Production from Giant Gas Fields in Norway and Russia and Subsequent Implications for European Energy Security

BENGT SÖDERBERGH
Dissertation presented at Uppsala University to be publicly examined in Siegbahnsalen, Ångström laboratoriet, Uppsala, Friday, February 19, 2010 at 09:15 for the degree of Doctor of Philosophy. The examination will be conducted in English.

Abstract

The International Energy Agency (IEA) expects total natural gas output in the EU to decrease from 216 billion cubic meters per year (bcm/year) in 2006 to 90 bcm/year in 2030. For the same period, EU demand for natural gas is forecast to increase rapidly. In 2006 demand for natural gas in the EU amounted to 332 bcm/year. By 2030, it is expected to reach 680 bcm/year. As a consequence, the widening gap between EU production and consumption requires a 90% increase of import volumes between 2006 and 2030. The main sources of imported gas for the EU are Russia and Norway. Between them they accounted for 62% of the EU’s gas imports in 2006. The objective of this thesis is to assess the potential future levels of gas supplies to the EU from its two main suppliers, Norway and Russia. Scenarios for future natural gas production potential for Norway and Russia have been modeled utilizing a bottom-up approach, building field-by-field, and individual modeling has been made for giant and semi-giant gas fields. In order to forecast the production profile for an individual giant natural gas field a Giant Gas Field Model (GGF-model) has been developed. The GGF-model has also been applied to production from an aggregate of fields, such as production from small fields and undiscovered resources.

Energy security in the EU is heavily dependent on gas supplies from a relatively small number of giant gas fields. In Norway almost all production originates from 18 fields of which 9 can be considered as giant fields. In Russia 36 giant fields account for essentially all gas production. There is limited potential for increased gas exports from Norway to the EU, and all of the scenarios investigated show Norwegian gas production in decline by 2030. Norwegian pipeline gas exports to the EU may even be, by 2030, 20 bcm/year lower than today’s level. The maximum increase in exports of Russian gas supplies to the EU amount to only 45% by 2030. In real numbers this means a mere increase of about 70 bcm In addition, there are a number of potential downside factors for future Russian gas supplies to the European markets. Consequently, a 90% increase of import volumes to the EU by 2030 will be impossible to achieve. From a European energy security perspective the dependence of pipeline gas imports is not the only energy security problem to be in the limelight, the question of physical availability of overall gas supplies deserves serious attention as well. There is a lively discussion regarding the geopolitical implications of European dependence on imported gas from Russia. However, the results of this thesis suggest that when assessing the future gas demand of the EU it would be of equal importance to be concerned about diminishing availability of global gas supplies.

Keywords: natural gas production, giant gas fields, depletion rate, forecasting, energy security, EU, Norway, Russia

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To my parents
This thesis is based on the following papers, which are referred to in the text by their Roman numerals.


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### Abbreviations

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<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>bboe</td>
<td>billion barrels of oil equivalent</td>
</tr>
<tr>
<td>bcm</td>
<td>billion cubic meters</td>
</tr>
<tr>
<td>bcf</td>
<td>billion cubic feet</td>
</tr>
<tr>
<td>CIS</td>
<td>Commonwealth of Independent States</td>
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<td>CO2E</td>
<td>Carbon dioxide equivalent</td>
</tr>
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<td>DEA</td>
<td>Danish Energy Agency</td>
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<td>DECC</td>
<td>Department of Energy and Climate Change</td>
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<tr>
<td>EIA</td>
<td>U.S. Energy Information Agency</td>
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<tr>
<td>FID</td>
<td>Final Investment Decision</td>
</tr>
<tr>
<td>Gb</td>
<td>Giga barrels (billion barrels)</td>
</tr>
<tr>
<td>GGF-model</td>
<td>Giant Gas Field model</td>
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<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>Mboe</td>
<td>Million barrels of oil equivalents</td>
</tr>
<tr>
<td>MDR-model</td>
<td>Maximum Depletion Rate model</td>
</tr>
<tr>
<td>NPD</td>
<td>Norwegian Petroleum Directorate</td>
</tr>
<tr>
<td>OECD</td>
<td>Organisation for Economic Co-operation and Development</td>
</tr>
<tr>
<td>Tcf</td>
<td>Trillion cubic feet</td>
</tr>
<tr>
<td>tcm</td>
<td>Trillion cubic meters</td>
</tr>
<tr>
<td>TPES</td>
<td>Total Primary Energy Supply</td>
</tr>
<tr>
<td>URR</td>
<td>Ultimate Recoverable Resources</td>
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</table>
1 Introduction

According to the BP Statistical Review (2009) global gas production in 2007 was 2945 billion cubic meters (bcm), and natural gas’ share of the world’s primary energy consumption was 21%. The power sector accounted for 39% of global gas use in 2007, and the industrial, residential, service and agricultural sectors 50%. Non-energy use of gas amounted to 11% of global gas consumption, mainly as feedstock for petrochemical and fertilizer production. (IEA, 2009) Gas-fired power plants are often preferred to coal- and oil-fired plants for environmental reasons, for their relatively low capital costs (hence minimizing investment risks) and for their short construction lead times. In addition, gas is a preferred technical and economical choice to back up intermittent renewables-based generation such as wind power. (IEA, 2008a)

In 2008, the International Energy Agency (IEA) projected global gas demand to increase by 52% between 2006 and 2030. Gas use is projected to become increasingly concentrated in power generation, and the power sector accounts for 57% of the projected increase in world gas demand, raising its share of global gas use from 39% to 45%. (IEA, 2008b) The power sector is the main driver of demand in almost all regions of the world, especially in non-OECD countries, where electricity demand is projected to rise most rapidly. Despite assumptions of rising gas prices in the longer term and growing use of renewables-based generating technologies, natural gas is expected to remain a highly competitive fuel for new power stations, especially when used in highly efficient combined-cycle gas turbines (CCGTs) and for mid-load generation. (IEA, 2009)

1.1 The development of gas dependence in the EU

Up to the 1950s gas discoveries in Western Europe were relatively small and natural gas had remained an almost negligible source of energy. Italy was among the first Western European countries where natural gas became a major component of the energy mix. During the Second World War gas discoveries had been made in the Po Valley, and by the mid-1960s Italy was the largest gas market in Western Europe. (Högselius, 2007)

The discovery in 1959 of the giant Groningen gas field in the Netherlands, the largest gas field ever to be discovered in Western Europe, initiated
a rapid development of European natural gas consumption. The Groningen field provided incentives for the development of large-scale gas infrastructure, since it soon became apparent that the production potential of the field exceeded domestic Dutch demand, and export contracts were signed with Belgium, France, Germany, Italy and Switzerland. The Groningen field started production in 1963. As of 2006, more than 60% of the estimated recoverable gas reserves initially in place have been produced, and the field’s share of total remaining Dutch gas reserves in 2006 was 66%. (Lyle, 2006)

Although Soviet gas production began to develop as early as the 1940s in the Ukrainian SSSR republic, large discoveries of gas within what today constitutes the European parts of Russia, were made in the 1950s at several sites along the Volga river and in the Urals area. However, during the Stalin era natural gas was not prioritized, thus representing only two percent of the Soviet Union’s primary energy supply in 1950. The breakthrough for Soviet gas utilization came in 1958, with a resolution that gave instructions for the development of the Soviet natural gas industry. This was the result of an increasing awareness of the enormous gas deposits on Soviet territory, caused by increased exploratory oil drilling. (Högselius, 2007) In the 1950s, major gas discoveries were made in the Krasnodar and Stavropol regions, and in the 1960s a number of “supergiant” fields were discovered in Western Siberia. The industrial strategy adopted in the late 1950s led to an increased use of natural gas, both in the Soviet Union as well as in the Soviet satellite states in Eastern Europe. The construction of pipeline networks were seen as a part of reaching economic integration within the Eastern bloc, and from the late 1960s through the 1970s the Soviet gasification program was extended to its satellite states in Eastern Europe. (Victor et al., 2006)

Large gas discoveries in the North Sea during the 1970s and early 1980s made the UK and Norwegian offshore production the center of Western Europe’s gas production. (Victor et al., 2006) However, from late 1960s it became widely accepted that Western European gas production would not be capable of meeting anticipated demand by the 1980s and 1990s, and already by 1963 the UK started importing liquefied natural gas (LNG) from Algeria. (Högselius, 2007) Since huge gas reserves were now present in the Soviet Union, export pipelines were built to Europe, and gas exports began to neutral Austria in 1968 (Stern, 2005). The importance of natural gas was reinforced after the oil crises of the 1970s when natural gas became increasingly attractive as an alternative to oil for the power sector, households and industry. In the early 1980s, plans to build a new pipeline intended for large scale export of gas from the Soviet Union to the Western European nations were developed. This raised a storm of protest in the U.S., including the Reagan Administration, who saw the pipeline as a threat to Europe’s security (Copulus, 1982; Hardt and Gold, 1982). The main reason for their concern was the perceived vulnerability of Western Europe to Soviet threats to cut off gas supplies in the case of a political crisis. However, European leaders dis-
missed the American concerns, arguing that the discoveries of giant natural
gas fields in Norway opened a new import possibility, and that Norwegian
gas could readily provide a substitute.

