DNV KEMA Energy & Sustainability

Study on LT-ST Markets in Gas

Final Report

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In collaboration with COWI Belgium

August 31, 2013

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By order of the European Commission - DG ENER

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Foreword

The present report has been prepared by DNV KEMA Energy & Sustainability, in collaboration with COWI Belgium, under the existing COWI Service Framework Contract with DG TREN (ENER and MOVE) covering Technical Assistance Activities (Ref. TREN/R1/350-2008 Lot 3) and in response to the Terms of Reference included under the Specific Contract No ENER/B2/2012-558/SI2.641184.

Readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the European Commission.

CONTENT

1 EXECUTIVE SUMMARY

The study in hand was prepared by DNV KEMA in collaboration with COWI Belgium on behalf of the European Commission – General Directorate Energy in order to analyze and assess the benefits and risks of an increase in short-term contracts across the entire value chain in the EU gas market, with a particular focus on the impact of an increase in short-term contracts on security of supply and competition.

The project was structured in three tasks. The main task was the analysis of the EU gas sector, which was clearly in the center of the project. Findings from this task were enhanced by the analysis of other markets. With the EU gas sector as a starting point, other markets were assessed in two directions, first, looking into gas markets elsewhere in the World, and second, looking into other commodity markets. In task 2 an analysis of the gas wholesale markets in the USA, Japan, China and Australia has been prepared to augment the analysis of the EU gas market and to identify similarities, but also major differences between the gas markets. Task 3 addressed other important and actively traded commodity markets. The Brent crude oil market, the Atlantic steam coal market and the EU electricity markets were analyzed. The common goal of tasks 2 and 3 were to compare the temporal contract structures and to explain the development paths and motivations behind the different contract structures observable in the other commodity sectors.

EU gas markets

Long-term contracts applied in the **EU wholesale gas sector** are not only characterized by the length of the contract, but pricing terms, such indexation to other price benchmarks like crude and refined product prices and the volume flexibility are basic elements in any LT gas contract. These elements are interrelated. Pricing at oil-index or fixed, high take or pay levels and long-term durations are at one side of the spectrum; pricing at the hub or gas indexed, low or no take or pay levels and short term duration are at the other side of the spectrum. A general trend to more flexible and more short-term oriented contracts on all levels of the value chain is observable. Gas contracts are becoming shorter down along the value chain. At the upstream side contracts tend to be long-term with durations for new contracts often in the range of 10 to 15 years, while at the downstream side contracts are typically more short-term oriented with durations typically below 5 years. Transport contract durations are generally comparable or somewhat shorter than the contract duration of the gas delivery contracts. Contract durations for gas storage tend to be comparable to transport contract durations. For large investments in infrastructure in and towards Europe we see these projects with back up by vertical integration and/or anchor shippers in order to ensure bankability of these projects. However, in light of the availability of these instruments as back-up it is hardly possible to say whether infrastructure investments would have gone ahead also without this back-up. In general, where mature markets exist, demand seems to be reasonably secure and (sufficiently) well predictable. In those markets, together with market-based pricing, long-term contracts provide little added-value. In developed market systems with liquid hubs there is less need for long-term transportation capacity to serve as physical back up for the commodity business. Long-term transport capacity booking serves as a hedge against the transportation congestion cost risk. Comparable to the pricing mechanism for storages (tariff indexed to summer/winter price differentials) we could imagine some TSOs to propose transportation tariffs related to locational price differentials.

In markets where competition already exists or is emerging, short-term contracts will make market entry and exit easier, thereby enhancing competition. More short-term contracts will have a positive impact on liquidity, as it gives additional room for volumes, hedging and paper trade. While parts of the gas volumes may be under oil-indexation or coal-indexation, well-functioning spot markets will provide transparent and robust (price) signals and will offer consumers a choice where from and how to source gas. In general, a transparent market is beneficial for smaller players and new market entrants. If interconnectivity is improved for the more “isolated” Member States and shorter term contracts and spot-trading are successfully promoted, we believe that the Member States in the eastern part of the EU may follow the same pathway, i.e. hubs will be established and prices will align, with price differentials representing the short-term cost for transport between the hubs.

Short-term contracting, and thus competition, generally has a positive impact on security of supply. More competition and liquidity will attract more competitors and more gas to the market when the price is right, thus supporting diversified supplies. In a competitive market (a deep and liquid spot market) scarcity situations are handled through price signals. The market will serve as a supply for last resort, as well as an outlet for (new) large supply projects and incremental gas. Moreover, future markets enable future delivery, contracting, and price discovery, supporting longer term investment signals.

