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International Outlook for Unconventional Gas and Implications for Global Gas Markets

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An Energy Studies Institute Report

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KEY ABBREVIATIONS

BCM	Billion Cubic Metres
CBM	Coalbed Methane
DES	Delivered Ex Ship
EIA	Energy Information Administration
FSU	Former Soviet Union
GIP	Gas-in-Place
HH	Henry Hub
ICE	Intercontinental Exchange
IOC	International Oil Company
JCC	Japan Crude Cocktail
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MMBtu	Million British Thermal Units
MTPA	Million Tonnes Per Annum
NBP	National Balancing Point
NGL	Natural Gas Liquids
NOC	National Oil Company
PSC	Production Sharing Contract
SNG	Synthetic Natural Gas
TCM	Trillion Cubic Metres
TFCG	Trillion Cubic Feet of Gas
TOP	Take-Or-Pay
WGM	World Gas Model

EXECUTIVE SUMMARY

The last five years have seen an explosion of interest in unconventional gas around the world as a consequence of the shale gas revolution in the USA. Not only do these newly discovered unconventional gas resources add substantially to already known reserves of natural gas but they are also more widely geographically distributed than conventional gas reserves, giving hope to many countries that they may be able to secure new domestic gas supplies. In Europe, a few governments are keen to assess and exploit their resources, whilst others are more hesitant. Several Latin American countries are pressing ahead in assessing their potential resources. In the Asian region, Australia, China, India and Indonesia are seen as having substantial resources of shale gas and coalbed methane.

The main motivations for these national programmes are energy security and economic competitiveness. In other words, a significant proportion of the new supplies of gas will be used to satisfy domestic demand, unlike in North America and Australia where incremental production is to be exported. It is likely that a number of countries will be successful in exploiting their unconventional gas resources and this will have a significant impact on regional and global flows of natural gas and on gas prices.

The aims of this project were to assess the likely levels of production of unconventional gas from different parts of the world over the period to 2035 and to evaluate the possible impacts on global gas flows and prices. The project was carried out in two stages:

- Stage 1: Assess the likely levels of production of unconventional gas in a number of key countries and produce alternative scenarios for changes of net gas imports to or exports from these countries.
- Stage 2: Assess the impact of these changes on trade flows and prices in international markets by modelling.

Stage 1: Approach – Future Unconventional Gas Production and Impacts on Imports/Exports

Country case studies were selected on the basis that they were representative of nations with ambitions to produce unconventional gas on a significant scale and reflect different geographical locations and political and economic systems. We did not attempt to cover all countries with ambitions to produce unconventional gas at a significant scale. Our analyses of the selected countries are based on published assessments of the geological potential for unconventional gas reserves combined with our own assessments of the above-ground factors which may encourage or inhibit the production of unconventional gas. From these considerations, we have derived optimistic and pessimistic projections for unconventional gas production for each case to the year 2035. The next step was to take published projections of (conventional) gas supply and demand and adjust them to take into account our projections of future unconventional gas production. This allowed us to produce alternative scenarios for changes in net gas imports or exports caused by unconventional gas production for each of the case studies. We also carried out a brief assessment of the outlook for exports from East Africa and Russia, as well as the assessment of the likelihood of significant product from gas hydrates to the year 2035.

Stage 1: Findings – Future Unconventional Gas Production and Impacts on Imports/Exports

The Importance of Above-Ground Factors

Geological conditions are clearly a critical determinant of the potential levels of unconventional gas production. However, above-ground factors will constrain shale gas and coalbed methane production in most countries, and the nature of these constraints will vary greatly between countries. As a consequence, there is probably no country that can reproduce the US experience. Of the countries which are actively pursuing shale gas exploration, China and Argentina have the largest potential reserves, but above-ground factors may pose serious constraints to future production, especially in Argentina.

Net Gas Importers with Rapidly Growing Demand
In those countries which are currently net importers of gas, such as China, India and Argentina, a significant proportion of incremental unconventional gas production will be consumed domestically. This is because a combination of economic growth, rising energy demand and fuel switching will allow the domestic gas market to absorb most or all of the incremental domestic gas production. Any decline in net imports will be significantly less than the rise in total gas production. A substantial rise in the production of unconventional gas in any of these countries might lead only to a modest decline in the rate of growth of net gas imports.

Net Gas Exporters with Rapidly Growing Demand
In those countries which are currently net exporters of gas and which have a rapidly rising domestic demand for gas, such as Indonesia, the additional supplies from unconventional gas may not result in significantly greater gas exports as much of the incremental gas production will be devoted to the domestic gas market.

Net Gas Exporters with Slowly Growing Demand
In those countries which are currently net exporters of gas but where gas demand is rising only slowly, such as Australia and Canada, any increase in exports arising from unconventional gas production will be constrained by the availability of LNG export capacity and by global demand for LNG. In these cases, the rate at which unconventional gas reserves are brought into production will be determined more by the demand from international gas markets than by domestic, above-ground factors.

Gas Hydrates
It is difficult to foresee the timing of the start of significant commercial exploitation of gas hydrates, but the first locations are likely to be in the Asian region, either onshore or offshore.

East Africa
Tanzania and Mozambique are set to become significant exporters of LNG, but uncertainty remains as to the timing of these exports because of a number of policy and regulatory challenges.

Stage 2: Approach – Impacts on Trade Flows And Prices in International Gas Markets
In Stage 2 we used the results from Stage 1 as inputs to the Nexant World Gas Model in order to evaluate the likely impact of unconventional gas production on the trade flows and prices in international gas markets to the year 2035. This model includes all known sales contracts and all known and planned infrastructure (pipelines and LNG terminals). In order to constrain the number of times the model was run, we aggregated the 13 cases examined in Stage 1 to produce four scenarios in addition to a base case. North America (USA and Canada) and Australia were modelled separately as their impacts on global gas markets could be significant, depending on the rate at which export infrastructure is constructed and utilised. A third case represented an optimistic scenario for unconventional gas production in Asia (China, India and Indonesia), and the fourth and final case assessed the likely consequences of gas exports from East Africa. We also developed a Base Case to study how the international gas market may evolve to 2035 with relatively modest supplies of gas from unconventional sources.

Stage 2: Findings – Impacts on Trade Flows and Prices in International Gas Markets
The main findings from the modelling exercise are as follows:

Production and Consumption of Natural Gas
Unconventional gas potential would lead to increased gas production for major exporters (in the case of Australia, North America and Indonesia) and for major importers with

unconventional gas potential (in the case of China and India). Natural gas consumption increases in Asia, keeping pace with increasing regional production.

Trade Flows of Natural Gas

Increased unconventional gas production would lead to increased LNG exports for major exporters (in the case of Australia and North America) and/or reduced gas imports for major importers with unconventional gas potential (in the case of China and India). This results in a re-orientation of LNG trading patterns which could lead to the shut-in of production in some regions.

The key driving factor for the change in trade patterns, caused by increased LNG trade flows from unconventional gas production, is that major importers find it economically advantageous to source LNG from new exporters, which in turn displaces spot trade flows of LNG from distant and more expensive exporters. For example:

- Increased Australian LNG exports flow mostly to Asia, which leads to diversions or shut-in of North American and African LNG exports to Asia.
- North American LNG exports brought on by the shale gas boom are expected to flow mostly to Europe, followed by Asia and Latin America. This has the potential to push out some African LNG from Europe and some Australian LNG from Asia.
- Reduced rate of growth of LNG imports from China and India, brought on by the development of domestic unconventional fields, prompts Africa to switch some LNG from Asia to Europe, as well a reduction in dependence on LNG exports from the Middle East.
- In general, greater LNG exports, or reduced LNG imports, in any one region are not likely to reduce contracted flows elsewhere as buyers are still obligated to abide by existing contracts to at least take or pay levels; however US LNG exports could be affected due to the tolling model adopted by US liquefaction plant owners.

Spot Prices

In general, spot prices are lower in scenarios with greater unconventional gas production, with the price effect strongest in the regions that either produce the unconventional gas or import the bulk of the LNG produced from unconventional gas sources.

- Greater unconventional gas production and LNG exports from Australia have the biggest impact on prices in Japan, followed by China and Europe.
- Greater unconventional gas production in China, India and Indonesia reduces these countries' import requirements and has the biggest impact on spot prices in China, followed by Japan and Europe.
- Greater unconventional gas production and LNG exports from North America impacts prices in Europe and Asia.

Contract Prices

- In general, contract prices are a function of the oil price rather than short-run supply and demand fundamentals.
- However, sustained greater unconventional gas production and/or greater LNG supply has the potential to permanently lower spot prices and thus lead to long-term downward pressure on contract prices, which may have a significant impact on contract price negotiations when contracts expire or are re-negotiated.

It is important to interpret these results with care. There is uncertainty over the precise magnitudes of the effect of unconventional gas on production, trade flows and prices, since the real world gas market has various complexities and imperfections that are not captured in the model. In particular, we note the following points:

- The price impact of an unconventional gas boom, whether localized or global, is likely to be greater than the impact predicted by the model, because increased supply strengthens the bargaining power of buyers relative to sellers, which could lead to further decreases in spot prices as well as re-negotiation of contract prices.

- The model estimates how trade flows of spot LNG are affected by increased unconventional gas supply. In practice, the additional supply is also likely to have an effect on contracted flows, as other LNG producers will find it more difficult to sign new contracts and/or renew existing contracts in a less tight market. We have partially accounted for this effect through careful scenario construction. For example, this explains why we do not have a scenario with both high Australian LNG exports and high North American LNG exports, since the market would not be large enough to accommodate them both. However, our model does not provide the full dynamic effects of an increase in unconventional gas supply.
- The modelling assumes that decisions to produce gas and sell gas to a particular destination are purely economic in nature and driven by economic fundamentals. In practice, domestic and international political factors also play into these decisions. For instance, in the model, Qatar gradually switches LNG from Japan and Korea to India due to the reduced shipping distance, but in practice Qatar has a long-standing relationship with Japan which it might not want to disrupt by reducing LNG flows, even though Japan is able to meet its LNG demand from other sources.

Overall Conclusion

The world is approaching a tipping point with respect to the production and consumption of natural gas. Environmental and supply security concerns are driving national policy changes which support a progressive switch from coal and oil to natural gas in industry, power generation and transportation. Technological breakthroughs that are allowing the production of different forms of unconventional gas on a large scale assist these policies in three ways: through the provision of new supplies of gas, through the geographic diversification of these supplies and through downward pressure on gas prices. The continuing availability of natural gas supplies will prolong the era of fossil fuel use. In contrast to North America and Australia which are likely to see a substantial rise in gas exports, in many countries these unconventional gas resources will be exploited primarily for domestic consumption and may not enter international markets. However, if the scale of production is large enough, it might reduce or constrain the call on international gas markets.

Limitations

This report should be seen as a preliminary analysis for two main reasons. First, with the exception of China and Indonesia, the authors carried out no in-country studies, but relied on published accounts. Second, the Nexant World Gas Model, despite its value, has a number of inherent limitations which are described in the report.

In addition, this research was concluded in July 2014 and therefore does not take into account the dramatic fall in oil prices and other events which occurred later that year.

CHAPTER 1. INTRODUCTION

1.1 Background to the Project

Gas is no longer considered to be a scarce source of energy. The share of natural gas in global energy consumption is set to grow over the next two decades, mainly as a result of a gradual switch from coal to natural gas by electrical power sectors and a switch from diesel to gas by industry and the transportation sector.[1] This absolute rise in the consumption of natural gas will be most marked in non-OECD Asia, notably China and India. The growing importance of natural gas has two main sources. First, it is cleaner than the other two fossil fuels, coal and oil, and can be seen as a transition fuel to a low-carbon future. Second, the combination of high energy prices and technological advance has led to the discovery of new reserves of gas, both onshore and offshore, boosting proven remaining global reserves by 35% between 2000 and 2011.

A growing proportion of the newly-proven reserves take the form of "unconventional" gas - that is to say, accumulations of gas which cannot be extracted by "conventional" technologies. Unconventional gas takes five main forms:

- Coalbed methane (CBM), where the gas remains within the coal from which it was generated.
- Shale gas, which lies within the shale from which it was generated.
- Tight gas, which occurs in reservoirs of very low quality.
- Biogenic gas, which is produced through contemporary biological processes.
- Gas hydrates in which the gas is preserved in ice on the deep-sea floor or in permafrost.

All these forms of unconventional gas have been known for many years, but the challenge has been to develop technologies to produce them in a commercially viable manner. CBM has been produced in the USA for more than twenty years. Tight gas has played an important role in the rise of gas production in China over the last fifteen years. Biogenic gas is produced in western Canada, whilst gas hydrates have yet to be exploited commercially.

The most significant recent development has been the successful adoption of horizontal drilling and hydraulic fracturing in the USA to make the large-scale production of shale gas commercially viable. This has resulted in total natural gas production in the US growing by 30% between 2006 and 2012, and has allowed the US to overtake Russia as the world's largest producer of natural gas in 2009. The sudden abundance of a relatively cheap source of gas supply has provided a significant boost to US economic competiveness and will change the country from a net importer to a net exporter of gas. In turn, this will have consequences on the flows of international gas trade and for gas prices.

The last five years have seen an explosion of interest in unconventional gas around the world as a consequence of the shale gas revolution in the USA. Not only do these newly discovered unconventional gas resources add substantially to already known reserves of natural gas but they are also more widely geographically distributed than conventional gas reserves, giving hope to many countries that they may be able to secure new domestic gas supplies. In Europe, a few governments are keen to assess and exploit their resources, whilst others are more hesitant. Several Latin American countries are pressing ahead in assessing their potential resources. In the Asian region, Australia, China, India and Indonesia are seen as having substantial resources of shale gas and CBM.

The main motivations for these national programmes are energy security and economic competitiveness. In other words, a significant proportion of the new supplies of gas will be used to satisfy domestic demand, unlike in North America and Australia where incremental production is to be exported. It is likely that a number of countries will be successful in exploiting their unconventional gas resources and this will have a significant impact on regional and global flows of natural gas and on gas prices.

[1] See, for example, the IEA's "Golden Age of Gas": International Energy Agency, *World Energy Outlook 2011* (Paris: OECD/IEA, 2011).

Whilst the primary determinants of future production of unconventional gas in the region will be the scale and nature of the geological resource, experience in the US and Europe demonstrates that many non-geological and non-technological factors will also play an important role, including: the general policy and institutional context, the governing policies, laws and regulations, gas pricing, the behaviour of different industry actors, societal attitudes, and a variety of concerns relating to water and the environment. These "above ground" factors will be critical in determining the trajectories of unconventional gas production in different countries around the world.

1.2 Aims and Structure of the Project

Whilst many studies have been published that examine the potential for unconventional gas production in individual countries or regions, there appears to be no published study which pulls together assessments for several countries and analyses quantitatively the likely impacts on international gas markets. The aims of this project were to assess the likely levels of production of unconventional gas from different parts of the world over the period to 2035 and to evaluate the possible impacts on global gas flows and prices. The project comprised three work packages:

- Work Package 1: Assessment of the possible trajectories for the future production of unconventional gas from selected countries around the world and for changes of trade flows across these national borders.
- Work Package 2: Assessment of the likelihood of significant production from gas hydrates.
- Work Package 3: The production of scenarios of future gas flows and prices to the year 2035 building on the outputs of Work Packages 1 and 2.

1.3 Report Structure and Research Methodology

Chapter 2 presents the results of Work Packages 1 and 2. The ten country case studies were selected on the basis that they were representative of nations with ambitions to produce unconventional gas on a significant scale and reflect different geographical locations and political and economic systems. Our analyses of the countries are based on published assessments of the geological potential for unconventional gas reserves combined with our own assessments of the above-ground factors which may encourage or inhibit the production of unconventional gas. From these considerations, we have derived optimistic and pessimistic projections for unconventional gas production for each case to the year 2035. The next step was to take published projections of conventional gas supply and demand and adjust them to take into account our projections of future unconventional gas production. This allowed us to produce alternative scenarios for changes in net gas imports or exports caused by unconventional gas production for each of the case studies. Also included in Chapter 2 is a brief assessment of the outlook for exports from East Africa and Russia, as well as an assessment of the likelihood of significant production from gas hydrates to the year 2035.

Chapter 3 presents the results of the modelling undertaken as part of Work Package 3. This work used the results from Work Packages 1 and 2 as inputs to the Nexant World Gas Model in order to evaluate the likely impact of unconventional gas production of the trade flows and prices in international gas markets. This model was developed by Nexant's Global Gas practice and simulates how interactions between supply availability and costs, transportation and LNG capacity and long term gas contracts interact to produce global, regional and national gas supply demand balances. The model includes all known sales contracts and all known and planned infrastructure (pipelines and LNG terminals). In order to constrain the number of times the model was run, we aggregated the 13 cases examined in Chapter 2 to produce four scenarios in addition to a base case. North America (USA and Canada) and Australia were modelled separately as their impacts on global gas markets could be significant, depending on the rate at which export infrastructure is constructed and utilised. A third case represented an optimistic scenario for unconventional gas production in Asia (China, India and Indonesia), and the fourth and final case assessed the likely consequences of gas exports from East Africa. Chapter 4 summarises the main conclusions from the study.

This report should be seen as a preliminary analysis for two main reasons. First, with the exception of China and Indonesia, the authors carried out no in-country studies, but relied on published accounts. Second, the Nexant World Gas Model, despite its value, has a number of inherent limitations which are described in the report. This research was concluded in July 2014 and therefore does not take into account the dramatic fall in oil prices and other events which occurred later that year.

CHAPTER 2. THE CASE STUDIES

2.1 Introduction

The principal aim of this chapter is to develop scenarios for the future production of unconventional gas from a selection of countries on different continents. The chapter presents the analyses of the individual case studies and the resulting scenarios for each case. The main outputs for each case study are two scenarios for the future supply and demand for natural gas to the year 2035, whether conventional or unconventional gas, and the implications for changes in the net export or import of natural gas. The optimistic scenarios show the supply/demand balance in the case when the exploitation of unconventional gas achieves a reasonably high degree of success. The pessimistic scenarios are based on the premise that non-geological factors substantially constrain, but do not halt, the exploitation of unconventional gas. The scenarios have been derived from an overall understanding of the outlook for the national energy sector, as well as specific understanding of the natural gas sector and unconventional gas.

The case studies provide a representative sample of countries which have significant potential resources of shale gas or CBM and which have or are putting in place policies to promote the extraction of this unconventional gas, namely:

- China
- Indonesia
- Australia
- Canada
- India
- Argentina
- UK
- Poland
- Europe

Each case study is based on a detailed analysis of the literature and, in the cases of China and Indonesia, this has been supplemented by in-country field work. The description of each case follows a standard format:

- Resource potential
- Motivations and policies
- Progress and plans
- Above ground determinants
- The two scenarios

The analysis of the likely constraints draws on our understanding of the key factors which have supported the US shale gas revolution, namely:

a. *Geology, Geography and Information*: The geology of many US basins is very favourable for shale gas. More than 100 years of oil and gas exploration and production has resulted in an enormous quantity of geological data, and this data is freely available. Furthermore, the topography in the key producing basins is amenable to intensive drilling programs and water is abundant in some but not all basins.

b. *Access to Land and the Gas Resource*: The USA is unique in that private land-owners generally own the rights to the mineral resources below their land. Some land is owned by the individual State whilst the remainder is owned by the federal government. This private ownership of the resource allows the companies to negotiate directly with the land owner for access to the land and the resource, which tends to radically reduce transaction costs and save time compared to a formal government licensing system. A second consequence of the private ownership of the resources is that it is easier for companies to gain the support of those who have been affected. As a result a robust social license to operate is present, especially in areas with a long history of oil and gas extraction.

c. *Rapid Drilling*: In order to explore, develop and bring into production a large quantity of shale gas, it is necessary to drill thousands of wells. In Pennsylvania, 5,000 wells were needed to produce at a rate of 30 bcm per year. In the Barnett Basin, nearly 18,000 wells were in production by 2012. Such a rapid rate of drilling requires the wide availability of the best technology and skills, ample capital, and efficient supply chains. In the US these were provided by the highly competitive and open oil and gas industry.

d. *Economic Incentives and Other Government Support*: The combination of gas shortages and high oil prices in the late 1970 persuaded the federal government to introduce an incentive pricing scheme for high cost gas as well as tax credits. At the same time it launched a long-term research programme into unconventional oil and gas technology, directly supported by the Department of Energy, the National Research Council and the Gas Research Institute. More recently, the high level of gas prices that prevailed in the USA between 2004 and 2008 provided the ideal trigger for the surge in shale gas production. Now that gas prices have fallen, the presence of a dynamic petrochemicals industry ensures a market for the natural gas liquids (NGLs) which are produced along with the shale gas in some basins.

e. *Market and Regulatory Environment*: The gas market in the USA is long-standing and well developed. The pipeline network is extensive and is governed by obligatory third party access. To date the regulations relating to hydraulic fracturing have been relatively relaxed, especially in those states where shale gas and shale oil are abundant, and authority to issue environmental and water permits lies with the States not the federal government. Together these factors have kept transaction costs low and provided easy access to markets.

Three other cases have also been analysed on the grounds that they are important factors in future world gas markets:

- Gas hydrates: a potential game changer at some time in the future.
- East Africa: a new supply of LNG to Asia.
- Russia: a pivotal actor in Eurasian gas markets.

2.2 Shale Gas and CBM

2.2.1 China

Resource Potential

This analysis focuses on shale gas, as it has the greatest potential to change China's gas balance. Current estimates suggest that China may have very large technically recoverable reserves of shale gas, possibly 30 tcm, which is more than the USA and the largest in the world. However, China's shale gas basins have a number of unfavourable characteristics compared to the best productive shale gas basins in the USA: greater depth, lower organic content, structural complexity, and low probability of Natural Gas Liquids (NGL). China also has a significant resource of CBM but production is rising only slowly. In addition, the government is supporting the construction of capacity to produce Synthetic Natural Gas (SNG) from coal.

Motivations and Policies

China's government supports the exploitation of shale gas as it can provide more clean energy, reduce the country's import dependence and improve its economic competitiveness. The classification of shale gas as an 'independent mineral resource' allowed the government to by-pass certain regulations, in particular removing the requirement for investors to cooperate with one of the Chinese National Oil Companies (NOCs) and opening the door for Chinese private companies. In 2012 the government announced a price subsidy for shale gas of RMB 0.40 per cubic metre ($ 1.84/MMBtu).

Progress and Plans

In March 2012, the government issued the Five-Year Shale Gas Development Plan which set a target of 6.5 billion cubic metres (bcm) for annual production in 2015, rising to 60-100 bcm by 2020. PetroChina and Sinopec have the rights over the most prospective areas for shale gas and have started exploration, particularly in the Sichuan Basin in south-west China. Early exploration success led to production 200 million cubic metres in 2013, most of which came from Sinopec's Fuling project. Shell has signed a Production Sharing Contract (PSC) with PetroChina, and a number of other International Oil Companies (IOCs) have joint study agreements with the NOCs. In areas outside those held by PetroChina and Sinopec, the government has held two licensing rounds, in 2011 and 2012. Twenty-one blocks were awarded. The winners included a range of energy companies mainly owned at the provincial level, but exploration progress has been very slow, not least due to the inexperience of many of the license holders. A third round is planned for 2014. After more than 20 years of development, CBM production reached 3 bcm in 2013.

Above Ground Determinants

Geological Information and Geography

- Although many shale gas basins, like the Sichuan Basin, have been relatively well-explored, geological information is less abundant than in the USA. The information is generally held by the NOCs and is therefore less readily available.
- Some of China's shale gas basins lie in arid regions where water is very scarce. Those basins with more plentiful water tend to have high population densities.
- Together with the complex geological conditions, these factors will tend to raise the costs of shale gas production and constrain the rate of production.

Rights of Access to Resources and Land

- The NOCs hold the rights to a large proportion of the prospective areas for shale gas. Outside these areas, access is governed by licensing rounds run by the central government and the PSC is used as the main vehicle for foreign oil companies to partner with Chinese companies. These factors will raise the transaction costs and constrain the rate at which exploration companies can gain rights to the shale gas resource.
- Obstruction by local populations of access to land has not been reported to be a serious problem to date.

Rapid Drilling

- In the short-term, China's oil companies lack the advanced technology, skills, experience and supply chains to support the rapid and efficient exploitation shale gas in the most efficient manner, and they therefore rely on partnering with foreign oil or service companies.
- The large NOCs are powerful actors, and their longstanding rights to the best shale gas acreage may prove an obstacle to rapid drilling. But the government has put pressure on the NOCs to explore this acreage rapidly.
- As a consequence, it may be difficult to sustain the level of drilling activity needed to meet and maintain the target level of production set for 2020.

Economic Incentives

- In the past, gas prices have been controlled by the government along the full-length of the supply chain. Steps have been taken to gradually raise prices and, in 2013, the government introduced a mechanism to link the price of new production to those of Liquefied Petroleum Gas (LPG) and fuel oil. Fiscal incentives have been introduced, including a price subsidy.

Market and Regulatory Environment

- The overall legal framework for shale gas exploitation is confused, especially as it applies to foreign investors.
- A key weakness in the mineral rights regulatory system is the relative inexperience of the Ministry of Land and Resources in licensing and regulating oil and gas.
- The gas market in China is relatively immature and the pipeline network is limited though expanding rapidly. In the past, there was no obligation on the NOCs to provide third party access at reasonable prices. New regulations are intended to address this problem, but their effectiveness has yet to be demonstrated, and PetroChina has indicated that it plans to sell off its pipelines.
- The country's regulatory system for the environment and water is highly fragmented and widely seen as being ineffective.

The Two Scenarios (Figures 2.1, 2.2)

In the "pessimistic scenario" (Figure 2.1) the production of shale gas fails to reach 100 bcm/yr by 2035. The production of SNG and CBM is enhanced in partial compensation, but total gas production falls far short of demand resulting in a sustained high level of net gas imports, reaching 150 bcm/yr by 2020 and rising even further to 200 bcm/year by 2035 on the back of sustained growth in gas demand (Figure 2.2).

The "optimistic scenario" (Figure 2.1) sees shale gas production rising to 250 bcm/yr by 2035, as well as rising production of SNG and CBM, though growing at a lesser rate than in the pessimistic scenario, due to competition from shale. The additional overall production would result partly in higher domestic usage of gas, but would also allow China to stabilize the level of net gas imports at about 115 bcm/yr by 2025, though net imports eventually increase to 150 bcm/year by 2035 due to sustained growth in gas demand (Figure 2.2).

Figure 2.1 China Scenarios for Gas Demand and Production (2010-2035)

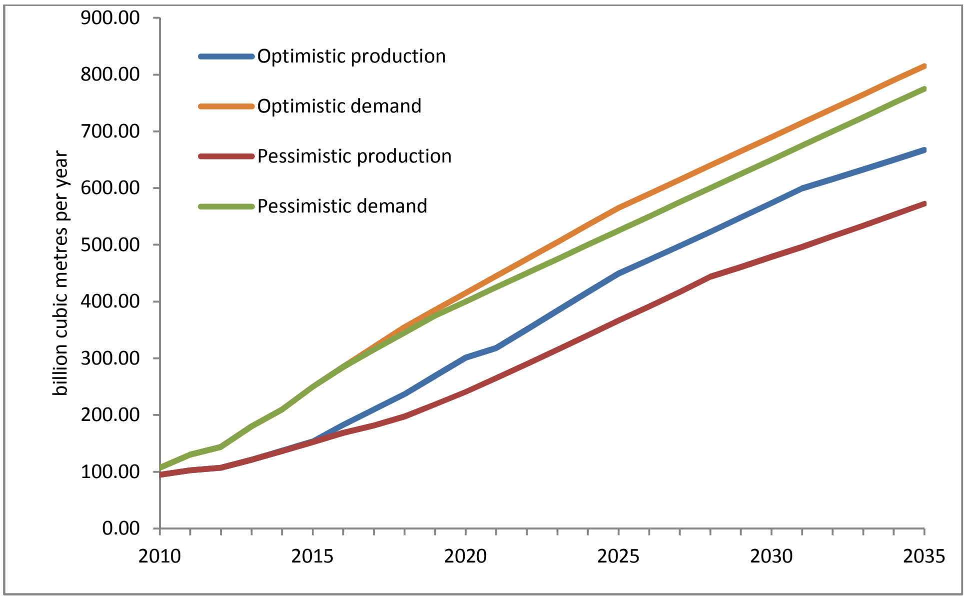
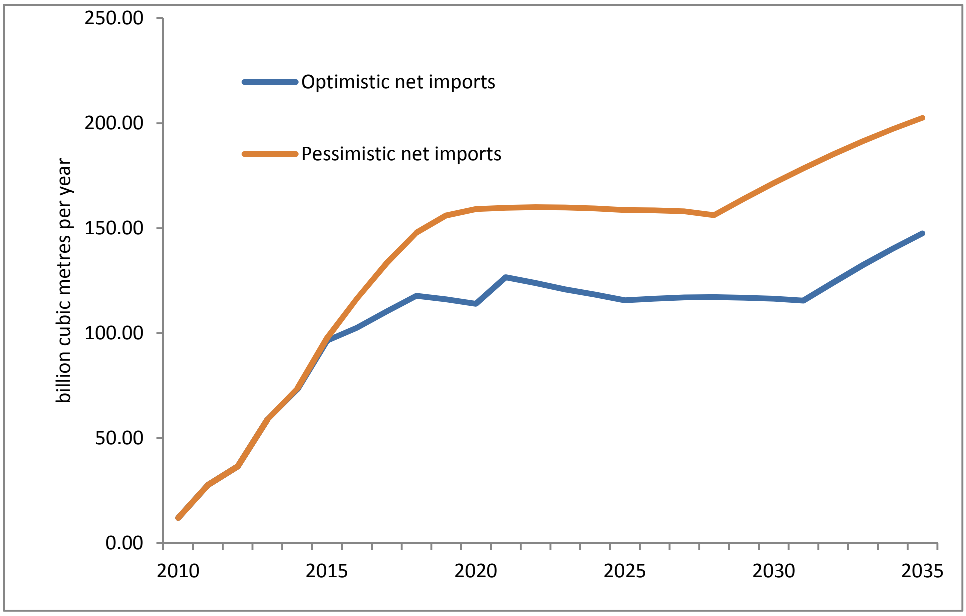


Figure 2.2 China Scenarios for Net Gas Imports (2010-2035)



Probabilities:

- Optimistic scenario: 65%
- Pessimistic scenario: 35%

2.2.2 Indonesia

Resource Potential

Indonesia has rich unconventional gas resources, particularly in CBM. The total speculative resource of CBM in Indonesia is 12.8 tcm distributed in 11 onshore coal basins, mainly in Sumatra and Kalimantan. The coal seams are of relatively low thermal rank (sub-bituminous) and have low-moderate gas content with reasonably high permeability. Geologic settings are mostly relatively simple. In addition, Indonesia has an estimated 1.3 tcm of risked, technically recoverable shale gas reserves.