1.1.1 Gas use and gas production within the EU

Within the EU, gas production, supply and user infrastructure have tended to
be developed on the basis of individual countries’ own reserves, and in relation
to diverse national energy policies. Hence gas use varies markedly between
countries both in its contribution to total primary energy supply (TPES),
and in final consumption. The share of natural gas in the EU energy supply mix,
has grown from 10% of TPES in 1973 to 25% in 2005. In the period between
1990 and 2005 gas use grew by 50%. The United Kingdom, Germany and Italy are the major gas users, and Italy is the most gas dependent major country in the EU in terms of share of TPES (38%). Gas provides some 28% of industrial energy needs EU wide, and more than a third of residential and commercial needs, being especially important in space heating. In the power sector its role has increased sharply from barely 7% of power output in 1990, to more than 20% in 2005. This trend is expected to continue since gas has become the preferred choice for new power plant investment in most EU countries where new nuclear plants are often formally prohibited, and coal plants difficult to develop from an environmental perspective. For example, in Italy gas accounted for 44% of power generation in 2005, and is forecast to grow to over 60% in a couple of years. (IEA, 2008a)

The production of gas within the EU peaked in 1996. Thereafter a production plateau followed and in 2004, production entered a state of decline. (IEA, 2008a) There is little hope of reversing this trend since production by the major producer, the UK, is plummeting by 8-10% per year. The UK and the Netherlands produce 70% of EU gas output, and gas production in the Netherlands peaked three decades ago and have been at a slightly declining plateau level ever since. (BP, 2009) Other less significant producers in the EU are Germany, Romania, Denmark and Italy. The natural gas production from the fifth largest producer in the EU, Denmark, is expected to be in a state of decline by 2010. (DEA, 2007)

An estimation using the maximum scenario value for remaining reserves,
gives an ultimate recoverable resources (URR) figure for the UK, excluding undiscovered reserves, of 3100 bcm. Undiscovered reserves in the UK’s part of the North Sea are likely to be relatively modest, due to the mature status of the region. Since 1995, the UK is the biggest gas producer of the EU. UK gas production peaked in the year 2000 at an annual production of 108 bcm, having produced 50% of the URR. Then followed what can more or less be characterized as a production collapse in 2000-2007 with gas extraction plummeting by 33%. (DECC, 2009) In 2004 the UK became a net importer of gas and in 2008 net imports amounted to 26% of domestic consumption.
(BP, 2008) In Fig. 1.1, historical UK production is showed as well as a forecast (author’s estimations) of future production.

Gas production in the Netherlands, rose steadily to 82 bcm/year in 1976. Since then it has declined on a gentle slope to 64 bcm/year in 2007, a level which can probably be maintained until around 2011 before a terminal decline sets in. In order to make it last as long as possible the Netherlands depleted its gas reserves in a more cautious way than the UK. Gas consumption in 2007 stands at 37 bcm/year, allowing the Netherlands to export 35 bcm, albeit the trend is declining, see Fig. 1.2. (Campbell and Heapes, 2008)
Figure 1.1. Historical as well as projected gas production in the UK. Source: BP (2009) and author’s estimations.

Figure 1.2. Historical and projected gas production in the Netherlands. Source: BP (2009), Campbell and Heapes (2008) and author’s estimations.
1.1.2 Imports to the EU

As pipeline technologies improved with new steel materials and more efficient compressors, longer pipelines became both technically and economically viable. Nonetheless, pipelines impose severe limitations on the natural gas trade. Pipelines are economic for trade over relatively small distances. For distances longer than 3000 – 5000 km (depending on the transport volume) the transport of natural gas in liquefied form (LNG) is generally more economic compared with pipeline transport (depending on the pipeline diameter and pressure). (Remme et al., 2008) As a consequence, markets connected by pipelines are regional in nature. These pipeline links have created two large key markets – North America and Russia-Europe, and many smaller networks in Latin America, South East Asia and the Middle East. (Victor et al., 2006) The gas pipeline network of the EU has been built along four major transit routes: east-west – with imports from Russia, from the north – with gas from Norway, in the center – with Dutch gas supplies, and from the south – with Algerian and Libyan gas.

Denser interconnections and incrementally longer pipelines are continuously expanding the regional pipeline gas markets, but the appearance of a truly global gas business can only take place with a large expansion of the LNG trade, which can enable gas trading over very long distances resulting in converging gas prices for the key regional pipeline markets. (Victor et al., 2006) However, The LNG market has evolved relatively slowly, mainly due to the large capital and production costs associated with LNG facilities. As of today, LNG accounts for about 30% of the international trade in gas (BP, 2009)

In 2006 the EU imported 57% of its total gas consumption. The main import sources are Russia and Norway, from which essentially all gas is imported by pipeline. The third largest exporter to the EU, Algeria, supplies gas by both pipeline and LNG. In 2005, LNG imports supplied about 13% of total gas consumption of the EU. The major LNG suppliers are Algeria, Libya, Qatar, and Nigeria. Fig. 1.3 shows each country’s share of total EU imports. Pipeline import routes to the EU are mainly from Russia directly and via Ukraine and Belarus, from Norway, from Algeria via Morocco and Tunisia, from Libya, and from Iran/Azerbaijan via Turkey. The total annual entry capacity is about 375 bcm. The EU has 14 LNG terminals in operation with a total capacity of around 103 bcm. Gross import capacity is thus almost 480 bcm, with most of the unused capacity on the pipelines from Russia. (IEA, 2008a)

At the end of 2007, there were 24 LNG terminals in operation worldwide with a total nominal capacity of 256 bcm per year, and world LNG production in 2007 grew by 9% to 233 bcm. Based on the nominal liquefaction capacity, global capacity utilization rate for existing LNG plants was 91%. When LNG projects start operations, initial troubles, as well as occasional
shortages of feed gas, often prevent them from producing at design capacity for a prolonged period. Thus, announced production capacity does not automatically mean the facility is in reality producing or capable of producing at planned production levels. World LNG production has increased by around 53% during the last five years, and this rapid expansion phase is expected to continue. An additional 146 bcm/year of capacity is under construction, which will take total capacity to around 400 bcm/year by 2012. Another 417 bcm/year of capacity is in the planning stage, though many of the planned projects have been announced, but not initiated, for several years. (IEA, 2008a, b)

According to the IEA (2008b) beyond 2012, there are uncertainties regarding the availability of incremental LNG supply for both OECD and non-OECD importing countries. Although a significant amount of capacity is planned and proposed, many projects have yet to be formally sanctioned, primarily because of shortage of skilled labor and higher material and engineering costs. These factors afflict many projects that have already been undertaken, discouraging companies from proceeding to final investment decisions (FID) on other projects, leading to some project cancellations. Only one FID was made in LNG production in 2006, three such decisions were made in 2007, and only one in 2008. With the assumption that half of the planned capacity is built, global LNG capacity would reach about 600 bcm by 2030. (IEA, 2008a, b, 2009a) Of total LNG exports in 2007, the EU imported 21%. Assuming that this relative share remains static until 2030, the available LNG supply for Europe would amount to 126 bcm by 2030. (BP, 2008)

The IEA (2008b) expects total natural gas output in the EU to decrease from 216 bcm/year in 2006 to 90 bcm/year in 2030. For the same period, EU demand for natural gas is forecast to increase rapidly. In 2006 demand for natural gas in the EU amounted to 532 bcm/year. By 2030, it is expected to reach 680 bcm/year. As a consequence, the widening gap between EU production and consumption requires a 90% increase of import volumes between 2006 and 2030, see Fig. 1.4.
Figure 1.3. EU gas imports in 2006. Source: IEA (2008a)

Figure 1.4. Forecast from the World Energy Outlook 2008, illustrating the increasing need of imports to the EU in order to meet expected demand. A 90% increase of import volumes between 2006 and 2030 will be required. Imports are divided into imports of LNG and imports of pipeline gas. Regarding LNG it has been assumed that the EU will maintain a static market share (21%), of global LNG supplies. Source: IEA (2008b) and author’s estimations.
1.2 Energy security

The interest in energy security is based on the notion that an uninterrupted supply of energy is critical for the functioning of an economy. (Kruyt et al., 2009) However, the concept of energy security is rather vague, and an exact definition is hard to give. This is partly due to the fact that energy security includes several dimensions, whose relative importance is highly context dependent. For further discussion, see Kruyt et al (2009) and Löschel et al (2009).

In an attempt to clarify the dimensions of energy security, the Asia Pacific Energy Research Centre (APERC) has proposed the following classification scheme, dividing elements relating to energy security into:

1. Availability—or elements relating to geological existence.
2. Accessibility—or geopolitical elements.
3. Affordability—or economical elements.
4. Acceptability—or environmental and societal elements.

(Kruyt et al., 2009)

Although all the above mentioned aspects are to some extent relevant for the gas supply situation of the EU, in this thesis the physical availability aspect is highlighted. As a quantitative measure of physical availability, the IEA (2007) has proposed the share of a country’s total energy supply met through pipe-based gas imports purchased through oil-indexed contracts. The rationale behind this measure is that due to the relative inflexibility of pipelines, physical unavailability concerns are predominantly linked to pipeline based imports. Generally for pipeline imports, the importing country cannot use the same infrastructure to import from other sources, as a pipeline tends to tie a customer to a given supplier. Also, other supplier countries may not be able to increase production to compensate for a supply shortfall in recipient countries, as their export infrastructure may also be operating at maximum capacity.