Security of supply also helps competition. A comfortable supply situation creates trust in the market, so that market parties can rely on the market to solve imminent (short term) supply issues, albeit probably at some price risk. We should however also be aware that competition cannot fully replace or solve security of supply risk. In some cases the market will not be able to address supply issues. For example, there probably is no business case for keeping enough gas available to cope with extremely cold days. For such events, political and regulatory interference is required to protect gas customers (and as has been used already in the past).

In addition, the current and expected gas market situation in the EU, with sufficient gas volumes and capacity available, makes long-term security of supply a less important issue for the coming year. As a consequence, more short term contracting will not affect investments in large gas projects.

Other gas markets (USA, Japan, China and Australia

Long-term contracts currently are applied in all four of the assessed countries, with significant differences though. To date, where costly large scale investments are required, long-term contracts of 10 years and more (often 20 years) seem to be applied on a rather general level, with the exception of US gas production investment. Alternatively (or additionally), companies tend to hedge their positions with vertical integration along the supply chain. Similarly where strategic considerations are playing a major role, for instance in order to secure gas supplies for an import dependent market.

For the time being, it seems that the traditional model of long-term contracts will be continued to be used at least in relation to large investments, as for instance the example of the recent LNG export agreements for US terminals shows. For EU market players it can be assumed that with increasing exposure to the world gas market (e.g. due to decline of domestic resources) their contractual structures are also shaped by the competitive environment on the world gas market.

In general, it can be observed that the market fundamentals essentially shape the contract structure. The characteristics of the gas infrastructure and the regulatory measures such as third-party access and liberalization determine the level of competition in a country. In a liberalized integrated gas market such as the US, the establishment of contractual terms and their change over time, was and is among others driven by changes of the market environment (either by endogenous development or pushed by the regulatory authorities) which have led or at least have allowed for to a much more important role of short-term contracts with durations of less than three years. In import-dependent China (and to similar extent in Japan) where the market is characterized by an oligopolistic structure and state-owned companies with supply obligations dominate the import side, the investment and import decisions are rather steered by security of supply questions (import costs are of less importance when monopolistic positions ensure cost coverage in an case). The lack of competition results in the fact that import companies are less exposed to volume risk associated with long-term contracts. The main bulk of demand is covered by long-term contracts and spot-term contracts aim to serve mainly as a flexibility tool to supply additional demand.

By assessing the selected countries a clear pattern evolves with regard to motivation toward long-term contracts: while the gas exporting market actors rather focus on securing cash-flow from their investments (secured return, increased bankability of the project), gas importers concentrate on securing stable supply for their domestic demand. Thus, on world market level exporting and importing parties meet which have strong interest in stable long-term relations. However, an increasing variety of exporting and importing parties, as well higher transparency and increased optionality, is likely to lead to resolving the mutual interdependency between exporters and importers.

For the EU that would mean that longer-term contracts (as described above) will – for the time being – mainly be found on a primary level at the interface between production companies in gas exporting countries and importing companies, as these companies will be stronger affected by the approach used also by other player on a world market level and will likely need to conform to a large extent to the requirements of production and infrastructure companies in order to secure access to gas supplies. On a secondary level, i.e. companies on the EU market getting gas from importers and supplying it onwards and trading on the internal market will much less bound by such constraints. Their activities will be much more shaped by the situation on the EU gas market with a strong competitive pressure. As for the importing companies the EU demand as such is not likely to shift away, there is also less pressure to have agreements with companies on the secondary level to match their agreements on the outside interface. Therefore, it seems likely that contracts on a secondary level will tend to be shorter than on the primary level. With regard to infrastructure, where public consultations and regulatory approval is replacing traditional methods like open seasons in order to facilitate investment decisions, contract durations may also have the tendency to be more short-term oriented. In the longer run, with changes towards shorter and more flexible contract models expected also on the world market level, this may easily lead also to a change of contract structures for the EU market parties, while at the same time, changes on the EU market will increase the momentum for the development towards more flexible contracts structures on the world market.

Other commodity markets (Brent crude, Atlantic steam coal and EU electricity)

Lessons to be learned for the temporal contract structures in the EU gas sector from the three other commodity sectors are not too obvious on first sight. However, some observations can be drawn from the other commodities. The occurrence of new steam coal producers led to increasing transport distances. Former national coal markets have grown together to only two regional wholesale markets (Atlantic and Pacific steam coal trade) tightly linked to each other by active arbitrage. This is not yet the case in the natural gas sector were price differentials between the European and American hub prices and Asian import prices are not arbitrage free given the specific LNG costs.