Motivations and Policies

The export of natural gas has been an important source of revenue for the country and all the more important after the country became a net oil importer. The government has recently changed this policy to encourage the use of Indonesia's natural gas resources within the country, with some substitution of oil by gas. This new policy approach has resulted in the government taking steps to encourage domestic production of natural gas, including unconventional gas.

Progress and Plans

Most oil and gas production in Indonesia is carried out under PSC arrangements with foreign contractors. More than 50 PSC's for CBM have been awarded to both Indonesian and foreign companies, but by the end of 2013 only three companies with PSCs had met their operational commitments. Commercial production occurs in only one contract area. The government has targeted 5 bcm/yr of CBM production by 2015, with plans to double production every five years after that. With regard to shale gas, the state-owned PT Pertamina was awarded the first shale gas project in the Sumbagut block in North Sumatra in May 2013.

Above Ground Determinants

Geological Information and Geography

- Geological information is relatively abundant in many of the prospective areas, but access to this information is controlled by the central government.
- The archipelagic geography of Indonesia means that some of the prospective areas are isolated from potential markets for gas.

Rights of Access to Resources and Land

- The central government controls access to resources and land, and issues environmental permits. But local governments have significant powers, which can delay projects.
- Serious delays in the development of CBM arise from the overlap between licenses for CBM and those for both coal and conventional oil and gas.
- Exploration and exploitation activities that are located in forest areas require permits from the Ministry of Forestry.
- Obstruction by local populations of access to land has not been reported to be a serious problem to date, but this could easily change.

Rapid Drilling

- The procurement of specialised CBM rigs is the main obstacle to rapid drilling, along with overlapping resource rights.
- Complex permitting processes and lack of coordination between government agencies

are sources of bureaucratic delays.

Economic Incentives

- The Indonesian government has raised official gas prices and CBM producers are able to negotiate deals with offtakers at prices in the range $8-10/MMBtu.
- The cost of shale gas development is expected to be relatively high due to Indonesia's shales being located at greater depths than in the USA.

Market and Regulatory Environment

- CBM and shale gas are regulated under a PSC regime designed for conventional oil and gas which is not always appropriate to unconventional gas.
- In 2013, a new regulation was issued on local content utilization of equipment, materials and services for upstream oil and gas activities.
- The gas transportation system in Indonesia is poorly developed, and requires considerable investment in pipelines and small-scale LNG terminals.
- In the national policy direction relating to the environment, there is no detail regarding CBM or shale gas yet.
- The advent of resource nationalism and the confusing and tightening regulatory environment could affect the investment climate which in turn will affect the exploration and production activities.

The Two Scenarios (Figures 2.3, 2.4)

The "optimistic scenario" (Figure 2.3) sees shale gas and CBM production rising to 60 bcm per year by 2035. Along with rising production of conventional natural gas, this would allow Indonesia to maintain its status as a net gas exporter in the long-run: though exports decline over the next few years, they eventually recover to around 50 bcm/yr by 2035 (Figure 2.4). Such a high level of exports would require the government to reverse its current policy of directing all new gas production to the domestic gas market.

In the "pessimistic scenario" (Figure 2.3) the production of shale gas and CBM reaches just 30 bcm/yr by 2035. At the same time the production of conventional gas grows more slowly than in the optimistic scenario. In this case, Indonesia's net exports of gas will decline and remain in the range of 20-25 bcm/yr over the period 2020-2035.

Figure 2.3 Indonesia Scenarios for Gas Demand and Production (2010-2035)

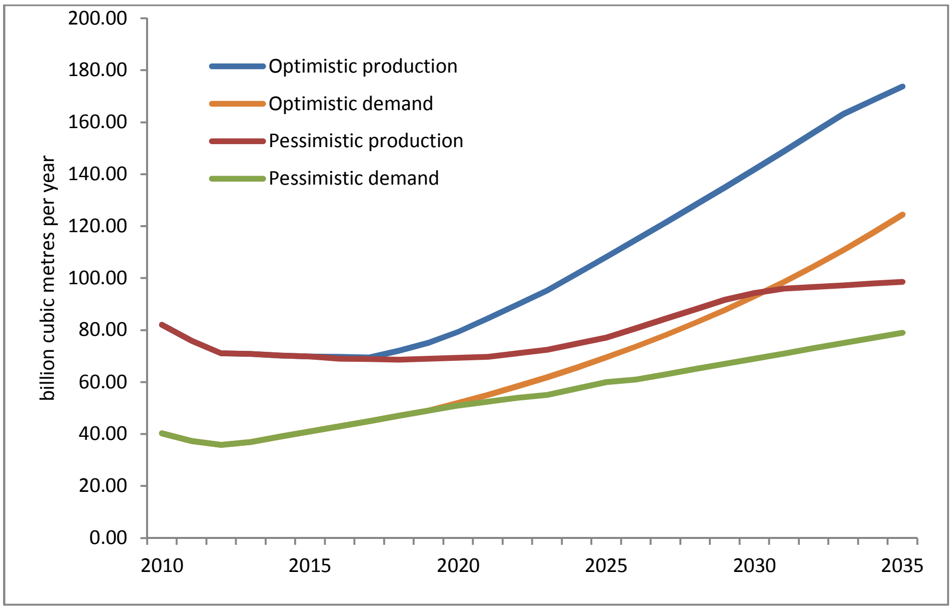
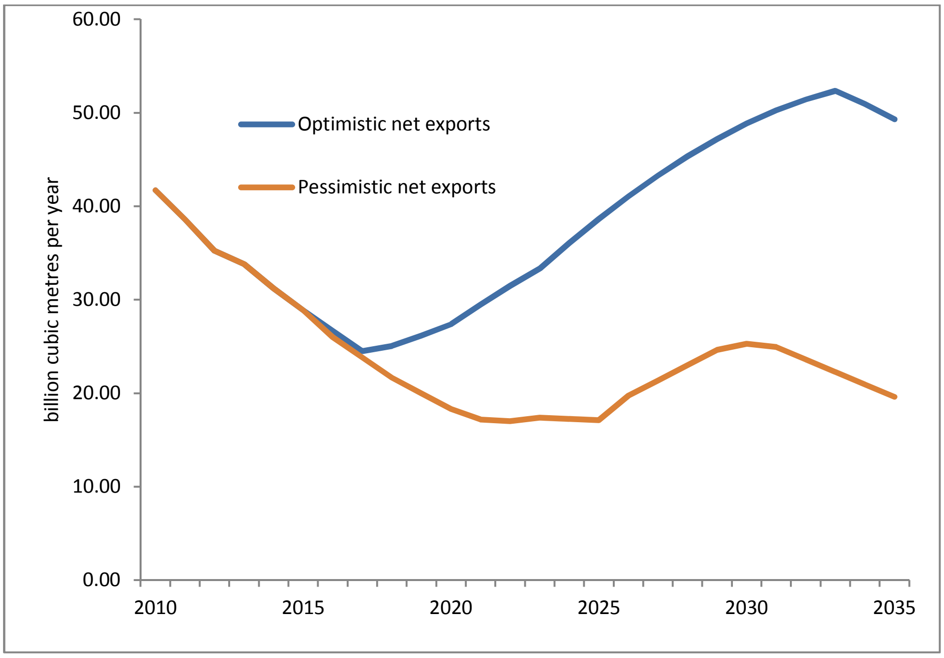


Figure 2.4 Indonesia Scenarios for Net Gas Exports (2010-2035)



Probabilities:

- Optimistic scenario: 30%
- Pessimistic scenario: 70%

2.2.3 Australia

Resource Potential

Australia has a very large potential resource for conventional gas (mainly offshore) and unconventional gas onshore. Economically recoverable reserves of conventional gas are estimated to be 2.9 tcm and those of CBM (known as coal-seam gas in Australia) are estimated at 0.9 tcm. A recent study places technically recoverable reserves of shale gas at 12.4 tcm, though the geological conditions may not be as favourable as the best US shales. If confirmed, this total level of gas reserves would place Australia on a par with the USA, but with a much lower level of consumption – 25 bcm/yr in Australia compared to 720 bcm/yr in the USA in 2012.

Motivations and Policies

Australia currently consumes only 30% of the natural gas it produces. The balance is exported. As a result, the main motivation for the development of unconventional gas is economic: the employment, tax revenue, foreign exchange earnings and GDP growth resulting from the extraction and export of large quantities of gas. In addition, gas as a cleaner fuel could gradually substitute for coal in power generation. There appear to be no specific policies to support the exploitation of shale gas and CBM, with the exception of the Exploration Development Incentive introduced by the new Australian government and which will come into effect in July 2014. This provides for additional tax allowances for mineral exploration.

Progress and Plans

CBM production has been ongoing since 1996, mainly in Queensland. The construction of LNG facilities for gas export on the east coast of Queensland has led to a significant growth in this industry. Total CBM production across Australia reached 6.1 bcm in 2012, which amounted to just over 10% of the total national output of gas that year of 58 bcm.

The Cooper Basin in Queensland and the Canning Basin in Western Australia are seen as having the greatest prospectivity for shale gas. The reserves in the Cooper Basin are on the way to commercial development. Gas from two wells flowed at 85,000 cubic metres per day and will be sold into the domestic gas market via existing pipelines. Exploration has started in a number of other basins.

Together with proven offshore gas reserves, these CBM and shale gas reserves could allow Australia to become the world's second-largest LNG exporter by 2015, and overtake Qatar to become the largest exporter by 2017.

Above Ground Determinants

Geological Information and Geography

- Geological information in some of the prospective shale gas and CBM basins is relatively abundant and readily available through the government.
- Though geographically remote, the Cooper Basin produces much of Australia's conventional onshore oil and gas, and thus infrastructure is already in place. This is not the case in the Canning basin.
- Water resources are scarce in most of the country's basins which are prospective for shale gas.

Rights of Access to Resources and Land

- The rights to explore for and exploit these resources are administered by State governments.
- Land owners are paid for any disturbance to their normal activities caused by gas exploration and production, through Land Access Agreements.
- Resistance to unconventional gas production on environmental grounds does occur in some locations and could delay production.

Rapid Drilling

- Large numbers of oil companies, large and small, are involved in assessing Australia's shale gas potential and in the ongoing exploitation of CBM.
- Most of Australia's hydrocarbon production takes place offshore. As a result, the capacity of the service industry and associated equipment, materials and skilled personnel is currently inadequate to support a very rapid build-up of onshore unconventional gas production.
- Public concern over the side effects of CBM has been growing and threatens to slow down CBM and, possibly, shale gas development.

Economic Incentives

- Australia has a relatively competitive domestic gas market. The main incentive to produce unconventional gas is to export.
- The carbon emissions tax which was introduced by the previous government in 2012 increased the cost of coal-fired generation, which is Australia's primary source of electricity. This would have driven a significant shift from coal to natural gas-based generation, which will increase domestic demand for natural gas. The current government has repealed this tax, with effect from 1st July 2014, however it is planning to bring in other measures to reduce carbon emissions. Whatever options are chosen, they are unlikely to have much effect on the volumes of gas exported, though the costs for the producers could rise.

Market and Regulatory Environment

- Each state has its own laws and regulations relating to hydrocarbon exploitation.
- The federal Ministry of the Environment has the power to suspend or halt projects on environmental grounds.
- States such as New South Wales have imposed buffer zones around residential areas and specified no-go zones for fracturing. It has also implemented regulations which require companies to consult with local communities.
- The Australian shale gas tends to be remote from population centres. Only the Cooper Basin has a pipeline network connected to the existing pipeline system. The natural gas transportation pipelines in Australia lack regional interconnections. Third party access exists for only a small proportion of the existing gas pipelines.
- A "reservation policy" obliges gas producers to supply a certain quantity of gas to the domestic market at a lower price than that in the international market. Some states apply the policy, such as Western Australia; some refuse to adopt the policy, such as the Northern Territory; some have not decided on their position, such as Queensland.

The Two Scenarios (Figures 2.5, 2.6)

Given the relatively low level of demand for gas in Australia relative to potential supply, the key issues are the likely share of unconventional gas in the export mix and the total LNG liquefaction capacity. The “optimistic scenario” (Figure 2.5) sees shale gas and CBM production rising to 120 bcm per year by 2035. This would allow unconventional gas to play a significant role in the country’s gas exports, provided the costs were competitive. As such Australia continues expanding its LNG export capacity even after the initial boom this decade, reaching 196 bcm (or 144 mtpa) by 2035 (Figure 2.6). This assumes that the international market can absorb this additional gas.

In the “pessimistic scenario” (Figure 2.5) the production of shale gas and CBM reaches just 55 bcm/yr by 2035. In this case, exports will continue to be dominated by offshore supplies, and Australia’s LNG expansion stops around 2025, stabilizing at 128 bcm (or 94 mtpa) by 2035 (Figure 2.6).

Figure 2.5 Australia Scenarios for Gas Production and Demand (2010-2035)

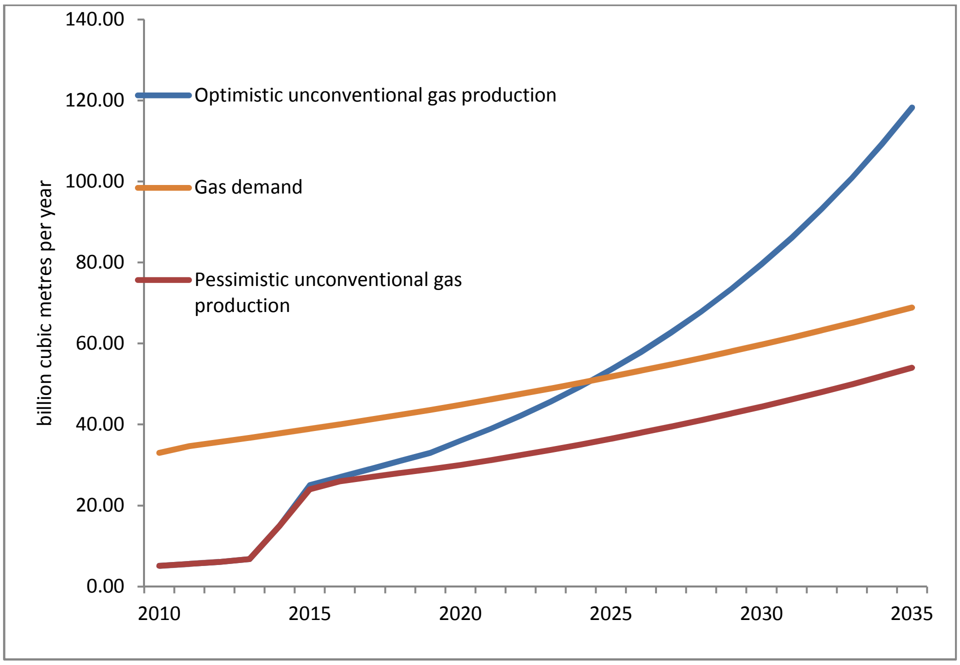
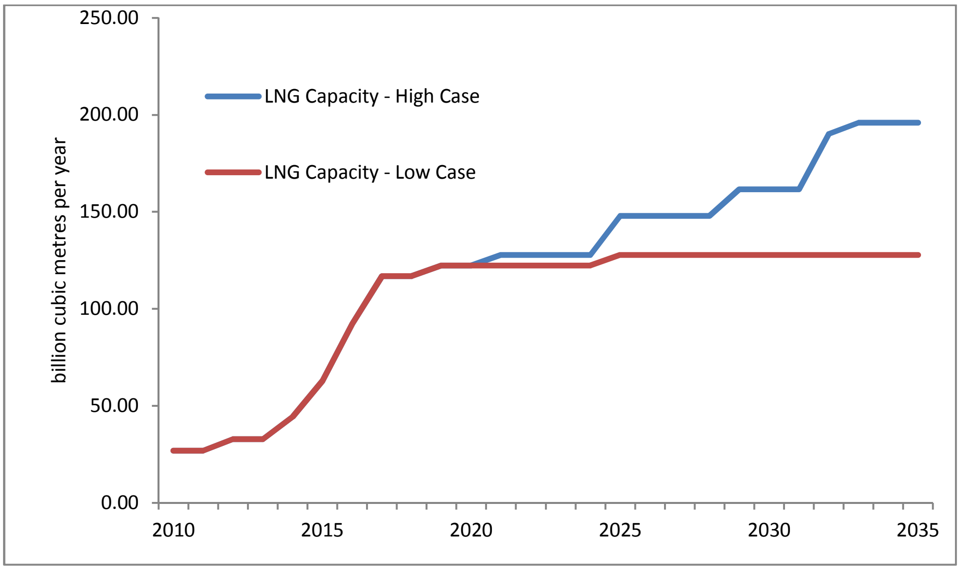


Figure 2.6 Australia Scenarios for LNG Export Capacity (2010-2035)



Probabilities:

- Optimistic scenario: 70% (assuming the international market can absorb this quantity)
- Pessimistic scenario: 30%

2.2.4 Canada

Resource Potential

Canada is rich in unconventional gas resources. Current production of tight gas stands at about 65 bcm/yr and of CBM is about 20 bcm/yr. Much of the future growth in unconventional gas production will come from shale gas for which the US Energy Information Administration (EIA) has estimated 16.2 tcm of risked, technically recoverable reserves. Most of the shale gas reserves are located in Western Canada, where five large sedimentary basins with thick, organic-rich shale formations are the Horn River, Cordova Embayment, Liard, the Deep Basin/Montney, and the Colorado Group. Among these, the Montney is very comparable to some of the US shale formations such as the Fayetteville Shale, the Woodford Shale, and the Barnett Shale.

Motivations and Policies

In the past, most of Canada's natural gas production has been derived from conventional sources. As this production has been declining due to resource depletion and has gradually been replaced by tight gas, Canada will have to increasingly rely on shale gas. The twin motivations for unconventional gas exploitation are to meet growing domestic demand for gas and to generate export revenues. Although the motivation is strong enough for shale gas development, there appear to be no specific policies to support the exploitation of shale gas in Canada.

Progress and Plans

Progress in exploiting unconventional gas plays has been slowing down recently, principally because demand is satisfied in both Canadian and US markets, and alternative LNG export routes have yet to be developed. By July 2009, 234 horizontal wells were producing from the Montney formation. Until now, about 1,200 wells have been drilled in the Montney formation. In the beginning, wells could produce between 85 and 149 thousand cubic metres per day. Several major and independent companies have been involved in the shale gas sector, such as Encana, Apache, Devon, Quicksilver, and Nexen, which are active in the Horn River play. Some joint development agreements have been signed between Encana and CNPC, and between Encana and Korean Gas Corp. Total shale gas production in 2013 was about 4 bcm.

Above Ground Determinants

Geological Information and Geography

- Geological information of the shale gas basins is abundant and available through the government.
- The shale gas basins of western Canada lie to the east of the Rocky Mountains, far from domestic markets in the east of the country and from potential export terminals on the west coast.

Rights of Access to Resources and Land

- Most mineral resources are owned by the Crown whereas most regulatory activity is conducted through provincial departments, commissions, or boards.
- In Western Canada, owners of the surface and rights over underground minerals are varied and include private individuals, entities, and the provincial or the federal Crown.
- Mineral agreements for gas exploitation are issued through public auctions.
- Opposition from First Nation communities is delaying approval for pipelines from Alberta to the coast of British Columbia.

Rapid Drilling

- Some provinces have considerable experience with hydraulic fracturing, such as Alberta; some are experiencing a slowdown in drilling activities such as British Columbia, where inadequate local infrastructure to handle production growth hinders drilling activities.
- Environmental opposition in Canada is constraining the pace of shale gas development. Several provincial governments have suspended exploration of shale gas.
- Any new gas production will have to be exported, but as yet Canada lacks the processing facilities to liquefy and ship LNG beyond North America. There are currently 15 proposed export projects from British Columbia and 2 from Nova Scotia.

Economic Incentives

- Some provinces, such as British Columbia and Alberta, have introduced favourable fiscal regimes to encourage new exploration and production of shale gas, but the fiscal regime for LNG export plants proposed by British Columbia is viewed as unattractive by investors.

Market and Regulatory Environment

- At the federal level, the National Energy Board regulates international and interprovincial aspects of the hydrocarbon industries.
- Both federal and provincial governments have jurisdiction over environmental matters. Various regulations may have articles relevant to shale gas activities. For example, both the Canadian Environmental Protection Act and the Fisheries Act have articles about the chemicals used in hydraulic fracturing in Canada. Alberta has issued a Directive to manage risks associated with hydraulic fracturing.
- In the absence of sufficient pipeline capacity to transport gas to markets, much of the gas resources in British Columbia remain shut-in.
- Establishment of a local entity is a relatively simple and quick process. It is common to use partnerships and joint ventures in the Canadian oil and gas industry. State participation is not required in a shale gas project.

The Two Scenarios (Figures 2.7, 2.8)

Canadian production capacity rapidly increases, after a brief decline till 2020, mainly due to increased unconventional gas capacity from tight gas formations and shale gas from Horn River, Cordova, Montney and Utica basins. The Canadian optimistic and pessimistic scenarios differ in the LNG export potential. Canada is rich in gas resources and its demand is forecast to be almost flat for next 20 years. Any increased production from newly developed basins is used to support exports, either as pipeline exports to the USA or as LNG elsewhere. The US shale gas boom has resulted in reduced Canadian gas exports by pipeline to the USA. Hence we focussed on the LNG infrastructure development as the driver for gas exports from Canada and on the likely projects and timelines for their completion to arrive at the scenarios.

In the optimistic scenario, we assume LNG exports from British Colombia start up around 2020 and that the Pacific Northwest LNG, BG Ridley Island, LNG Canada and Kitimat LNG plants will all be on-stream by 2025. This would result in there being 46 mtpa (62 bcm) of liquefaction capacity by 2025 with exports of perhaps 45-50 bcm. The viability of additional capacity depends on how Asian LNG demand evolves and potentially there could be support for a further 15-20 mtpa (20-27 bcm/yr) of additional liquefaction capacity in British Columbia that could come on stream between 2025 and 2035. In the optimistic scenario LNG exports could reach about 65-70 bcm by 2035. A change to the fiscal terms or to the pricing policy of the LNG producers, perhaps by linking LNG prices to Canadian natural gas hub prices rather than using a market netback, could lead to higher exports.

The pessimistic scenario assumes there is limited demand for Canadian LNG in Asia and that only 4-5 of the proposed liquefaction plants are sanctioned and go ahead. Some gas may be diverted to support US liquefaction plants in Oregon. In this scenario LNG exports are likely to be around 55 bcm by 2035

Figure 2.7 Canada Scenarios for Gas Production and Demand (2010-2035)

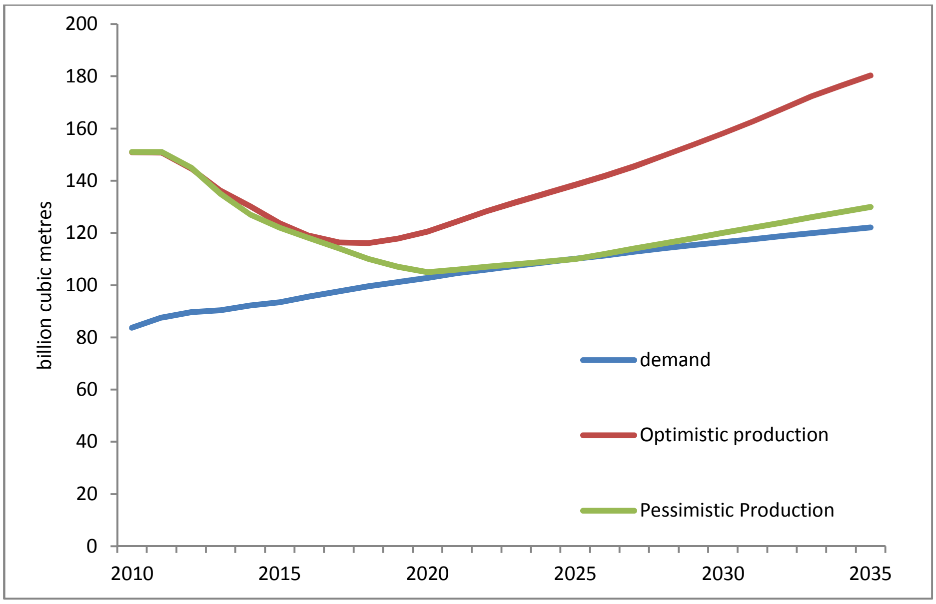
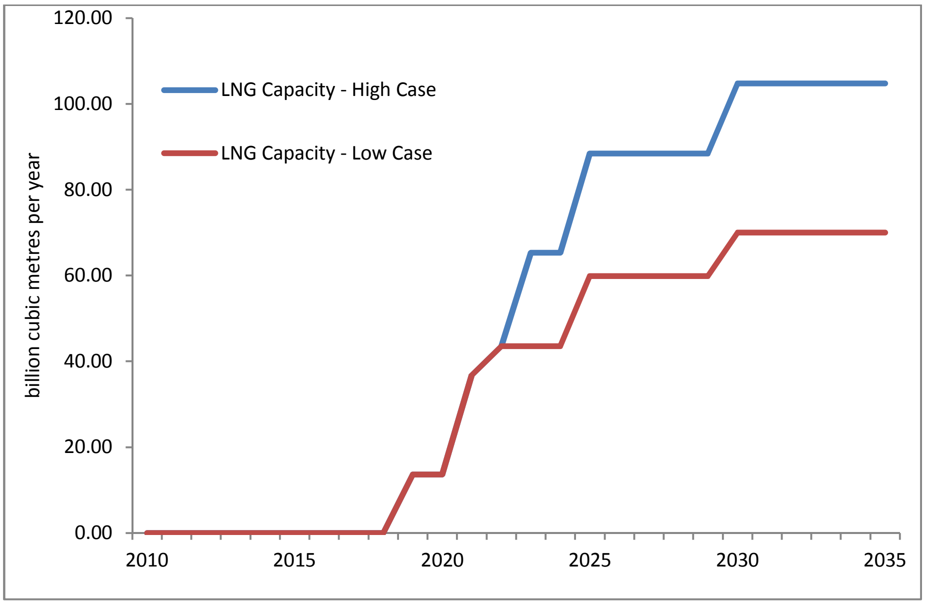


Figure 2.8 Canada Scenarios of LNG Export Capacity (2010-2035)



Probabilities:

- Optimistic scenario: 50%
- Pessimistic scenario: 50%

2.2.5 India

Resource Potential

India is at the very early stage of its efforts to evaluate its shale gas base. The US EIA estimates India's technically recoverable shale gas resource at 2,718 bcm. CBM has a longer history of development in India than shale gas. The Ministry of Petroleum & Natural Gas estimates India's CBM resources (onshore and offshore) at anywhere between 254.9 bcm and 2,605 bcm. Large reserves of CBM have been confirmed in the Cambay basin of Gujarat State, the Assam-Arakan basin in northeast India, the Gondwana basin in Central India, and the Cauvery basin in Southern India.

Motivations and Policies

India has been a net importer of natural gas since 2004. From 2001-2011, gas consumption grew at an annual rate of 10%. India is increasingly dependent on imports to meet domestic natural gas needs. It needs to support the exploitation of shale gas and CBM. A new CBM policy had been planned to provide incentives to Coal India Ltd to produce CBM gas from their coal mines, but the policy was rejected by Indian Oil Minister Veerappa Moily, who asked for a re-draft to encourage competition and efficiency in the CBM sector. A new pricing formula for all forms of gas had been expected to come into effect in April 2014, but was postponed to allow the decision to be made by the incoming government. In June 2014 the new administration decided to postpone the revision in natural gas prices by three months pending a comprehensive review

Progress and Plans

Four bidding rounds for CBM exploration blocks have been held and 33 blocks awarded. Commercial CBM production started on 14th July 2007. However, there has not been any significant commercial production yet. Only 5 blocks are currently producing a total of approximately 0.23 million cubic metres per day. Although India aims to produce 3.99 million cubic metres per day by the end of its 12th Five-Year Plan ending on 31 March 2017, actual production is likely to fall short of the government target.

Major companies operating CBM blocks are Oil and Natural Gas Corporation Limited, Coal India Limited and Indian Oil Corp. Other domestic operating companies in India include: Oil India Limited, Petronet, and Reliance Industries Limited. The two biggest state-owned oil companies, Oil and Natural Gas Corporation Limited and Oil India Limited, dominate India's upstream gas sector.

Above Ground Determinants

Geological Information and Geography

- Geological information of the shale and CBM basins is readily available through the Directorate General of Hydrocarbons (DGH) under the Ministry of Petroleum and Natural Gas.
- Eight out of nine major shale basins in India are in water-scarce regions. Concerns about water availability and quality led to a delay in India's first auction of shale gas leases.

Rights of Access to Resources and Land

- Hydrocarbon resources are owned by the nation. The DGH licenses and monitors the exploration and production process and prepares bid documents.

- The CBM blocks are awarded on the basis of international competitive bidding. India has no comprehensive set of rules and regulations concerning the development of its shale gas resources.
- Land acquisition for shale-gas exploration will be difficult since “high-power compressors and the potential for aquifer pollution could unsettle local populations”.