1.3 Objective: The potential future levels of gas supplies to the EU from Norway and Russia

All of the EU’s gas imports from Russia are by pipeline, as are most of its imports from Norway. In 2007, 52% of total gas demand was met through pipeline imports. (IEA, 2008b; BP 2008) According to the scenario presented in Fig. 4, this figure may increase to 68% by 2030. Such a development is obviously problematic, if the IEA’s measure of physical energy security is applied. Moreover, while the IEA’s measure implicitly assumes that
sudden and temporary supply disruptions are the main threats to physical energy security, there is also the issue of whether there are enough gas resources to supply Europe in the long term. Therefore, when assessing the long term energy security of the EU, an investigation of its suppliers’ gas resources and future production capacities plays an important part. The objective of this thesis is to assess the potential future levels of gas supplies to the EU from its two main suppliers, Norway and Russia.
2 Gas reserves and Production

It is important to define the distinction between reserves and resources. Reserves are those quantities of gas in known fields which are considered to be both technically possible and economically feasible to extract under defined conditions. Resources are the total quantities which are estimated to exist, including both those in known fields which are not considered economically feasible to extract and those in undiscovered fields. Of the total amounts of petroleum in place for a given reservoir only a certain percentage, called the recovery factor, can be recovered. The total petroleum resource estimated to be recoverable from this given reservoir, is the ultimately recoverable resource (URR) for that area. (Thompson et al., 2009)

2.1 Production

Reliable data for natural gas production is difficult to get. In many cases production data does not specify if it is gross production or net production (gross production minus re-injected and flared). There are many possible losses of gas in the supply chain from the well to the end-costumer. As an example, liquefaction of natural gas leads to an average loss of 12% of the originally produced gas. In some cases losses are hidden or not being paid attention to. The sometimes unclear distinction between marketed and dry gas may cause confusion. From the same gas source, the amounts of marketed gas may be larger than dry gas as some liquids may be simultaneously produced. In addition, the heat content of gas varies for different fields and regions. (Laherrère, 2004)

There are in particular ambiguities and lack of transparency concerning Russian gas production. This is partly because of unclear amounts of flared volumes and a Russian practice towards reporting gross production figures, that is, not excluding flared, vented and re-injected volumes. (Paper VI) However, the UK Department of Energy and Climate Change (DECC) and the Norwegian Petroleum Directorate (NPD) have detailed and transparent public production databases. In particular the NPD database has been of great use since it has complete historical production series for each field separating between gross and net production. These are the main reasons why gas production from Norway and the UK has been studied in order to develop and validate the Giant Gas Field-model. For more on this, see Paper V.
2.2 Reserves

Under Society of Petroleum Engineers (SPE) International standards, petroleum reserves are classified as Proved, Probable and Possible, based on both geological and commercial factors. SPE International standards take into account the probability that hydrocarbons are present in a given geological formation as well as the commercial viability of a given deposit pending on economic factors such as exploration and drilling costs, ongoing production costs, transportation costs and the prevailing prices for the hydrocarbons. In addition, the criteria around commerciality also include some evidence of commitment to proceed with development projects within a reasonable time frame, as well as confirmation of a market, production and transport facilities and required lease extensions. (Etherington et al., 2005)

Proved Reserves are those quantities of petroleum, which, if probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Probable Reserves are those additional reserves which are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves, and there should be at least a 50% probability that the actual quantities recovered will equal or exceed the Proved plus Probable (2P) estimate. Possible Reserves are those additional reserves which are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, and there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. (SPE, 2007)

Russia has its own classification system of petroleum resources, focused on the actual physical presence of in-place volumes as well as the probabilities of their presence. The Recoverable Reserves are represented by categories A, B and C1, where A represents Reasonably Assured, B – Identified, C1 – Estimated and C2 – Inferred. The Russian system splits the undiscovered volumes into three categories that can be roughly described as Prospects – D1, Leads – D2 and Plays D3. ABC1 figures should correspond to proved reserves plus some 50% of probable reserves in the SPE system and, in addition, resources not qualifying as economic in the SPE system, although technically feasible to extract. However, there are claims that Russian reserve figures are exaggerated and that in reality ABC1 figures even exceed the corresponding 2P values, and correspond more closely to 3P values (Laherrère, 2004) For more, see Paper VI.

Many forecasters use proven (1P) reserve figures for estimations and forecasts. This is a dubious practice since 1P reserves in general only reflect a fraction of the estimated ultimate recoverable reserves for a field or a region. Hence, results acquired by analysis of 1P reserve figures, in many cases have limited use. Proven plus probable reserve estimates are confidential
in most countries, although there are exceptions, such as the case for the UK and Norway. However, 2P figures for many fields, regions and countries can be acquired from scout companies such as Wood Mackenzie or IHS. (Laherrère, 2004) Although 2P data are not strictly the equivalent of a best estimate of a field’s URR, there are several reasons for the use of 2P figures as an estimate for URR figures for sufficiently explored fields. For strategic planning many companies make a “best estimate” of how much petroleum they believe in time, will be technically feasible and economically viable to recover, and this figure is generally represented by the sum of the proved and probable estimates (2P). (SPE, 2007) For mathematical reasons, when making aggregation of reserve estimates the SPE recommend the use of 2P figures. The use of aggregated 1P figures may yield a very conservative estimate of the total amount of 1P reserves, and the aggregate of 3P figures may produce overly optimistic results. (Thompson et al., 2009)

2.2.1 Global gas reserves

There are great uncertainties regarding the amounts of total global ultimate recoverable resources of gas, as well as present gas reserves. First, the use of reserve definitions varies between countries and organizations, and much of the existing data is not available in the public domain. (Laherrère, 2007). Secondly, the amounts of gas yet-to-be discovered are difficult to estimate, and different approaches exist. (UKERC, 2009) Finally there are unconventional sources of gas, whose future production potential is difficult to assess. (IEA, 2009b)

IEA (2009) reports the global proven natural gas reserves at 182 tcm, referring to Cedigaz, adding that the figure includes unconventional gas (4% of the total). According to BP (2009), the proved global gas reserves stand at 185 tcm, the IHS industry database (2009) reports the global 2P gas reserves at 188 tcm, and Laherrère (2004) has given an estimation at 171 tcm. There is a huge geographical inequality of the distribution of discovered natural gas resources, as illustrated in Table 2.1, where an estimation of the world’s ultimate recoverable gas resources, made by Laherrère (2004), is presented. According to Laherrère, the world’s ultimate recoverable resources of conventional gas are estimated to be 280 tcm, which is the equivalent of 1800 billion barrels of oil equivalents (bboe). This figure is just slightly below the number of 2000 billion barrels (Gb) given by Laherrère (2007) for ultimate recoverable resources of conventional oil reserves (excluding extra heavy oil). Laherrère estimates unconventional gas reserves to 70 tcm. The IHS has a significantly higher figure for global ultimate recoverable conventional gas resources at 428 tcm, thus accepting the higher estimates of reserve growth and undiscovered resources from the United States Geological Survey (USGS). (Laherrère, 2004) The IHS sets remaining recoverable unconven-
tional gas resources at 64 tcm. The IHS estimates of global ultimate recoverable gas resources, are presented in Table 2.2. (Chew and Stark, 2009)

Table 1.1: Discovered reserves, remaining reserves and yet-to-be discovered are presented in the table, along with an estimation of URR. Source: Laherrère (2004).

<table>
<thead>
<tr>
<th>Region</th>
<th>Estimated URR</th>
<th>Discovered</th>
<th>Remaining reserves</th>
<th>Yet-to-be discovered</th>
<th>% of URR produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>Middle East</td>
<td>84</td>
<td>80</td>
<td>74</td>
<td>4</td>
<td>7%</td>
</tr>
<tr>
<td>CIS</td>
<td>56</td>
<td>51</td>
<td>31</td>
<td>5</td>
<td>35%</td>
</tr>
<tr>
<td>U.S.</td>
<td>35</td>
<td>34</td>
<td>7</td>
<td>1</td>
<td>77%</td>
</tr>
<tr>
<td>Asia</td>
<td>32</td>
<td>26</td>
<td>21</td>
<td>6</td>
<td>16%</td>
</tr>
<tr>
<td>Africa</td>
<td>22</td>
<td>17</td>
<td>15</td>
<td>5</td>
<td>13%</td>
</tr>
<tr>
<td>L. America</td>
<td>22</td>
<td>16</td>
<td>12</td>
<td>6</td>
<td>19%</td>
</tr>
<tr>
<td>Europe</td>
<td>22</td>
<td>17</td>
<td>9</td>
<td>5</td>
<td>38%</td>
</tr>
<tr>
<td>Canada</td>
<td>7</td>
<td>6</td>
<td>2</td>
<td>1</td>
<td>62%</td>
</tr>
<tr>
<td>World</td>
<td>281</td>
<td>248</td>
<td>170</td>
<td>34</td>
<td>28%</td>
</tr>
<tr>
<td>Of which OPEC</td>
<td>101</td>
<td>98</td>
<td>87</td>
<td>3</td>
<td>11%</td>
</tr>
</tbody>
</table>