Long term contracts are rather an exception in the steam coal, crude oil and electricity markets. Downstream or upstream vertical integration are preferred to mitigate price and volume risks. These risk mitigation strategies are mainly applied in case of capital intense long term investments with high upfront investments. Long term contracts are applied in cases where corporate vertical integration is not possible or where it is not well suited due to the ownership structure (e.g. minor interests in assets with a long lifetime). Long term contracts as a proxy (in particular in the electricity sector) mimic the characteristics of a corporate integration. In the electricity sector these long term contracts are structured as tolling agreements. A tolling agreement leaves the primary fuel price risks to the tolling customer. The tolling agent receives a fixed fee to cover the investment costs. The duration of these long term contracts resembles the financing structures of the investments (usually between 15-20 years). However, vertical integration besides the reliance on standardized short term wholesale contracts seems to be the preferred risk mitigation strategy. Vertical integration along the natural gas supply chain is hampered by political and legal issues.

A high capital intensity of exploration and production is a particular characteristic of the crude oil and natural gas markets. The prevailing risk mitigation strategy of long term contracts in the natural gas sector is not observable to the same degree in the crude oil sector. Some E&P companies from emerging and developing countries are integrating downstream. A potential explanation for this structural difference is potentially the price expectation of market participants. As can be seen from the forward curve for crude oil, prices will only decrease in the future starting from a rather high spot price.

Overall Conclusions

More short-term oriented markets will lower entry barriers for new entrants (either entirely new or existing parties willing to extend their geographical areas of supply), joining the ranks of second-tier players, thereby further increasing competition and liquidity (where physical conditions such as the availability of diverse supply sources and interconnection capacities allow).

Where markets are sufficiently liquid, transport and storage capacity will rather have the role of a hedge against regional or intertemporal price spreads. The expectation with regards to these spreads will determine the willingness to pay for such capacities. Thus, risks for market parties will mainly be reduced to financial risks, i.e. the residual price risk if for instance the lack of transport capacities forces a market party to source gas from a comparably more expensive hub.

More competitive and liquid trade based on adequate price signals will likely attract more market parties and larger gas volumes to the market. This will increase the diversity and affect positively security of supply. In particular, liquid forward markets which will likely be strengthened by increased transaction volumes on short-term markets, will provide effective signals to market parties, producers and infrastructure investors.

Already today, spot market prices are behaving quite volatilely. News with regards to unusually low storage levels at the end of winter, outages of a North Sea pipeline or only unusually low temperatures in spring for instance have an immediate impact on prices, driving pricing levels upwards. The consequences from an increase of short-term and spot trade will be twofold.

- First, spot market prices will increasingly be influenced by the short-term supply and demand, which would lead to a higher volatility of prices.
- Second, the larger volumes traded under these prices will improve price signals to consumers.

To the extent consumption will respond effectively to price signals, the improved price signals and the larger traded volumes exposed to spot-market prices will lead to more efficient consumption.

Whilst the new market equilibrium is sought for, price signals may serve well to discourage consumption in case of scarcity situations and thus enable the supply systems to maintain overall system stability and to deliver the gas where it is valued most. Furthermore, any reduction of demand as reaction to price signals (and also the other way round, any increase of consumption in case of low prices) will stabilize prices. In addition, also where longer term supply contracts prevail but pricing is developed towards more short-term elements, i.e. where hub-indexed pricing is included, gas prices will be subject to the short-term variations of spot-prices, improving the efficiency of economic signals generated by prices.

The expected result will be that investors will rather commit investments when the outlook is rather positive, i.e. when prices are attractive and the general market exception is rather the continuation of stable or increasing prices, and will be more hesitant to invest during phases of depressed prices. The outcome will thus be a development of gas markets more into the direction of a boom-and-bust-cycle-type economy. In general, investors reacting on such price signals independent of each other will likely provide a higher level of diversification, thus fostering competition and security of supply. Although, the long-term security of supply should thus be supported, such a cyclical pattern may have some negative side-effects though, mainly because of the time lag between an investment decision and the investment to take effect. The oil market shows a pretty similar pattern and allegedly still suffers from investment cutting during the low oil-price phase at the end of the 1990ies. However, assuming an increased efficiency of scarcity signals as elaborated above, the market should show the necessary resilience to absorb a strengthening of cyclical patterns. In addition, as already mentioned above, forward markets will have an increasing role in providing future-oriented price signals for investors.

In many of the assessed markets, vertical integration seems to serve as a hedge to mitigate any risks involved in short-term markets, for both sides.