Rapid Drilling

- Until now there are 500 CBM wells drilled, including core holes, test wells and pilot wells.
- Neither the equipment (rigs) nor the skills are sufficient to support shale gas development. The Indian explorers need to rely on foreign firms to develop the shale gas resources in the country.
- Oil and Natural Gas Corporation Limited is going to seek technical help from ConocoPhillips for shale gas drilling. Oil India Limited is also searching for cooperation with Carrizo to drill some wells. Yet India has been slow to open up the gas sector, and not many companies are involved in drilling yet.

Economic Incentives

- Just as the Indian economy is developing towards a market-oriented one, its gas market is also in a state of transition.
- In 1998, the government launched the New Exploration Licensing Policy (NELP), which opened the entry of the private sector and provided real impetus for the development of the gas industry.
- The price of CBM is currently set by the central government. The protracted process of pricing approvals since 2011 has made Reliance Industries Limited unable to develop its CBM fields in the state of Madhya Pradesh.

Market and Regulatory Environment

- The blocks for CBM exploration are offered through an open competitive bidding system coordinated and conducted by DGH and the Central Mines Planning and Design Institute which is under the Ministry of Coal. Whilst the whole process is transparent and open, the response has generally been poor as many of the blocks on offer have been deemed to be unattractive due to location and/or low prospectivity.
- The sector of gas transportation infrastructure was opened to private investors in 2006 and this led to a rapid expansion of the pipeline network. However, most CBM blocks lie far from these pipelines, and third party access is not mandatory.
- The Ministry of Environment and Forests has the power to suspend or halt shale or CBM projects on environmental grounds. It insists that the only exploration blocks that should be released are those where sea water, not fresh water, is used. Concerns of the Ministry of Water Resources about water availability and quality led to a delay in India’s first auction of shale gas leases.
- Uncertainty about allocation of fiscal revenues between the central and state governments discourages the potential incentives of state governments in supporting shale gas development.

The Two Scenarios (Figures 2.9, 2.10)

The “optimistic scenario” (Figure 2.9) sees shale gas and CBM production rising to 30 bcm/yr by 2035, as well as rising production of conventional natural gas. The additional overall production would result partly in higher domestic usage of gas and would partly offset gas imports, though net imports continue to rise throughout the outlook period eventually reaching 85 bcm/year by 2035 (Figure 2.10).

In the "pessimistic scenario" (Figure 2.9) the production of shale gas and CBM reaches only 15 bcm/yr by 2035, and in addition conventional natural gas production is in decline for many years before it grows again. The lower production would result partly in lower domestic usage of gas, but it also leads to greater gas imports, so that net imports rise to as much as 100 bcm/year by 2035 (Figure 2.10).

Figure 2.9 India Scenarios for Gas Demand and Production (2010-2035)

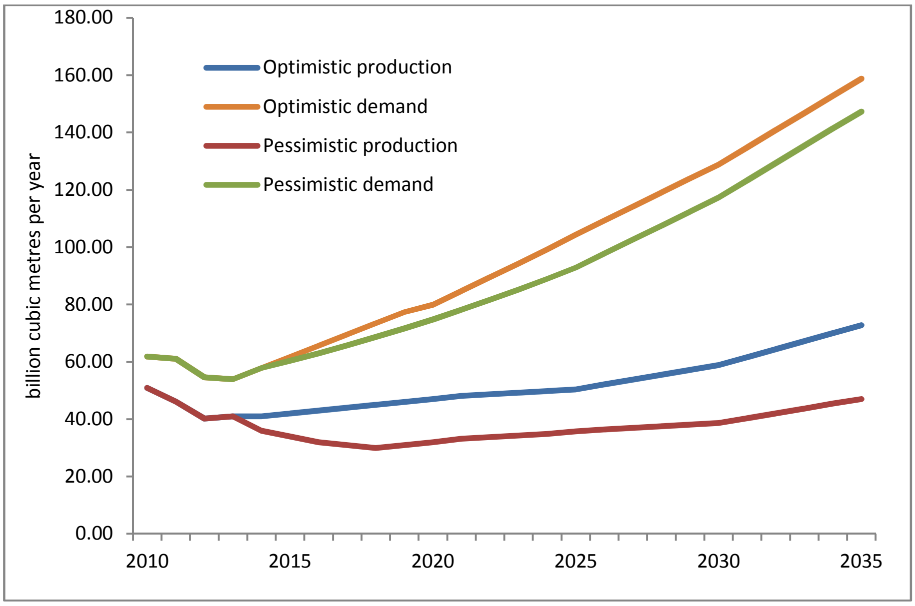
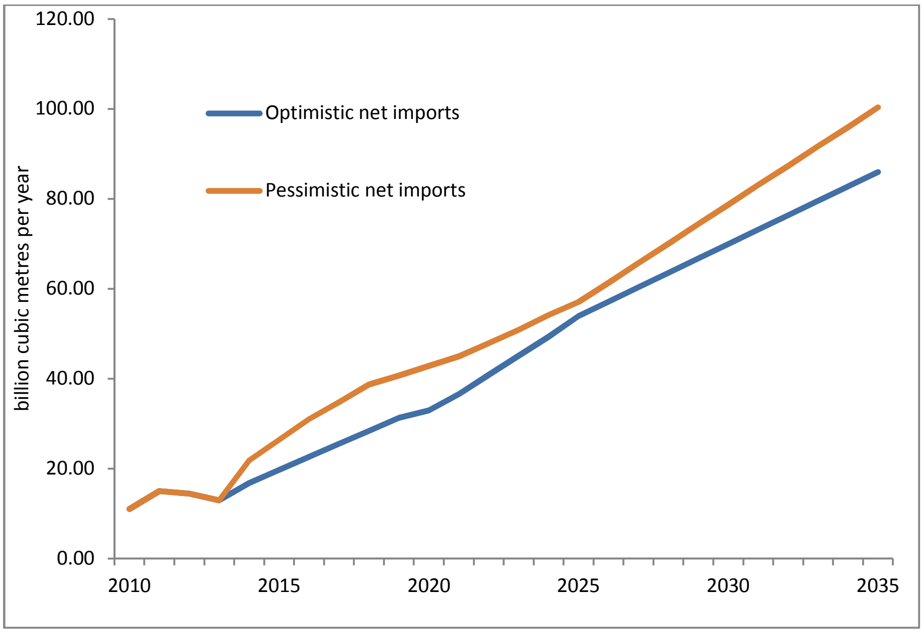


Figure 2.10 India Scenarios for Net Gas Imports (2010-2035)



Probabilities:

- Optimistic scenario:40%
- Pessimistic scenario: 60%

2.2.6 Argentina

Resource Potential

Argentina may have as much as 23 tcm of technically recoverable shale gas resources, giving the country the third largest assessed shale endowment in the world. More than half of Argentina's technically recoverable shale gas resources are found in the Neuquén basin in the western part of the country. This analysis will focus on the Neuquén Basin as the shales in this basin, especially the shallower Vaca Muerta Formation, have properties similar to the best shales in the USA such as the Eagle Ford shale. Like the Eagle Ford shale, the shales of the Neuquén Basin yield oil as well as dry gas and wet gas. This will help to encourage a high level of exploration and production activity.

Motivations and Policies

Argentina became a net importer of gas in 2008, and domestic demand is growing very fast. The demand-supply gap is widening and expensive LNG cargoes are draining the country's foreign reserves. Argentina is in desperate need of domestic gas production, both conventional and unconventional. In November 2012, the government announced the Gas Plus programme which seeks to encourage investment in unconventional gas production and accelerate the production of natural gas by allowing companies to "sell natural gas from new or unconventional fields at higher prices." Thus, the wellhead prices can be as much as $7.50/MMBtu compared with a ceiling of $5/MMBtu previously. The average current wellhead price in the Neuquén Basin is $2.70/MMBtu. Therefore, the significant price increase may stimulate shale gas production. In 2013, the government attracted non-Argentine state investors to invest in Argentina's shale gas sector.

Progress and Plans

YPF, the Argentinian NOC, and the local unit of Dow Chemical Co. have reached an agreement to invest a total of $188 million for shale gas exploration in the Vaca Muerta formation. Under this agreement, Dow will invest $120 million while YPF will invest $68 million. Other companies exploring in the Neuquén Basin include Exxon Mobil, American Petrogas Inc (API), EOG Resources, and Madalena Ventures. In April 2014, Chevron Corp. confirmed its plan to continue investing in Argentina's shale sector with YPF to fund a $1.5 billion joint venture.

The central government persuaded the Central Bank to permit local banks to lend to YPF as if it were a private rather than public company (normally the Central Bank can only lend up to 35% of their gross assets to the public sector). The Neuquén Province government hopes to organise an international auction of areas on Vaca Muerta shale in 2014, but this may be undermined by disputes with the federal government.

Above Ground Determinants

Geological Information and Geography

- The Neuquén basin has already been a major oil and gas producer from conventional and tight gas, and therefore there will be a large amount of geological information.
- The area has a relatively low rainfall (30 cm/yr) and shale gas extraction may compete with agriculture for water.

Rights of Access to Resources and Land

- The Provincial governments control access to the shale gas resource, and their economic interest is to promote exploration and production. They have also established their own

provincial oil companies which raises the risk of conflicts of interest. However, the federal government is currently trying to wrest control of the licensing process from the Provinces.
- Landowners cannot prohibit access to the gas and local communities do not have formal participation in the decision-making process. As a result, the only way in which they can influence production and distribution is through civic or court action, and such actions are increasing in frequency.

Rapid Drilling

- Currently Argentina has about 80 rigs running. There is plentiful supply of skilled labour, older drilling equipment and logging/drilling services for conventional oil and gas exploration. However, rigs with top drives are in high demand and there is scarcely any fracking equipment in the country. In the Neuquén basin, pressure pumping capacity is in extremely short supply. The potential growth for service demand could be very large and it would take years to expand the service capacity.

Economic Incentives

- The increase in gas prices for new production should provide adequate financial incentive for shale gas exploration and production.
- The power of both federal and provincial governments to tax hydrocarbon production raises the risk of an uncoordinated escalation of the tax burden in the future ("the obsolescing bargain").

Market and Regulatory Environment

- Federal government agencies play an import role in regulating the upstream and downstream gas industry as well as environmental protection. This mix of federal and provincial regulation raises the risk of bureaucratic delays.
- The Neuquén Basin is relatively well served by pipelines. The gas pipeline system is governed by open-access regulations and the pipeline companies are obliged to expand their capacity to accept new supplies.
- A key regulatory risk is that of expropriation. Aided by the governments of Santa Cruz and Chubut Provinces, the federal government expropriated from the Spanish company, Repsol, its majority stake in YPF on the grounds of under-investment. It then transferred the stake to YPF and nationalised YPF. This action substantially raised the perceived political risk in Argentina.

The Two Scenarios (Figures 2.11, 2.12)

The "optimistic scenario" (Figure 2.11) sees shale gas production rising to 130 bcm per year by 2035. This would allow Argentina to develop the domestic gas market further, leading to higher gas demand. In addition it would also lead to a relatively rapid reduction in Argentina's net gas imports in the 2020s, with Argentina eventually emerging as a potential gas exporter.

In the "pessimistic scenario" (Figure 2.11) the production of shale gas reaches only 65 bcm/yr by 2035. With falling production of other (conventional) gas, it would be more difficult in this scenario for Argentina to develop its domestic gas market, and therefore gas demand would not increase by as much. Argentina remains a net importer for the most part with the net import requirement rising to 25 bcm/yr in 2025 before declining over the next decade. By 2035 Argentina could be a marginal gas exporter.

Figure 2.11 Argentina Scenarios for Gas Demand and Production (2010-2035)

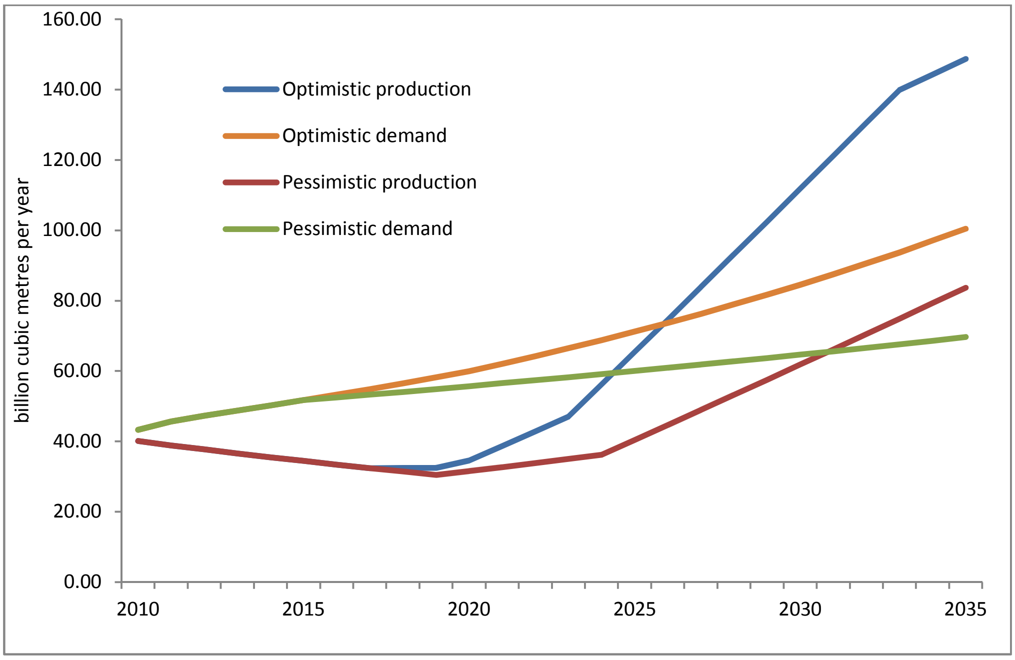
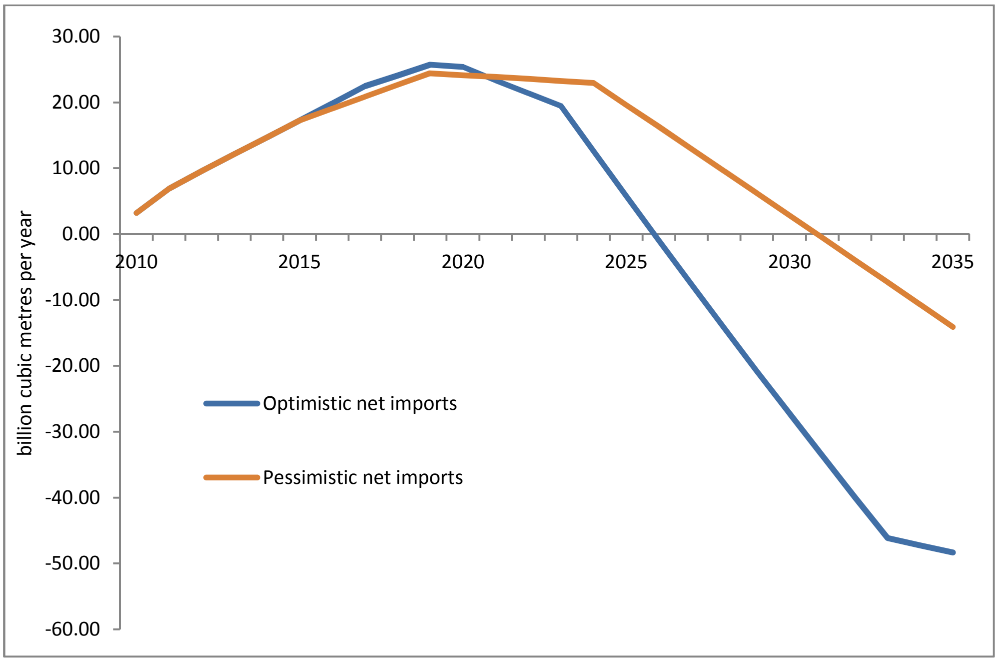


Figure 2.12 Argentina Scenarios for Gas Imports (2010-2035)



Probabilities:

- Optimistic scenario:30%
- Pessimistic scenario: 70%

2.2.7 United Kingdom[2]

Resource Potential

The US EIA estimates that the United Kingdom (UK) has approximately 0.74 tcm of risked, technically recoverable shale gas. The Carboniferous- and Jurassic-age shale formations in northern, southern and central regions of the UK highlight the substantial prospects of shale gas in the country. The British Geological Survey estimates that one of UK's largest shale formations - the Bowland shale - is far superior to one of the US highest producing plays - the Barnett shale. There is approximately 36.7 tcm of gas in place (GIP) in the Bowland Basin of north-west England, making shale gas development in the UK very prospective. Yet the UK shale resources are located at depths substantially deeper than equivalent shale plays in the US.

Motivations and Policies

UK's natural gas production has been on a long-term declining trend. In 2004, UK became a net importer of natural gas and in 2005 it became a net importer of crude oil. In recognition of its increasing dependence on imported fuels, the UK government needs to stimulate gas production to address the domestic production declines.

During 2014 the government announced a number of policies and proposals to support the exploitation of shale gas in the UK. These include tax breaks, a guaranteed flow of revenues to local communities and the removal of the right of landowners to block horizontal drilling beneath their land.

Progress and Plans

Exploration for shale gas is at an early stage in the UK. Until now, the only company that has conducted shale gas hydraulic fracturing is Cuadrilla, which carried out fracturing in April/May 2011 on the Preese Hall site in Lancashire. Cuadrilla is applying for permit to drill up to four wells on the Bowland shale as part of its efforts to make the UK the pioneer of Europe's shale industry. It is also hoping to produce test volumes in 2015, and commercial production is expected to take place at the end of the decade. Most companies that are active in Britain's shale gas industry are smaller or local companies, though the international oil company, Total, announced in January 2014 that it would undertake a major exploration programme.

Until now 12 shale gas exploration wells have been drilled. The next (14th) licensing round is planned for 2014, with shale gas areas available for licensing.

Above Ground Determinants

Geological Information and Geography

- Geological information in the prospective shale gas basins is readily available through the government.
- The significant groundwater strata are sandstones that lie between 600m and 1200m below ground level, much shallower than the shales. These sandstones are confined within impermeable geological formations and are therefore effectively isolated.

Rights of Access to Resources and Land

- The state owns the hydrocarbon resources. The Department of Energy & Climate Change (DECC) issues licenses to authorize the exploration, drilling and production. The

[2] Note: the cases of the UK and Poland have not been modelled separately using the Nexant World Gas Model, but are used to inform the scenarios and modelling for Europe.

operators, under the licenses, have exclusive rights to explore and/or exploit gas resources in the UK.
- All shale gas operations require access agreements with the relevant landowners where the operators do not own all or any of the land required for their operations. In the past it has also been necessary to obtain the consent of any neighbouring landowners beneath whose land the drilling will be undertaken. This requirement is in the process of being removed.

Rapid Drilling
- The UK is technologically advanced in horizontal drilling. However, it does not have an extensive onshore drilling services industry. Onshore rigs and associated equipment are not sufficient to meet the UK's shale gas market, which presents a barrier to the UK shale gas development.
- Political support for shale gas has been increasing, and public resistance in the north-west of England seems to have declined. However, demonstrations against shale gas exploration have occurred, notably in the south of England.

Economic Incentives
- The UK natural gas sector is fully privatized, from production, transmission, to distribution, and the domestic gas market is open and competitive. As a consequence, CBM and shale gas will have to be competitive with gas piped from the North Sea and mainland Europe and with LNG.
- Currently there is no fiscal regime specific for shale gas development in the UK. The 2014 Finance Act introduced some new measures to stimulate the shale gas industry development.

Market and Regulatory Environment
- The planning and permitting system in the UK for one exploration well to be drilled and fractured involves four agencies and two public consultations. This overly complicated system could hinder shale gas development in the UK.
- Before hydraulic fracturing begins, prior consent of the planning authority and the Environment Agency (EA) are required. The following environmental permits are needed: a water abstraction license; notification to the EA indicating the intention to drill; permits for waste treatment and the operation of waste facility. If the EA has any doubt that the groundwater may not be effectively protected, it is entitled to require additional permits to be obtained or to prohibit the activity.
- The UK has a nationwide pipeline network. Where capacity is available, third party access to the pipelines is granted. Where access to infrastructure is restricted, the energy regulatory authority in the UK may exempt major new pipelines from the provisions relating to third party access for a certain period, subject to the approval of the European Commission.

The Two Scenarios (Figures 2.13, 2.14)

The production of unconventional gas (shale gas and CBM) rises to 20 bcm/yr by 2035 in the optimistic scenario but to just 5 bcm/yr in the pessimistic scenario. Meanwhile the production of conventional gas from the UK continental shelf continues to decline. A further key factor is the scale of demand for natural gas in the UK. This is very difficult to forecast at present on account of the deep uncertainty concerning the future scale of nuclear and renewable power generation which could progressively replace gas. For this reason, two demand profiles are shown. Depending on the combination of supply and demand, net imports could rise from 40 bcm/yr today to 60 bcm/yr by 2035, or could fall to 20 bcm/yr.

Figure 2.13 UK Scenarios for Gas Demand and Production (2010-2035)

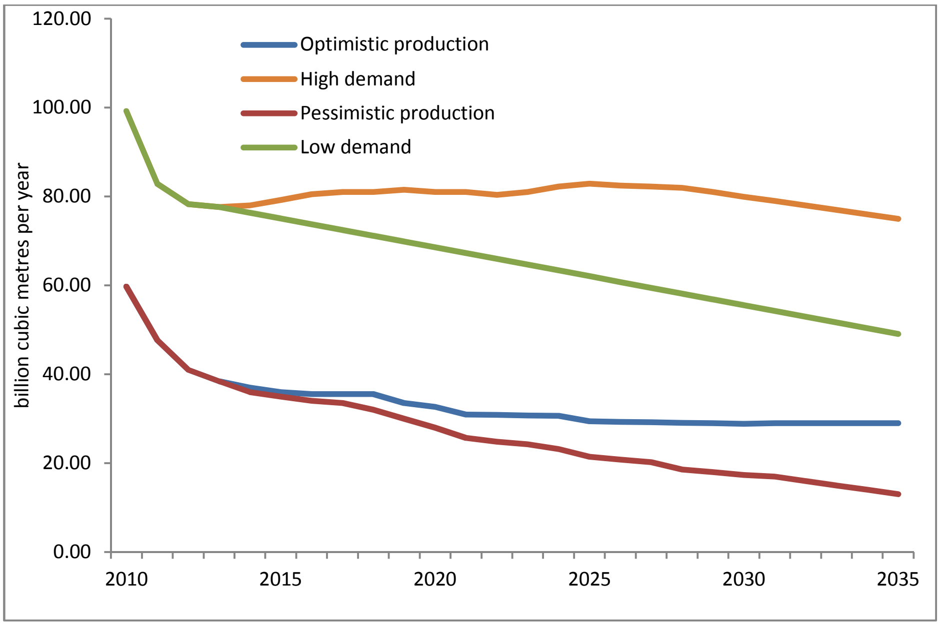
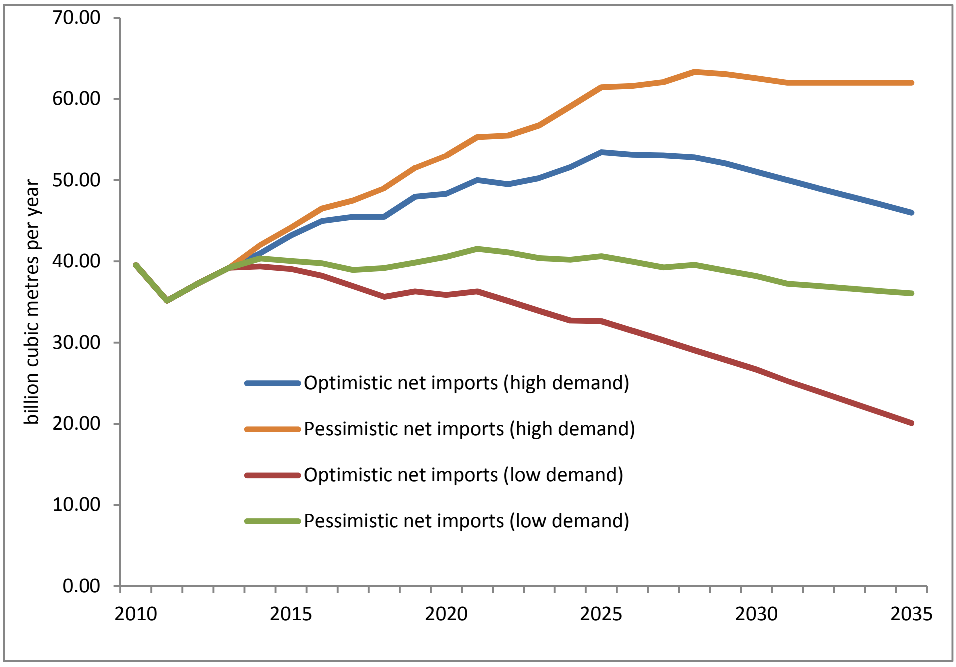


Figure 2.14 UK Scenarios for Net Gas Imports (2010-2035)



Probabilities:

- Optimistic production scenario: 50%
- Pessimistic production scenario: 50%

2.2.8 Poland[3]

Resource Potential

The US EIA estimates that Poland's risked, technically recoverable shale gas in four basins (Baltic/Warsaw Trough, Lublin, Podlasie and Fore Sudetic) is approximately 4.13 tcm. The Baltic Basin is shown to have the most potential due to its relatively simple structure, while the Podlasie and Lublin Basins have great potential but a more complex structural setting. In addition, the Fore Sudetic Basin has non-marine coaly shale potential.

Motivations and Policies

Poland's plan to accelerate its search for shale gas stems from its goal of reducing its reliance on Russian gas. A new draft law providing more attractive conditions has been drafted to develop unconventional gas in Poland. Previous regulations that gave a state company the right to a stake in every concession have been abolished. The new law would streamline the system with just one license for developers to cover exploration, surveying, and exploitation, rather than the current three-tier system covering each stage respectively. Yet the new law will place tougher controls and inspections on the companies that invest in unconventional resources. As of June 2014, this draft law was under deliberation in the lower house of parliament.

Progress and Plans

As of May 2013, 109 shale gas exploration licenses had been awarded, covering more than 35,000 km^2, no less than one-third of the country's area. At that time 30 vertical exploration wells, and six vertical and two horizontal production test wells had been drilled. Lane Energy Poland, an exploration company controlled by ConocoPhillips, began shale gas production of about 8,000 cubic metres per day from its test well in Lebork in the north of Poland.

Polskie Gornictwo Naftowe i Gazownictwo (PGNiG), the national oil and gas company of Poland, has stepped up exploration. As of June 2013, PGNiG held 15 shale gas exploration licenses and had drilled four exploration wells in the Baltic Basin. These wells have produced shale gas from two vertical wells. Recent news shows that it may take six more years to make shale gas production commercially viable, as exploration has failed to meet expectations.

Above Ground Determinants

Geological Information and Geography

- As there has been little oil and gas exploration in Poland, relevant geological information on shale gas is in short supply.

Rights of Access to Resources and Land

- The issue of access to land in Poland is governed by general rules of law and the agreement with the land owner. The right of mining ownership is owned by the State Treasury.
- To conduct exploration or exploitation activities in Poland, an entity needs to possess title to the surface of the land. Two steps are compulsory. The first is to obtain a licence for exploration or exploitation activities; the second is to conclude a mining usufruct agreement. Once the relevant licence is granted, the agreement will be executed immediately.

[3] Note: the cases of the UK and Poland have not been modelled separately using the Nexant World Gas Model, but are used to inform the scenarios and modelling for Europe.

- The shale gas industry in Poland faces strong opposition from environmental groups that remain concerned about hydraulic fracturing and continue to confront large oil and gas businesses on the potential problems of water contamination and the destruction of the landscape from the fracking process.

Rapid Drilling

- There is widespread public support for shale gas development, notwithstanding the opposition of environmental groups.
- Currently there are two major players involved in the drilling service in Poland. One is the United Oilfield Services (UOS); the other is Exalo, a PGNiG-owned entity made of several PGNiG subsidiaries. Both are domestic companies.
- Drilling is not as prospective as it appears to be. Poland has grown in the number of exploration wells since 2009, but the growth rate has not been fast enough to accommodate the new rigs. In 2012, the market was oversupplied. Drilling activity declined in Poland in 2013. Some companies are leaving the market.
- In addition to oversupply in quantity, the quality and age of these rigs is not up to standard.

Economic Incentives

- Poland implemented favourable policies for shale gas development, including a simple tax and royalty fiscal system. The investing company is exempted from mandatory government back-in rights, and enjoys reduced production royalties.
- Poland has tried to make the fiscal regime more attractive to unconventional gas investors. The tax to the companies investing in unconventional gas will be less than those companies developing conventional deposits. Yet the taxation will not start until 2020.
- The Polish gas market is still effectively monopolized by PGNiG, which sells gas at a rate set by the regulator. Currently the price is at around $525 per tcm, roughly 30% higher than the average on the European continent.

Market and Regulatory Environment

- Oil and gas exploration activities are subject to general Polish mining regulations, particularly the Geological and Mining Law Act (GML), which was established by the chamber of the Polish Parliament and came into force on 1 January 2012.
- There is doubt about whether the GML 2012 can guarantee fair play in the concession award process. Not all the evaluation criteria of the offers for exploration and extraction of the hydrocarbons are publicly available and transparent.
- Institutional inefficiencies and unclear division of powers in the policy-making hinders shale industry development. Currently it takes about 130 days to obtain a license in Poland.
- Poland has a mature pipeline system. Third party access to pipeline infrastructure requires domestic policy reform, which is underway.

The Two Scenarios (Figures 2.15, 2.16)

The production of natural gas, mainly shale gas, rises to 22 bcm/yr by 2035 in the optimistic scenario but to just 5 bcm/yr in the pessimistic scenario. The scale of demand for natural gas is likely to be related, in part, to the level of domestic gas production as well as to broader energy policy decisions to switch from coal to natural gas. In the optimistic scenario, rising demand causes net imports of gas to rise from 11 bcm/yr in 2013 to 17 bcm/yr by 2019 before steadily falling to 5 bcm/yr by 2035. Under the pessimistic scenario, net gas imports remain in the range 11-13 bcm/yr through the period to 2035.