Table 2.2: Cumulative production, discovered reserves, remaining reserves, resource growth, yet-to-be discovered and estimated remaining recoverable unconventional resources are presented in the table. Two estimations of the global URR figure are given one with conventional gas and one with unconventional gas included. The share of cumulative production is given in the right column. (1 tcm=1000 bcm) Source: Chew and Stark (2009)

<table>
<thead>
<tr>
<th>(31/12) 2007</th>
<th>tcm</th>
<th>% Produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative production</td>
<td>88</td>
<td></td>
</tr>
<tr>
<td>Discovered</td>
<td>276</td>
<td>32%</td>
</tr>
<tr>
<td>Remaining reserves</td>
<td>188</td>
<td></td>
</tr>
<tr>
<td>Resource growth</td>
<td>24</td>
<td></td>
</tr>
<tr>
<td>Yet-to-be discovered</td>
<td>129</td>
<td></td>
</tr>
<tr>
<td>Unconventional</td>
<td>64</td>
<td></td>
</tr>
<tr>
<td>URR Conventional</td>
<td>428</td>
<td>20%</td>
</tr>
<tr>
<td>URR Total</td>
<td>492</td>
<td>18%</td>
</tr>
</tbody>
</table>

Per unit of energy generated, the transportation of gas, whether by pipeline or in the form of liquefied natural gas (LNG), is significantly more expensive than transporting oil, and transport usually represents the largest share of the total cost of gas supply. In recent years rampant cost inflation has reinforced this situation. Much of the world’s gas resources are located far from the main markets, and the exploitation of these resources is very dependent on the cost of production as well as the sales price of gas. Gas that is currently not developed due to lack of economic profitability is referred to as stranded gas. Consequently, it is uncertain whether the infrastructure needed to develop large parts of discovered resources and transport the gas to the main centers of demand can be built due to economic, geopolitical and tech-
nical barriers. These uncertainties are often referred to as above ground risks. (IEA, 2008b; Jahn et al., 2007)

2.2.2 Gas reserves in giant fields

The importance of giant oil fields in estimating future global, as well as regional levels of oil supply, has been described in several works. (Horn, 2007; Robelius, 2007; Sandrea, 2009; Simmons, 2002). Globally, more than 40,000 oil fields have been discovered. However, about 40% of the estimated global recoverable resources are contained in only 555 giant oil fields. (Horn, 2007) As with oil, the distribution of the global gas reserves is characterized by a high concentration of discovered recoverable gas resources in a relatively small number of giant gas fields. A giant gas field is defined as a gas field that is able to produce ultimately more than 3000 billion cubic feet (3 tcf), the equivalent of 84 bcm, which corresponds to 500 million barrels of oil equivalents (Mboe). (Halbouty, 2001)

The statistics for discovered gas fields are not as transparent as for oil. Data is commonly unclear partly because gas comes from multiple sources, such as fields with nonassociated gas only, fields with both nonassociated gas reservoirs and oil reservoirs with associated gas, oil fields with associated gas, coalbed methane gas and shale gas. With the exception of the US, most gas production and reserves statistics do not differentiate source details. (Sandrea, 2009)

Estimates of the global number of nonassociated gas fields are in the range of 28,000, of these about 365 are giant fields. (Sandrea, 2009) Horn (2007) reports a slightly higher figure of 383 giant gas fields. However, regarding the giant gas fields’ share of the total discovered ultimate recoverable gas, their estimations differ. According to Sandrea (2009), giant gas fields account for 75%, while Horn (2007) reports a 44% share. According to Horn (2007), the total figure of discovered recoverable gas resources in giant gas fields amounts to 174 tcm. Fig. 2.1 shows the total amount of discovered gas in giant gas fields per decade, as well as the total number of giant gas field discoveries per decade. Giant gas discoveries accelerated in the 1960s and peaked in the 1970s, partly owing to the discovery of the world’s biggest gas field, the super giant North Field, on the border between Qatar and Iran. After the 1970s there has been a downward trend of smaller amounts of discovered volumes, and the average size of discovered gas volumes have been declining as well, see Fig. 2.2.
Figure 2.1: Amounts of discovered gas per decade in giant gas fields, as well as the number of giant gas fields discovered. Source: Horn (2007).

Figure 2.2: Average size per decade for discovered giant gas fields. Source: Horn (2007)
3 Forecasting methods

The oil crisis of 1973-1974 generated a large interest in the field of energy modeling and forecasting. This development can be seen as a part of a larger trend towards increased use of modeling and forecasting for planning and decision making. (Baumgarten and Midttun, 1987) In addition, discussions about resource scarcity were common within the field of energy research, for examples see Wilson (1977), Heal (1974) and Meadows et al (1977). However, the idea that economic and humanitarian progress is defined by the limits of natural resources, has been assumed by several early scholars, perhaps most famously by Malthus (2004) and Jevons (1866). The concern about the depletion of fossil fuels can be said to begin with the British economist W.S. Jevons’ essay The Coal Question, first published in 1865. The main point of the essay was that the exponential increase in Britain’s coal consumption was bound to hit a resource constraint at some point, and Jevons doubted that there would be any other energy source taking the place of coal once production declined. (Jevons, 1866) In this regard, he turned out to be wrong, although Britain’s coal production did peak in 1913. However, Jevon’s forecast became obsolete by the introduction of new energy sources.

In recent years the Hubbert curve, a resource-constrained model for forecasting of the global oil production, has received much attention see Campbell & Laherrère (1998) and Edwards (1977). The Hubbert curve was developed by the American geologist M.K. Hubbert and presented in 1956. (Hubbert, 1956) Hubbert projected the future United States oil production based on two estimates of the total amount of oil that would be produced in the United States, and he arrived at two predicted dates for peak production, one in the mid-1960s, the other around 1970. As it turned out, U.S oil production peaked in 1970. It may appear that the peak of U.S. oil production in 1970 vindicates the Hubbert-curve, and it has become perhaps the most well-known tool for the modeling of depletion of finite natural resources.

3.1 Hubbert Modeling

Besides the bell shaped production curve, Hubbert added other elements to his analysis, and modern Hubbert modeling is a constellation of techniques. There are three core methods of modern Hubbert analysis. The first step is an analysis of past discoveries. Discovery data are plotted. Reserve growth
in an existing field is backdated to the date of discovery, and a best fitting curve (typically logistic) is matched to discoveries. (Brandt, 2007)

Secondly, future hydrocarbon discoveries are estimated. Total amounts of hydrocarbons to be found are extrapolated in a number of ways. These methods include the creaming curve-method, which estimates an asymptote for total discoveries when plotting cumulative discoveries by cumulative new field wildcat wells drilled (Campbell and Laherrère, 1998). A newer technique, sometimes called Hubbert linearization, is advocated by Deffeyes (2001) There is also a method using a statistical relationship such as the parabolic fractal law to infer the size of undiscovered fields using the distribution of already-discovered field sizes, see Laherrère (2000).

Finally a projection of future production is performed. The production from the discovered and estimated yet to be discovered hydrocarbon volumes, is modeled as a typically logistic or Gaussian curve, and fitted to historical production data such that the area under the production curve equals the sum of discovered and not yet discovered hydrocarbon volumes.

Hubbert assumed a logistic model to forecast cumulative discoveries and production. The Hubbert curve is a bell shaped function given by the differential equation:

\[
\frac{dQ}{dt} = bQ \left(1 - \frac{Q}{URR}\right) \quad (1)
\]

When modeling production, URR is the ultimate recoverable resources, Q denotes the cumulative production and dQ/dt is the rate of production. Equation (1) describes discoveries or production over time. Since this curve is symmetrical, the peak rate of extraction occurs when exactly half of the resource is depleted. The logistic curve has been frequently used to model population growth and other natural growth phenomena. But there is no theoretical justification for its application to resource extraction. The Hubbert curve is not explanatory, in the sense that it derives a macro pattern from micro assumptions. It could, however, be justified on purely empirical grounds as a descriptive model. The Hubbert curve is illustrated in Fig. 3.1.
Figure 3.1: Hubbert’s theoretical bell shaped curve over resource extraction. Two curves are depicted in order to illustrate the effects of varying b-values. The URR figures are the same for both curves.

3.2 Critique of the Hubbert curve

As has been argued that there is no theoretical basis for the assumption of a Hubbert curve. The historical production does not necessarily determine the future production as the Hubbert model implies. The Hubbert model does not take into account the incentives of the oil producer as well as the geological characteristics of individual fields. Production at a given oil field is determined at least in part by the decisions of the producers. These producers, across regions, nations, and even at a global level, respond to common incentives. Both long and short-term trends may simultaneously influence producers across the globe. At a regional level, common incentives include local transport costs, availability of nearby markets, status of infrastructure, tax regimes and other regulatory pressures. National politics can force production up or down, particularly in nations with central control over production. A systematic comparison by Brandt (2007) has shown that the Hubbert model is rather mediocre in describing historical production data compared to other simple growth-decline models.