- Companies at the demanding end may want to ensure access to resources and favorable pricing conditions and/or hedge against price fluctuations
- Companies at the supplying end may want to ensure offtake of volumes and mitigate risk of renegotiations

Thus, vertical integration could have a positive impact for both sides. An ownership stake of a major buyer of the gas in an offshore development will on the one side serve well to ensure the investor and financing institutions that the risk to strand the investment and there will be no buyer for the gas is rather limited, as the buying side shows a commitment.

Whilst the above focus on the impact an increase in short-term contracts will have on the EU gas market, the question remains open which role long-term contracts will still play in future.

From the research undertaken so far and also from the interviews conducted in the course of the project, the conclusion is that for the time being long-term contracts will continue to be used for parts of the sector despite the certain increase of short-term contracts and transactions all along the value chain as well as spot trading.

However, long-term contracts are already subject to changes and will change further in the years to come. The contract duration will have to be seen in close relation with prices or pricing formulas chosen in this contracts, as well take into account opening clauses.

For commodity, it seems safe to assume that the traditional long-term, oil-indexed contract will not prevail in the long-run. Thus, also where long-term contractual relations will continue to exist, the changing market situation with a strong development towards short-term contracts in general is expected lead to changes of pricing in long-term contracts and in fact will lead to pricing rather based on short-term market developments. Currently, the existence of and change to long-term contracts based on hub price development can already be observed, e.g. for deliveries to Europe which are then based on development of NBP or other European trading hubs, or LNG supplies from the US, which are based on Henry Hub prices (plus a fixed component to cover infrastructure costs). Also price baskets will likely increase in importance.

2 INTRODUCTION

2.1 Background

DNV KEMA in collaboration with COWI Belgium was assigned by the European Commission – General Directorate Energy with a project to provide technical assistance in analyzing and assessing the benefits and risks of an increase in short-term contracts across the entire value chain in the EU gas market, with a particular focus on the impact of an increase in short-term contracts on security of supply and competition. The work was largely based on desk research, with further insights gained from a series of expert interviews conducted in the course of the project. Furthermore, the project work was accompanied by several rounds of discussions with colleagues from the European Commission during which valuable feedback was provided.

This report is structured as follows:

- The first section provides and an overview of the approach used for this project. In brief, the project primarily focused on the analysis of the EU gas sector, but in order to corroborate the findings from this analysis and the see whether additional learning could be taken, the analysis was extended to selected other gas markets and to selected other commodity markets.
- The following chapter focuses on the EU gas sector, providing a description of the present situation and ongoing developments of the contractual structures along the supply chain as well as specific conclusions with regards to the EU gas sector and the key topics of the this project, i.e. security of supply and competition.
- Chapter 3 provides the brief descriptions and the analysis of the gas markets selected for this project, i.e. Australia, China, Japan and USA.
- The next chapter provides a similar analysis the other commodity markets selected for this project, i.e. steam coal, Brent crude oil and electricity (with a focus on a few EU Member States).
- The final chapter 5 concludes with a summary of the insights and conclusions gained during the project, merging the results of the analysis of the EU gas sector with insights gained from the analysis of other gas and commodity markets.

It needs to be pointed out that the conclusions of this report are derived based on the assumption of the existence of a liquid gas market, as it for instance in UK, Germany, Belgium, France and The Netherlands and increasingly also in other Member States such as Austria and Italy. While it is the target of EU energy policy to create an internal gas market providing access to liquid trading throughout the Union, this is not necessarily the case in all Member States (yet), as we are fully aware.

2.2 Problem Analysis and Project Structure

The EU gas sector is traditionally dominated by long-term contractual relationships in the field of gas supply and transport. These long-term contractual relationships stem from the beginning of the development of the gas sector in Europe and had the purpose of fostering the building of necessary gas infrastructures.

During the development of the EU gas sector until today, contractual relationships on import, transport and supply/trading level were dependent on and influenced by each other.

In light of the liberalization of the gas sector which took place on EU and national level, there is a trend towards shorter contract durations, promoted by arising competition in many fields of the gas sector. Shorter contract durations on the commodity side may also lead to shorter contract durations on the transport side. At the same time, a market oriented approach towards shorter contract durations will not change the inevitably long-term perspective of infrastructure investors, either on exploration/production level or on transport level, and those investors' needs to safeguard their investments.

Temporal[1] contract structures in other markets, for instance other gas markets around the globe as well as in markets for other commodities, may have seen similar developments towards a more short-term orientation and could serve as examples providing "lessons-learned" for the case of the EU gas sector. In addition, the developments in other gas markets may well have an impact on the situation and the development of the EU gas sector.