Figure 2.15 Poland Scenarios for Gas Demand and Production (2010-2035)

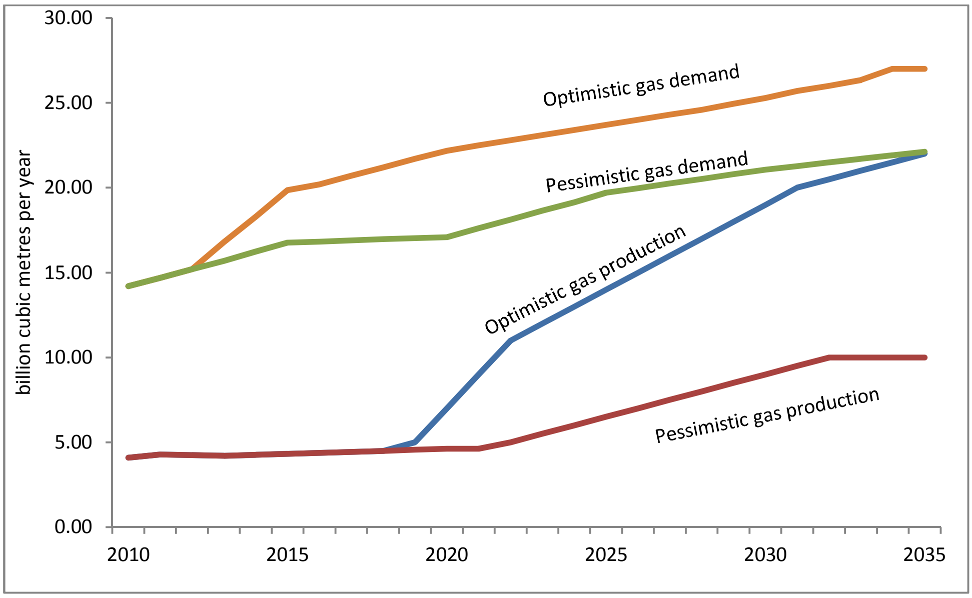
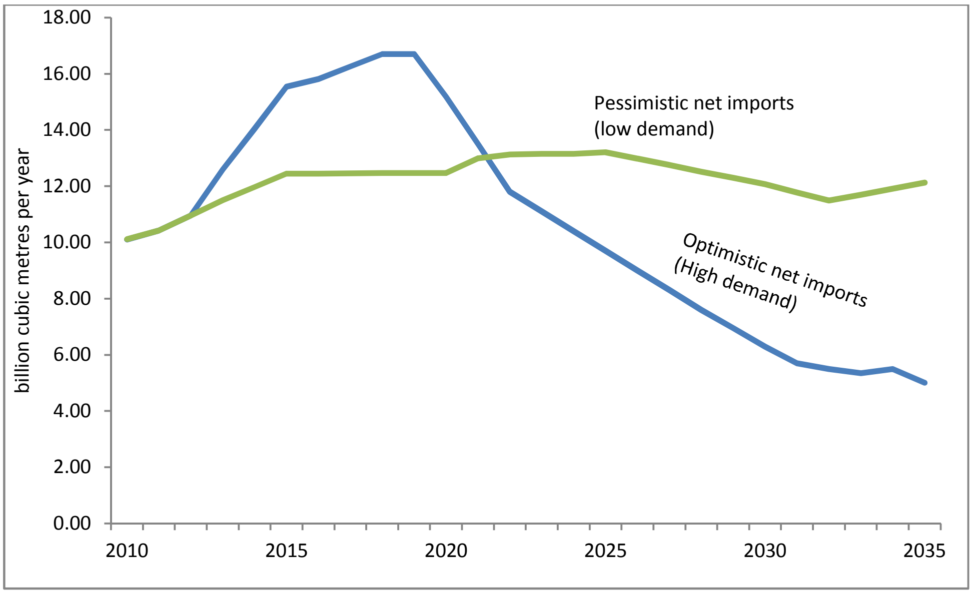


Figure 2.16 Poland Scenarios for Net Gas Imports (2010-2035)



Probabilities:

- Optimistic scenario: 50%
- Pessimistic scenario: 50%

2.2.9 European Union

In this project, we have treated the European Union as a single gas market because it was not feasible to model a large number of separate European countries. Also, the constant fluctuations in national government policy makes it extremely difficult to assess which countries will be producing significant quantities of shale gas by 2035. As a consequence we have produced an overall EU projection for the purposes of modelling, and have used the UK and Poland as illustrations of countries which are trying to move forward with shale gas.

Resource Potential

The US EIA estimates that the European Union (EU) could hold about 12 tcm of recoverable shale gas reserves across several member states, but with more than half of these reserves lying in Poland and France. Compared to the US, the EU's geology is less favourable for shale gas development.

Motivations and Policies

Domestic production of conventional national gas is declining in Europe and dependence on external supply is growing. This makes Europe vulnerable to supply interruptions and fluctuations in energy prices. Unconventional resources, such as shale gas, could replace conventional resources and improve energy security and price stability.

The EU's 27 member states have the right to make individual decisions about their energy mix and on the issue of hydraulic fracturing, which means that national governments retain the right to decide if and where they want to explore shale gas.

Progress and Plans

There is currently no commercial production of shale gas, but the European Commission has stated that commercial drilling could commence in 2015. In the meantime, explorative drilling is essential in order to confirm Europe's potential reserves. Exploration is currently taking place in the UK, Poland, Germany, Romania, Denmark and Hungary. Bulgaria, the Czech Republic, France, Luxembourg and the Netherlands have not permitted hydraulic fracturing.

Above Ground Determinants

Geological Information and Geography

- Geological information in the prospective shale gas basins of some Member States is relatively abundant and can be accessed through the government, such as UK, while the information of some other Member States is not readily available, such as Poland.

Rights of Access to Resources and Land

- The landowners in the EU do not possess the mineral rights. This removes a compelling incentive for landowners to cooperate in the exploration of shale gas on their lands.
- Compared to the US, farm plots are smaller and land ownership is more diffuse in Europe, which makes any request for land access more complicated and slower as developers have to deal more often with the government bureaucracy and with more land owners.

Rapid Drilling

- Compared to the US, the EU has fewer smaller exploration and production companies and less service companies.
- The EU does not have significant onshore gas production, except in the Netherlands, which makes the presence of shale gas equipment and activities more disconcerting for the local communities.
- The EU does not have a large number of land rigs and does not have large quantities of equipment for onshore hydraulic fracturing.
- In general, there is widespread public opposition to hydraulic fracturing and the European governments are highly sensitive to the public's sentiments on this topic. Public disruption could be the main barrier to shale gas operations in the densely populated parts of Europe.

Economic Incentives

- Compared to the US, the EU has a more restricted regional gas market.
- There are fewer pipelines, and a more restricted pipeline access regime which would make it more challenging to bring any gas produced to the market in the EU.
- A competitive pipeline market is one of the central objectives of the energy market liberalization process in the EU. It is not yet on track to meet the target of completing the internal energy market by 2014.
- In general, there is no fiscal regime specific for shale gas development in the EU.

Market and Regulatory System

- The European Commission is not going to establish binding measures on shale gas.
- The positions of the EU Member States on shale gas policy and legislation are quite divergent. Some, such as France, have banned the activity, whereas others, such as Poland and the UK, have conducted exploratory drilling. The current Ukraine crisis may force some governments to reconsider their bans.
- Compared to the US, EU developers operate under a stricter work programme detailing different stages of development, along with a stricter programme of inspections. This makes it less suitable for unconventional gas exploration since the exploration process requires a wide degree of flexibility involving multiple wells and constant adjustments as drilling proceeds.
- The EU has tighter environmental regulations which make shale gas exploration more complicated in places that have permitted such activities.

The Two Scenarios (Figures 2.17, 2.18)

Unconventional gas production in the EU rises to 100 bcm/yr by 2035 in the optimistic scenario, but to only 20 bcm/yr in the pessimistic scenario. A single projection of gas demand is used, based on the European Commission's own projections of gradually declining demand. In the optimistic scenario, net imports decline from 315 bcm/yr today to 250 bcm/yr by 2035. In contrast, net imports fluctuate in the range of 295-320 bcm/yr in the pessimistic scenario.

Figure 2.17 EU Scenarios for Gas Demand and Production (2010-2035)

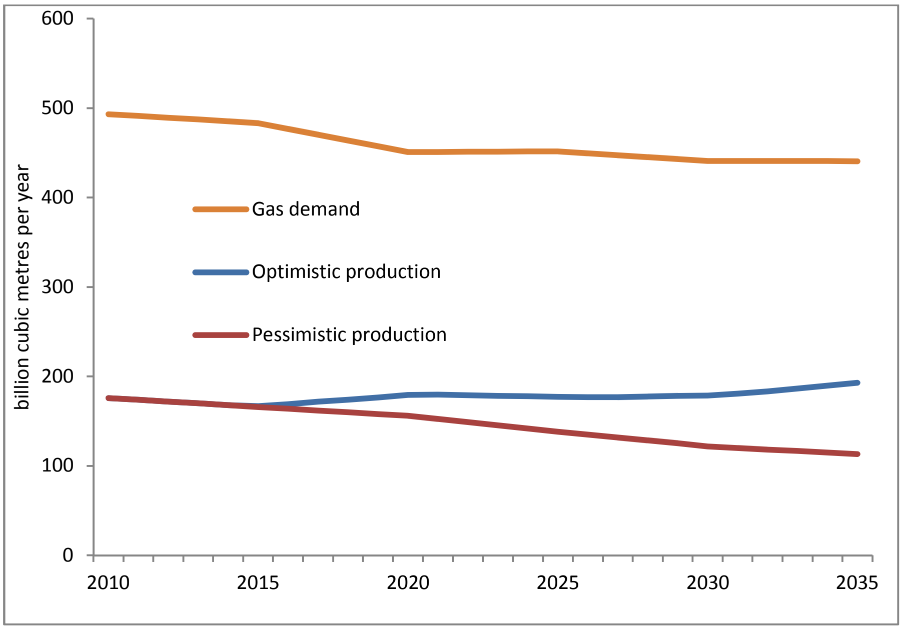
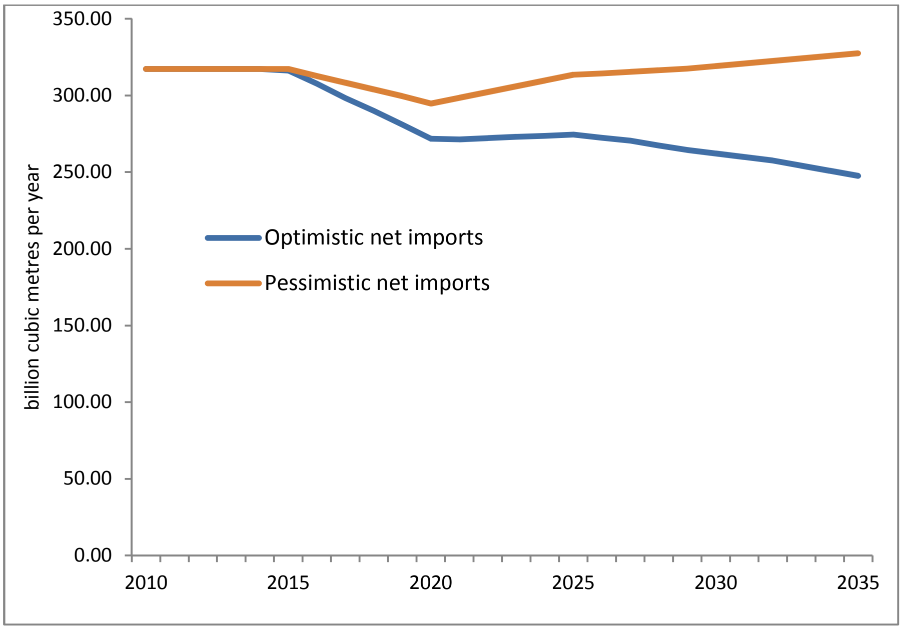


Figure 2.18 EU Scenarios for Net Gas Imports (2010-2035)



Probabilities:

- Optimistic scenario: 40%
- Pessimistic scenario: 60%

2.3 Other Cases

2.3.1 Gas Hydrates

Resource Potential

Gas hydrates occur in a wide range of geographical locations and geological settings (Figures 2.19 and 2.20). The vast proportion of these hydrates is believed to lie in deep marine settings. However, a small proportion is found in onshore locations, within permafrost in the Arctic and on the Tibetan Plateau, and these hydrates are likely to be cheaper to exploit than those lying in the deep sea. The total global resource of gas hydrate is estimated as being as high as 20 tcm, with a significant share occurring within the Asian region, both onshore in China and Russia and offshore in the western Pacific Ocean, in Southeast Asia and in the India Ocean. The state of knowledge is such that this estimate is little better than a guess, but hydrates do appear to represent the world's largest potential sources of natural gas if existing technologies can be adapted to exploit them economically and safely.

Technologies for Exploitation

The production of gas from hydrates is much more complex and challenging than the exploitation of conventional gas accumulations. The three possible methods for recovering methane trapped in the hydrate deposits are thermal stimulation, depressurization and chemical injection. While the technology for applying these methods for conventional fossil fuels is mature, they cannot be directly employed for unconventional methane hydrate deposits. Recent efforts on laboratory tests have revealed that thermal stimulation and depressurization might not be an economically suitable as standalone production methods and that a combination of both can work to great advantage to sustain natural gas production from these hydrate deposits.

Another approach that is gaining a lot of traction, belonging to the class of "chemical injection" methods, involves the injection of carbon dioxide to produce natural gas from these hydrate deposits. This process would secure the future energy needs and mitigate carbon dioxide emissions simultaneously by replacing methane trapped in the gas hydrate deposits with carbon dioxide. This is feasible because CO_2 hydrate is more stable than the existing methane hydrates at the prevailing conditions of pressure (depth) and temperature.

Environmental and Safety Risks

The main environmental risk involved in the extraction of gas hydrates, regardless of location and geological setting, is the uncontrolled release of methane into the atmosphere. This risk applies to both onshore and offshore locations. Extraction activities on permafrost in the Arctic or on Asian plateaus will require additional care to be taken to manage the impacts on surface and ground waters, wildlife and vegetation. At all locations, the safe management of drilling operations will be a major priority in order to protect personnel and equipment.

Field Tests

Most field tests on gas hydrates have taken place in the Arctic on account of the lower costs and less demanding engineering challenges in comparison to the deep marine setting. The longest running programme is at the Mallik site in the Mackenzie River delta in the Canadian Arctic. This programme dates back to 1998 and is led by a consortium including Japan, Canada and the USA. It has shown that sustained gas flows of thousands of cubic metres per day can be achieved from a sand reservoir using conventional gas field technologies with slight modifications in design. Similar test programmes are under way in Alaska. These locations have the advantage of being close to existing oil and gas field infrastructure. China has been testing permafrost hydrate production in the Qinghai-Tibet region since 2007, and Gazprom is funding research in West Siberia.

A number of countries have been testing deep marine hydrates, notably Japan, the USA, China, Korea, Malaysia and India. The area of most intense activity is in the northwest Pacific Ocean and its marginal seas where the gas-importing nations of Japan, China and Korea hope to exploit nearby sources of natural gas. Japan cemented its position as the world leader in the development of deep marine hydrates by carrying out a sustained flow test in the Nankai Trough in March 2013.

Outlook

Whilst there are no technology stoppers for exploiting this huge resource, specific technological breakthroughs will depend on the effective management of the sand and water production during the production of natural gas from hydrate deposits, as well as the appropriate mitigation of environmental risks. It is highly likely that permafrost natural gas hydrate deposits located in Canada, the USA, Russia and China will be exploited before the deep marine accumulations and that some production may be achieved by 2020. Whilst Japan and Korea have announced their intention to start commercial production of gas from deep marine hydrates by 2016, this is likely to be at a very small scale. In addition to the technological, safety and environmental challenges, the sustained, large-scale production of natural gas from hydrates will also depend on the prevailing gas price.

In conclusion, the outlook for the production of natural gas from hydrates is very uncertain. The history of shale gas in the USA has shown that the timing of technological and commercial breakthroughs is unpredictable, as is the scale of production after the breakthrough. Over the period to 2035, we would expect that the technical challenges for the exploitation of onshore and deep marine hydrates will have been largely solved. The key issue will be whether the cost of production is competitive with other sources of gas supply (including shale gas, tight gas and CBM) and whether certain countries, like Japan, Korea and China, are prepared to subsidise production on the grounds of security of supply. Environmental opposition is likely to be significant.

Scenarios

For the purposes of our quantitative analysis, we have assumed that the production of gas from hydrates does not reach any significant level before 2035. However, it is necessary to watch developments closely as this could be one of the "Black Swans" that has a disruptive effect on international gas markets (see Chapter 4).

Figure 2.19 Map of Discovered And Inferred Gas Hydrate Deposits. "Gas Hydrate Recovered" Refers to Recovery of Gas Hydrates for Research Purposes.[4]

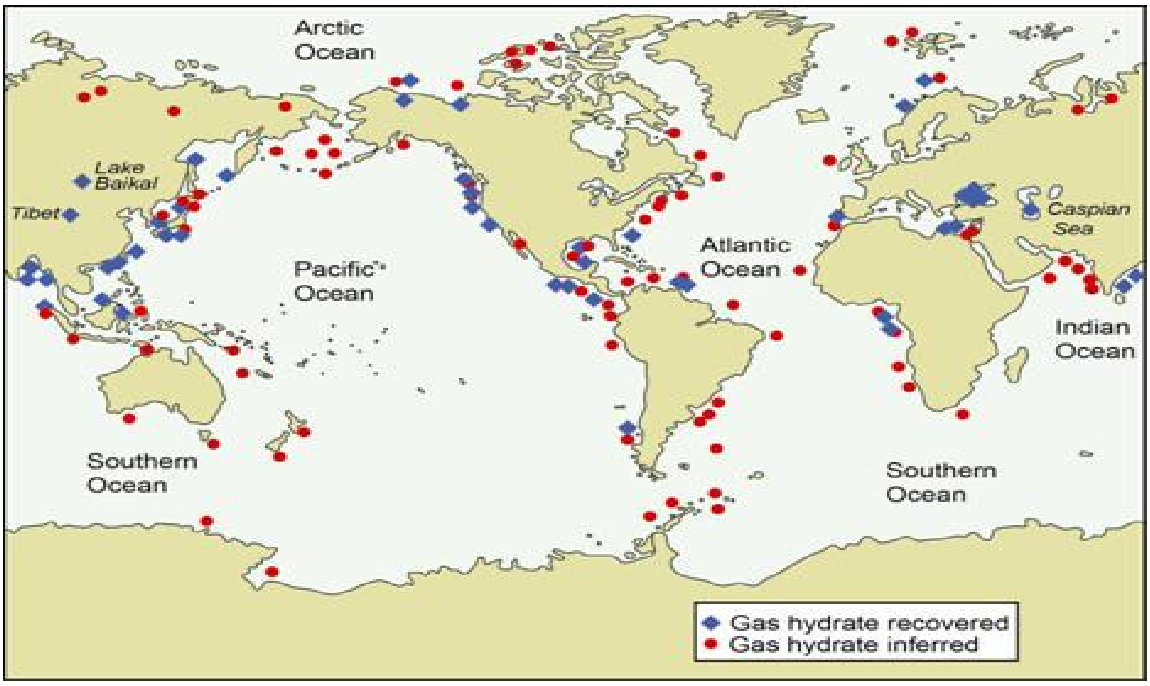
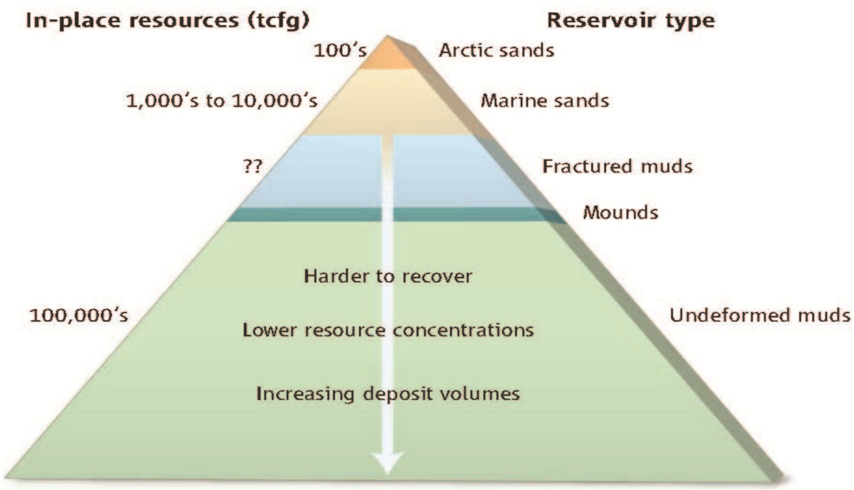


Figure 2.20. Natural Gas Hydrate Pyramid Showing the Relative Share of Resources in Different Geological Settings (tfcg = Trillion Cubic Feet of Gas).[5]



[4] Source: United States Geological Survey (2013). http://woodshole.er.usgs.gov/project-pages/hydrates/primer.html

[5] Source: Boswell, R., 2009. Is gas hydrate energy within reach? *Science* 325(5943), 957-958.

2.3.2 East Africa (Mozambique and Tanzania)

East Africa is included as a case study, despite not having significant potential for unconventional gas, because it is set to emerge as a major new supplier of LNG to South and Southeast Asia. This, in turn, is likely to reduce the call on gas from Australia and North America.

Resource Potential

Mozambique's gas reserves are estimated to be in the range 7.1 tcm to 8.5 tcm, almost as much as the US reserves, which are about 9.3 tcm. Tanzania's gas reserves are estimated at 1.2 tcm with the Petroleum Development Authority indicating that they could be as high as 6 tcm. These rich gas resources have prompted plans to develop LNG export facilities in both countries. Mozambique is planning to build a large 20 mtpa liquefaction plant (with potential to expand to 50 mtpa) and Tanzania a 10 mtpa plant. LNG exports from these plants could start around 2020.

Progress in Mozambique and Tanzania

The Rovuma offshore field in Mozambique is attracting major interest. Anadarko, ENI, and Statoil are actively operating several areas within this field. Anadarko has drilled more than a dozen successful wells. ENI has announced that it encountered a gas column measuring about 80-feet thick while drilling its Agulha 2 well in the Rovuma basin. The government will auction rights to develop Rovuma gas for the domestic market. First gas from the Rovuma Basin is expected in 2018. The government has yet to make a decision on how much Rovuma Basin gas will be allocated to the domestic market. ENI and Anadarko are also discussing the unitisation of the giant Prosperidade gas find and the development of a 20 mtpa onshore liquefaction plant. Since 2004, Mozambique has been exporting natural gas to South Africa via the Sasol Petroleum International Gas Pipeline with a peak capacity of 14.8 million cubic metres per day. Besides the Sasol Petroleum International Gas Pipeline, a second major pipeline to South Africa is being planned: the Gasnosu pipeline from Cabo Delgado in Mozambique to South Africa. If approved by the government, construction on Gasnosu will begin in 2016 and is expected to be operational by 2018.

In Tanzania, BG, Ophir Energy, Statoil, and ExxonMobil operate several blocks. BG and its partner Ophir made a series of discoveries in 2011 and 2012. They found in-place reserves in the blocks (#1, #3, and #4) in the range 480-600 bcm, up to the threshold necessary to support a two-train LNG project. Statoil and ExxonMobil operate one block (#2) offshore Tanzania. Besides the existing discoveries in Block 2, Statoil has made new discoveries and is acquiring new 3D seismic technology to help identify additional targets in the block, boosting discovered gas volumes by 57-85 bcm. This brings the total discovered gas volumes in Block 2 to about 570 bcm. The large size of these reserves has led the government to encourage BG and Statoil to consider developing a single unitised LNG plant for all these discoveries. As a consequence, the partners in blocks 1, 3 and 4 and other partners in Block 2 have signed a Heads of Agreement setting out how license partners in the blocks will collaborate on the potential two-train, 10 mtpa LNG project.

Policy Constraints

A draft petroleum policy document from the Tanzanian government suggests that the government does not intend to ease contract terms for the oil and gas sector. In the meantime, operators such as BG and Statoil will not move forward with LNG export plans until the petroleum policy (long-anticipated Gas Act) is approved and published. However, the current debate about Tanzania's constitutional reforms has delayed the approval of the Gas Act, which is expected to be agreed in 2015. Hence, the LNG project sponsors may sanction the project in 2016. In particular, the fiscal terms in Tanzania's model production sharing agreement are among the toughest in Africa. Tanzania's offshore royalty rate has been raised from 5% to 7.5%.

A minimum signature bonus payment of $2.5 million and a production bonus of at least $5 million are required. The level of exploration work commitment in the initial term of agreements has also been increased. All these factors are deterring investments in the Tanzanian gas sector.

In Mozambique barriers to investment remain and a competitive market environment in the economy has yet to be established. Excessive administrative delays and a weak legal system are key challenges for energy/gas sector development in the country. Most business enterprises in Mozambique need a license to operate and the licensing process is still complicated and cumbersome. Preparation of the necessary documents may involve several government departments and is very time consuming. To improve the process and encourage development of petroleum and gas industry in Mozambique, the Ministry of Mining has submitted a decree law laying out the framework for exploration and production contracts in the country to the Council of Ministers. It is hoped that the law, along with the proposed change to Mozambique's petroleum and fiscal legislation, is passed before the national elections in October 2014.

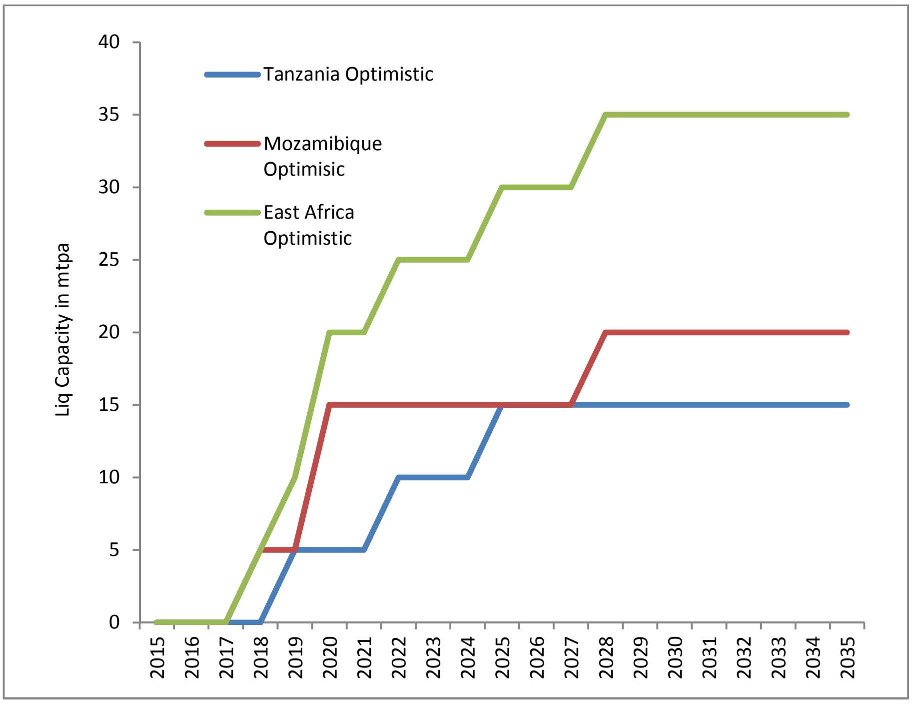
Scenarios (Figure 2.21)

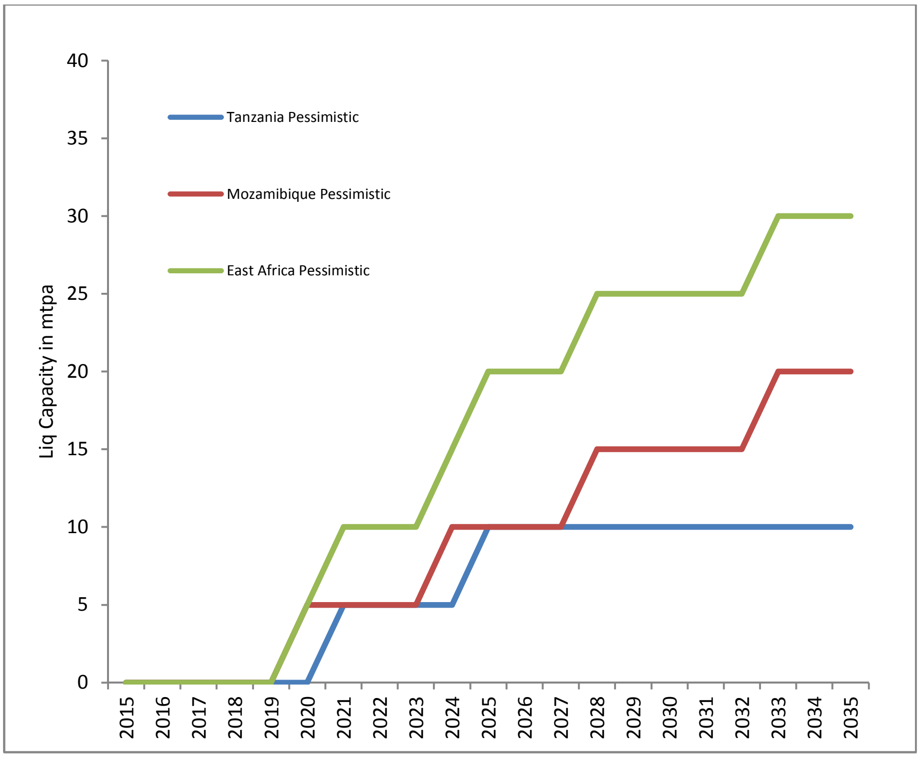
The key differences between the optimistic and pessimistic cases for East Africa are the start dates of the LNG plants and then the speed of ramp up towards an ultimate goal of 50 mtpa liquefaction capacity in Mozambique. In the optimistic scenario the first train of the 10 mtpa onshore liquefaction plant in Tanzania starts up in 2019 and the second in 2022. The first two trains of the Mozambique onshore LNG plant start-up in 2020, but if ENI goes ahead with its proposed offshore floating liquefaction plant (FLNG) it starts up in 2018. The sponsors move towards their ultimate goal of 50 mtpa of liquefaction capacity by adding a further 5 mtpa train every three years and having 35 mtpa of capacity by 2035.

