,u)                #Dual to prod exp budget
          lambdaT(a,u)            #Dual to TSO flow cap
          muT(u)                  #Dual for TSO budget
          sigma(p,u)              #dual to cvar linearization
          y(p,u)                  #variable from linearizaton of cvar
          k(p)                    #quantile variable from CV@R function
;

variables
         tau(a,u)             #congestion fee on arc a
         phi(p,n,u)           #Dual to mass balance eq
         cvarObj              #value of cvar objective function
         socwelfObj           #value of socwelf objective function
             pi(n,u)          #price from inverse demand function
;

#Equations
```

```
equations
          eq_prodCap(p,r,n,u)       #production capacity constraint
          eq_massBalance(p,n,u)     #mass balance
          eq_ProdExpBudget(p,u)     #expansion budget for producer
          eq_expRes(p,r,n,u)        #expansion of reserves
          eq_flowCap(a,u)           #flow rate capacity constraint
          eq_TSOExpBudget(u)        #expansion budget for TSO
          eq_nodePrice(n,u)         #inverse demand curve in market n
          eq_arcFlow(a,u)           #arc flow constraint
          eq_qStat(p,r,n,u)         #Stat eq for prod wrt q
          eq_qSStat(p,n,u)          #Stat eq for prod wrt qS
          eq_eRStat(p,r,n,u)        #Stat eq for prod wrt eR
          eq_ePStat(p,r,n,u)        #Stat eq for prod wrt eP
          eq_fStat(p,a,u)           #Stat eq for prod wrt f
          eq_sStat(a,u)             #Stat eq for TSO wrt s
          eq_eAStat(a,u)            #Stat eq for TSO wrt eA
          eq_kStat(p)               #Stat eq for prod wrt kP
          eq_yStat(p,u)             #Stat eq for prod wrt y
          eq_lin(p,u)               #Constraint for linearization of cvar
          eq_cvarObj                #CV@R optimization obj fun
          eq_socwelfObj             #socwelf optimization obj fun
          eq_linOpt(p,u)            #Constraint for linearization of cvar
                                    #for optimization
;

#Stationarity
eq_kStat(p) ..  - 1 + sum(endNodes(uu), sigma(p,uu)) =G= 0;

eq_yStat(p,u)$(endNodes(u)) ..  1 / alpha(p) * Prob(u) - sigma(p,u) =G=
    0;

eq_qStat(p,r,n,u)$(nProd(p,n)) ..
          GAMMA(u) * D(u) * (CL(p,r,n) + 2 * CQ(p,r,n) * q(p,r,n,u)) *
          sum(match(u,uu), sigma(p,uu))
          + lambdaP(p,r,n,u)$(nProd(p,n))
          - phi(p,n,u)
          + rhoP(p,r,n,u)$(nProd(p,n)) * D(u) + sum(succ(u,uu), D(uu) *
          rhoP(p,r,n,uu)$(nProd(p,n)))
          =G= 0;

eq_qSStat(p,n,u) ..
          - GAMMA(U) * D(u) *
          (delta(p,n) * (INT(n,u) - SLP(n,u) * (sum(pp, qS(pp,n,u)) +
          qS(p,n,u))) + (1 - delta(p,n)) * (INT(n,u) - SLP(n,u) * sum(pp,
          qS(pp,n,u)))) * sum(match(u,uu), sigma(p,uu))
           + phi(p,n,u) =G= 0;

eq_ePStat(p,r,n,u)$((not(endnodes(u)) and (nProd(p,n)))) ..
          GAMMA(u) * CdeltaP(p,r,n) * sum(match(u,uu), sigma(p,uu))
          - sum(succ(u,uu),  lambdaP(p,r,n,uu))
          + muP(p,u) * CdeltaP(p,r,n)
          =G= 0;
```