2.3 Methodology & Approach

The project was structured in three tasks, as depicted in the following figure. The main task was the analysis of the EU gas sector, which was clearly in the center of the project. Findings from this task were enhanced by the analysis of other markets. With the EU gas sector as a starting point, other markets were assessed in two directions, first, looking into gas markets elsewhere in the World, and second, looking into other commodity markets. The conclusions are primarily based on the analysis of the EU gas sector itself, whereas the look into other gas sectors and other commodity markets was meant to substantiate and corroborate these conclusions, to identify potentially valuable lessons learned and to assess any potential impact developments on these markets may have on the EU gas market.

[1] With temporal structure, we mean the role of long- and short-term contractual relationships along the value chain how contract durations in each step of the value chain influence each other.

Figure 1 Scope and Structure of the Project

Task 1 – Analysis of the role of long- and short-term contractual relationships in the European gas sector

The EU gas sector was in the center of the project. During the project an analysis of the role of short-term and long-term contractual relationships was made, in particular aiming at:

- the mutual dependence or influence of contract durations for commodity and capacity products,
- the role of contract durations from the perspective of investments, financing and security of supply,
- respective risk characteristics associated with the contracts, and
- the impact of contract durations on the competitiveness of gas markets.

Task 2 – International comparative analysis of the temporal structure in other gas markets

The second task was meant to enhance the analysis made under task 1 by having a closer look at the temporal structure of other important gas markets around the globe with the aim to derive a lesson-learned for the EU gas sector development. The analysis was aiming to provide an analysis of contract structures in the USA, Japan, China and Australia. Depending on the individual situations of these countries, the focus was either more on the domestic markets or on import or export side of these markets.

Task 3 – Cross-sector comparative analysis of the temporal structure in other relevant commodity markets

Similar to task 2, task 3 was having a look at the temporal structure of other markets in order to complement the results of task 1. Whereas task 2 spread the analysis to other gas markets outside EU, task 3 had a focus on other commodity markets, with a clear focus on the EU, but where appropriate the analysis also drew on experience in other countries.

Whereas conclusions were made also for each of the tasks, the conclusion provided at the end of this report takes account of the results of all three tasks.

The analysis was principally based on desk research, using publicly and freely available sources in English language, for instance company and governmental websites and those of international organizations, as well as research and business reports. In addition, information provided by DG ENER's Energy Market Observatory was used.

In addition, a series of expert interviews have been conducted during the course of the project. Potential candidates for the interviews were jointly selected with the European Commission. Interviews were held as phone interviews and were aimed at rather being background discussions. In total, eleven well reputed experts from financial institution, market parties and academia were invited, of which seven accepted the invitation, sometimes participating in the interviews together with colleagues.[2] In order to guide the interviewees through the interviews a guideline was distributed in advance, see Annex 1. The insight gained from the interviews was used to strengthen or challenge the findings from desk research as well as to strengthen the understanding of interrelations between markets and market segments and the expectation of future developments.

2.3.1 Analysis of the EU Gas Sector

The objective of this first task of the project was to analyze the role of long and short term contractual relationships in the European gas sector with respect to security of supply and competition. The main question to address was to describe the consequences of a higher proportion of short term contracts.

In a first step we have provided an overview of the **current contractual terms** across the entire gas value chain in Europe. For this we have distinguished between:

- The parties across the gas value chain, i.e. producers, wholesalers, suppliers and end consumers;
- The different type of contracts, i.e. gas commodity contracts (negotiated contracts and OTC contracts respectively) and gas capacity contracts (transport and storage).

After starting the research, it became obvious that the further down the value chain the shorter the contract duration. Furthermore, a lot of price discussions and renegotiations are going on in the gas delivery contracts in the upstream part of the value chain (producers – wholesalers) in Europe. Given the overall research question, we focused on the commodity contracts used in the first part of the value chain. We furthermore addressed the connection between these commodity contracts and the capacity products, especially transport, and the potential risks or benefits of temporal divergence in these contract structures.

Subsequently, we have investigated and analyzed the risks and benefits of long term and short term contractual relations (including spot markets) in the light of **competition** (promotion of market entry, lowering of entry barriers and avoiding foreclosure of certain market parties) and liquidity on the European gas markets. Our analysis focused on three basic questions:

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[2] We herewith would like to thank all our interview partners for their valuable insights and contributions: Bertrand Benichou, Thierry Bros, Laurent Hamou, Hiroshi Hashimoto, Ichiro Kutani, Tatiana Mitrova, Tetsuo Morikawa, Steinar Solheim, Kim Talus, László Varró, Akira Yanagisawa.

- What is the impact of shorter term contracts on liquidity and competition?
- What is the impact of shorter term contracts on the role of gas exporters in downstream markets?
- Which role do long and short term contracts play in the competition between coal and gas in power generation?