In the pessimistic scenario, start-up of the new onshore facilities is delayed due to the time taken to secure agreements with host governments and later buyer acceptance due to strong competition from USA and Canada. In this case the first train is brought on in Tanzania in 2021 and the second in 2025. In Mozambique the FLNG unit does not come on until 2020 and start-up of the onshore plant is delayed to 2024. It also starts with one train rather than two and the additional trains are added every five years rather than the three years in the optimistic scenario. Liquefaction capacity in 2035 is 20 mtpa in Mozambique and 10 mtpa in Tanzania.

LNG exports from East Africa are 12 mtpa in 2025 rising to 36 mtpa in 2035 in the Optimistic case and 5 mtpa and 30 mtpa respectively in the pessimistic scenario.

Figure 2.21 East Africa Scenarios for LNG Capacity in mtpa (2015-2035).





2.3.3 Russia

Russia is included as a case study on account of the vast scale of its proven and potential gas reserves and because of its ability to supply both European and Asian gas markets.

Resource Potential

Russia holds the world's largest natural gas reserves, with 33 tcm as of 1st January 2013, accounting for about 17% of the world's total proven reserves. The bulk of its natural gas reserves under development and production are in Western Siberia, whereas Gazprom (Russia's largest energy company) is increasingly investing in new regions, in the north and east of the country. In 2012, Russia was the world's second-largest dry natural gas producer (592 bcm), second only to the United States (681 bcm). Most of its natural gas was exported to Europe.

Russia-Europe Gas Relations

Europe is the biggest market for Russian gas and Russia is the largest supplier of gas to Europe. Abrupt disruption to these supplies is mutually destructive. Understanding this, Europe is trying to reduce dependence on Russia and develop alternative sources of supply. Yet this is not easy. Europe is seeking piecemeal solutions such as increasing gas imports from other sources as LNG and via pipeline, greater spending on renewable energy and a re-think on nuclear power. It is expected to see a long term decline in gas supply from Russia to Europe.

The Russian piped-gas supply could be replaced by LNG. Europe already has 142 bcm of LNG terminal capacity which is scheduled to increase to 192 bcm by 2017. The problem is that their small amount of imports (53 bcm in 2013) has led the LNG producers to lose faith in Europe as a customer and to direct production away from Europe to Asia. This has made it more difficult for the European buyers to secure additional LNG. Without a clearly articulated energy policy, Europe can only muddle through these difficulties. The current Ukrainian crisis forces Russia to take meaningful steps to "look East" and develop Asian markets. In the long-run, Russia's total gas exports to Asia Pacific by pipeline and in the form of LNG could be higher than their sales to Europe.

Russia-China Gas Relations

On 21st May 2014 China and Russia signed a $400 billion gas supply deal for 38 bcm piped gas exports per year, which opens up a new market for Russia as it risks losing European customers over the Ukraine crisis. The deal will be the catalyst allowing the development of the east Siberian reserves and the development of Asian markets for both piped gas and LNG. It assumes that the development of the Sobinsko-Palginskoye, Kovyktinskoye (reserves of 1.5 tcm) and Chayyandinskoye (reserves of 1.2 tcm) gas fields and then the construction of the Power of Siberia pipeline from Kovyktinskoye to Vladivostok will enable the transfer of production in the Yakutia and Irkutsk regions to the Pacific coast.

Currently, China-Russian relations are in good shape and it is expected that the relations will continue to improve. However, the deal does not mean that Russia is giving up on Europe. Although the deal is significant, the volume is still much smaller than Russian exports to Europe. In 2013, Gazprom supplied Western Europe and Turkey with over 160 bcm of gas, dwarfing the proposed deal of 38 bcm per year to China. The China-Russia deal does not significantly affect European gas supply and its energy consumption structure.

Scenarios (Figures 2.22, 2.23)

Russia is the world's largest producer of natural gas and its ability to act as the swing producer endows it with considerable market power. The Russian shift towards supplying gas towards the east is projected to be well supported by the expansion of Sakhalin LNG and the construction of the Vladivostok LNG trains, which will enable Russia to supply Asian demand for LNG. Pipeline flows to Europe decline as Europe moves away from piped gas from Russia to LNG exports from Africa and North America. The pipeline gas supply agreement with China as well as possible additional projects will increase pipeline exports to Asia. All of this leads to the Russian export scenario as shown in Figure 2.22 and Figure 2.23.

Figure 2.22 Russia Projections of Gas Production and Demand (2005-2035)

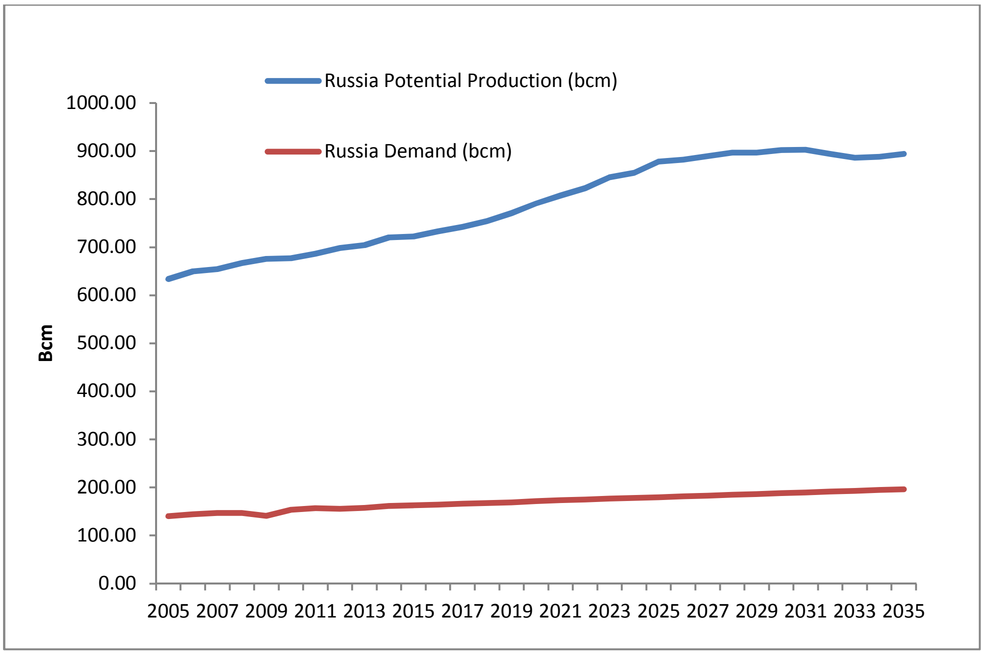
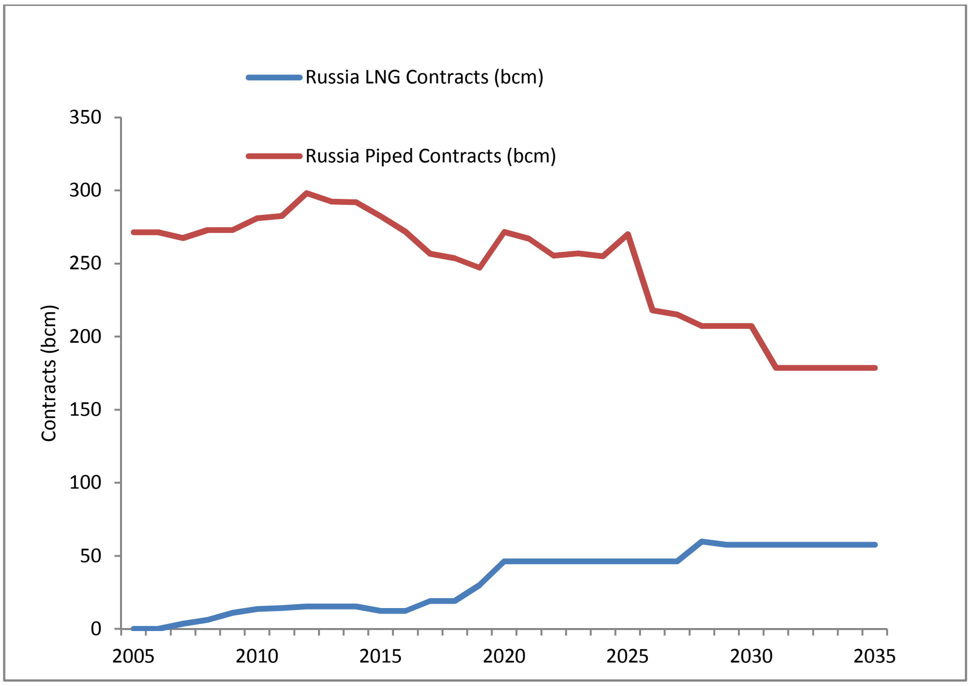


Figure 2.23 Russia Projections of Gas Export Contracts (2005-2035)



2.4 Main Findings

The main findings are as follows (see Table 2.1):

The Importance of Above-Ground Factors

Geological conditions are clearly a critical determinant of the potential levels of unconventional gas production. However, above-ground factors will constrain shale gas and CBM production in most countries, and the nature of these constraints will vary greatly between countries. As a consequence there is probably no country that can reproduce the US experience. Of the countries which are actively pursuing shale gas exploration, China and Argentina have the largest potential reserves, but above ground factors may pose serious constraints to future production, especially in Argentina.

Net Gas Importers with Rapidly Growing Demand

In those countries which are currently net importers of gas, such as China, India and Argentina, a significant proportion of incremental unconventional gas production will be consumed domestically. This is because a combination of economic growth, rising energy demand and fuel switching will allow the domestic gas market to absorb most or all of the incremental domestic gas production Any decline in net imports will be significantly less than the rise in total gas production. A substantial rise in the production of unconventional gas in any of these countries might lead only to a modest decline in the rate of growth of net gas imports.

Net Gas Exporters with Rapidly Growing Demand

In those countries which are currently net exporters of gas and which have a rapidly rising domestic demand for gas, such as Indonesia, the additional supplies from unconventional gas may not result in significantly greater gas exports as much of the incremental gas production will be devoted to the domestic gas market.

Net Gas Exporters with Slowly Growing Demand

In those countries which are currently net exporters of gas but where gas demand is rising only slowly, such as Australia and Canada, any increase in exports arising from unconventional gas production will be constrained by the availability of LNG export capacity and by global demand for LNG. In these cases, the rate at which unconventional gas reserves are brought into production will be determined more by the demand from international gas markets than by domestic, above-ground factors.

Gas Hydrates

It is difficult to foresee the timing of the start of significant commercial exploitation of gas hydrates, but the first locations are likely to be in the Asia-Pacific region, either onshore or offshore.

East Africa

Tanzania and Mozambique are set to become significant exports of LNG, but uncertainty remains as to the timing of these exports because of a number of policy and regulatory challenges.

Table 2.1 – Unconventional Gas Production and Net Exports (Imports) for Optimistic and Pessimistic Scenarios for Different Countries

bcm/yr	**Unconventional Gas Production by 2035**		**Natural Gas Exports (Imports) by 2035**	
	Optimistic	Pessimistic	Optimistic	Pessimistic
China	250	100	(150)	(200)
Indonesia	60	30	50	20
Australia	120	55	196	128
Canada**	205	100	70	55
India	30	15	(85)	(100)
Argentina	130	65	50	10
UK	20	5	(20)	(60)
Poland	22	5	(5)	(11)
EU	100	20	(250)	(320)
East Africa*	**LNG Liquefaction Capacity by 2035**		**Natural Gas Exports (Imports) by 2035**	
	Optimistic	Pessimistic	Optimistic	Pessimistic
	48	40	48	32
Russia*	**LNG Exports by 2035**		**Gas Pipeline Exports by 2035**	
	50		170	

**East African and Russian scenarios are driven by conventional gas production.*
***In the Canadian scenarios the figures for natural gas exports refer to export capacity not to actual exports.*

CHAPTER 3. MODELLING GLOBAL GAS MARKETS

3.1 Objective, Methodology and Case Selection

3.1.1 Objective

The geological, political and economic analysis of individual countries in the preceding sections estimated unconventional gas potential for each country. This involves estimates of production and demand figures for optimistic and pessimistic scenarios. Such figures are helpful for studying the potential impact of unconventional gas sources on the domestic sector. But the global impact of unconventional gas production can be better understood if we also take into account the implications for international trade. In this section we study the impact of unconventional gas, both at the domestic and global scale, using the Nexant World Gas Model (WGM) with the objective of identifying the potential impacts on international trade flows and prices of natural gas up to the year 2035.

3.1.2 Choice of Cases for Modelling

We aggregated the outputs from the 12 country case studies described in Chapter 2 to develop four cases for modelling. Three of these consider different scenarios of unconventional gas development, namely (i) Australia – Optimistic and Pessimistic cases (ii) North America – Optimistic and Pessimistic cases (iii) Global – Optimistic and Pessimistic cases. In addition we consider a fourth scenario looking at new conventional gas development: (iv) East Africa – Optimistic and Pessimistic cases. We have also developed a Base Case to study how the gas market may evolve to 2035 with relatively modest supplies of gas from unconventional gas sources.

The Australian, North American, and East African scenarios follow the Chapter 2 case studies of Australia, Canada and East Africa respectively. In the North American scenario, we also used the unconventional gas data for the US to come up with the optimistic and pessimistic North American scenarios. The global optimistic scenario is optimistic about unconventional gas in China, India and Indonesia and conservative/pessimistic about unconventional gas in other regions. The global pessimistic scenario considers a low case where unconventional gas prospects for all regions are conservative/pessimistic.

The assumptions for Russian production, and pipeline and LNG trade profile are separately modelled and used. Russia is the largest producer of natural gas and its ability to act as the swing producer endows it with considerable market power. Hence we used the Russian scenario, with pipeline flows to Europe gradually declining, replaced by LNG exports and increased exports to China, as a common input to all the case studies. Thus the four simulation runs covered all the scenarios developed from the unconventional gas case studies.

3.1.3 Modelling Methodology

In this section we briefly discuss the assumptions, features, uses of scenarios, and some limitations of the model to better understand the methodology of its use in this project. The WGM is comprehensive as it covers every country in the world which consumes or produces natural gas. It has an outlook period to 2035 and captures flows at the country to country level by pipeline and LNG, with contracted and un-contracted flows separately identified. Supply and demand for piped gas and LNG for each node is balanced as a mass balance equation for a period (one quarter) as

Domestic Production + Imports by Pipe and LNG + Storage Withdrawal = Domestic Consumption + Exports by pipe and LNG + Storage Injections

The model was used with the scenarios developed from four individual case studies as described in Section 3.1.2. Demand forecasts were exogenously estimated based on considerations of economic growth, energy intensity and population growth. The forecasts were then aggregated for each country and loaded in the database as an input data. Due to the exogenous nature of the data, we were able to change demand information for a country to match the scenarios. Supply data was included in the database as a cost curve for each producing country. The cost curves included a maximum production profile over time and cost of production. As with demand assumptions, these production curves could be replaced in the database according to the unconventional gas scenarios.

In addition, the model also took into consideration the infrastructure needed to support international trade including production fields and basins, pipelines, LNG liquefaction and regasification terminals and storage facilities, together with their associated costs. The inclusion and timing of new infrastructure projects could be controlled, allowing the model to be used to test the impact of individual projects on world trade and pricing. This flexibility allowed us to further test for supply scenarios based on various assumptions of infrastructure development for LNG exports. In addition, essential variables such as seasonal demand variations, supply swing and storage capacities (working volume and deliverability) were also included in the model as inputs.

Using the scenario assumptions, the model matched supply to demand on the basis of least cost taking into account production costs and transportation by pipe and LNG. The pricing of gas also took into account the tightness of the market and, in the case of contracts, the linkage with oil prices. Flows within nodes were constrained according to the available infrastructure and within the bounds of long term contracts where appropriate. If the export and import nodes were both specified, the model delivered at least the take-or-pay (TOP) level from the export node to the import node. Volumes above the TOP level could be delivered to the import node, diverted to another location or even shut in (not produced). The model decided between these options on least-cost grounds. Diverted volumes were priced on a spot basis.

Long term contracts can be prolonged or allowed to expire at the end of existing terms. If contracts are allowed to expire, this would create more opportunities for spot trade to occur. Spot trade (un-contracted flows) can take place with respect to any available liquefaction and regasification capacity over and above that needed for contractual obligations.

The oil price assumption used in all our cases was based on Nexant's forecasts, as described in the next section. Oil product prices were essential in the model as they were used to derive gas prices under long term gas contracts (oil-indexed contracts) into Europe and Asia. Specifically, the Japan Crude Cocktail (JCC) is often used as a benchmark for LNG contracts particularly in the Far East.

The model's strength is in providing a comprehensive set of output on gas trade, prices, production, consumption and infrastructure utilization figures which could be reconfigured based on user needs and used for various forms of analysis. The flexibility in adding a wide number of features into scenarios (e.g. production potential, demand, infrastructure timing, signing and expiry of long-term contracts) helps to better model realistic case assumptions. The cost minimization as an objective is a powerful tool which is rooted in economic fundamentals of how trade decisions are often made. But the model has some limitations in that:

a. It does not endogenously allow for creation of contracts and infrastructure decisions to support increased production capacity based on economic grounds. Any assumptions for contracts and timing of infrastructure decisions need to be exogenously fed to the model. But careful selection of such data enables us to model decisions as close to reality as possible, with a slight penalty in increased database complexity.
b. It cannot account for market power of dominant producers and consumers to alter the trade flow to their own benefit.
c. The effect of various scenarios of demand and supply on infrastructure decisions and decisions to sign/extend contracts cannot be directly estimated by the model, and instead must be incorporated into the scenario assumptions prior to running the model.

Finally, it should be noted that the inputs to the model were set in early 2014, and therefore any changes in the markets or in the schedule of projects since then are not reflected in the outputs of the model.

3.1.4 Interpreting the Outputs of the Model

The model output is a set of values that can be broadly classified under production, consumption, trade flows and price data. It is the interpretation of the results that helps provide the explanatory power to understand the effect of a scenario. Here we must take note that, rather than giving credence to the absolute value of the model results, it is the informed analysis of what the values mean in the overall context of the scenario that illuminates the results. Hence the output is often better understood as a difference between two cases. This is relevant as we are principally interested in the incremental effects of a set of assumptions related to unconventional gas production when compared to a base case.

Care must also be exercised in interpreting the values. For example, a price difference of $1.50 between same price benchmarks (e.g.: Henry Hub or National Balancing Point) of two cases in a particular year should be interpreted more in line with how that particular benchmark is affected by the effect of scenario assumptions when compared to other benchmarks and in which direction, rather than the absolute magnitude of the differential. This is relevant as prices show high volatility in the long term (Figure 3.7 for historical price plot) so that any price forecasts using a complex model would be more valuable if used as a tool to understand the price trends rather than predict the absolute price changes.

3.2 Base Case Analysis

In this section, we describe the assumptions behind the "Base Case" of the World Gas Model. We then examine using the model, how the global gas market may be expected to evolve to 2035 under these assumptions, in terms of consumption, production, liquefaction capacity, trading flows and prices. This section thus sets the context for the scenario analysis that focuses more specifically on unconventional gas developments in the following section.

3.2.1 Base Case Assumptions

Summary of Assumptions

In order to operationalize the gas model, assumptions are required on oil prices, gas demand, gas production potential, liquefaction capacity, and piped gas and LNG contracts. The model is then able to forecast (based on these assumptions) gas production, trading flows and prices. The underlying assumptions behind the Base Case were as follows:

- *Oil Prices*: Our oil price assumptions were based on Nexant's forecasts. Oil prices decrease in the medium-term, with Brent prices expected to reach about $87/barrel by 2016, consistent with the forward curve from ICE (Intercontinental Exchange). However Brent prices are expected to gradually increase in the long-term, reaching $108/barrel by 2020, $115/barrel by 2025, and stabilizing at $120/barrel from 2030 onwards.
- *Gas Demand*: Our gas demand assumptions are described in more detail below.
- *Liquefaction Capacity*: Our liquefaction capacity assumptions are described in more detail below.
- *Gas Production Potential*: Our Base Case assumptions on production potential were drawn from Nexant's World Gas Database, which includes detailed assessments of production potential and costs for different fields and different types of gas (e.g. conventional gas, shale gas, CBM etc.) for each country. In the Base Case, we took a conservative view of potential unconventional gas production in the countries that are being analysed in this report. As

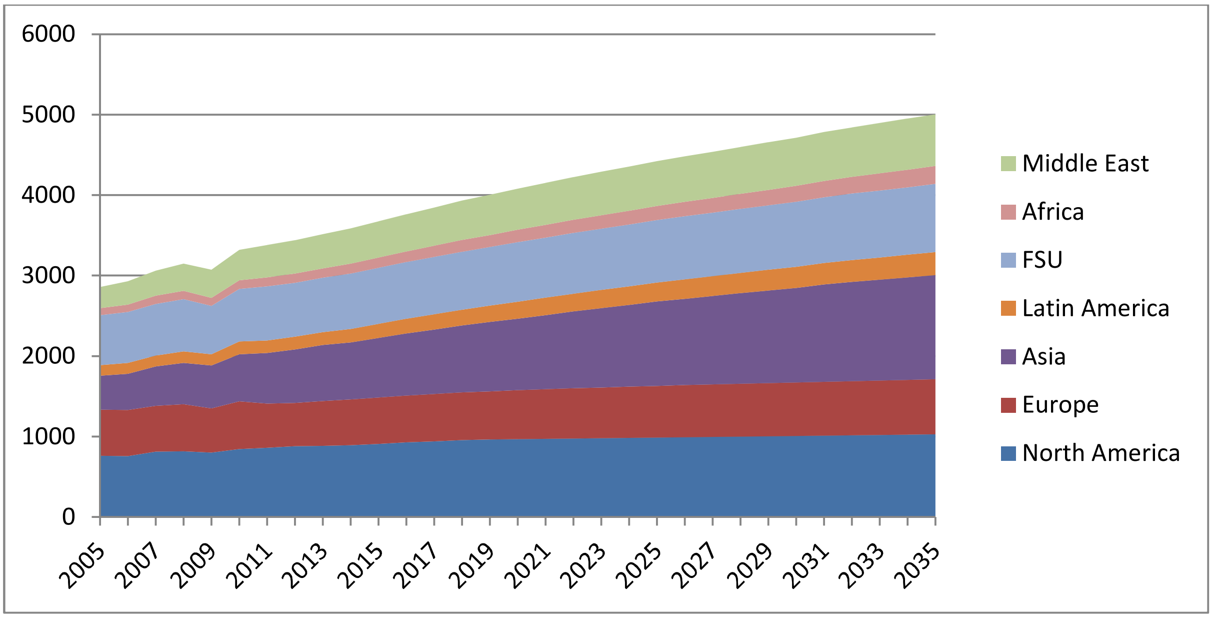
Chapter 2 highlights, though, there is significant upside and downside potential for unconventional gas, depending on regulatory developments, economic incentives, rights of access and geological factors. These uncertainties are explored in the scenario analysis described in the next section.

- *Piped Gas and LNG Contracts*: The World Gas Database contains a detailed database of existing and proposed piped gas and LNG contracts, including details on their pricing formulas, contracted quantities, take-or-pay levels and expiry dates. Many of these contracts are set to expire before the end of our outlook period (i.e. before 2035). In such cases, we have examined the demand and supply situations of both the exporting country and importing country in order to assess whether the contracts are likely to be renewed or not. Geopolitical developments also feed into these assumptions: for instance, Russian piped contracts to Europe are expected to decline in volume as we expect European efforts at diversification of gas imports to intensity in the aftermath of the current crisis in Ukraine. Under these assumptions, the volume of contracted gas continues to grow, but at a slower rate than overall gas consumption particularly beyond 2025, implying that spot and short-term contracts are likely to play a more important role with time.

Gas Consumption Assumptions

Our forecasts of gas consumption are drawn from Nexant's World Gas Database, and are broadly consistent with the International Energy Agency's forecasts. Figure 3.1 illustrates gas consumption forecasts by region.[6] The largest growth in gas consumption comes from Asia, in particular from China and India. Gas consumption also grows rapidly in the Middle East and Former Soviet Union (FSU). Gas consumption grows more moderately in North America and slowly in Europe.

Figure 3.1 Gas Consumption Forecasts in bcm by Region (2006-2035)



[6] We followed the International Gas Union's classification of regions in this report, with one modification. "Asia" included East Asia (China, Japan, Korea, Taiwan), South Asia, Oceania (Australia, New Zealand, and Papua New Guinea), and all of the countries in the ASEAN. The remaining regional definitions are self-explanatory.

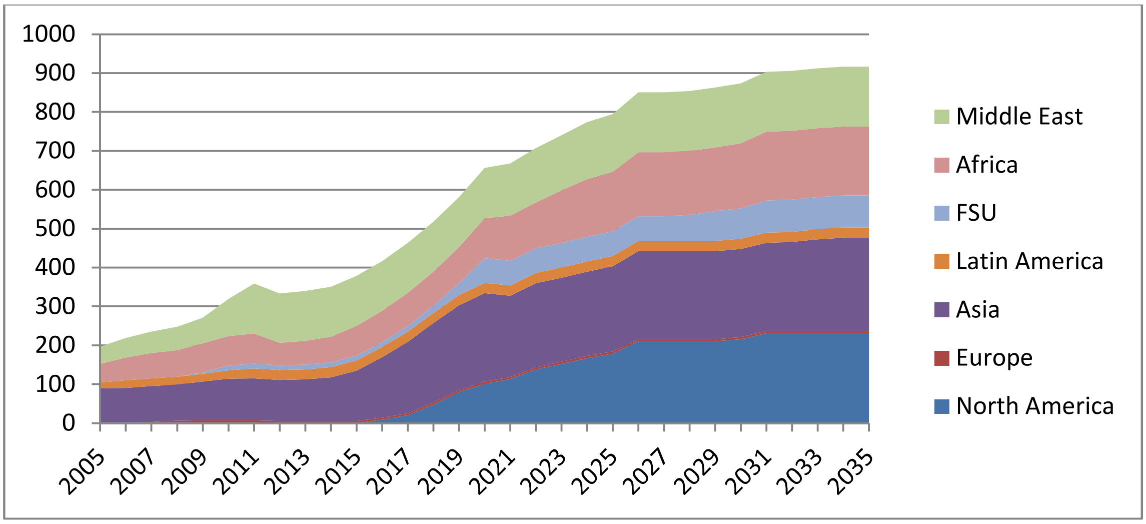
Liquefaction Capacity Assumptions

The World Gas Database includes detailed data on each liquefaction plant that has already been built or is under consideration. Our assumptions on future liquefaction capacity were derived as follows:

- Existing and under construction LNG plants remain operational until 2035 except in cases where there are plans to shut them down earlier (e.g. for some LNG plants in Indonesia).
- For LNG plants that have already been proposed, we assess whether and when they will become operational based on project economics, the likelihood of getting buyers, and regulatory support.
- We have also assumed that additional LNG plants will be built in countries that are likely to have significant future export capabilities, even if they have not yet announced concrete plans for building additional infrastructure.
- Overall, our assumptions lead to a base case that is generally optimistic on LNG liquefaction capacity.

Figure 3.2 shows our liquefaction capacity forecasts by region. The most noticeable feature of this chart is the massive growth in the LNG market from now till 2035. Historically, the major LNG exporting regions have been the Middle East (Qatar), Asia (Indonesia and Malaysia) and Africa (Algeria and Nigeria). Between 2015 and 2025, significant growth in LNG capacity is expected in Asia, as Australia emerges as a major LNG exporter, and North America, as the US and Canada also begin building LNG export plants. LNG capacity in Africa increases between 2020 and 2030 as Tanzania and Mozambique begin producing significant volumes of gas. Finally, LNG capacity in the FSU is also forecast to increase as we expect Russia to build more LNG plants (mostly targeted towards Asia) in order to reduce its reliance on piped exports to Europe.

Figure 3.2 Liquefaction Capacity Forecasts in bcm by Region (2006-2035)



3.2.2 Base Case Results

Gas Production

Figure 3.3 illustrates forecasts of gas production by region. North American production is expected to grow rapidly, driven by the unconventional gas boom in the USA and (to a lesser extent) in Canada. Gas production increases significantly in Asia, driven by rising domestic demand for gas as well as increased Australian LNG exports. Increases in African production after 2020 are also export-driven, whereas production growth in the Middle East and FSU is mostly driven by rising domestic demand for gas. European production decreases due to declining conventional gas production, though the emergence of shale gas slows down the rate of decline after 2025.