```
eq_eRStat(p,r,n,u)$((not(endnodes(u)) and (nProd(p,n)))) ..
          GAMMA(u) * CdeltaR(p,r,n) * sum(match(u,uu), sigma(p,uu))
          - sum(dirsucc(u,uu), deltaR(p,r,n,uu) * rhoP(p,r,n,uu))
          - sum(succ(u,uu), sum(b(u,uu,uuu), deltaR(p,r,n,uuu)) *
          rhoP(p,r,n,uu))
          + muP(p,u) * CdeltaR(p,r,n)
          =G= 0;

eq_fStat(p,a,u) ..
          GAMMA(u) * D(u) * tau(a,u) * sum(match(u,uu), sigma(p,uu))
          - sum(nn$nPlus(a,nn), phi(p,nn,u))
          + sum(nn$nMinus(a,nn), phi(p,nn,u))
          =G= 0;


#CONSTRAINTS

#Profits(u) means profits in node u.
eq_lin(p,u)$(endNodes(u)) ..
          y(p,u) - k(p)
#profits(pred(u)
          + sum(Pred(u,uu), GAMMA(uu) * (sum(n, D(uu) * qS(p,n,uu)
          *(delta(p,n) * (INT(n,uu) - SLP(n,uu) * sum(pp, qS(pp,n,uu))
          ) + (1-delta(p,n)) * (INT(n,uu) - SLP(n,uu)
          * sum(pp, qS(pp,n,uu))))) )
          - sum(a, D(uu) * tau(a,uu) * f(p,a,uu))
          - sum(r, sum(n, eR(p,r,n,uu)$(nProd(p,n)) * CdeltaR(p,r,n) +
          eP(p,r,n,uu)$(nProd(p,n)) * CdeltaP(p,r,n)))
          - sum(r, sum(nProd(p,n), D(uu) * (CL(p,r,n) * q(p,r,n,uu) +
              q(p,r,n,uu) * q(p,r,n,uu) * CQ(p,r,n)) ))) )
#profits(u)
          + GAMMA(u) * (sum(n, D(u) * qS(p,n,u) *(delta(p,n) *
          (INT(n,u) - SLP(n,u) * sum(pp, qS(pp,n,u))) + (1-delta(p,n))
          * (INT(n,u) - SLP(n,u) * sum(pp, qS(pp,n,u))))) )
          - sum(a, D(u) * tau(a,u) * f(p,a,u))
#No investments in last stage
          - sum(r, sum(nProd(p,n), D(u) * (CL(p,r,n) * q(p,r,n,u)+
          q(p,r,n,u) * q(p,r,n,u) * CQ(p,r,n)) )))
          =G= 0;


#In optimization, congestion cancels out and is removed.
eq_linOpt(p,u)$(endNodes(u)) ..
          y(p,u) - k(p)
#profits(pred(u)
          + sum(Pred(u,uu), GAMMA(uu) * (sum(n, D(uu) * qS(p,n,uu)
          *(delta(p,n) * (INT(n,uu) - SLP(n,uu) * sum(pp, qS(pp,n,uu)))
          + (1-delta(p,n)) * (INT(n,uu) - SLP(n,uu)
          * sum(pp, qS(pp,n,uu)))))
#         - sum(a, D(uu) * tau(a,uu) * f(p,a,uu))
          - sum(r, sum(n, eR(p,r,n,uu)$(nProd(p,n)) * CdeltaR(p,r,n) +
```

```
            eP(p,r,n,uu)$(nProd(p,n)) * CdeltaP(p,r,n)))
            - sum(r, sum(nProd(p,n), D(uu) * (CL(p,r,n) * q(p,r,n,uu)+
            q(p,r,n,uu) * q(p,r,n,uu) * CQ(p,r,n))))) )
#profits(u)
            + GAMMA(u) * (sum(n, D(u) * qS(p,n,u) *(delta(p,n) * (INT(n,u)
            - SLP(n,u) * sum(pp, qS(pp,n,u))) + (1-delta(p,n)) *(INT(n,u) -
            SLP(n,u) * sum(pp, qS(pp,n,u)))) )
#           - sum(a, D(u) * tau(a,u) * f(p,a,u))
#No investments in last stage
            - sum(r, sum(nProd(p,n), D(u) * (CL(p,r,n) * q(p,r,n,u)+
            q(p,r,n,u) * q(p,r,n,u) * CQ(p,r,n)))))
            =G= 0;