The Hubbert curve is built on a mathematical function with no reference to influencing variables such as resource price or extraction cost. On this
ground it has been criticized by economists in particular, sometimes fiercely, see Lynch (2003) and Watkins (2006). Even the application of resource constrained models are still surrounded by controversy. Adelman (1990) has questioned Hubbert’s fundamental assumption by stating that the amount of mineral in the earth is an irrelevant non-binding constraint to production. Another example from Adelman (1993); “Minerals are inexhaustible and will never be depleted. A stream of investment creates additions to proved reserves from a very large in-ground inventory. The reserves are constantly being renewed as they are extracted [...]”

However, the main weaknesses of the critics of the Hubbert model are their inability to present a useful forecasting alternative. Constructing a formal model for petroleum forecasts that includes economic variables is notoriously difficult. For example Lynch (2003) and Simon (1996) suggest that it is necessary to resort to simple extrapolation as a forecasting method, see Paper I. However, if any oil and gas production model should be useful, it must incorporate the fact that fossil fuels are finite resources. The Hubbert model is one of few tools available for forecasting of finite fossil fuels. Although it may be too simple to accurately predict for example the exact year of peak oil etc, it has the potential to distinguish between reasonable and unreasonable scenarios. From a long-term policy planning perspective, this should still be valuable information.

### 3.3 Maximum depletion rate model

The Hubbert-model may be viewed upon as a sort of “rule of thumb”. There are only two parameters that may be adjusted, the URR figure and the production growth rate \( b \), see Fig. 3.1. The Maximum Depletion Rate Model (MDR-model), described in Paper I, is a resource-constrained production model which does not assume that production growth and decline is symmetrical, or that the production peak occurs at the depletion mid-point. The main idea with the MDR-model is the assumption that there is a limit to the rate at which the remaining resource can be extracted. In the MDR-model there are three parameters, growth rate, decline rate and the URR figure.

The depletion rate of remaining reserves, \( d_\delta \), denotes the relation between the annual production and the reserves at the beginning of the year in question. The R/P-ratio is the inverse of the depletion rate of remaining reserves, \( d_\delta \). (Paper I) A central assumption of the MDR-model is the existence of a maximum depletion rate of remaining reserves (minimum R/P ratio) which constrains production in relation to the available resource base. In other words, only a certain fraction of the remaining resource can be produced during one year.
The implementation of the MDR-model consists of four steps and involves three initial parameters:

- Define a resource base, fixed or non-fixed.
- Assume a maximum $d_\delta$-value. (the equivalent of a minimum $R/P$ value)
- Assume a default production curve until the maximum $d_\delta$-value ($R/P_{\text{min}}$) is reached.
- For each year: (1) compute the remaining resource base; (2) compute the $d_\delta$ resulting from the default production curve; (3) if the resulting $d_\delta$ is higher than the maximum $d_\delta$-value, then let the production rate be determined by the maximum $d_\delta$-value.

Fig. 3.2 illustrates the resulting forecasts of two hypothetical applications of the MDR-model using a fixed resource base. As is evident in the graphs, the MDR-model divides the production into two distinct phases: one “demand constrained” and one “geology constrained”. The production is not geologically constrained as long as $d_\delta$ is smaller than the assumed maximum $d_\delta$. Therefore, it can actually be quite arbitrarily defined. The two simplest options are either, after the initial build-up phase, to keep it at a constant plateau level (typical of many individual fields, where the plateau is determined by the technical capacity), or to let it grow at a constant rate (suitable for regions). The peak/end-of-plateau point marks the phase shift. This is of course a considerable simplification of reality. Both demand and geological constrains are more or less present throughout. The MDR-model gives precedence to the dominant constraint during the growth and decline phases, respectively. (Paper I)
Figure 3.2: Two hypothetical applications of the MDR-model. (a) illustrates a typical field model, where the production goes through a build-up and plateau phase until the 10% maximum d₄₀-value is reached, and (b) illustrates a typical region where production is assumed to grow by 5% annually until the 3% maximum d₅₀-value is reached.
Brandt (2007) used production data from 139 oil-producing regions of various sizes, from US state level to continents, in order to test the goodness-of-fit of three simple growth/decline models: Hubbert, linear and exponential. Brandt also allowed for asymmetrical growth/decline patterns. In 74 of the 139 regions, both a growth and decline rate could be estimated. Brandt’s results were that asymmetrical models generally had a better fit than symmetrical ones, even when adjusting for the increased complexity. The Hubbert model (symmetrical or asymmetrical) had the best fit in 19 of the 74 cases, the linear model in 16 cases, and the exponential model in 32 cases. In 7 cases there was no clear best-fitting model. Brandt showed that regions generally have a slower decline rate than growth rate, and he found no evidence that the Hubbert model would fit better to larger regions than smaller ones. The exponential growth/decline model was the single best-fitting of the models tested. (Paper I)

3.4 Field-by-Field Modeling

Hubbert modeling does not take into consideration all available data, since it only utilizes a URR figure and a best fit to existing production data by adjusting the b-parameter. Since such a large portion of the global recoverable gas and oil resources are contained in a relatively small number of giant fields, individual modeling of the giant fields will include more of the data available, such as individual field production profiles, current production status as well as announced development plans for a field. These additional data should enhance the predictive potential for gas and oil production forecasts at regional as well as global levels.

3.4.1 Definitions

The production for year \( t \) is denoted \( q_t \), and \( Q_t \) is the cumulative production at the end of year \( t \). \( R_0 \) is the estimated URR figure, and the reserves that remain to be produced at the beginning of year \( t \), are defined as \( R_t \). Production of a finite resource always results in depletion. We define the level of depletion \( D \) as:

\[
D_t = \frac{Q_t}{R_0} \tag{2}
\]

The depletion rate of initial reserves (\( d \)) denotes the relation between the annual production and the reserves originally present in the field, \( R_0 \). \( d \) is defined as the annual increase in depletion level:

\[
d_t = \frac{q_t}{R_0} \tag{3}
\]
The depletion rate of remaining reserves \( d_{\delta, t} \), denotes the relation between the annual production and the reserves at the beginning of the year in question, defined as:

\[
d_{\delta, t} = \frac{q_t}{R_t}
\]

(4)

The decline rate \( \lambda \), denotes year-over-year change in production, and is defined as:

\[
\lambda_t = \frac{(q_t - q_{t-1})}{q_{t-1}}
\]

(5)

For more on this, see Paper VI.

3.4.2 The Giant Gas Field Model

When developing a gas field a primary criterion is often to ensure a long sustainable plateau, in order to get the highest rate of return on capital invested. In addition, a long plateau production is often desirable since the customers usually require a stable supply at an agreed rate over several years (Jahn et al., 1998). Every gas field has a unique production profile, although its frames are set by the characteristics of the reservoir, technical development plans, availability of sufficient funding, management of the production and market conditions for the sale of produced gas. A standard gas field goes through a build-up phase, during which production rises as new wells are put into production. The build-up phase is followed by a plateau phase for larger gas fields, when the rate of production is roughly flat, as new wells are brought on stream, offsetting declining production from older wells. The same stabilizing effect is achieved by the installation and use of field compressors. Finally, a decline phase begins when the gas field’s rate of production falls continuously until the field is de-commissioned and abandoned. In order to model the production from giant and semi-giant gas fields, the giant gas field production model (GGF-model) has been developed, see Paper V.

The Build-up phase (AB), see Fig. 3.3, is modeled as a linear increasing production curve from start-of-production \( q_A \) – until the planned plateau production level \( q_B \) is reached. The cumulative production from A to B is called \( Q_{AB} \). The plateau production is modeled as a period of flat production, until the end of the plateau phase at year C-1, is reached. The decline phase is modeled with an exponential decline curve. The decline phase is set to start if the cumulative production until the onset of the Decline phase \( (Q_{AB} + Q_{BC}) \) plus the cumulative production during Decline phase, \( Q_{CD} \), is equal to the URR figure of the field. If these criteria are fulfilled, the production should be in decline with a decline rate \( \lambda \), which will be the same as \( d_{\delta} \) at the
time for the onset of the decline. When a field is already in its decline phase, as standard procedure, the $\lambda$-value is set as the $d_\delta$-value for the field. For more on this, see Paper V.

**Figure 3.3:** Schematic illustration of the production profile of a giant gas field. Discovery is time=0, followed by the chronological points in time A, B, C, and D.

Observed decline rates and depletion rates for giant gas fields are correlated to the size of the field, and the depletion rates tend to be higher for smaller gas fields (See Paper V and Paper VI). Depletion rates for production of associated gas have, in general, the tendency to be lower on average compared to similar-sized non-associated gas fields. (Paper V) An important component of the GGF-model is to include a parameter for plateau production based upon depletion rate. The GGF-model uses the $d$-value to estimate planned plateau production levels. An analysis of $d$-values, can also be a useful tool when one has to decide if a field, already at what seems to be a production plateau, will remain at approximately the same production level as it currently produces. This procedure is used if there is a lack of official statements of planned future production levels. For more on this, see Paper V and Paper VI.