Figure 3.3 Gas Production Forecasts in bcm by Region (2006-2035)

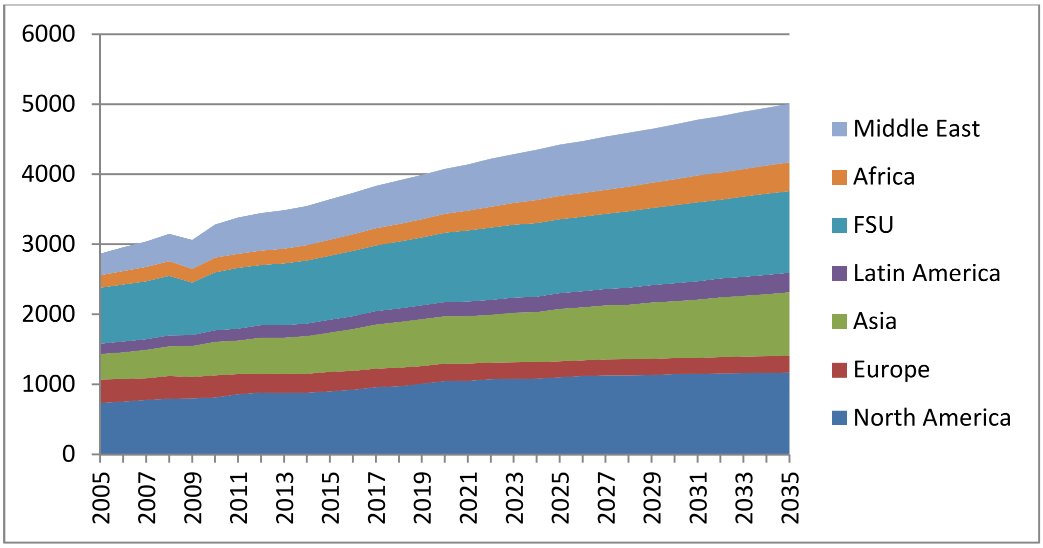
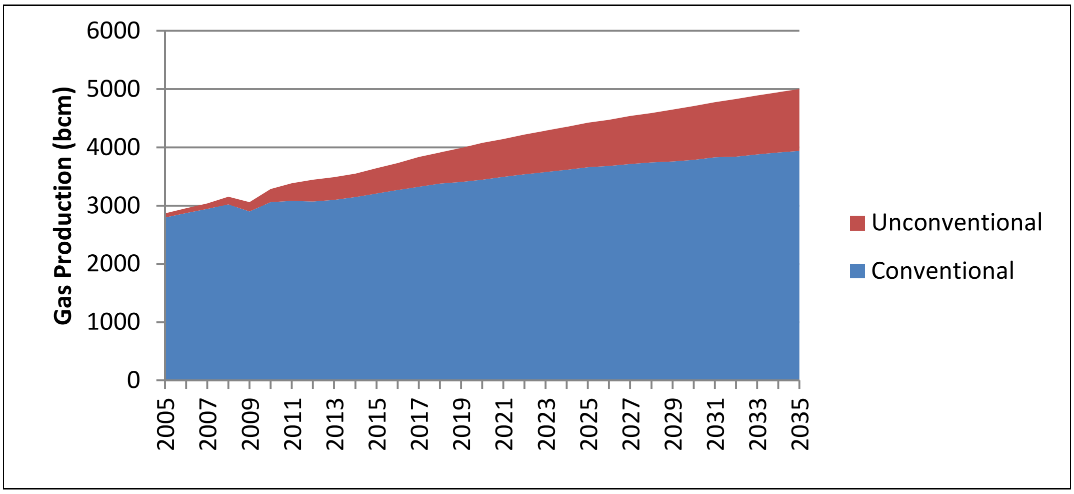


Figure 3.4 illustrates how the share of conventional and unconventional gas in total gas production is expected to evolve over time, based on the base case model runs. Although the lion's share of gas continues to be supplied from conventional resources, unconventional gas production is expected to grow at a remarkable rate, accounting for around 20% of total gas production by 2035 from only 7% in 2010.

Figure 3.4 Gas Production by Type of Gas (2006 – 2035)



LNG Trade Patterns

Figure 3.5 shows the evolution of LNG flows into Asia till 2035. LNG flows into this region are expected to grow rapidly in line with economic growth. Middle Eastern flows into Asia remain stable, but rising LNG demand is met from other sources. Intra-Asian flows increase as Australia begins to emerge as a major LNG exporter, and these are soon followed by North American LNG flows. It is also evident that Asia is the preferred market for East African LNG when it comes on-stream. FSU also export LNGs to Asia though at a lesser scale.

Figure 3.5 LNG Flows to Asia (in bcm) (2006-2035)

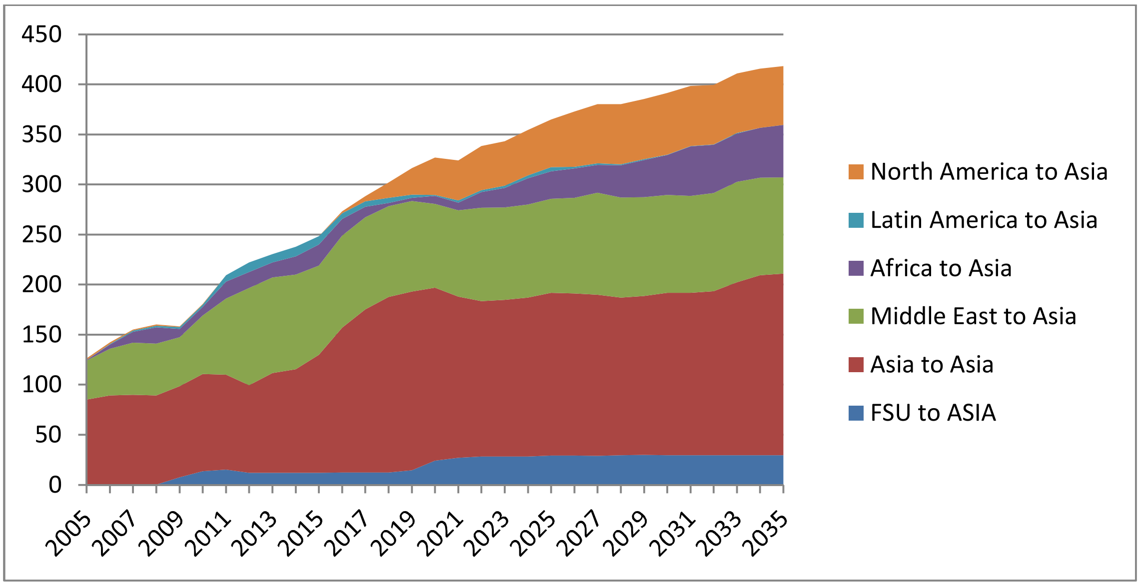
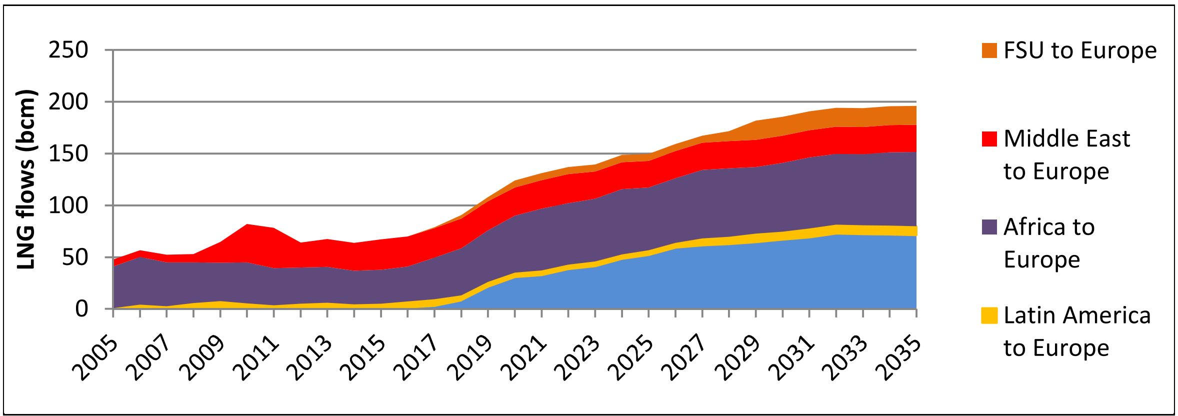


Figure 3.6 shows the evolution of LNG flows into Europe. Although European gas demand grows very slowly, LNG flows into Europe increase quite rapidly as Europe tries to diversify away from Russian piped gas imports. As discussed earlier, we expect Europe's contracted imports from Russia to gradually decrease. While LNG flows from Middle East to Europe remain stable, there is a considerable increase in LNG flows from Africa to Europe as well as from North America to

Europe; as the US emerges as an LNG exporter in the late 2010s. Indeed in our modelling results, Europe eventually imports more North American LNG than does Asia, even though export contracts have thus far largely been signed with Asian countries. Europe's LNG market could grow less rapidly if (i) there is a less significant move away from Russian pipeline imports (ii) North American LNG exporters prefer to run at less than full capacity rather than export LNG to Europe, which could happen if the pricing terms for European LNG sales are not favourable enough.

Figure 3.6 LNG Flows to Europe (2006-2035)



Prices

The model uses oil price and competing fuel price information to estimate both term and spot gas prices. But it is instructive to note the historical evolution of gas prices. A plot of historical prices for four major benchmarks is given in Figure 3.7. Natural gas trade is characterised by sharp changes in price and inventory levels. Price levels and price differentials between different benchmarks are also observed to fluctuate quite widely for both short term and longer periods. The volatility of prices itself changes over time. In the plot of historical gas prices in the US, Europe and Asia in Figure 3.7, three distinct regimes of volatility can be found.

To understand how the prices behaved in the past, we briefly look into some of the key characteristics of the plotted historical price chart (Figure 3.7). We find that the Japanese contracted LNG prices were trading below Henry Hub prices for most of the first half of last decade. This was on account of lower crude oil prices to which the Japan prices were indexed and also due to Henry Hub prices showing significant volatility. Henry Hub prices can be seen to have exhibited high volatility with distinct "eras" for example: the Enron Bankruptcy in early part of the decade (2001-02), the US shale drilling boom in 2005-06 when prices momentarily peaked, the financial crisis of 2008 and finally the unconventional gas boom in the last part of the decade. The United Kingdom's National Balancing Point (NBP) itself showed significant volatility on account of factors related to high continental gas prices in 2001-02, unexpected cold weather when supplies were tight in 2005-06, oversupply due to warm temperatures and Norwegian imports in 2008, and supply concerns arising from the Ukraine – Russia conflict in 2009. After a brief recovery post 2010, the NBP price has remained depressed due to recessionary demand.

Looking at the period from 2008 to 2014, market prices were close with steady price differentials for most of 2008. Then Henry Hub prices started their downward drift on high unconventional gas production and depressed demand in North America in year 2009 which was further exacerbated by the warm winter in North America in 2011/12. The price differentials widened further after March 2011, when the Fukushima incident put the Asian demand and Asian spot prices on a higher trajectory. In the first half of 2014 there was softening of Japanese spot prices on account of glut of supply, high storage levels and depressed demand. Therefore it can be seen that price data for a period can show considerable variation effected by various events that cannot be forecast with any certainty. Over the last five years the differential between the US Henry Hub price and the spot price of LNG into Japan has varied from zero to $16.80/MMBtu.

Figure 3.7 Historical Natural Gas prices (2000-2014Q1) for HH, NBP, Japan Term and Japan Spot (in $/MMBtu)

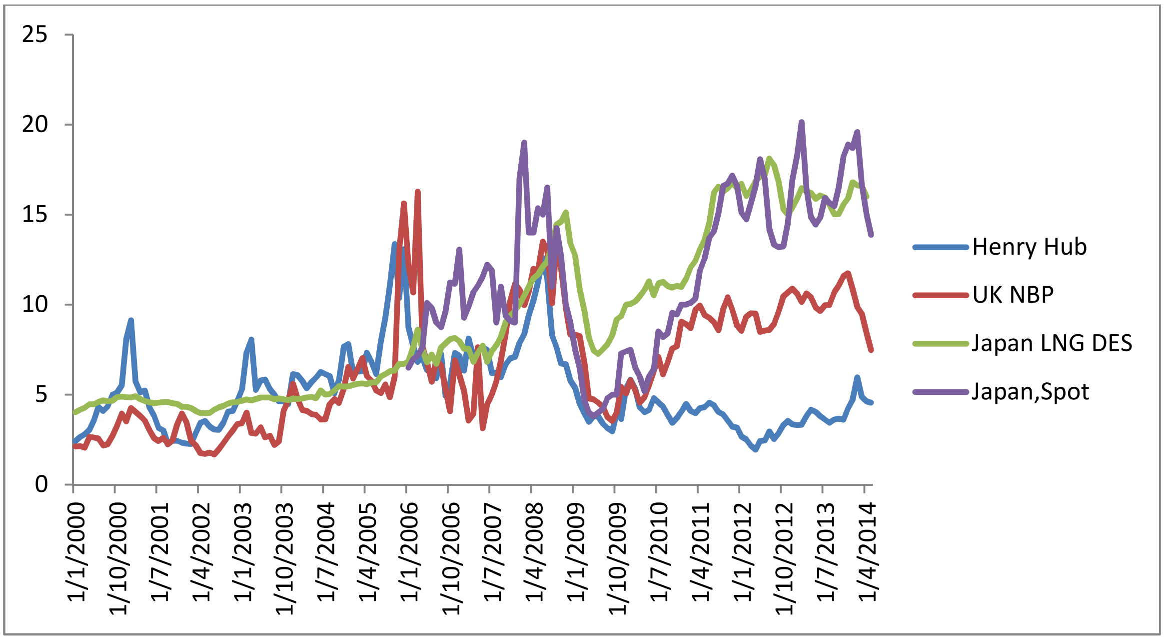


Figure 3.8 shows the evolution of different gas prices over the outlook period. The average price paid by Japan for contracted LNG is expected to decrease in the next few years in line with oil prices, but picks up again as oil prices recover from 2017 onwards. The average price paid by Germany for contracted pipeline gas imports, which is a benchmark for European contract price, similarly moves in tandem with the oil price though it tends to be $2-3/MMBtu lower than Japanese contract prices.

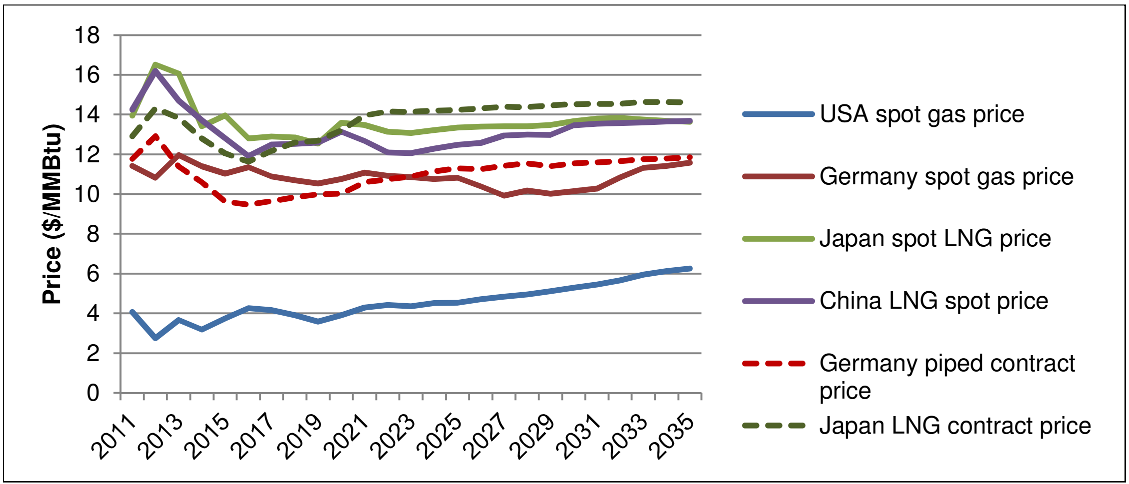
Unlike contract prices, which are a function of oil prices, spot prices are an output of the Gas Model and are determined by demand and supply fundamentals. Spot LNG prices in Japan and China are expected to fall from the levels they reached in the aftermath of the Fukushima disaster, as new LNG from Australia and North America enters the market. Asian prices stabilize from 2020 onwards, however, because after 2020 the arrival of new LNG more closely matches increases in LNG demand. European spot prices also decrease from current levels particularly as North American LNG enters the market, and in general remain lower than Japanese spot LNG prices. Spot prices in North America gradually increase as the US and Canada export increasing quantities of LNG, but remain much lower than prices in Asia and Europe.

Thus, there is only a weak tendency for prices to converge in our base case. Inter-regional spot price differentials do decrease but remain significant. A major reason is that we expect the LNG market to remain dominated by long-term oil-indexed contracts in the foreseeable future. Spot market liquidity does grow over time but not nearly fast enough to have a significant influence on inter-regional price differentials. Price convergence would happen to a greater degree relative to our base case provided:

- There is a much faster move away from oil-indexed contracts to hub-indexation in Asia, putting downward pressure on contract prices and therefore spot prices in the premium

Asian markets.
- There is less reliance on long-term contracts in the future and greater reliance on the spot market, increasing spot market liquidity and therefore making it more difficult for inter-regional price differentials to persist.
- The outlook for gas supply, and in particular unconventional gas supply, is more optimistic than in our base case. We examine this possibility in much greater detail in Section 3.3.

Figure 3.8 Gas Prices, Base Case (2011 – 2035)



3.2.3 Main Findings

The key takeaway points from the Base Case are as follows:
- Gas consumption is expected to grow most rapidly in Asia (China, India and Indonesia).
- Production increases are driven mainly, but not entirely, by unconventional gas.
- The LNG market is projected to grow almost three-fold between now and 2035, with large expansions in LNG export capacity in North America, Australia, East Africa and Russia.
- There is considerable re-orientation of LNG trading patterns over time, with India and China increasingly emerging as the major buyers of LNG from the Middle East, Australia and East Africa, and European LNG demand from North America and Africa increasing if Europe switches away from pipeline imports.
- Asian spot LNG prices fall from their post-Fukushima levels as new LNG enters the market, but remain at a premium to European spot gas prices.
- North American prices gradually increase over time but continue to trade at a significant discount relative to Asia and Europe gas spot prices.

3.3. Scenario Analysis

In the previous section, we presented our base case assumptions and discussed how gas production and consumption, LNG trading flows and gas prices may be expected to evolve in the next two decades. However as Chapter 2 of this report highlights, there is considerable uncertainty over the prospects for unconventional gas supply, and it is important to understand how this may affect global gas markets. In this section, therefore, we examine how different scenarios for unconventional gas development could affect global gas markets, trade flows and prices.

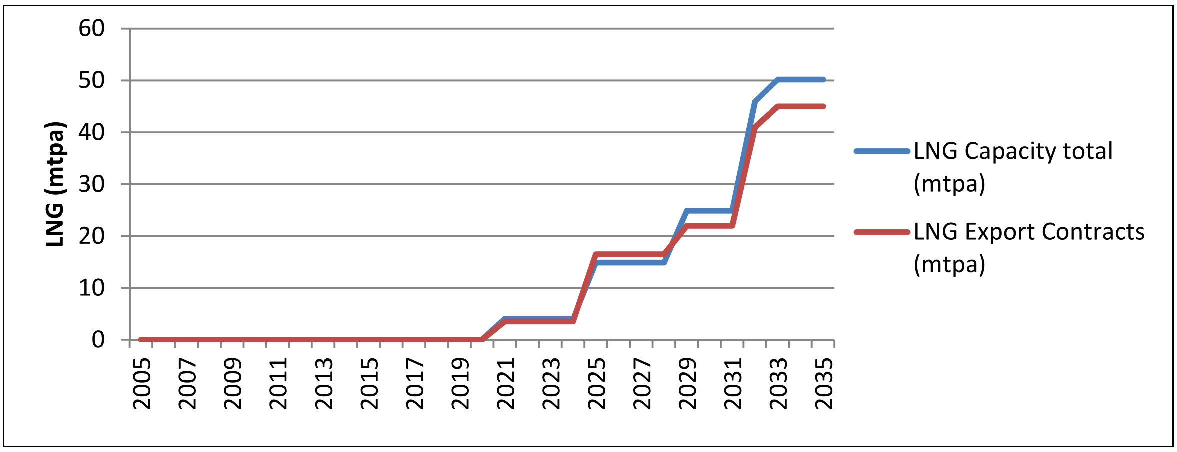
3.3.1 Australia Scenarios

Scenario Assumptions

We begin by analysing how the optimistic and pessimistic scenarios for Australian shale and CBM production (presented in Figure 2.5 in the last chapter) could affect global gas markets. Given that Australia can only feasibly export gas in the form of LNG, the main effect on the rest of the world is through the effect on the LNG market. We assume that in the optimistic (high) case, Australia continues expanding its LNG capacity even after the initial boom this decade, reaching 196 bcm (or 144 mtpa) by 2035 (see Figure 2.6 in the last chapter). In the optimistic scenario, Australia also signs a greater volume of LNG export contracts, reaching 163 bcm (or 120 mtpa) by 2035.

By contrast, in the pessimistic (low) case, Australia's LNG expansion stops around 2020, stabilizing at 128 bcm (or 94 mtpa) by 2035 (see Figure 2.6). Australia signs fewer contracts than in the high case, with LNG contracts reaching only about 100 bcm (or 74 mtpa) by 2035, similar to current levels.

Figure 3.9 Australia's LNG Capacity and Export Contracts: Differences Between High and Low Cases (2005-2035)



The differences between the two cases are summarized in Figure 3.9 below, which shows the difference in LNG capacity and LNG export contracts between the High and Low cases. In the High Case, Australia has 45 mtpa (61 bcm) greater LNG capacity and 50 mtpa (68 bcm) greater than in the Low case. Comparing the High and Low cases, as we do in the analysis that follows, allows us to understand the implications of an Australian unconventional gas-induced LNG boom on global gas trading flows and prices.

Scenario Results

We firstly analyse the impact on production. Figure 3.10, which shows (Production in High Case – Production in Low Case) for each region, illustrates that in the Australia High Case:

- Asian gas production is higher relative to the Low Case due to higher Australian gas production.
- Gas production in FSU, Africa, and Latin America decreases (leading to a negative production difference in Figure 3.9).

Figure 3.10 Differences in Production Between High Case and Low Case (in bcm), 2011 – 2035

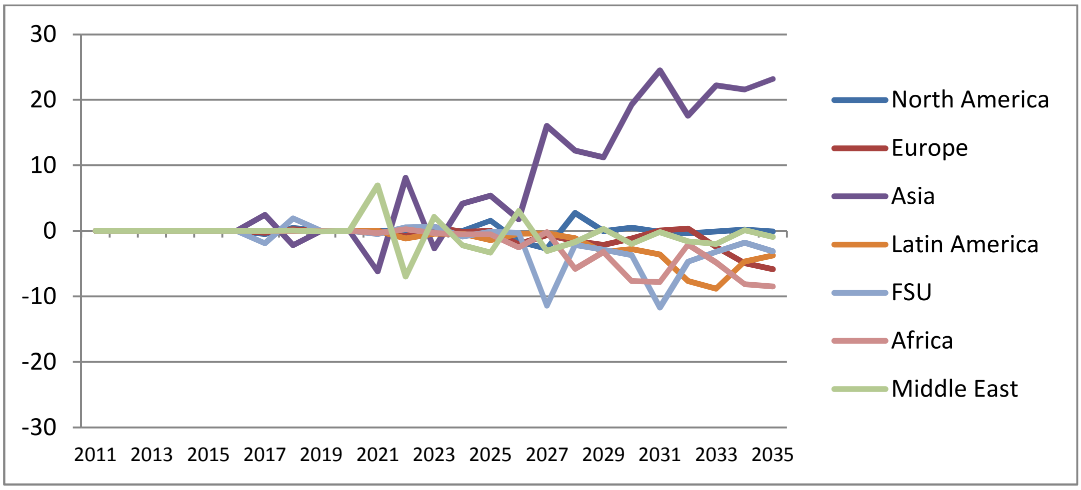


Figure 3.11 shows how inter-regional LNG trade flows in 2035 differ between the High and Low Cases. A positive sign means that trading flows increase in the High case relative to the Low Case, and vice versa if the sign is negative.[7] There is considerable re-orientation of un-contracted LNG flows. The results in Figure 3.11 can be best understood as a sequence of events following increased unconventional gas production in Australia:

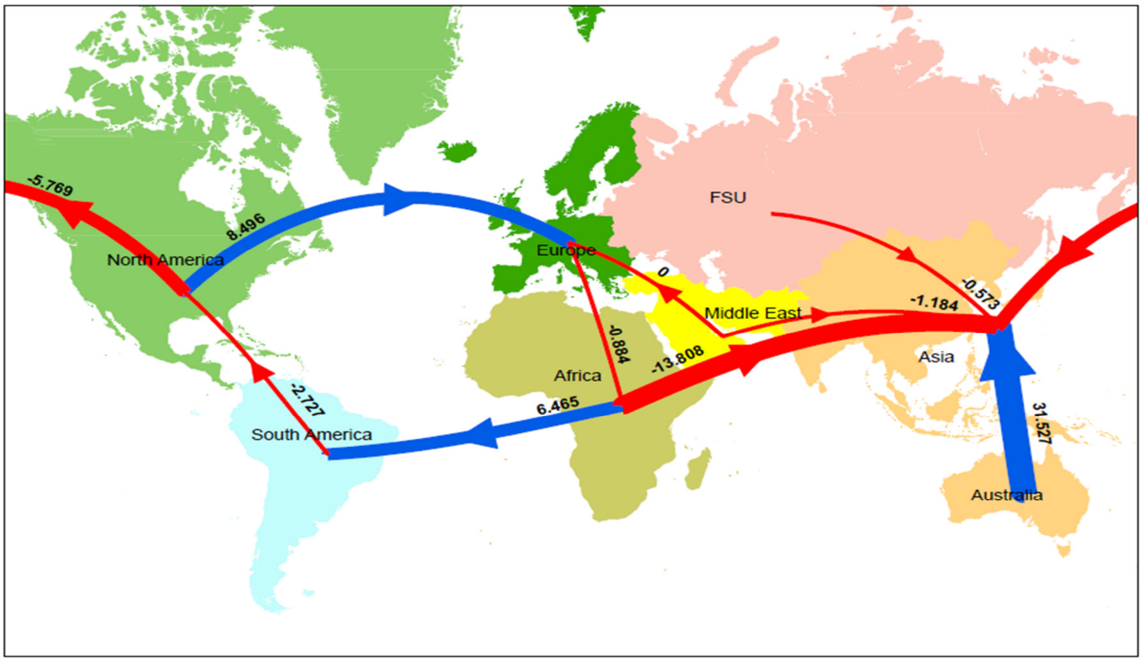
- The additional LNG available from Australia in the High Case leads primarily to increased intra-Asian LNG flows (i.e. increased flows from Australia to Japan, Korea and India).
- As a result, Asia demands less LNG on the spot market, leading to reduced LNG flows from Africa and North America to Asia.
- Africa re-directs some of this LNG to Latin America.
- North America re-directs LNG from Asia and Latin America to Europe in the form of spot exports.

It is important, however, to note that:

- There is very little impact on contracted flows, which form the bulk of LNG trade. Thus, even an Australian unconventional boom would leave the majority of LNG trade unchanged. This is a common theme throughout the report, and is a result of the contractual nature of gas trade.
- The one exception is that in the US, LNG export companies have largely adopted a tolling model, under which the buyers pay a fixed tolling fee to the LNG plant owner and fully assume the price risk. These contracts allow buyers much greater flexibility in deciding how much LNG to take from the contracts. Thus in practice, greater Australian LNG exports could lead to a reduction in contracted flows from North America, if the buyers choose to reduce their contracted imports from the US, rather than reducing spot imports from elsewhere.

[7] Similar results are obtained for other years and are omitted for brevity.

Figure 3.11 Differences in LNG Trading Flows between High Case and Low Case in bcm, 2035 (Red Lines represent decrease in trade flows and Blue lines represent increase in trade flows)



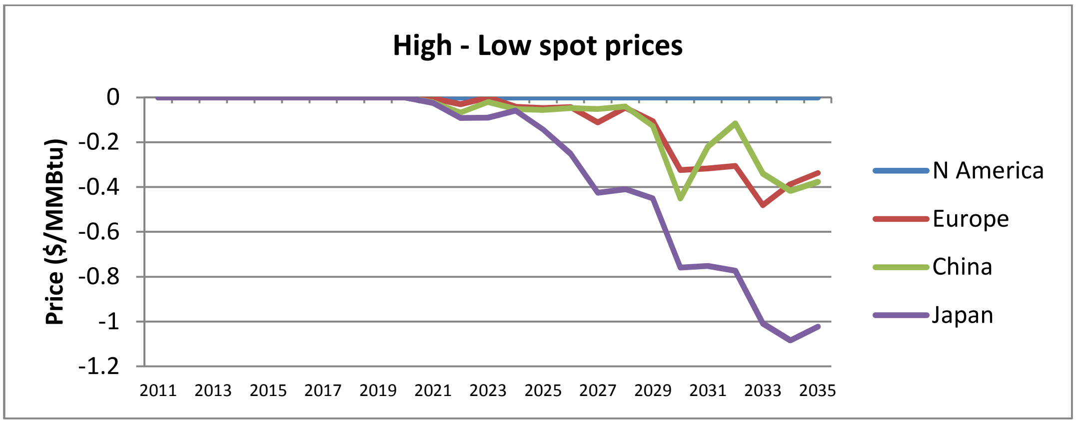
(Prepared by Anton Finenko, ESI)

Figure 3.12 shows how spot prices differ between the High and Low Cases. There is no impact on contract prices, since these are for the most part indexed to the price of oil. In general, spot prices are lower in the High Case than in the Low Case, as increased LNG supply depresses prices. The difference in spot prices widens in later years, consistent with the fact that the difference in gas production and LNG capacity between the two cases increases with time. The biggest price impact is on Japan, where the spot price in the High Case is $1/MMBtu lower than in the Low Case in 2035; prices fall to a lesser extent in China and Europe, in both cases by around $0.40/MMBtu in 2035.

It is important to interpret these results with care. In particular, these price differences should be regarded as the minimum extent by which prices will differ. The model assumes a perfect market for spot gas flows where gas demand is met in the most efficient way possible by minimizing costs. If these conditions are not fully met in practice, price differences between the High and Low Cases will tend to be greater. For instance, an important determinant of actual spot prices is the relative bargaining power of buyers and sellers which cannot be quantitatively modelled. In a scenario with high Australian LNG exports, the bargaining power of sellers is likely to weaken, which could lead to prices falling by a greater degree than illustrated in Figure 3.12.