eq_ProdCap(p,r,n,u)$(nProd(p,n)) ..
            CAPP0(p,r,n)
            - q(p,r,n,u)
            + sum(pred(u,uu), eP(p,r,n,uu))
            =G= 0
;

eq_massBalance(p,n,u) ..
            sum(r,  q(p,r,n,u)$(nProd(p,n)))
            + sum(aPlusn(n,a), f(p,a,u))
            - qS(p,n,u)
            - sum(aMinusn(n,a), f(p,a,u))
            =E= 0;

eq_ProdExpBudget(p,u)$(not(endNodes(u))) ..
            BP(p,u)
            + sum(r,sum(nProd(p,n),
            - CdeltaP(p,r,n) * eP(p,r,n,u)$(nProd(p,n))
            - CdeltaR(p,r,n) * eR(p,r,n,u)$(nProd(p,n))
            ))
            =G= 0;

eq_expRes(p,r,n,u)$(nProd(p,n)) ..
            RP0(p,r,n) - sum(pred(u,uu), D(uu) * q(p,r,n,uu)) - D(u) *
            q(p,r,n,u)
            + sum(pred(u,uu), deltaR(p,r,n,uu) * eR(p,r,n,uu -
            prev(uu))$(nProd(p,n)))
            + deltaR(p,r,n,u) * eR(p,r,n,u - prev(u))$(nProd(p,n))
            =G= 0;

#TSO equations
eq_eAStat(a,u)$(not(endNodes(u))) ..
            Prob(u) * GAMMA(u) * CDeltaA(a)
            - sum(succ(u,uu), lambdaT(a,uu))
            + CDeltaA(a) * muT(u)
            =G= 0;

eq_sStat(a,u) ..
            - Prob(u) * GAMMA(u) * D(u) * (tau(a,u) - CF(a))
```

```
          + lambdaT(a,u)
          =G= 0;

eq_flowCap(a,u) ..
          CAPA0(a)
          + sum(pred(u,uu), eA(a,uu))
          - s(a,u)
          =G= 0;

eq_TSOExpBudget(u)$(not(endNodes(u))) ..
          BTSO(u) - sum(a, CDeltaA(a) * eA(a,u))
          =G= 0 ;

#Market clearing equations
#substituted out of the MCP:
eq_nodePrice(n,u) ..  INT(n,u) - SLP(n,u) * sum(p, qS(p,n,u)) - pi(n,u)
          =E= 0;

eq_arcFlow(a,u) .. s(a,u) - sum(p,f(p,a,u)) =E= 0;

#Optimization objectives
eq_cvarObj .. cvarObj =E=
          - sum(p,
          k(p) - (1 / alpha(p) ) * sum(endNodes(uu), Prob(uu) *
          y(p,uu) ))
          - sum((a,u), Prob(u) * GAMMA(u) *( s(a,u) * D(u) * ( - CF(a)) -
          CDeltaA(a) * eA(a,u)$(not(endNodes(u)))))
          - sum((n,u), Prob(u) * GAMMA(u)* (INT(n,u) - (INT(n,u) -
          SLP(n,u) * sum(pp, qS(pp,n,u)))) / 2 * sum(p, qS(p,n,u)) * D(u))
;

eq_socwelfObj .. socwelfObj =E=
          - sum(p,
          + sum(n, sum(u, Prob(u) * GAMMA(u) * D(u) * qS(p,n,u) *
          (INT(n,u) - SLP(n,u) * sum(pp, qS(pp,n,u)))))
          - sum(nProd(p,n), sum(u, sum(r, Prob(u) * GAMMA(u) *
          D(u) * (q(p,r,n,u) * CL(p,r,n) + q(p,r,n,u) *
          q(p,r,n,u) * CQ(p,r,n) ) ) ))
          - sum((n,u,r), Prob(u) * GAMMA(u) *
          (eR(p,r,n,u)$((nProd(p,n))and(not(endNodes(u)))) *
          CdeltaR(p,r,n) +
          eP(p,r,n,u)$((nProd(p,n))and(not(endNodes(u)))) *
          CdeltaP(p,r,n) ) ))
          + sum((a,u), Prob(u) * GAMMA(u) *( s(a,u) * D(u) *
          CF(a) ))
          + sum((a,u), Prob(u) * GAMMA(u) * CDeltaA(a) *
          eA(a,u)$(not(endNodes(u))))
          - sum((n,u), Prob(u) * GAMMA(u)* (INT(n,u) - (INT(n,u)
          - SLP(n,u) * sum(pp, qS(pp,n,u)))) / 2 * sum(p,
          qS(p,n,u)) * D(u))
;
```