### 3.4.3 The giant gas field model applied on aggregate of fields

The GGF-model can also be used to make forecasts for aggregates of fields constituting the gas production of a region or a significant share of a region’s production. The model is then used in a similar manner as with single giant gas fields. The GGF-model applied on an aggregate of fields consists of a build-up phase and a plateau phase, followed by an exponential decline.
phase. The main parameters are the same for the GGF-model, when used on an aggregate of fields, as for the GGF-model used on single fields. (Paper V)

The reasons why the GGF-model can be applied to aggregates of fields and regions are based on theoretical assumptions as well as observed data. The theoretical assumption is that infrastructure for a region or country is generally designed for a certain maximum production volume, and it would be uneconomical to invest in an infrastructure with excess spare capacity for longer periods of time. Consequently, investments in infrastructure tend to be designed for a period of plateau production at near maximum volumes. The observed production behavior is exemplified in Paper V, with the historical production profiles for France and the Netherlands.

The estimation of parameters becomes much more uncertain for aggregates of fields constituting regions, than for individual fields. This is because the URR figures tend to be more uncertain for countries and regions, than for single fields. The depletion rate for an aggregate of fields must lie between the smallest and largest depletion rate among the single fields. With growing time-lag between when fields go into production, the depletion rate becomes increasingly lower than the average depletion rate among the fields that constitute the region. For more on this, see Paper V.

3.5 Data sources

For Paper III, reserve and production data for individual oil sands projects have been collected mainly from oil companies and oil and gas industry journals. Governmental data and various sector reports have also been valuable sources. For Paper V, reserve and production data for the Norwegian and UK giant natural gas fields have mainly been gathered from the Norwegian Petroleum Directorate and from the UK Department of Energy and Climate Change. Future production plans for individual fields have been found in various oil industry news media as well as from the companies involved in developing the fields, such as StatoilHydro, etc. For Paper VI, field specific data on giant gas fields has been gathered from a variety of sources such as scientific literature, governmental reports, geological reports, peer-reviewed articles, oil and gas industry journals, bond loans prospectus for the financial markets, Gazprom and its development partners, independent gas producers and international oil companies. Although reducing the risks of using non-accurate or old figures, it naturally causes traditional problems of data inconsistencies. Most data from sources like AAPG, EIA, Gazprom, independent gas producers and international oil companies are generally deemed to be of high credibility. When evaluating what data to use, on those occasions when these sources give significantly different values, one must ultimately use personal judgment.
4 Results

In Paper I the MDR-model is explained and validated. In Paper II the MDR-model is used to model various fractions of the future global oil supply. In Paper III the concept of field-by-field modeling is described. In Paper IV a field-by-field analysis of existing Danish oil and gas fields is used to determine Denmark’s future production potential. In Paper V the GGF-model is explained and validated. A forecast for total Norwegian gas production is given by utilizing the GGF-model for existing individual fields, aggregate of fields, contingent resources and undiscovered resources. Depletion rate of initial reserves is used when modeling production from contingent resources and undiscovered resources. In Paper VI the GGF-model is applied on existing Russian gas fields, and a production forecast is presented. Depletion rate of initial reserves is used to estimate plateau production for a number of individual gas fields. In Paper V and VI the potential future levels of gas supplies from Norway and Russia to the EU are assessed, and their implications for European energy security are discussed.

4.1 Applying the Maximum depletion rate model
   (Paper I-II):

4.1.1 Paper I

According to the long-term scenarios of the International Energy Agency (IEA) and the U.S. Energy Information Administration (EIA), conventional oil production is expected to grow until at least 2030. The EIA has published results from a resource-constrained production model which ostensibly supports such a scenario. In Paper I the model is described and analyzed in detail, and it is shown that the model, although sound in principle, has been misapplied due to a confusion of resource categories. A correction of this methodological error reveals that EIA’s scenario requires rather extreme and implausible assumptions regarding future global decline rates. This result puts in to question the basis for the conclusion that global “peak oil” would not occur before 2030.

The model applied by the EIA, henceforth referred to as the Maximum Depletion Rate-model (MDR-model), has been found to be very useful when implemented correctly, especially for field-by-field modeling. The results
indicate that resource-constrained models are presently the only feasible tools for long-term oil production scenarios. The MDR-model is shown to be consistent with empirical experience at the field level, and to be at least as good as other resource-constrained models at a regional level. It is therefore reasonable to use it for global scenarios. When applying the MDR-model, the best way to account for uncertainty is to use a range of values for all relevant parameters.

Further, the results indicate that EIA has constructed unreasonable world scenarios for global crude oil production by making an invalid analogy between depletion rate based on “proved reserves” and depletion rate based on estimated URR figures. A correct implementation of the model shows that global crude oil production may start to decline well before 2030, and an imminent peak cannot be ruled out. The result puts into question the extent to which the EIA’s and IEA’s official production forecasts are reasonable since these assume that oil production will grow by 1% annually at least until 2030.

4.1.2 Paper II
The assessment of future global oil production presented in the IEA’s World Energy Outlook 2008 (WEO 2008) is divided into 6 fractions; four relate to crude oil, one to non-conventional oil, and the final fraction is natural-gas-liquids (NGL):

1. Crude oil – currently producing fields.
2. Crude oil – fields yet-to-be developed (“fallow fields”).
3. Crude oil – fields yet-to-be found.
4. Crude oil – additional EOR (enhanced oil recovery).
5. Non-conventional oil.

In Paper II the six fractions of the IEA reference liquid fuels forecast have been individually analyzed in an effort to verify (and if necessary, challenge) important aspects of WEO 2008 report. In determining whether or not the WEO 2008 reference scenario for new field developments, as well as fields-yet-to-be found, are realistic, depletion rate analysis has been utilized. Only certain depletion rates are reasonable for real production, and the approach is to compare the depletion rate behavior in the IEA outlooks with historical experiences, and see if they agree with realistic values.

The depletion rate analyses show that production from the fractions fields yet-to-be developed and fields yet-to-be found is based on unrealistically high depletion rates never before seen in history. The 75 Mb/d of crude oil production forecast for year 2030 appears significantly exaggerated, and is more likely to be in the region of 55 Mb/d. Moreover, examination of the
other fractions strongly suggests lower than expected production levels. In total, the results of this paper point to a world oil supply in 2030 of 75 Mb/d, some 26 Mb/d lower than the IEA predicts.

4.2 Applying field-by-field modeling (Paper III-IV)

4.2.1 Paper III: A crash programme scenario for the Canadian oil sands industry

Oil sands, also known as tar sands, are a type of heavy oil deposit. The sands are mixtures of sand or clay, water, and a dense and viscous form of heavy oil called bitumen. Since bitumen is deficient in hydrogen it must be upgraded into higher quality synthetic crude oil (SCO) to make it an acceptable feedstock for conventional refineries. The objective of Paper III is to present a 12-year short-term oil sands production forecast, as well as an extended long-term forecast. The short-term forecast covers the 12-year period 2006–2018, and the long-term covers the period 2006–2050.

The oil sands of Canada are extracted in two ways: open cast mining and in situ thermal extraction through wells. In situ methods have to be applied to extract bitumen from deposits too deep for surface mining. They rely on reducing the viscosity of the bitumen with the help of solvents, steam or underground combustion. Steam injection is the most widely used method. The Short-term Production Forecast is performed by a project-by-project investigation of 26 major oil sands projects’ reserves and the projects’ planned production levels. It has been assumed that all major proposed oil sands projects are carried out and developed on schedule. It has also been assumed that supply growth is unconstrained by pipeline capacity, availability of investment capital, increasing natural gas prices, CO2E emissions and environmental issues such as ground and water pollution. If natural gas were to become too expensive it is assumed that large-scale residue burning for fuel will be possible with no regard being paid to accelerating CO2E emissions. The oil sand industry’s need for energy and hydrogen is mainly supplied by natural gas. The demand of natural gas for the Short-term Crash programme is studied in order to illustrate the potential problems of energy supplies to a scaled up oil sands industry. In addition, the potential greenhouse gas (GHG) emissions problems associated with the implementation of a crash programme are also covered.

The production from the studied oil sands projects are presented in the Short-term Crash programme forecasts. Fig. 4.1 illustrates the mining forecast and Fig. 4.2 the in situ forecast. The short-term crash programme starting at 2006, by 2018 achieves a production of 3.6 mb/d of bitumen, of which 2.9 mb/d is SCO. Of the total production of 3.6 mb/d, upgraded bitumen from mining accounts for 2.3 mb/d, upgraded in situ production for 0.61
mb/d and nonupgraded in situ produced bitumen for 0.73 mb/d. The forecasts would result in a natural gas use of about 3.1–3.2 Bcf/day by 2018, which means more than four times more natural gas use than the level of 2004. This will occur in the same period of time as the US continues to import a considerable part of Canadian natural gas production. Canada is also itself dependent on natural gas for a significant part of its electricity generation.

The estimated future export to the US, as well as Canadian natural gas demand for electricity have been studied and are illustrated in Fig. 4.3 together

*Figure 4.1:* Crash programme forecast, mining.

*Figure 4.2:* Crash programme forecast, in situ.