Finally we investigated and provided an analysis of the risks and benefits of long term and short term contracts (including spot markets) with respect to **security of supply** issues. The focus of our work was on the following three basic questions:

- Do the long term and short term contractual relationships provide appropriate investment signals and financial stability/viability for the exploitation of gas fields and new infrastructure?
- What are the benefits and disadvantages of the move towards spot and futures trading with respect to security of supply?
- To what extent can short-term contracts replace long-term supply contracts?

2.3.2 Comparative Analysis of Other Gas Sectors

The overall goal of the second task of the project was to take stock of the temporal structure of four other large gas markets, i.e. USA, Japan, China and Australia, and assess the existing long- and short-term contractual relationships. The aim of this task is to provide a comparative analysis of the selected countries identifying and explaining the reasons and drivers for the temporal contract structures as they are.

Given the individual nature of the selected countries, the focus of the research and analysis is not the same in all four cases. With the overall aim to derive insights for the EU gas market, the focus of the research was chosen as follows:

- USA
  USA is a very mature gas market. Apart from imports from Mexico and Canada, the US gas sector is self-sufficient. The high level of self-sufficiency is supported by the shale gas boom taking place over the last years. With expected future LNG exports, USA will become a net exporter of gas. The main focus of the analysis of the US system is on
  - What is driving pipeline investments?
  - What drove recent pricing developments and where will pricing likely develop to?
  - Why did long-term contracts disappear?
  - What drives the development of USA becoming a gas exporter?
- Australia
  Australia's gas market is characterized by the limited connections to the rest of the world (LNG only) and its segmentation into several geographic zones. In brief, the Australian gas

market may be described as rather immature with strong vertical relations along the value chain. Australia is already on established supplier of LNG. The wealth of Australia's gas resources (also unconventional resources) and the soaring demand for gas in the Asia Pacific region seems to have triggered major investments into additional LNG export facilities. It is expected that the first of the new LNG export trains start operations in 2014. Future increases of LNG exports already put pressure on domestic gas markets and prices. Given the overall situation it is concluded that the focus is on Australia's role as gas exporting country whereas the domestic Australian gas market is of less relevance for this study and will not be assessed beyond a high-level overview. Based on the project's objective, the main research questions with regards to Australia is:

  - What is driving liquefaction investments?
  - Which contract structures are in place to support the investments?

- Japan and China

  Japan and China are two of the biggest natural gas consumers in the world. China´s main bulk of supply is indigenous production, however the additional demand mainly resulting from increasing consumption is covered by LNG and pipeline imports. Given Japan´s very limited domestic natural gas resources and the lack of pipeline connections, it is the biggest LNG importer in the world. Both countries can be characterised by the lack or at least a certain scarcity of interconnected pipeline capacities, low industry concentration (e.g. oligopolistic structure in China and regional monopolies in Japan) and the dominance of vertically integrated, in many cases state-owned companies. According to our observations, both markets show a very limited level of competitiveness. Given these country specific characteristics and in line with the overall aim of the study, we focused on the side gas imports (LNG and piped gas) by concentrating on the following research questions:

  - What is the expected future role of indexation?
  - Will Asia/Pacific likely absorb gas which would otherwise be meant for Europe?

Apart from the research foci for each of the selected countries, the research into each of the countries also covered the following items (although to a differing extent, depending on the country):

- General gas sector structure
- Gas market
- Regulation of gas markets and infrastructure
- Framework for new infrastructure investments
- Role of the country as gas exporting or gas importing country
- Current developments and expected future developments

2.3.3 Comparative Analysis of Other Commodity Sectors

Task 3 was a cross-sector comparative analysis of the evolution of the temporal contract structure in other relevant commodity markets. The following commodity markets were chosen for the cross-sector comparison:

- The Brent crude oil market:
  Brent crude oil is one of the major price markers for the world trade in crude oil (West Texas Intermediate being the other) and is the benchmark for all Atlantic basin crude oils. The Brent crude oil comprises all crude oil produced from the four fields Brent, Forties, Oseberg and Ekofisk (the latter two being Norwegian fields, whereas the other two are British fields). Brent crude trade has developed since the 90ies. The Brent crude oil market is defined as covering all transactions, which will be directly or indirectly affected by the Brent price benchmark.

- The Atlantic sea-trade of steam coal:
  The Atlantic sea-trade of steam coal accounts for roughly one third of the international sea trade of steam coal, with the other traded market being the Pacific sea trade, which makes up two thirds of the international sea trade of steam coal. The combined sea trade represents only around 1/7 of the total world steam coal consumption. However, the sea trade is a rather young phenomenon, which developed only gradually after the second oil crisis (1979 / 1980).