```
#MCP MODEL
Model mcp
/eq_kStat.k
eq_yStat.y
eq_qStat.q
eq_qSStat.qS
eq_eRStat.eR
eq_ePStat.eP
eq_fStat.f
eq_ProdCap.lambdaP
eq_expRes.rhoP
eq_prodExpBudget.muP
eq_massBalance.phi
eq_lin.sigma
eq_sStat.s
eq_eAStat.eA
eq_flowCap.lambdaT
eq_arcFlow.tau
eq_TSOExpBudget.muT
/

#OPTIMIZATION MODEL WITH RISK AVERSION
Model cvarOpt
/eq_ProdCap,
eq_expRes,
eq_prodExpBudget,
eq_massBalance,
eq_flowCap,
eq_arcFlow,
eq_TSOExpBudget,
eq_linOpt,
eq_nodePrice,
eq_cvarObj
/

#OPTIMIZATION MODEL WITH RISK NEUTRALITY
Model socwelfOpt
/eq_ProdCap
eq_expRes
eq_prodExpBudget
eq_massBalance
eq_flowCap
eq_arcFlow
eq_TSOExpBudget
eq_socwelfObj
eq_nodePrice
/;
```

C.3 Solve and report

```
#This is new_solve. It attempts to solve the problem using
#different starting points

set       alphaIter
          deltaIter;

#Report parameters for file output
parameter
          sstat(*,alphaIter,deltaIter),
          mstat(*,alphaIter,deltaIter),
          qSave(*,alphaIter, deltaIter, p,n,u)
          expProfit(p,alphaIter, deltaIter)
          scenprofit(p,u,alphaIter,deltaIter)
          cumprofit(p,u,alphaIter,deltaIter)
          rev(p,alphaIter, deltaIter,u)
          prodcost(p,alphaIter, deltaIter,u)
          production(p,r,n,u,alphaIter, deltaIter)
          cumulativeProd(p,r,n,u,alphaIter, deltaIter)
          totalReserves(p,r,n,u,alphaIter, deltaIter)
          expansion(p,r,n,u,alphaIter, deltaIter)
          transcost(p, alphaIter, deltaIter, u)
          scenConsumerSurplus(n,u,alphaIter, deltaIter)
          cumConsumerSurplus(n,u,alphaIter, deltaIter)
          expConsumerSurplus(n,alphaIter, deltaIter)
          invest(p,alphaIter, deltaIter,u)
          expTSOProfit(alphaIter, deltaIter)
          scenTSOProfit(alphaIter, deltaIter,u)
          cumTSOProfit(alphaIter, deltaIter,u)
          CVAR(p,alphaIter, deltaIter)
          errorFlag
          reserveExpansion(p,alphaIter, deltaIter,u)
          price(alphaIter,deltaIter,n,u)
          scensocialWelfare(alphaIter, deltaIter, u)
          cumsocialWelfare(alphaIter, deltaIter, u)
          expsocialWelfare(alphaIter, deltaIter)
          report(*,alphaIter,*,*,*,*)
          method
;

#Find an initial solution
solve socwelfOpt min socwelfObj using nlp;

set alphaIter    /j1*j1/;
set deltaIter /i1*i1/;
method(alphaIter,deltaIter) = 0;
parameter storedAlpha(p), storedDelta(p,n);

#Solve the problem using the methods mentioned in Ch 6
#for solving the problem using different starting points
```

```
loop(alphaIter,
       loop(deltaIter,
         errorFlag = 1;
         storedAlpha(p) = alpha(p);
         storedDelta(p,n) = delta(p,n);