40
with the forecasted Canadian Natural Gas Production and the demand from the oil sands industry. The future available gas for other consumption is also shown.

![Figure 4.3. Available Canadian natural gas for other consumption. The curve named for other consumption illustrates a probable future increasing scarcity of natural gas for other consumption in Canada.](image)

The crash programme will consume more than 12 TcF of natural gas between 2006 and 2018. Canada’s remaining natural gas reserves amount to 54 TcF and its discovered reserves to 36 TcF. Thus by 2018 all proven reserves would have been produced and in addition 24% of all additional discovered natural gas resources. It is possible to use bitumen as fuel and for upgrading. However, a full conversion to burning residue for fuel and upgrading seems to be impossible to combine with the fulfillment of the obligations under the Kyoto Agreement.

A Long-term Crash Programme Production Forecast, 2006–2050, of the Canadian oil sands industry has been performed, and is presented in Fig. 4.4. The mining production forecast results in a mining production of the whole established mineable reserve of bitumen. The great uncertainty associated with forecasting the long-term effects of a crash programme for the Canadian oil sands industry is the potential of in situ oil sands production. The long-term future is in this form of production, since more than 80% of the remaining established oil sands reserves are only extractable by in situ methods. The Long-term Crash Programme Production Forecast would give a total oil sands production of approximately 5 mb/d by 2030, and 5–10 years later even slightly higher at almost 6 mb/d of oil sands production by 2035–2040 followed by a slow decline.
Figure 4.4: Long-term Oil Sands Crash Programme Production Forecast. The Long-term Oil Sands Crash Programme scenario consists of the Long-term In situ Crash Programme Production Forecast and the Long-term Crash Programme Mining Forecast. Together they result in a production of approximately 5 mb/d by 2030.

Most likely the Canadians will have to construct nuclear plants to provide energy for a more durable long-term crash programme with a large share of in situ production. Nuclear power is an energy source largely free from GHG emissions, which would allow the oil sands industry to accelerate production without making it impossible for Canada to meet its commitments to the Kyoto Agreement. But constructing nuclear power plants is a complicated matter, and the development of this energy source has obvious social and economic constraints.

Paper III illustrates the benefits of field-by-field (project-by-project) modeling. 26 identified oil sands projects have been modeled, thus increasing the transparency of the forecasting method as well as striving for achieving higher accuracy and credibility. Paper III illustrates the great difficulties of rapidly expanding the oil sands industry of Canada in any practical way. Either CO2E emissions must be neglected or a lower production pace than expected is achieved. In addition there are other serious environmental problems, primarily associated with oil sands mining, such as land destruction, ground water drainage and large lakes filled with oil sands by-products. While the theoretical future oil supply from the oil sands is huge, the potential ability for the Canadian oil sands industry to meet expectations of bridging a future oil supply gap is not based on reality. Even if a Canadian crash programme were immediately implemented it would only barely offset the combined declining conventional crude oil production in Canada and the North Sea. The more long-term oil sands production scenario does not even manage to compensate for this decline by 2030.
4.2.2 Paper IV: Future Danish oil and gas export

In this paper a field-by-field analysis of existing oil and gas fields is used to determine Denmark’s future production potential. The production contribution from new field developments is also estimated as well as from undiscovered oil and gas deposits. The overall aim is to analyze the production behavior of Danish oil and gas fields. From this, possible future production profiles are created, where historical experience is applied to future developments. The Danish Energy Agency (DEA) makes forecasts for future Danish oil and gas production. A thorough examination of their data and establishment of an independent forecast for comparative purposes could prove beneficial for both planners and policy makers. Consequently, this study also aims to perform an independent review of the DEA forecast to determine if they have arrived at a reasonable estimate range or not.

All gas fields are separately analyzed, and official production data from the DEA is used. A forecast for total Danish gas production has been performed using the GGF-model described in Paper V. The GGF-model has been used to model production from the single giant field Tyra, as well as four semi-giant fields and one smaller field. Smaller fields, possible and undiscovered resources are modeled together as one entity.

The Tyra field, with an estimated URR figure of 78 bcm, is the only Danish gas field that can be classified as a gas giant, and it accounts for about 57% of the URR of discovered gas. An outlook for future Danish gas production can be seen in Fig. 4.5, and the forecasted production is similar to estimates from the DEA. The paper shows that by 2030 Denmark will no longer be an oil or gas exporter.
4.3 Paper V: European energy security: The future of Norwegian natural gas production

4.3.1 Paper V: Scope and methods

The EU is expected to meet its future growing demand for natural gas by increased imports. In 2006, Norway had a 21% share of EU gas imports. The Norwegian government has communicated that Norwegian gas production will increase by 25–40% from today’s level of about 99 bcm/year. The ambition with Paper V is to present forecasts for total Norwegian natural gas production as well as for the amounts of gas delivered to the European markets by pipeline.

The scenarios for the future natural gas production potential for Norway have been modeled utilizing a bottom-up approach, building field-by-field, and then adding production from contingent resources and finally undiscovered resources. Individual modeling has been made for 24 giant and semi-giant Norwegian fields. In order to forecast the production profile for an individual giant natural gas field the Giant Gas Field Model (GGF-model)
has been developed. Production from associated gas has been modeled by the same GGF-model as non-associated gas. The GGF-model has also been used to model the production from an aggregate of fields, such as production from small fields, contingent resources and undiscovered resources. The values for the parameter $\lambda$, used to model production for individual gas fields, have been determined by studying the historical production for six giant fields in Norway and the UK. By looking at historical production series for nine European countries, values for the parameters $d_{ag}$, as well as for $\lambda$, have been assumed. These values have been used to model production from contingent resources and undiscovered resources.

Norwegian gas production has been divided into the three regions; the North Sea, the Norwegian Sea and the Barents Sea, and each region has been studied separately. The production has been separated into four sub-groups based on the resource classes, forming the basic building blocks for the creation of forecasts: (1) Recoverable reserves in giant and semi-giant fields. (2) Recoverable Reserves in small fields. (3) Contingent resources. (4) Undiscovered resources. Finally, a high and a low production forecast for Norwegian gas production is presented, as well as a forecast for gas delivered to the EU markets by pipeline. The pipeline exports forecast is derived by excluding production from the Snøhvit field and all other production from the Barents Sea, since gas from this region will be marketed as LNG.

### 4.3.2 Paper V: Main findings

The initially present recoverable gas resources in Norwegian fields, up to the end of 2007, are 3544 bcm. Nearly 80% of these reserves are concentrated in only ten giant gas fields, and the 24 modeled gas fields contain 92%. In 2008, 18 giant and semi-giant fields accounted for more than 90% of Norwegian gas production.

All major Norwegian giant gas fields have been put into production and, with the exception of Ormen Lange and Snøhvit they have already reached their planned production level. Only a 20–25% growth of Norwegian gas production is possible due to production from currently existing recoverable reserves and contingent resources. The high production scenario requires that another 1875 bcm of gas are to be discovered, which is more gas than the current remaining recoverable reserves in the Norwegian North Sea. However, no giant gas fields have been discovered in Norway during the last 10 years, thus the discovery rate must improve significantly.

Total Norwegian gas production peaks between 2015 and 2020, with peak production at 124–135 bcm/year. By 2030 the production is 96–115 bcm/year, see Fig. 4.6. Norwegian gas production exported by pipeline peaks between 2015 and 2016, with minimum peak production in 2015 at 118 bcm/year and maximum peak production at 127 bcm/year in 2016. By 2030 the pipeline export levels are 94–78 bcm, see Fig. 4.7.
Figure 4.6: The fast development forecast with figures from the NPD for undiscovered resources (high Case) and the slow development forecast, with a lower estimation (Low Case) for undiscovered resources. The Barents Sea is included with High Case (NPD) figures for undiscovered resources and contingent resources. The two forecasts enclose a range in which future Norwegian gas production can be expected to materialize with peak production occurring in 2015–2020 at 124–135 bcm/year. These two forecasts are compared with the high 140 bcm and the low 125 bcm target forecast from the NPD.
Figure 4.7: Fast development High Case resources forecast and the slow development Low Case resources production forecast for Norwegian natural gas exports by pipeline. Historic as well as future production from the Barents Sea is excluded. The two forecasts enclose a range in which future Norwegian gas production exported by pipeline can be expected to materialize, with peak production occurring at 118 bcm in 2015 for the slow development Low Case resources pipeline export forecast, and at 128 bcm in 2016, for the fast development High Case resources pipeline export forecast.

4.3.3 Paper V: Discussion

The results show that there is a limited potential for increased gas exports from Norway to the EU and that Norwegian gas production is declining by 2030 in all scenarios. Norwegian pipeline gas exports to the EU may, by 2030, even be 20 bcm/year lower than today’s level. At the same time, according to forecasts from the IEA, the total gas imports to the EU must increase by almost 90% by 2030. Diminishing import volumes from Norway will have negative consequences for the energy security of the EU, as it will increase the relative dependence on the other major suppliers of gas to Europe.