- The European (EU) electricity market - exemplary for Germany, Italy and the United Kingdom:
  Historically, electricity markets were partially or fully vertically integrated. If corporate borders existed along the value chain, the two different legal entities were most often tied together by means of bilateral long-term contracts. The liberalisation led to an unbundling of grid activities, constituting a natural monopoly, from all other competitive activities along the value chain. Vertical integration between generation and supply has been abandoned in some jurisdictions after the liberalisation, but gradual reintegration has occurred after this split up (e.g. United Kingdom). EU Electricity markets are today characterised by a mix of short term highly standardised spot transactions over long term supply contracts to a complete vertical integration (subject to the limitations of the grid unbundling). We have chosen to illustrate the development of EU electricity market by referring to the three markets of Italy, Germany and the United Kingdom.

First, the development of the three selected commodity wholesale markets in the past was assessed. The analyzed market show a differing levels of maturity of wholesale markets. In addition, the drivers that led to different developments in the three commodity sectors and shaped the markets as they are today, differ from one sector to the other.

Second, the impact of changes in the temporal contract structures on the two most important criteria for energy policy, security of supply and competitiveness were analyzed.

The analysis was finished with an analysis of the analogies but also differences between natural gas and the three commodity sectors in question.

3 TASK 1: ANALYSIS OF THE ROLE OF LONG- AND SHORT-TERM CONTRACTUAL RELATIONSHIPS IN THE EUROPEAN GAS SECTOR

The objective of this first task of the project was to analyze the role of long and short term contractual relationships in the European gas sector with respect to security of supply and competition, among others, looking at investment signals versus liquidity etc., and possible future developments in these contractual relationships.

We have divided this task into three parts:

1. In the first part we provide an overview of current contractual terms across the entire gas value chain in Europe.
2. In the second part we analyze the impact that an increase in short-term contracts will have on competition in the EU gas sector.
3. In the third part we analyze the impact on security of supply.

Each part ends with a summary of our respective analysis. The key findings of our analysis on the EU gas sector, merged with the findings from other gas and commodity markets, are presented in chapter 5.

3.1 Contractual Terms across the Gas Value Chain in Europe

In this section we provide an overview of current contractual terms across the entire gas value chain in Europe. We have made a distinction between contracts for the commodity (bilateral negotiated contracts or traded gas markets) and capacity (transport and storage). Within each of the four types of contracts we have further distinguished between the different market parties across the gas value chain, i.e. producers, large importers (wholesalers), small wholesalers (suppliers) and end consumers.

We start with a more conceptual approach on contractual relationships for the commodity which will be followed by an overview of the current situation in the EU gas market. Thereafter we will more briefly discuss the contracts for capacity – as we have restricted ourselves to the duration – where we will focus on the mutual dependence or influence of contract durations for commodity and capacity products. At the end of this chapter we provide a summarizing table containing an overview of the current contractual situation in the EU and our conclusions on this.

3.1.1 A General Overview of Commodity Contracts

Buyers and sellers can enter into structured, non-standard contracts with each other bilaterally[3], negotiating contract details on an individual basis. This has been the 'traditional' way of conducting business in gas purchase and sale and was used primarily when large volumes and long-term delivery periods are concerned. The role of this type of negotiated contract for gas delivery, both pipeline and LNG, is discussed in further detail in section 2.1.2.

Over-the-counter (OTC) non-regulated trades are also bilateral, however involving standardized physical and financial deals. Such trades are based on standard agreements defining, for example, the standard point of delivery, the quality of the gas delivered along with other practical and legal terms. OTC trades can also be for standard volumes and clip sizes (and multiples thereof), e.g. 1 MWh per hour per day. OTC financial (or paper) trades are less common. Financial trades are similar to physical trades, however, without the intention to actually deliver gas. Financial contracts are settled – as the name says – financially, for instance by a payment of the difference of the agreed price and the actual spot price. Bilateral physical or financial OTC trades are often brokered, whereby the broker or intermediary brings buyers and sellers together without, however, taking a position themselves. The broker is not a counterpart in the gas deal. In contrast, with exchange traded gas, the buyer and seller of gas have the exchange operator as the central counterparty operating as a clearing house. Thus, exchange trade is fully anonymous and standardized. Section 2.1.3 discusses the role of OTC and exchange trade in the EU gas market.

Natural gas supply contracts contain various terms and parameters determining how the ownership title to the gas is transferred between the seller and buyer. In bilateral contracts, the specification of these parameters and their related price effects is based on negotiation and mutual agreement between the parties on an individual contract basis (i.e. they should be agreed for each and individual contract). In OTC and exchange traded contracts most of the contract parameters are fixed by the standards and parties only have to define the quantity, the price and the period of delivery. As the pricing terms, the length of the contract and the volume flexibility are the basic elements in any gas contract or trade, we have honed our analysis in on these contract items.