#Method 1: Solve normally
         method(alphaIter,deltaIter) = 11;
         solve socwelfOpt minimizing socwelfObj using nlp;
         solve mcp using mcp;
         if(mcp.modelstat = 1,
             display alpha, delta;
             errorFlag = 0;
             method(alphaIter,deltaIter) = 1;
         else
             method(alphaIter,deltaIter) = 12;
         );

        if(errorFlag = 1,
#Method 7: Set alpha = 1, delta inbetween
             method(alphaIter,deltaIter) = 71;
                 alpha(p)$(alpha(p)<> 1) = 1;
                 delta(p,n)$(delta(p,n) <> 1) = delta(p,n)
                 + 0.25 * (1 - delta(p,n));
                 solve mcp using mcp;
                 if(mcp.modelstat = 1,
                     alpha(p) = storedAlpha(p);
                     delta(p,n) = storedDelta(p,n);
                     solve mcp using mcp;
                     if(mcp.modelstat  = 1,
                         method(alphaIter,deltaIter) = 7;
                         errorFlag = 0;
                         display alpha, delta;
                     );
                 );
             alpha(p) = storedAlpha(p);
         );
         if(errorFlag = 1,
#Method 8: Set alpha = inbetween, delta inbetween
             method(alphaIter,deltaIter) = 81;
             alpha(p)$(alpha(p)<> 1) = alpha(p) + 0.7 * (1 - alpha(p));
             delta(p,n)$(delta(p,n) <> 1) = delta(p,n)
             + 0.25 * (1 - delta(p,n));
             solve mcp using mcp;
             if(mcp.modelstat = 1,
                 alpha(p) = storedAlpha(p);
                 delta(p,n) = storedDelta(p,n);
                 solve mcp using mcp;
                 if(mcp.modelstat  = 1,
                     method(alphaIter,deltaIter) = 8;
                     errorFlag = 0;
                     display alpha, delta;
```

```
                );
            );
            alpha(p) = storedAlpha(p);
        );
        if(errorFlag = 1,
#Method 6: Set alpha = 1, delta inbetween
            method(alphaIter,deltaIter) = 61;
            alpha(p)$(alpha(p)<> 1) = 1;
            delta(p,n)$(delta(p,n) <> 1) = delta(p,n)
            + 0.5 * (1 - delta(p,n));
            solve mcp using mcp;
            if(mcp.modelstat = 1,
                alpha(p) = storedAlpha(p);
                delta(p,n) = storedDelta(p,n);
                solve mcp using mcp;
                if(mcp.modelstat  = 1,
                    method(alphaIter,deltaIter) = 6;
                    errorFlag = 0;
                    display alpha, delta;
                );
            );
            alpha(p) = storedAlpha(p);
        );
        if(errorFlag = 1,
#Method 5: Set delta=1
            method(alphaIter,deltaIter) = 51;
            delta(p,n) = 1
            solve mcp using mcp;
            if(mcp.modelstat = 1,
                delta(p,n) = storedDelta(p,n);
                solve mcp using mcp;
                if(mcp.modelstat  = 1,
                    method(alphaIter,deltaIter) = 5;
                    errorFlag = 0;
                    display alpha, delta;
                );
            );
            delta(p,n) = storedDelta(p,n);
        );
        if(errorFlag = 1,
#Method 2: Perturb alpha
            method(alphaIter,deltaIter) = 21;
            alpha(p)$(alpha(p)<> 1) = alpha(p) + (1 - alpha(p))/2;
            solve mcp using mcp;
            if(mcp.modelstat = 1,
                alpha(p) = storedAlpha(p);
                solve mcp using mcp;
                if(mcp.modelstat  = 1,
                    method(alphaIter,deltaIter) = 2;
                    errorFlag = 0;
                    display alpha, delta;
                );
```