Since most LNG is traded on a term basis, the more significant question is how contract prices may be affected by Australian unconventional gas. In the High Case, with greater availability of LNG and cheaper spot gas, there could be downward pressure on contract prices particularly in Asia, where the spot price impact is the greatest. Buyers may be able to get more favourable pricing terms, either when they renew expiring contracts, or by re-negotiating existing contracts. However, both the timing and magnitude of any such contract price decreases (if they happen at all) is uncertain. Thus, although Figure 3.12 suggests a comparatively moderate effect of Australian unconventional gas on spot prices, the actual effect on prices may well be significantly greater and may extend to contract prices as well as spot.

Figure 3.12 Difference in spot prices between the High and Low Cases, 2011 – 2035



Main Findings from Australia Case

- The impact of Australian unconventional gas on global gas markets will be via the effect on the LNG markets.
- An unconventional gas-induced boom in Australia supported by increased export capacity would lead to growing LNG exports to Asia, potentially displacing spot LNG exports from Africa and North America; contracted flows, except from the US to Asia, are not likely to change.
- Increased Australian LNG exports lead to lower spot prices in particular in Japan and to a lesser extent in Europe and China. This could lead to downward pressure on long-term contract prices particularly in Asia.

3.3.2 North America Scenarios

Scenario Assumptions

The North American scenarios model the likely impact of unconventional gas production together with development of export infrastructure in a timely manner in North America. North American production capacity, at 988 bcm/yr in 2014, and its demand, at 822 bcm/yr as of 2014, is the second highest in the world. The development of unconventional gas fields (shale fields in USA and tight gas in Canada) is estimated to increase the production capacity to over 1290 bcm/yr by 2035. The proportion of conventional production capacity in total production capacity declines from 51.2% in 2014 to 39% in 2035 (Figure 3.13). There is moderate demand increase in North America driven mainly by US demand (Figure 3.14).

Figure 3.13 Production Capacity in North America

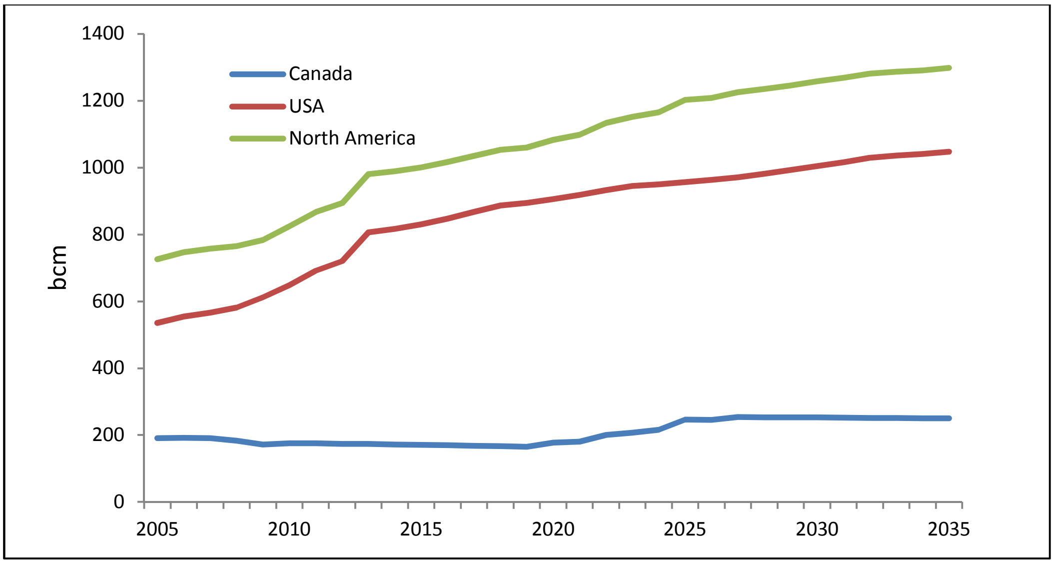
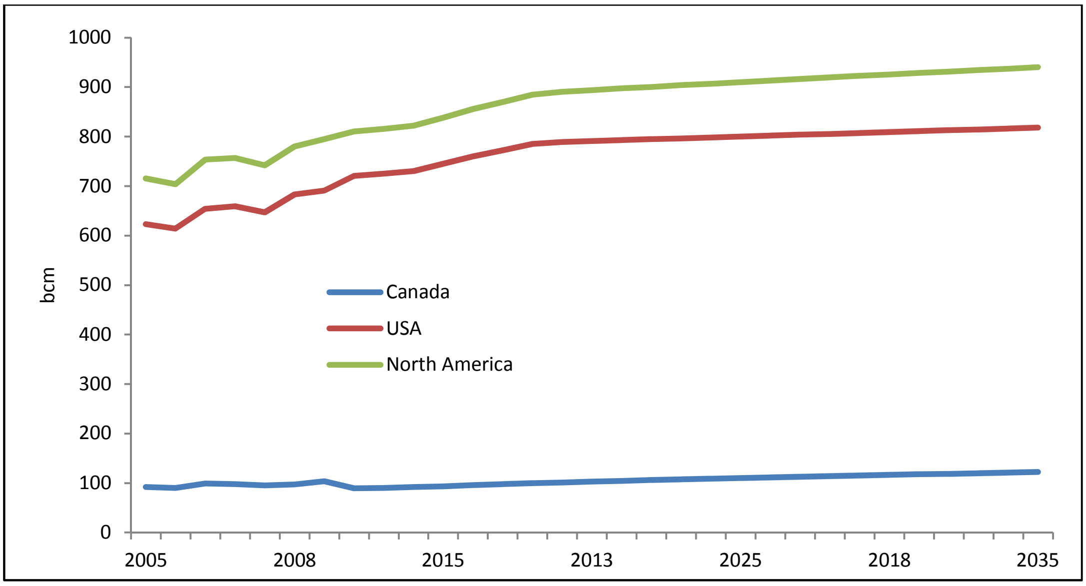


Figure 3.14 Demand in North America



The North America Optimistic and Pessimistic cases are distinguished by the build-up of LNG liquefaction capacity and the proportion of LNG capacity signed as LNG contracts. In the optimistic case, we assume that some of the proposed LNG plants with most attractive economic incentives come online and North America is able to sign new supply contracts. US LNG capacity is expected to rise to 104 mtpa (141 bcm) by 2035 with export contracts of 99 mtpa (135 bcm), while Canada's LNG rises to 77 mtpa (104 bcm) with Canada being able to sign LNG contracts of 50 mtpa (68 bcm) (Figure 3.15 and 3.17).

In the pessimistic case, only a small number of currently planned LNG plants and associated LNG contracts which are already signed are included and no further developments are assumed. Thus both the infrastructure capacity build-up as well signing of contracts are reduced. US LNG capacity is expected to rise to 92 mtpa (125 bcm) with export contracts of 60 mtpa (82 bcm), while Canada's LNG capacity is expected to rise to 52 mtpa (71 bcm) with export contracts of 30 mtpa (41 bcm) (Figure 3.16 and 3.18).The difference between optimistic and pessimistic cases can be summarized as follows:

- North America is able to sign about 60 mtpa (82 bcm) of additional contracts in the optimistic case by 2035.
- North America builds 40 mtpa (54 bcm) of additional LNG capacity in the optimistic case by 2035.

Figure 3.15 US LNG Capacity and Contracts (Optimistic)

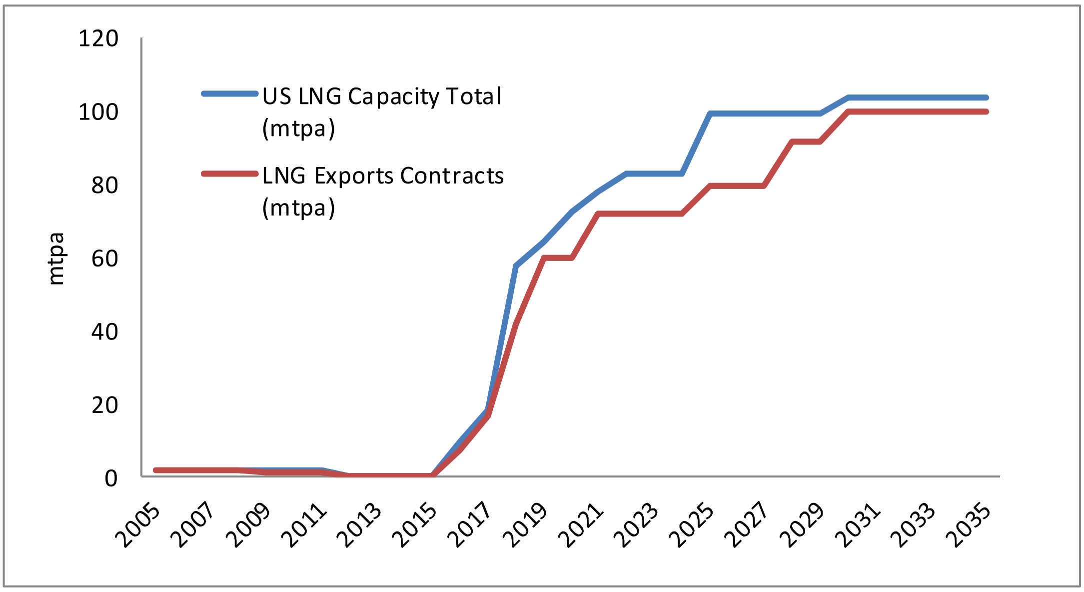


Figure 3.16 US LNG Capacity and Contracts (Pessimistic)

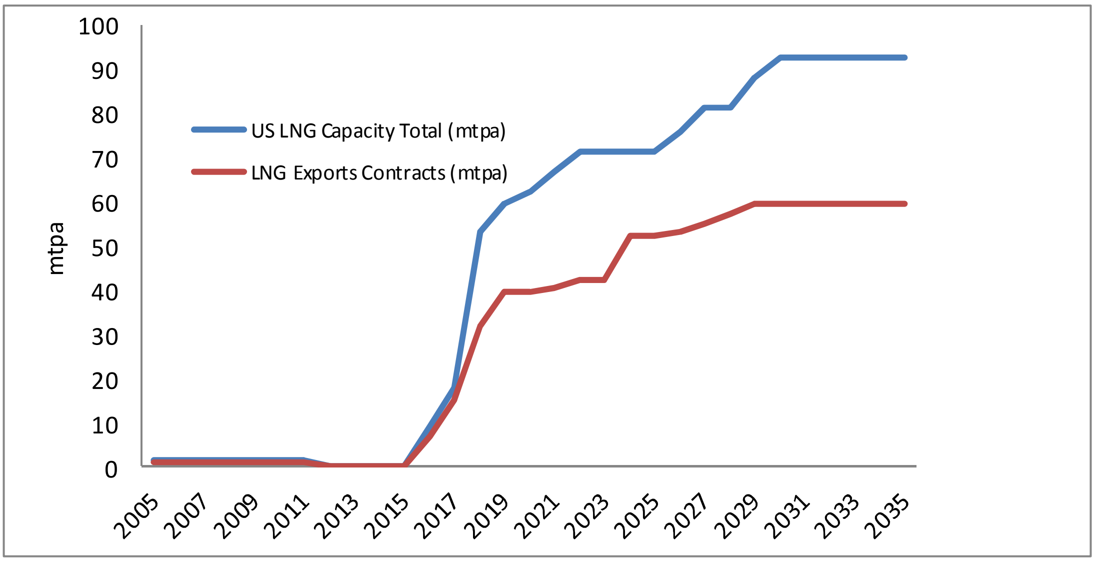


Figure 3.17 Canada LNG Capacity and Contracts (Optimistic)

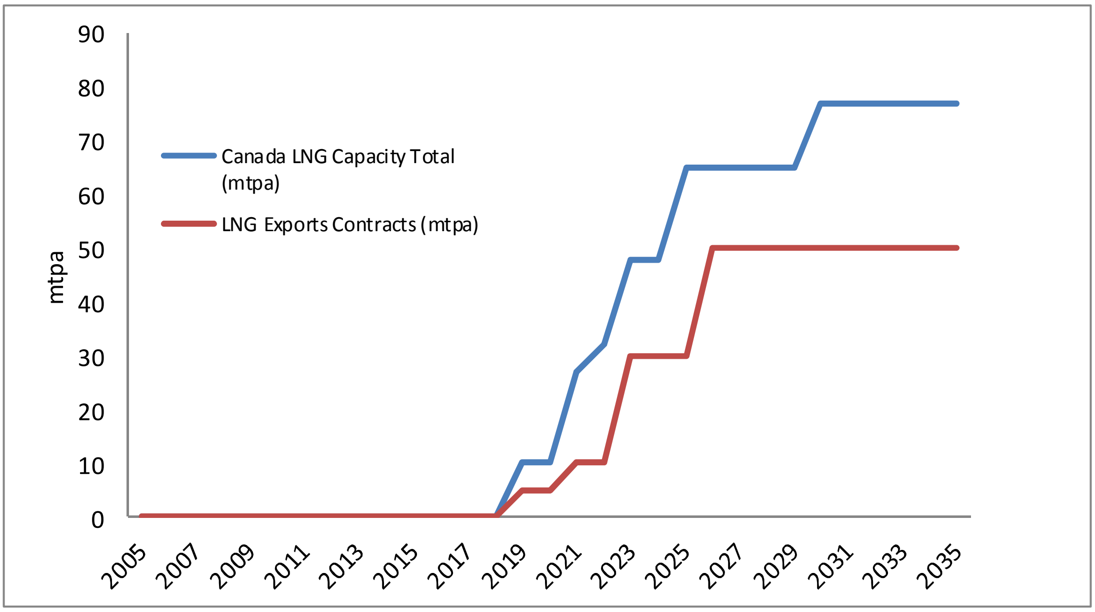
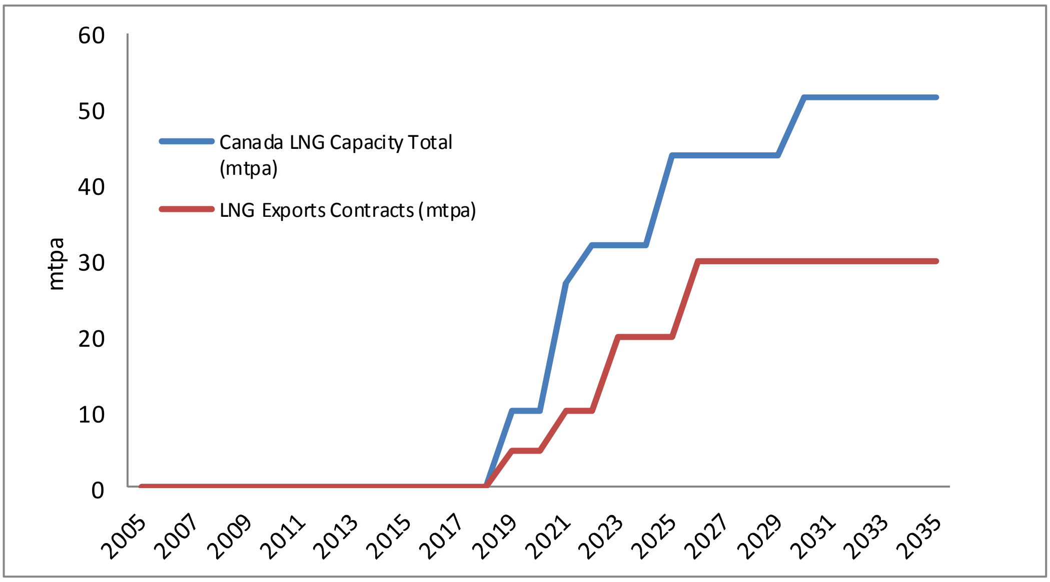


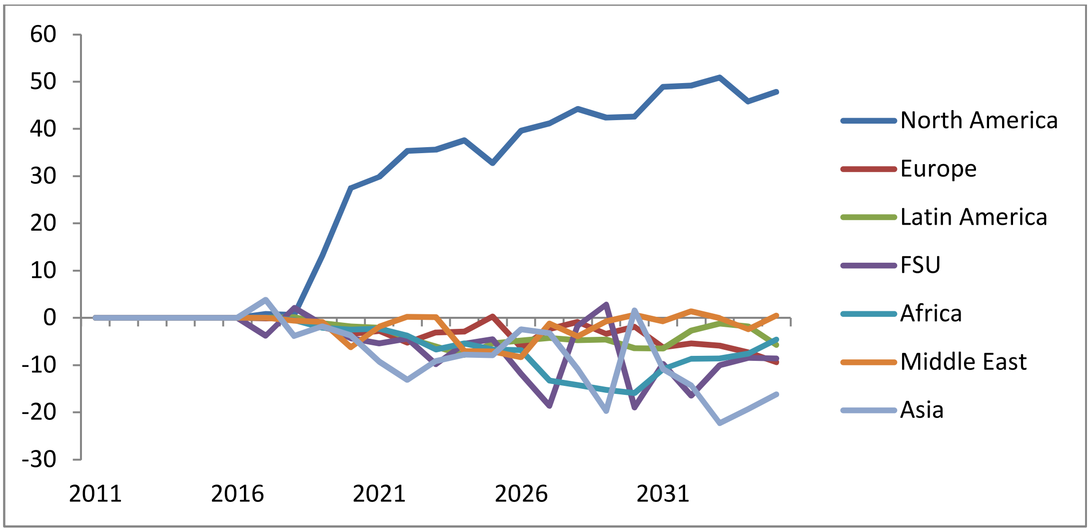
Figure 3.18 Canada LNG Capacity and Contracts (Pessimistic)



Scenario Results

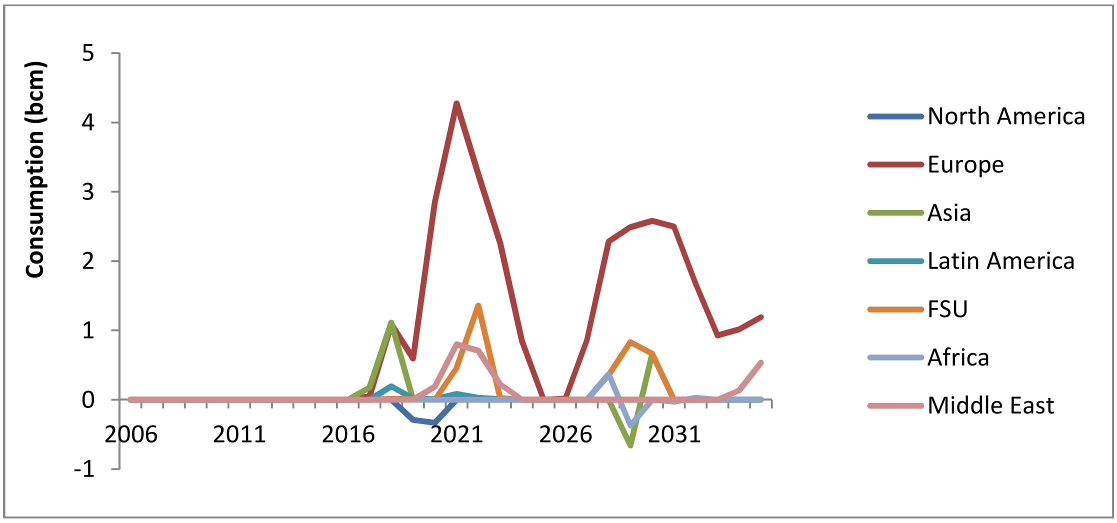
It is informative to look at the differences in production between the optimistic and pessimistic cases (Figure 3.19). Increased production from North America displaces gas from all other regions. The displacement is notable in the case of Asia and to a lesser extent for FSU.

Figure 3.19 Differences in Production between High Case and Low Case (in bcm), 2011 – 2035



The marginal production increase of 50 bcm/yr by 2035 mostly supports exports. This is because consumption hardly changes between the scenarios for North America, as shown in Figure 3.20. This is due to the price inelastic nature of demand.

Figure 3.20 Differences in Consumption between High Case and Low Case, 2011 – 2035

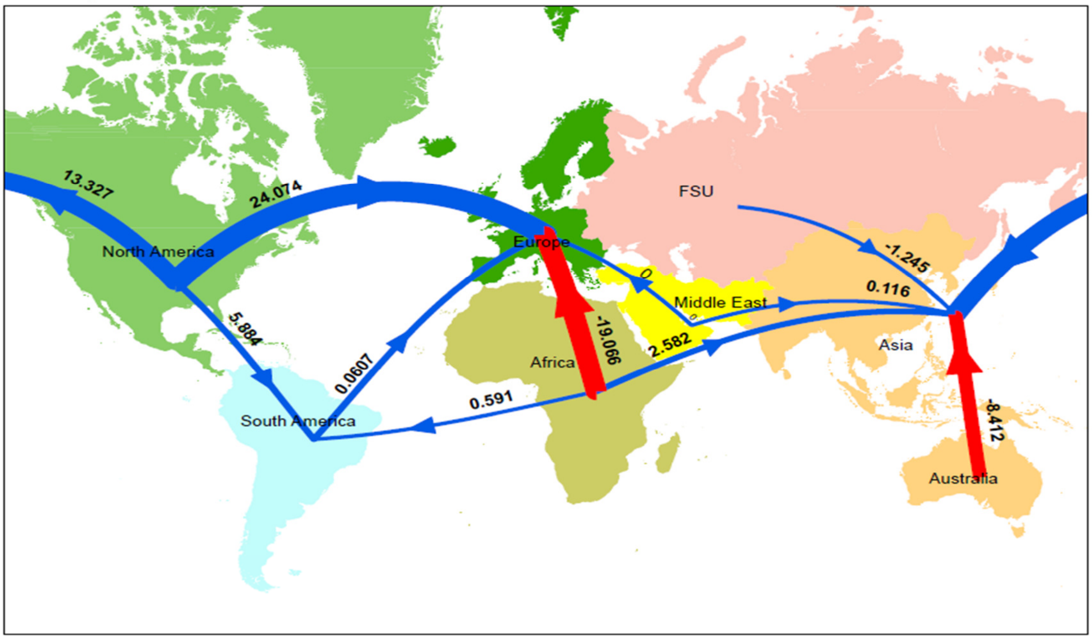


To study the impact of North American gas production on global trade flows, we present differences in the trade flows for the year 2025 (the results for the other years are similar) and note the patterns (see Figure 3.21).

- The additional North American LNG in 2025 (in High Case) flows mostly to Europe, followed by Asia and Latin America.
- This pushes out some African LNG from Europe and some Australian LNG from Asia.

It is again important to note that a more optimistic scenario for North American LNG has very little impact on contracted flows elsewhere, which form the bulk of LNG trade. This is due to the fact that all active contracts are honoured to at least take-or-pay level, which results in little flexibility in modifying contracted flows.

Figure 3.21 Difference in LNG Trading Flows between High Case and Low Case (in bcm) (North America), 2030 (Blue Arrows show increase in trade flows and Red arrow show decrease in trade flows)



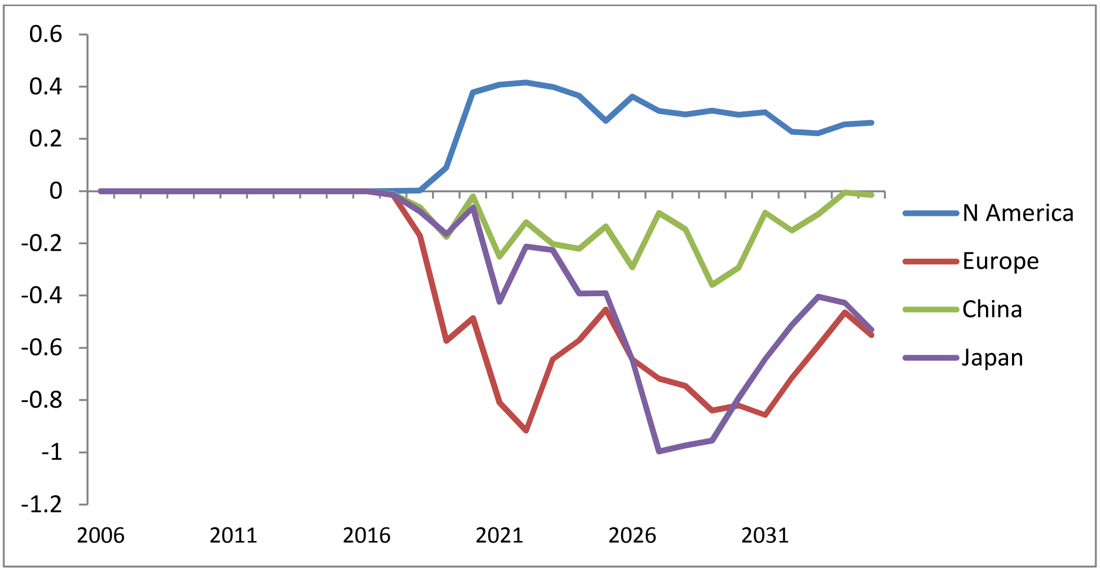
(Prepared by Anton Finenko, ESI)

If we plot the difference in spot prices between optimistic and pessimistic scenarios (Figure 3.22), we see that:

- Spot prices in North America increase marginally due to increased LNG exports.
- Initially North American LNG has a larger impact on European spot prices, but as Japan starts to receive more imports, spot prices in both markets decrease by about \$1/MMBtu from the low case.
- The international price impact of US LNG exports is greater than its domestic price impact. This result is broadly consistent with most market studies.

As with the Australia case, there is little direct impact of increased LNG exports from one region (in this case North America) on average LNG contract prices. However, due to lower spot prices in Europe and Asia, and the potential for North America to swing from one region to another, there would be downward pressure on contracted LNG prices in the long-run in the High case.

Figure 3.22 Difference in Spot Prices Between the High and Low Cases, in \$/MMBtu (North America)



Main Findings from North America Case

- The impact of North American unconventional gas on global gas markets will be via the effect on the LNG markets.
- Incremental North American LNG in the optimistic scenario flows mostly to Europe, followed by Asia and Latin America, pushing out some African LNG from Europe and some Australian LNG from Asia; contracted flows, however, are not likely to change.
- Increased North American LNG exports lead to lower spot prices in particular in Europe and Japan, and could put downward pressure on long-term contract prices in Europe and Asia.

3.3.3 East Africa Scenarios

Scenario Assumptions

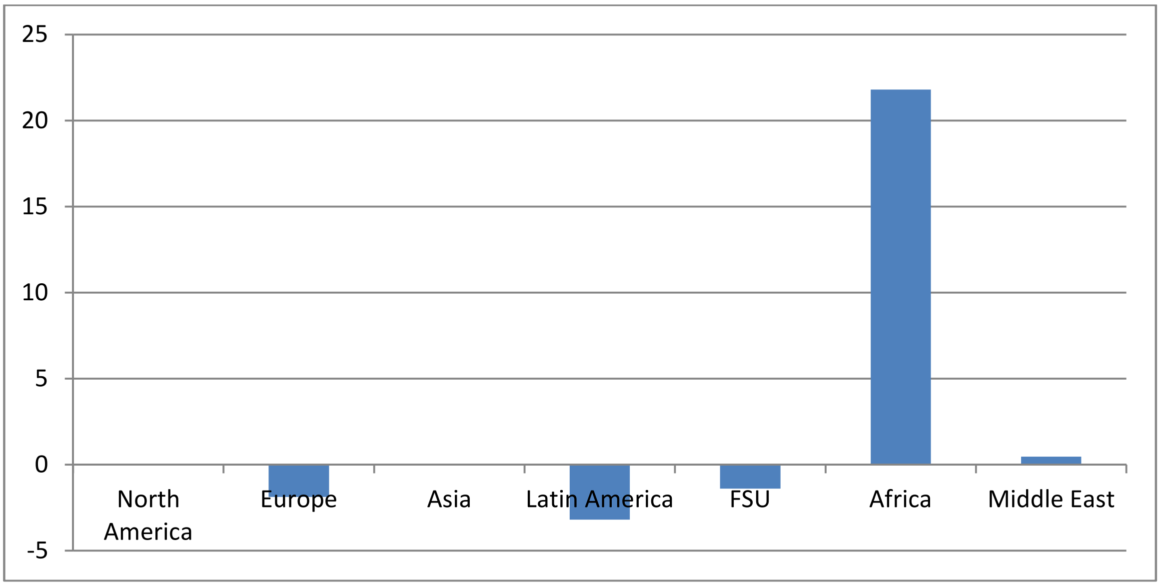
In the East Africa high and low cases, we change assumptions on the ramp-up dates of operation of LNG plants in Tanzania and Mozambique. The key difference between the Optimistic and Pessimistic cases of East Africa is described in section 2.3.2 (see Figure 2.21). In the optimistic case, East African LNG exports begin in 2018 and reach 48 bcm by 2035. In the pessimistic case, East African LNG exports begin only by 2020 and reach 32 bcm by 2035.

As such, long run LNG capacity is the same for both optimistic and pessimistic scenarios, and the only difference is the rate of build-up of capacity. A faster ramp-up of East African LNG exports leads to a period between 2018 and 2025 when East African LNG exports are significantly higher in the High Case, due to the first wave of LNG exports coming on faster, as well as a period between 2030 and 2033 when East African LNG exports are higher in the High Case, due to the second wave of LNG exports coming on faster.

Scenario Results

Faster LNG exports in the High Case lead to greater gas production in Africa, most notably between 2020 and 2025 and to a lesser extent in the early 2030s. As Figure 3.23 illustrates for the year 2022, this displaces production elsewhere, especially in Asia (i.e. Australia). The African production increase is almost in line with the ramp up of LNG infrastructure and LNG exports from the region.