4.4.1 Paper VI: Scope and methods

In 2006, Russia supplied 41% of EU gas imports. The current and potentially increasing European dependency on Russian gas has spurred an intense debate on the subject of the energy security of the EU. Two major worries concerning the European dependence on Russian gas supplies have been frequently voiced. First, a fear has emerged among many Western policy analysts and commentators that gas might be used by the Russian elite as an “energy weapon” in the international geopolitical game. Secondly, worries of insufficient Russian gas supplies, primarily due to lack of investments in the upstream sector and inefficient domestic use of gas, have been expressed.

The objective of this paper is to present forecasts of total Russian gas production based upon gas reserves in existing giant fields. In addition the potential of increased future gas supplies to the European markets and to the markets of the former Soviet Union countries, the Commonwealth of Independent States, (CIS) is investigated.

The Russian reserves classification system is described, followed by a description of Russia’s gas reserves and production, including the main gas producers. The data and information used for the creation of the forecasts are discussed since there are some ambiguities and lack of transparency concerning Russian gas production data, partly because of unclear amounts of flared volumes and a Russian practice towards reporting gross production figures, that is, not excluding flared, vented and re-injected volumes. Then Russian gas exports and domestic sales of gas are examined as well as the present and planned transmission capacity of the Russian pipeline network. The present and future gas production areas in Russia are accounted for, and a short explanation of the geology of the main producing region of Western Siberia is also presented.

A forecast of Russian gas production has been made, as well as a forecast of total Eastern Siberian and Far East production, and potential scenarios for future gas exports to the European and CIS markets is presented. The scenarios for Russian natural gas production have been modeled utilizing a bottom-up approach, building field-by-field. Individual modeling with the GGF-model has been made for 83 giant gas fields. To obtain the d-values used in the GGF-model, a number of giant gas fields have been studied, and a staircase function has been fitted to the data points, where the purpose is to find the most likely mean depletion rates for future giant gas field developments. See Fig. 4.8. In a similar way a staircase function has been applied to a data set of observed decline rates for giant gas fields in order to obtain the λ-values used in the GGF-model. See Fig. 4.9.
Figure 4.8: Depletion rates for 42 Russian producing and planned fields. Data from 12 producing and planned UK and Norwegian fields of the North Sea have been included as well. Estimated depletion rates used for modeling are illustrated with a staircase function.

Figure 4.9: Observed decline rates for 15 giant natural gas fields already in decline - eight Russian and seven fields in the Norwegian and UK areas of the North Sea. Estimated decline rates used for modeling are illustrated with a staircase function.
4.4.2  Paper VI: Main findings

In principle all Russian gas production is produced by 36 giant gas fields, and about 95% of Russia’s gas reserves are contained in giant fields and semi-giant fields larger than 30 bcm. URR figures for the largest 83 giant gas fields have been gathered and their combined URR figure amounts to 61 tcm.

A field-by-field study shows that the major producing Russian gas fields are in decline, and by 2013 much larger supplies from the Yamal Peninsula and the Shtokman field will be needed in order to avoid a decline in production. The production reaches a plateau in 2025 at 949 bcm/year with the highest peak production in 2032 at 956 bcm. See Fig. 4.10. In Fig. 4.11, the effects from a five-year development delay of the Yamal peninsula are illustrated. In this scenario substantial production growth may occur by 2020, rising fast until 2025, and thereafter a slow development rate with a peak in production in 2037 at 890 bcm/year. In the forecast, the estimated development for Russian domestic demand has been included. The difference between the forecasts of total Russian gas production and the projected demand curve yields the available net export capacity of Russian gas.

Gas from fields in Eastern Siberia and the Far East will mainly be directed to the Asian and Pacific Rim markets, thereby limiting its relevance to the European and CIS markets. The available net export capacity available for the European market and the CIS markets, have been derived by subtracting the production from East Siberia and the Far East from total Russian production. The results are illustrated with three forecasts in Fig. 4.12, one illustrating net exports for the Russian gas forecast with no delays, another showing the effects of the five-year development delay of the Yamal Peninsula, and a third illustrating the effects of a five-year delay in start of production of the Shtokman field. Fig. 4.12 shows that if the development of the Yamal Peninsula is delayed by five years there is no available net increase of exports to the European and CIS markets. If there are no delays net exports capacity may increase from the 2008 level by about 45% to a plateau level of 275 bcm by 2015–2016 lasting until 2030, followed by a short increase before the onset of decline. A five year delay of the Shtokman project results in a potential exports level increase of 40% by 2016, although by 2020–2025 it decreases to about 25%, followed by an increase after 2030.
Figure 4.10: Forecast for all producing giant fields in Russia and all planned production from giant fields.

Figure 4.11: Forecast for all producing giant fields in Russia and all planned production from giant fields. Yamal production delayed by five years.
Within a few years much larger supplies from the Yamal Peninsula and the Shtokman field will be urgently needed, if Russian production is to avoid a decline and be able to increase. It is important that the Yamal Peninsula is developed as planned, since any longer delays will make a significant impact on potential exports volumes to the European and CIS markets. It has been optimistically assumed that all potential exports from the Barents Sea and Yamal will be directed to the European and CIS markets, disregarding planned LNG exports from Shtokman to the US market, and statements from Gazprom that West Siberian gas will supply the Altai pipeline to China. Despite these assumptions, the maximum export increase to the European and CIS markets amounts only to about 45% for the period 2015-2030. If an equal percentage increase for both markets is assumed, in real numbers a mere increase of about 70 bcm of Russian export volumes to the EU can be expected. However, domestic production within the EU is expected to fall by 126 bcm for the period 2006-2030. There are a number of potential downside factors for future Russian gas supplies to the European and CIS markets. From a European energy security perspective, these factors should be closely monitored.
monitored. In addition, there should be further research on how much de-
mand for gas the fast growing economy of China may yield in the coming 20
years.
5 Key findings and conclusions

The results indicate that resource-constrained models are presently the only feasible tools for long-term gas production forecasting. The MDR-model was found to be consistent with empirical experience on the field level, and to be at least as good as other resource-constrained models on a regional level. Therefore it is reasonable to use it for gas production scenarios.

When forecasting gas production, the best method to handle uncertain data is to use a range of values for relevant parameters. Since a large share of the global gas reserves is contained in a relatively small number of giant fields, the field-by-field approach is considered to be the most effective method for forecasting future gas supplies. The MDR-model is the basis for the GGF-model. An important component of the GGF-model is to include a parameter for plateau production based on depletion rate. The GGF-model was found to be a valuable tool for field-by-field modeling as well as for modeling on regional levels.

The results show that the energy security of the EU is heavily dependent on gas supplies from a relatively small number of giant gas fields. The main import sources for gas supplies to the EU are Russia and Norway, accounting for 62% of EU’s gas imports in 2006. In Norway almost all production originates from 18 fields of which 9 can be considered as giant fields. In Russia 36 giant fields account for essentially all gas production. The scenarios examined show that there is a limited potential for increased gas exports from Norway to the EU and that Norwegian gas production in all scenarios is showing a decline by 2030. Norwegian pipeline gas exports to the EU may, by 2030, even be 20 bcm/year lower than today’s level. The maximum export increase of Russian gas supplies to the EU, amounts to only about 45% by 2030. In real numbers this means a mere increase of about 70 bcm. At the same time, domestic production within the EU is expected to fall by 126 bcm during the period 2006-2030. As a result, by 2030, the additional gas supplies from Russia will not even be able to compensate for the domestic decline of production within the EU. In addition, there are a number of potential downside factors for future Russian gas supplies to the European markets.

Consequently, given the results and assumptions presented, a 90% increase of import volumes to the EU by 2030 will be impossible to achieve. From a European energy security perspective the dependence of pipeline gas imports is not the only energy security problem to be in focus, the question
of physical availability of overall gas supplies deserves serious attention as well. There is a lively discussion regarding the geopolitical implications of European dependence on imported gas from Russia. However, the results of this thesis suggest that when assessing the future gas demand of the EU it would be of equal importance to be concerned about diminishing availability of global gas supplies.

A requirement for further research would be the publication of transparent and verified production and reserves data for the world’s giant gas fields. Methods for estimating undiscovered volumes of gas should be further developed and utilized. In addition, a thorough examination should be performed to estimate the quantities of future global LNG supplies that may be realistically achieved. Economic modeling ought to be incorporated when modeling individual giant fields in an effort to estimate more accurately relevant parameters such as planned start of production, build-up time and plateau production levels.
6 Svensk sammanfattning


ner kommer med all sannolikhet att exporteras till de asiatiska marknaderna, och då främst Kina. Med de resultat och antaganden som presenterats i avhan-dlingen är det inte möjligt för EU att öka sin import med 90% från 2006 års nivå. För energisäkerheten inom EU är det inte endast beroendet av pipe-line import som är en vital fråga. Idag är det en livlig diskussion inom EU angående de geopolitiska konsekvenserna av importberoendet via pipeline av rysk gas. Huruvida det i framtiden finns tillräckligt med gas överhuvudtaget för export till EU är en fråga som förtjänar uppmärksamhet och noggrant måste utredas och analyseras. De resultat som presenterats i denna avhand-ling visar att det är lika berättigat att diskutera problematiken kring en fram-tida minskning av totala gasleveranser till EU.
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