```
                );
                alpha(p) = storedAlpha(p);
        );
        if(errorFlag = 1,
#Method 3: SOCWELF—>CVAR—>MCP
                method(alphaIter,deltaIter) = 31;
                solve socwelfOpt min socwelfObj using nlp;
                solve cvarOpt min cvarObj using nlp;
                solve mcp using mcp;
                if(mcp.modelstat = 1,
                    method(alphaIter,deltaIter) = 3;
                    errorFlag = 0;
                    display alpha, delta;
                );
         );
         if(errorFlag = 1,
#Method 9: Perturb alpha a little more
                method(alphaIter,deltaIter) = 91;
                alpha(p)$(alpha(p)<> 1) = alpha(p) + 0.7 * (1 - alpha(p));
                solve mcp using mcp;
                if(mcp.modelstat = 1,
                        method(alphaIter,deltaIter) = 92;
                        alpha(p) = storedAlpha(p);
                        solve mcp using mcp;
                        if(mcp.modelstat  = 1,
                                method(alphaIter,deltaIter) = 9;
                                errorFlag = 0;
                                display alpha, delta;
                        );
                );
                alpha(p) = storedAlpha(p);
         );
         if(errorFlag = 1,
#Method 4: Set alpha = 1
                method(alphaIter,deltaIter) = 41;
                alpha(p)$(alpha(p)<> 1) = 1;
                solve mcp using mcp;
                if(mcp.modelstat = 1,
                        alpha(p) = storedAlpha(p);
                        solve mcp using mcp;
                        if(mcp.modelstat  = 1,
                                method(alphaIter,deltaIter) = 4;
                                errorFlag = 0;
                                display alpha, delta;
                        );
                );
         alpha(p) = storedAlpha(p);
         );
#Perform calculations after solving the problem
$INCLUDE calculations.tex
      );
);
```

```
display method;

#Output to .gdx file. "Run" is defined in the data file.
execute_unload "%run%"
         qS.l, price, invest,
         scenConsumerSurplus, cumConsumerSurplus, expConsumerSurplus,
         scenProfit, cumProfit, expProfit, cvar,
         scenSocialWelfare, cumSocialWelfare, expSocialWelfare,
         scenTSOProfit, cumTSOProfit, expTSOProfit,
         method, reserveExpansion,
         report, qSave, mstat, sstat, rev, prodcost,
         production, cumulativeProd, totalReserves, transcost
```

C.4 Calculations

```
$ontext
CALCULATIONS
This file contains the calculation statements.

UPDATED: 20.3.
$offtext


#PRODUCER RELATED
transcost(p,alphaIter, deltaIter, u)
     = sum(a, GAMMA(u) * f.l(p,a,u) * tau.l(a,u) * D(u));

rev(p,alphaIter, deltaIter, u) =
     sum(n, GAMMA(u) * D(u) * qS.l(p,n,u) * (INT(n,u) - SLP(n,u) * sum
              (pp, qS.l(pp,n,u))));

prodcost(p,alphaIter, deltaIter, u) = sum(n,
         sum(r, GAMMA(u) * D(u) * (q.l(p,r,n,u) * CL(p,r,n)
         + q.l(p,r,n,u) * q.l(p,r,n,u) * CQ(p,r,n))) ) ;

invest(p,alphaIter, deltaIter,u) = sum((n,r), GAMMA(u) * (
         eR.l(p,r,n,u) * CdeltaR(p,r,n)
         + eP.l(p,r,n,u) * CdeltaP(p,r,n)) );

scenProfit(p, u, alphaIter, deltaIter)=
            + rev(p,alphaIter, deltaIter,u)
         - transcost(p,alphaIter, deltaIter,u)
         - prodcost(p,alphaIter, deltaIter,u)
         - invest(p,alphaIter, deltaIter,u);

cumProfit(p,u,alphaIter, deltaIter)$(endNodes(u)) =
         sum(pred(u,uu), rev(p,alphaIter, deltaIter,uu)
```

```
          - transcost(p,alphaIter, deltaIter,uu)
          - prodcost(p,alphaIter, deltaIter,uu)
          - invest(p,alphaIter, deltaIter,uu))
          + rev(p,alphaIter, deltaIter,u)
          - transcost(p,alphaIter, deltaIter,u)
          - prodcost(p,alphaIter, deltaIter,u)
          - invest(p,alphaIter, deltaIter,u);

expProfit(p,alphaIter, deltaIter) = sum(u, Prob(u) *(
          rev(p,alphaIter, deltaIter,u)
          - transcost(p,alphaIter, deltaIter,u)
          - prodcost(p,alphaIter, deltaIter,u)
          - invest(p,alphaIter, deltaIter,u)));

cvar(p,alphaIter, deltaIter) = k.l(p) - 1 / alpha(p)
          * sum(endNodes(u), Prob(u) * y.l(p,u));