Figure 3.23 Differences in regional production between East Africa High and Low Cases in year 2022 (in bcm)



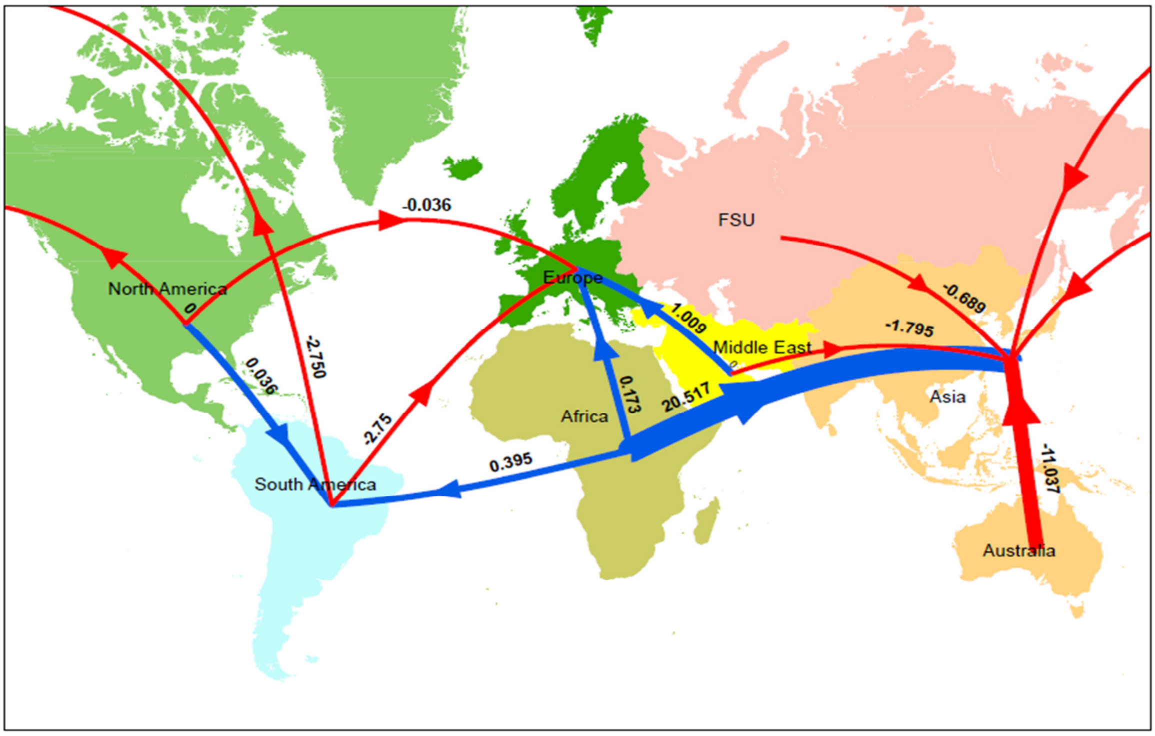
Comparing inter-regional flows in 2022 when the difference in East African LNG exports between the two scenarios is the greatest, we see that:

- Africa significantly increases LNG shipments to Asia after the infrastructure expansion in East Africa (Figure 3.24).
- This displaces some spot LNG flows from Latin America to Asia and from the Middle East to Asia, as well as spot LNG flows within the region (i.e. from Australia to Asian

importers).

- There is little impact on contracted flows; however in practice, because of the tolling model adopted by US LNG exporters, greater East African LNG exports could lead to a shut-in of some contracted US LNG flows to Asia.

Figure 3.24 Difference in LNG Trading Flows between High Case and Low Case (in bcm), 2022 (Blue arrows show increased trade flows and red arrow show decreased trade flows)

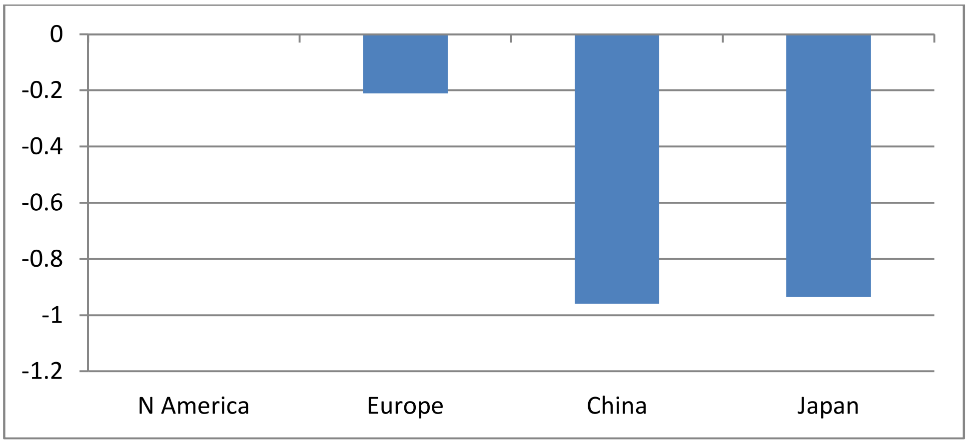


(Prepared by Anton Finenko, ESI)

A faster rise in East African LNG exports in the High Case briefly depress Asian spot prices by up to $1/MMBtu in the early 2020s relative to the Low Case (Figure 3.25). However the price difference disappears in the later years once East Africa begins exporting LNG in the Low Case as well. There is little impact on European prices in the East African optimistic and pessimistic scenario.

The timing of East African LNG exports is unlikely to have much impact on contract prices, since the effect of faster LNG exports on spot prices is only temporary. This is different from the North American and Australian cases, where the spot price impact is more permanent and thus there is long-term downward pressure on contract prices in optimistic scenarios.

Figure 3.25 Differences in Regional Spot Prices Between East Africa Optimistic and Pessimistic Scenarios For Year 2021 (in $/MMBtu)



Main Findings from the East African Case

- The timing of East African LNG exports will have short-run effects on the LNG markets particularly in the early 2020s.
- Incremental East African LNG in the optimistic scenario flows mostly to Asia and the Asia Pacific, replacing some LNG flows from Australia, Middle East and Latin America to Asia.
- In the optimistic ("high") scenario, increased East African LNG exports leads to lower spot prices in Asia during the period when African export capacity ramps up in comparison to the pessimistic case, but the effect does not persist and as such is unlikely to affect contract prices.

3.3.4 Global Scenarios

Scenario Assumptions

We analyse how the "global" optimistic (High) and pessimistic (Low) scenarios for unconventional gas production could affect global gas markets. In the Low Case, we take a conservative/pessimistic view of unconventional gas prospects in all of the countries considered in this study. The High Case is optimistic on the prospects of unconventional gas in China, Indonesia and India, but pessimistic/conservative on unconventional gas everywhere else, so that it effectively amounts to an "Asia optimistic" scenario.

The optimistic and pessimistic scenarios for China, India and Indonesia have already been discussed in detail in Chapter 2 (refer to Figures 2.1 and 2.2 for China, Figures 2.3 and 2.4 for Indonesia, and Figures 2.9 and 2.10 for India). For each country, the driving factor in the High Case is increased potential for unconventional gas production, which leads both to (i) reduced gas imports relative to the Low Case and (ii) increased domestic demand relative to the Low Case, as we expect the governments to institute policies to further develop the gas market if domestic supply is greater.

Putting these scenarios together, we see from Table 3.1 that gas demand in these three countries increases by almost 100 bcm in the High Case relative to the Low Case by 2035. In addition, as Table 3.2 illustrates, net gas imports in the three countries *decrease* by almost 100 bcm in the High Case relative to the Low Case (in the case of Indonesia, this means that gas exports *increase* in the High Case relative to the Low Case). Comparing the High and Low cases, as we do in the analysis that follows, allows us to understand the implications of these unconventional gas-induced changes in production, consumption and net import requirements on global gas trading flows and prices.

Table 3.1 Difference in gas demand between High and Low Cases

Demand (bcm)					
	2015	**2020**	**2025**	**2030**	**2035**
China	0	15	40	40	40
India	1	5	11	11	11
Indonesia	0	1	10	24	45
TOTAL	1	26	61	75	96

Table 3.2 Difference in net gas import requirement between High and Low Cases

Net Imports (bcm)					
	2015	**2020**	**2025**	**2030**	**2035**
China	-1	-45	-43	-55	-55
India	-7	-10	-3	-9	-14
Indonesia	0	-9	-22	-24	-30
TOTAL	-8	-64	-68	-88	-98

Scenario Results

We firstly analyse the impact on production. Figure 3.27 shows that in the Global High Case,

- Gas production in Asia is higher relative to the Low Case, and the difference increases with time as the unconventional gas boom in China, Indonesia and India becomes more and more pronounced.
- As a result, production in other regions decreases, with the effect most notable for the FSU in the 2030s, in part because Chinese unconventional gas production in the 2030s is high enough that China can begin to reduce its reliance on Russian and Central Asian gas imports.
- The increase in Asian gas production is much greater than the compensatory decrease in production elsewhere; this is because of higher gas demand in the High Case.

Figure 3.27 Differences in Production Between High Case and Low Case, 2011 – 2035

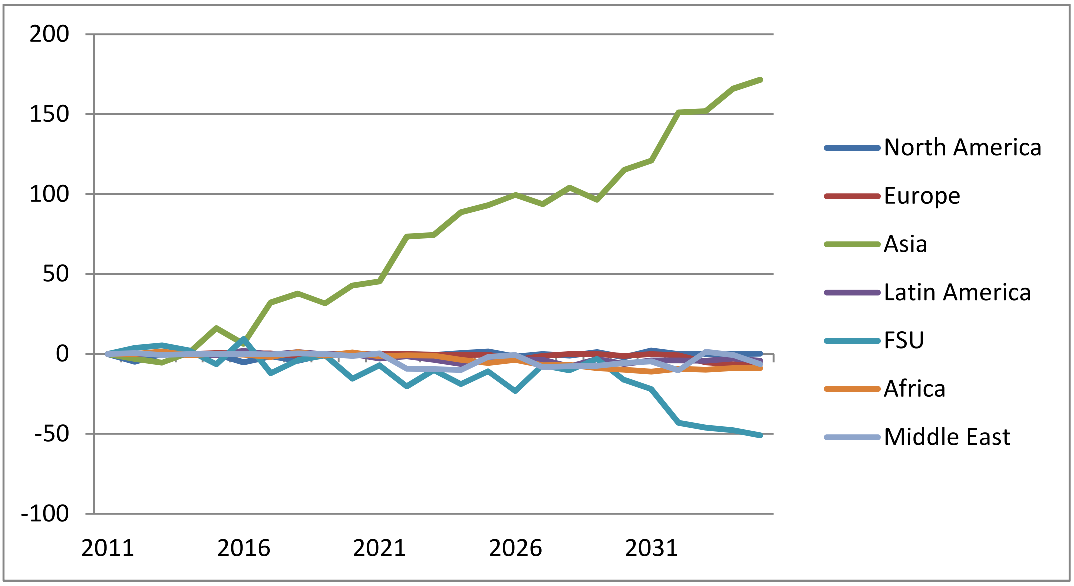


Figure 3.28 shows how gas consumption differs between the High and Low Cases. The difference is almost entirely driven by the gas demand differences in China, India and Indonesia: as we saw in Table 3.2, in all 3 countries, gas demand is higher in the High Case than in the Low Case.

Figure 3.28 Differences in Consumption Between High Case and Low Case, 2011 – 2035

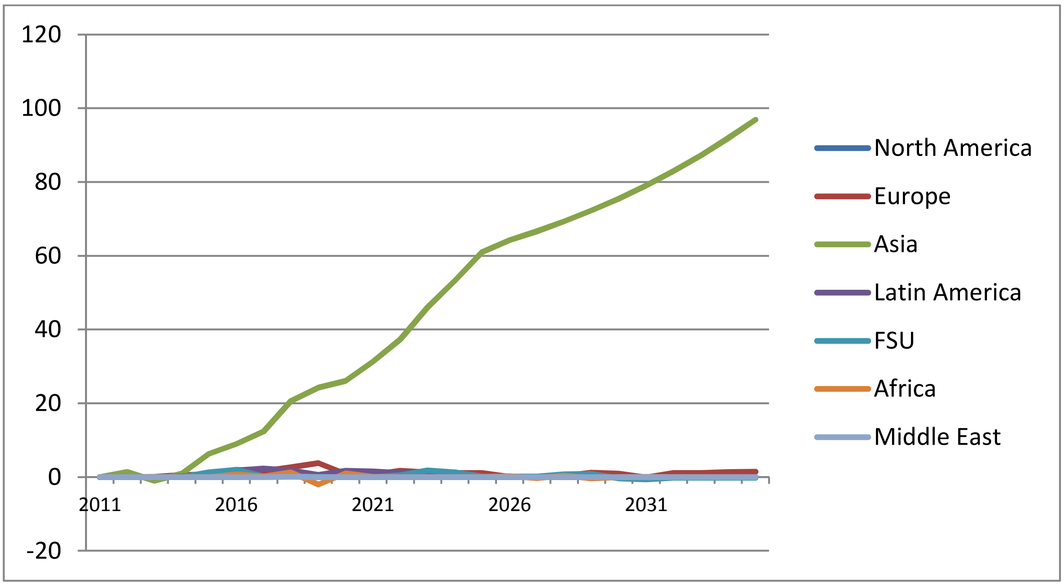


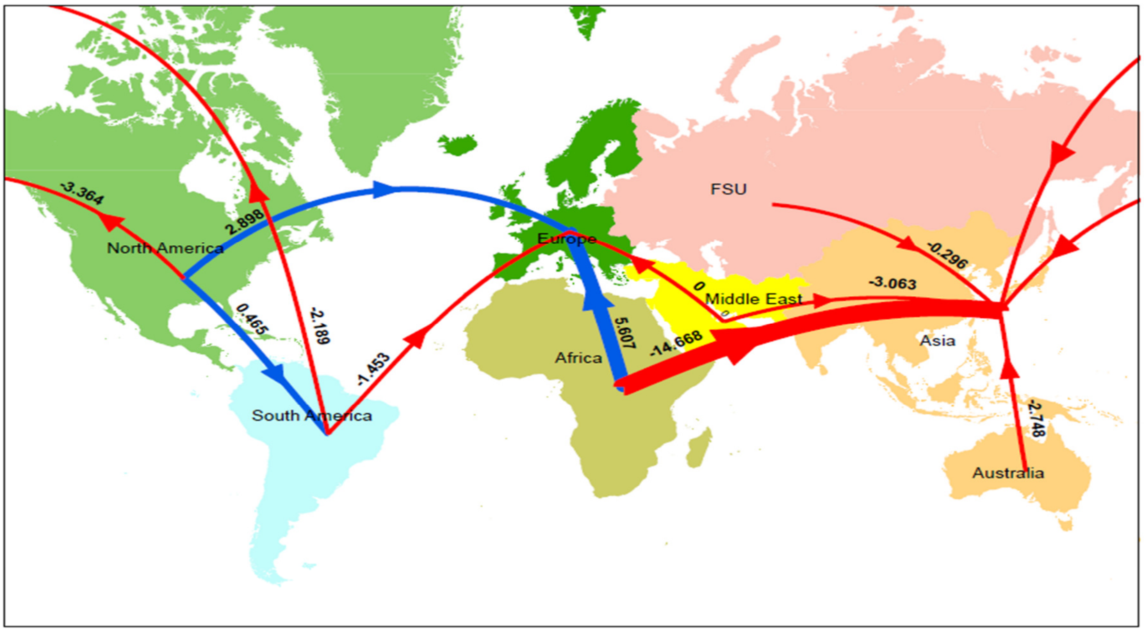
Figure 3.29 shows how inter-regional LNG trade flows in 2035 differ between the High and Low Cases (a positive sign means that trading flows increase in the High case relative to the Low Case, and vice versa if the sign is negative).[8] There is some impact on contracted flows as well as considerable re-orientation of un-contracted LNG flows. The results in Figure 3.29 can be best

[8] Similar results are obtained for other years and are omitted for brevity.

understood as a sequence of events following increased unconventional gas production in China, India and Indonesia:

- Due to increased domestic gas production, China and India reduce their imports of un-contracted LNG, leading to
    - Reduced contracted Australian LNG exports to Asia.
    - Significantly reduced un-contracted African LNG exports to Asia.
    - Small reduction in Middle East LNG exports to Asia.
- Reduced LNG demand in Asia forces Africa to switch some LNG from Asia to Europe, as well as to shut-in some production.
- At the same time, Indonesia increases its spot LNG exports, leading to increased un-contracted LNG flows within Asia.
- Increased availability of Indonesian LNG within Asia results in North America re-directing some of its LNG exports from Asia to Europe.
- Europe is able to reduce its piped imports from Russia further, with more LNG available from both Africa and North America: this also explains why FSU production gets shut-in in Figure 3.12.
- Because of the tolling model adopted by US LNG exporters, an Asian unconventional gas boom could have a greater effect on North American LNG exports to Asia than Figure 3.30 suggests (refer to the discussion in Section 3.3.1).

Figure 3.29 Differences in LNG Trading Flows Between High Case and Low Case (in bcm), 2035 (Blue arrows show increase in trade flows and red arrows show decrease in trade flows)



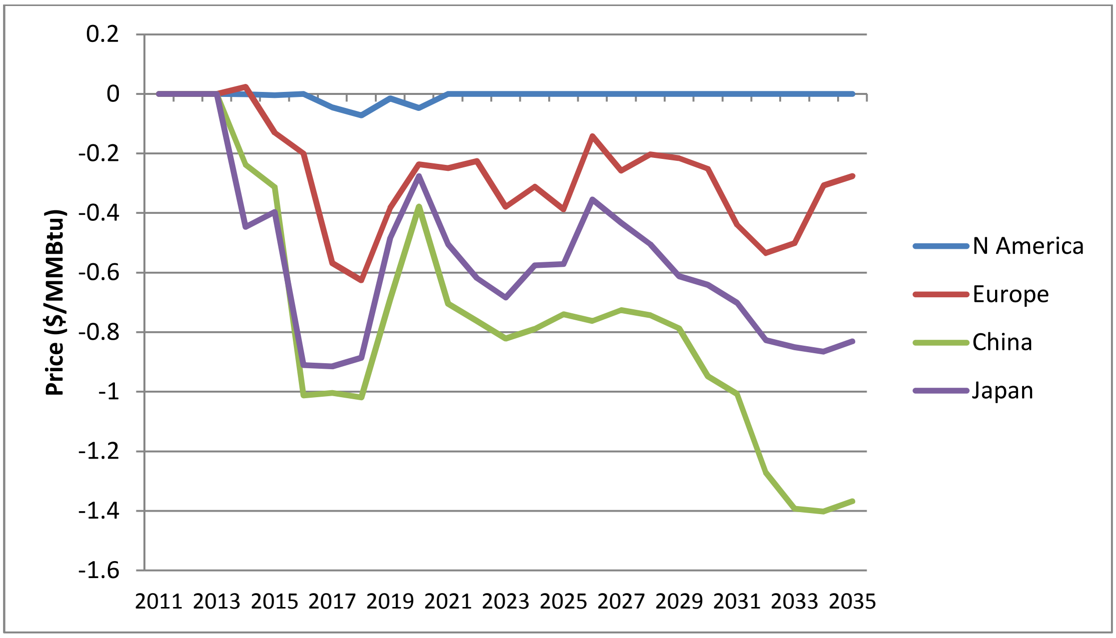
(Prepared by Anton Finenko, ESI)

Figure 3.30 shows how spot prices differ between the High and Low Cases.

- In general, spot prices are lower in the High Case than in the Low Case, as increased production and reduced imports depress prices. The difference in spot prices widens in later years, consistent with the fact that the difference in unconventional gas production and net import requirement between the two cases increases with time.
- The biggest price impact is on Asia, with the spot LNG price in China in particular and Japan to a lesser extent falling by a relatively significant degree.
- There is a relatively modest drop in spot prices in Europe.

- As noted before in Section 3.3.1, these price differences should be regarded as the *minimum* extent by which spot prices will differ; in practice, due to the imperfectly competitive nature of the gas market, the actual effect on prices may well be considerably more significant.
- As with all the cases we have looked at, there is little direct impact of increased unconventional gas production on average LNG contract prices. However, due to lower spot prices in Asia, and reduced reliance of major Asian buyers on imported gas, there would be downward pressure on contracted LNG prices in the long-run in the High case.

Figure 3.30 Difference in Spot Prices Between the High and Low Cases, 2011 – 2035



Among all the scenarios, therefore, the Global High Case is the one that could have potentially the biggest impact on spot prices in particular in Asia and the Asia Pacific. This is a nice illustration of the fact that in the gas market of the future, while unconventional gas development in any one country may not have a large effect in isolation, if unconventional gas develops simultaneously in a number of countries, there could be a very significant effect on global gas trading flows and prices.

Main Findings from Global Scenarios

- Increased unconventional gas production in China, India and Indonesia would lead to:
  - Reduced net gas imports in China and India and increased gas exports in Indonesia.
  - Increased domestic consumption of gas in China, India and Indonesia.
- China and India reduce their imports of un-contracted LNG from East Africa and Middle East, prompting Africa to switch some LNG from Asia to Europe, as well as to shut-in some production.
- Increased availability of Indonesian LNG within the Asia Pacific region results in North America re-directing some of its LNG exports from Asia to Europe.
- Increased unconventional gas production in Asia partially displaces gas production in the FSU, because both China (due to increased domestic production) and Europe (due to

greater availability of LNG) are able to reduce their reliance on piped gas imports.

- In an optimistic scenario for unconventional gas production in China, India and Indonesia, spot prices would be significantly lower in Asia and marginally lower in Europe, relative to a more pessimistic scenario; there would be no direct impact on contract prices, but lower spot prices and reduced Asian LNG import requirements could lead to long-term downward pressure on contract prices.

3.4 Main Findings

The main findings from the modelling exercise are as follows (see Table 3.3):

Production and Consumption of Natural Gas

Unconventional gas potential would lead to increased gas production for major exporters (in the case of Australia, North America and Indonesia) and for major importers with unconventional gas potential (in the case of China and India). Natural gas consumption increases in Asia keep pace with increasing in regional production.

Trade Flows of Natural Gas

Increased unconventional gas production would lead to increased LNG exports for major exporters (in the case of Australia and North America) and/or reduced gas imports for major importers with unconventional gas potential (in the case of China and India). This results in a re-orientation of LNG trading patterns which could lead to the shut-in of production in some regions.

The major driving factor for the change in trade patterns, caused by increased LNG trade flows from unconventional gas production, is that major importers find it economically advantageous to source LNG from new exporters, which in turn displace spot trade flows of LNG from a distant and more expensive exporter. For example:

- Increased Australian LNG exports flow mostly to Asia, which leads to diversions or shut-in of North American and African LNG exports to Asia.
- North American LNG exports brought on by the shale gas boom are expected to flow mostly to Europe, followed by Asia and Latin America. This has potential to push out some African LNG from Europe and some Australian LNG from Asia.
- Reduced rate of growth of LNG imports from China and India, brought on by development of domestic unconventional fields, prompts Africa to switch some LNG from Asia to Europe, as well as a reduced dependence on LNG exports from the Middle East.
- In general, greater LNG exports (or reduced LNG imports) in any one region are not likely to reduce contracted flows elsewhere as buyers are still obligated to abide by existing contracts; however US LNG exports could be affected due to the tolling model adopted by US liquefaction plant owners.

Spot Prices

In general, spot prices are lower in scenarios with greater unconventional gas production, with the price effect strongest in the regions that either produce the unconventional gas or import the bulk of the LNG produced from the unconventional gas.

- Greater unconventional gas production and LNG exports from Australia have the biggest impact on prices in Japan, followed by China and Europe.
- Greater unconventional gas production in China, India and Indonesia reduces these countries' import requirements and has the biggest impact on spot prices in China, followed by Japan and Europe.
- Greater unconventional gas production and LNG exports from North America impacts prices in Europe and Asia.

Contract Prices

- In general, contract prices are a function of the oil price rather than short-run supply and demand fundamentals.
- However, *sustained* greater unconventional gas production and/or greater LNG supply has the potential to permanently lower spot prices and thus lead to long-term downward pressure on contract prices, which may have a significant impact on contract price negotiations when contracts expire or are re-negotiated.

Table 3.3 Trends in Trade Flows and Benchmark Prices for Optimistic (High) and Pessimistic (Low) Scenarios

	Trends in Major Trade Flows, 2035 High vs Low		**Trends in Major Benchmark Prices, 2035 High vs Low**	
	Increase	**Decrease**	**Increase**	**Decrease**
Australia	Australia to Asia	Africa to Asia		**Japan Spot*** European Spot Chinese Spot
North America	North America to Europe North America to Asia	Africa to Europe Australia to Asia	North America Spot	Asian Spot European Spot
East Africa	Africa to Asia	Australia to Asia FSU to Asia Middle East to Asia	No perceptible changes in prices by 2035	
Global Scenario (Asia Optimistic vs Pessimistic)	Africa to Europe North America to Europe North America to Latin America	Africa to Asia North America to Asia Australia to Asia Middle East to Asia		**Asian Spot*** **Japan Spot*** European Spot

**Price changes highlighted in bold are more significant than the other price changes.*

As noted before, it is important to interpret these results with care. There is uncertainty over the precise magnitudes of the effect of unconventional gas on production, trade flows and prices, since the real world gas market has various complexities and imperfections that are not captured in the model. In particular, we note the following points:

- The price impact of an unconventional gas boom whether localized or global is likely to be greater than the impact predicted by the model, because increased supply strengthens the bargaining power of buyers relative to sellers, which could lead to further decreases in spot prices as well as re-negotiation of contract prices.
- The model estimates how trade flows of spot LNG are affected by increased unconventional gas supply; in practice, the additional supply is also likely to have an

effect on contracted flows, as other LNG producers will find it more difficult to sign new contracts and/or renew existing contracts in a less tight market. We have partially accounted for this effect through careful scenario construction. For instance, this explains why we do not have a scenario with both high Australian LNG exports and high North American LNG exports, since the market would not be large enough to accommodate them both. However, our model does not provide the full dynamic effects of an increase in unconventional gas supply.

- The modelling assumes that decisions to produce gas and sell gas to a particular destination are purely economic in nature and driven by economic fundamentals; in practice, domestic and international political factors also play into these decisions. For instance, in the model, Qatar gradually switches LNG from Japan and Korea to India due to the reduced shipping distance, but in practice Qatar has a long-standing relationship with Japan which it might not want to disrupt by reducing LNG flows, even though Japan is able to meet its LNG demand from other sources.

CHAPTER 4. CONCLUSIONS

If the production of unconventional gas continues to grow significantly, there will be consequences for international gas markets. The nature and scale of these consequences will depend greatly on the prevailing energy policy and energy balance within the country in which the incremental unconventional gas is produced.

Many countries around the world have potential resources of unconventional gas in different forms and several governments are trying to support the exploitation of these resources. In addition to the geological and geographical conditions of the resources, there are a number of above-ground factors which will determine the rate at which unconventional gas production rises in each country.

In those countries which are currently net importers of gas and have a growing domestic gas market, the rate at which unconventional gas production rises will depend primarily on the ability of the respective governments and societies to successfully support investment in exploration and production. This in turn will be influenced by the prevailing political and economic conditions in the country. Further, much of this gas will be used to satisfy and possibly accelerate domestic consumption. As a consequence, the reduction of net gas imports is likely to be significantly less than the growth of gas production.

Nevertheless, the success of a number of Asian countries like China, India and Indonesia in exploiting their unconventional gas resources would result in changes of trade flows and prices in international markets. Flows of LNG from Africa and the Middle East to these countries might decline and cause a fall in spot gas prices across Asia.

In contrast, in those countries which are major exporters of gas and where domestic demand is relatively flat, the rate at which unconventional gas production rises will be determined to a great extent by the construction of gas export facilities (LNG plants and pipelines) which in turn will depend on conditions in international gas markets. Increased LNG exports from Australia will mainly flow to Asia, causing a reduction of flows to this region from the Atlantic Basin producers, possibly driving down spot LNG prices in Asia. A higher level of LNG exports from North America are expected to boost gas flows to Europe as well as to Asia and depressing spot LNG prices in these two regions.

This analysis has not taken into account possible events which could cause major discontinuities in international energy and gas markets. Such "Black Swan" events might include:

- The start of large-scale production of gas hydrates before 2035. This would most likely take place onshore or offshore China, Japan or Korea. This development could significantly depress LNG prices in the region.
- The emergence of Iran as a major gas exporter which would have the effect of increasing trade flows from the Middle East to Asia and depressing LNG prices.
- In contrast, severe political instability in Qatar which accounts for 30% of world LNG exports, or the sustained closure of the Strait of Hormuz would create a major crisis in international gas markets, with serious consequences for trade flows and prices.
- Another serious nuclear accident on the scale of Fukushima might persuade governments with ambitious plans for nuclear energy (e.g. China and India) to scale down these programmes. Under these circumstance, their import requirement for natural gas would grow faster than predicted, putting upward pressure of gas prices in both the short and long term.
- Another severe regional (e.g. Asia 1997) or global (2008) financial crisis would have significant short and medium term consequences for international gas markets.
- Recent events in Ukraine have triggered two potentially significant trends. The first is the acceleration of Russia's need to look to Asian markets for future gas sales, as exemplified by the deal signed for gas exports to China in May 2014. The second is the impact on its oil and gas industry of sanctions on the supply of oil and gas equipment to Russia. Whilst this provides opportunities for Chinese suppliers, the absence of highly sophisticated equipment is likely to constrain progress in

exploring for oil and gas in Russia' offshore Arctic region.
- The widespread implementation of effective carbon pricing measures which would accelerate the switch from coal to natural gas.

In Summary

The world is approaching a tipping point with respect to the production and consumption of natural gas. Environmental and supply security concerns are driving national policy changes which support a progressive switch from both coal and oil to natural gas in industry, power generation and transportation. Technological breakthroughs that are allowing the production of different forms of unconventional gas on a large scale assist these policies in three ways: through the provision of new supplies of gas, through the geographic diversification of these supplies and through downward pressure on gas prices. The continuing availability of natural gas supplies will prolong the era of fossil fuel use. In contrast to North America and Australia which are likely to see a substantial rise in gas exports, unconventional gas resources in many countries will be exploited primarily for domestic consumption and may not enter international markets. However, if the scale of production is large enough, it might reduce or constrain the call on international gas markets.

This report should be seen as a preliminary analysis for two main reasons. First, with the exception of China and Indonesia, the authors carried out no in-country studies, but relied on published accounts. Second, the Nexant World Gas Model, despite its value, has a number of inherent limitations which are described in the report. This research was concluded in July 2014 and therefore does not take into account the dramatic fall in oil prices and other events which occurred later that year.

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