#TSO RELATED
scenTSOProfit(alphaIter, deltaIter,u) = sum(a, GAMMA(u)
          *( s.l(a,u) * D(u) * (tau.l(a,u)- CF(a))
          - CDeltaA(a) * eA.l(a,u)));

cumTSOProfit(alphaIter, deltaIter,u)$(endNodes(u)) =
          sum((a,pred(u,uu)), GAMMA(uu) *( s.l(a,uu) * D(uu)
          * (tau.l(a,uu)- CF(a))
          - CDeltaA(a) * eA.l(a,uu)))
          + sum(a, GAMMA(u) *( s.l(a,u) * D(u) * (tau.l(a,u)- CF(a))
          - CDeltaA(a) * eA.l(a,u)));

expTSOProfit(alphaIter, deltaIter) = sum((a,u), Prob(u)
          * GAMMA(u) *( s.l(a,u) * D(u) * (tau.l(a,u)- CF(a))
          - CDeltaA(a) * eA.l(a,u)));


#SOCIAL WELFARE RELATED
scenConsumerSurplus(n,u,alphaIter, deltaIter) =
          GAMMA(u) * (INT(n,u) - (INT(n,u) - SLP(n,u)
          * sum(pp, qS.l(pp,n,u)))) / 2 * sum(p, qS.l(p,n,u)) * D(u);
cumConsumerSurplus(n,u,alphaIter, deltaIter)$endNodes(u) =
          sum(pred(u,uu), GAMMA(uu) * (INT(n,uu) - (INT(n,uu)
          - SLP(n,uu) * sum(pp, qS.l(pp,n,uu)))) / 2
          * sum(p, qS.l(p,n,uu)) * D(uu))
          + GAMMA(u) * (INT(n,u) - (INT(n,u) - SLP(n,u)
          * sum(pp, qS.l(pp,n,u)))) / 2 * sum(p, qS.l(p,n,u)) * D(u);
expConsumerSurplus(n,alphaIter, deltaIter)
          = sum(u, prob(u) *
          scenConsumerSurplus(n,u,alphaIter, deltaIter));

scenSocialWelfare(alphaIter, deltaIter,u)
          = sum(n, scenConsumerSurplus(n,u,alphaIter, deltaIter))
          + sum(p, scenProfit(p,u,alphaIter, deltaIter))
          + scenTSOProfit(alphaIter, deltaIter, u);
```

```
cumSocialWelfare(alphaIter, deltaIter,u)$(endNodes(u)) =
          sum((n,pred(u,uu)),
          scenConsumerSurplus(n,uu,alphaIter, deltaIter))
          + sum((p,pred(u,uu)), scenProfit(p,uu,alphaIter, deltaIter))
          + sum(pred(u,uu), scenTSOProfit(alphaIter, deltaIter, uu))
          + sum(n, scenConsumerSurplus(n,u,alphaIter, deltaIter))
          + sum(p, scenprofit(p,u,alphaIter, deltaIter))
          + scenTSOProfit(alphaIter, deltaIter, u);
expSocialWelfare(alphaIter, deltaIter) =
          sum(n, expConsumerSurplus(n,alphaIter, deltaIter))
          + sum(p, expProfit(p,alphaIter, deltaIter))
          + expTSOProfit(alphaIter, deltaIter);

price(alphaIter,deltaIter,n,u) =
          INT(n,u) - SLP(n,u) * sum(p, qS.l(p,n,u));


#PRODUCTION AND QUANTITY RELATED
production(p,r,n,u,alphaIter, deltaIter) = D(u) * q.l(p,r,n,u);

cumulativeProd(p,r,n,u,alphaIter, deltaIter)$(ord(u)=1) =
          production(p,r,n,u,alphaIter, deltaIter);
cumulativeProd(p,r,n,u,alphaIter, deltaIter)$(ord(u)>1) =
          production(p,r,n,u,alphaIter, deltaIter)
          + sum(pred(u,uu), production(p,r,n,uu,alphaIter, deltaIter));

expansion(p,r,n,u,alphaIter, deltaIter) =
          sum(uMinus(u,uu), eR.l(p,r,n,uu) * deltaR(p,r,n,u));

totalReserves(p,r,n,u,alphaIter, deltaIter)$(ord(u)=1) = RP0(p,r,n );
totalReserves(p,r,n,u,alphaIter, deltaIter)$(ord(u)>1) = RP0(p,r,n)
          + sum(pred(u,uu), expansion(p,r,n,uu,alphaIter, deltaIter))
          + expansion(p,r,n,u,alphaIter, deltaIter);

reserveExpansion(p,alphaIter, deltaIter,u) =
          sum((n,r,pred(u,uu)), eR.l(p,r,n,uu) )
          + sum((n,r),eR.l(p,r,n,u));

#Put all the parameters in a report parameter
report("qS",alphaIter,deltaIter,p,n,u) = qS.l(p,n,u);
report("price",alphaIter,deltaIter,"Price[$/cf]",n,u) =
          price(alphaIter,deltaIter,n,u);
report("invest",alphaIter,deltaIter,p,"-",u) =
          invest(p,alphaIter, deltaIter,u);
report("scenConsumerSurplus",alphaIter,deltaIter,"-",n,u) =
          scenConsumerSurplus(n,u,alphaIter, deltaIter);
report("cumConsumerSurplus",alphaIter,deltaIter,"-",n,u) =
          cumConsumerSurplus(n,u,alphaIter, deltaIter);
report("expConsumerSurplus",alphaIter,deltaIter,"-",n,"-") =
          expConsumerSurplus(n,alphaIter, deltaIter);
report("scenProfit",alphaIter,deltaIter,p,"-",u) =
          scenProfit(p,u,alphaIter, deltaIter);
```

```
report("cumProfit",alphaIter,deltaIter,p,"-",u) =
          cumProfit(p,u,alphaIter, deltaIter);
report("expProfit",alphaIter,deltaIter,p,"-","-") =
          expProfit(p,alphaIter, deltaIter);
report("CVAR",alphaIter,deltaIter,p,"-","-") =
          CVAR(p,alphaIter, deltaIter);
report("scenSocialWelfare",alphaIter,deltaIter,"-","-",u) =
          scenSocialWelfare(alphaIter, deltaIter, u);
report("cumSocialWelfare",alphaIter,deltaIter,"-","-",u) =
          cumSocialWelfare(alphaIter, deltaIter,u);
report("expSocialWelfare",alphaIter,deltaIter,"-","-","-") =
          expSocialWelfare(alphaIter, deltaIter);
report("scenTSOProfit",alphaIter,deltaIter,"-","-",u) =
          scenTSOProfit(alphaIter, deltaIter, u);
report("cumTSOProfit",alphaIter,deltaIter,"-","-",u) =
          cumTSOProfit(alphaIter, deltaIter, u);
report("expTSOProfit",alphaIter,deltaIter,"-","-","-") =
          expTSOProfit(alphaIter, deltaIter);
report("method",alphaiter,deltaIter,"-","-","-") =
          method(alphaIter, deltaIter);
report("alpha",alphaIter,deltaIter,p,"-","-") = alpha(p);
report("delta",alphaIter,deltaIter,p,n,"-") = delta(p,n);
report("arcExp",alphaIter, deltaIter,"-",a,u) = eA.l(a,u);
report("shaleResInvest",alphaIter, deltaIter,p,n,u) =
          eR.l(p,'shale',n,u);
report("convResInvest",alphaIter, deltaIter,p,n,u) =
          eR.l(p,'conv',n,u);
report("shaleProdCapInvest",alphaIter, deltaIter,p,n,u) =
          eP.l(p,'shale',n,u);
report("convProdCapInvest",alphaIter, deltaIter,p,n,u) =
          eP.l(p,'conv',n,u);
report("Production",alphaIter, p,r,n,u) = q.l(p,r,n,u);
```

C.5 Data

The data input files for the different cases can be found in the attached .zip file.