Please note that these contract elements are also closely interrelated. For example, a long-term contract without any take-or-pay (ToP) provision would, in practice, not be a long-term firm commitment. Furthermore, if long-term contract pricing would be fully gas hub based, the buyer could take the gas and sell it at that hub with a small risk, if any, to his revenue (determined by the difference between the indexed or average reference price and the spot price). In this case, the long-term contract would lose its function as a guarantee of demand because the seller may also offer part of its gas volumes

[3] Or they can even adopt a strategy of vertical integration, which can be regarded as the ultimate long term relationship or contract (see for example the work of Joskow and Williamson).

directly at the hub.[4]. Thus the ToP obligation is no longer credible for ensuring offtake. It can be concluded that ToP obligations and price indexation (tying the price development to another market) are to some extent complementary elements. This is also illustrated in Figure 2 which shows the development from long-term to short-term contracts along the dimensions of pricing and volume flexibility. Of course, in practice, the route taken may not always be the direct one, with a plethora of options available for current contract details.

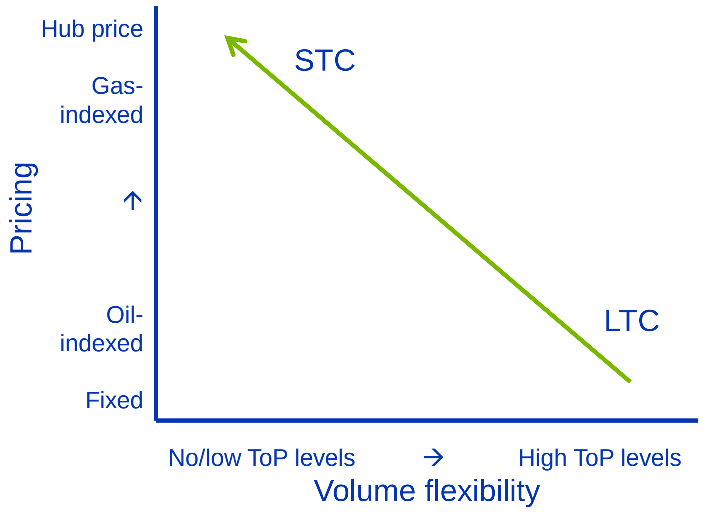

Figure 2: Trade-off between volume flexibility and price indexing

In the definition of long-term contracts we not only refer to the contract duration, but also to the Take-or-pay obligations and pricing obligations. A traditional long term contract in this definition is thus characterized by a contract duration extending beyond the traded forward market, flexibility through ToP obligations and an indexation to a price benchmark different than the spot gas market price. If we compare, for example, a gas delivery contract for the duration of 3 years, with 70% ToP and a 50% oil linked price with another contract (for the same volume), for 10 years but without a ToP commitment and a price indexed to a gas hub. According to contract durations the first contract is shorter term, however the latter, longer term contract contains risk mitigating elements.

One of the main motivations of (long-term) contracts in the past was for parties to agree on risk-sharing or risk-allocation respectively. Under a long-term ToP commitment, for instance, the seller puts the volume risk on the buyer of the gas, ensuring for himself that the gas is taken anyway (or at least paid for). With pricing along substitute fuels (e.g. oil) or netback from the value of the product

[4] Provided that he has access to the hub. Moreover, it may be difficult to offer large volumes of incremental gas directly at the hub (although a sufficiently deep and liquid hub should be able to accommodate these volumes)

produced with the gas (e.g. power), the price risk is taken from the buyer. With a changing contractual landscape, also risk allocation changes, as is further explained below in the following sections.

3.1.2 Gas Delivery – Negotiated Contracts

Long-term contracts developed in Europe to open up natural gas a route into the heat markets. Back then the dominating primary fuels in the heat market were primarily refined oil products, such as heavy and light fuel oil. Since their prices are tightly linked to the market price of crude oil, the long-term contracts were linked to a basket of prices for crude oil and refined oil products. A second important feature of the long-term contracts were contract durations of 20 years and longer to allow for the recovery of exploration and initial production costs of new gas fields. The third important characteristic of a "traditional" long-term contract was the flexibility inherent in the import contract. The contract allowed the buyer to modulate the off-takes of his customers in accordance with a volatile gas demand within a range of 20-30% of the nominal value of the contract. As a result, the risk sharing in a long-term contract was as follows: the seller assumed the price risk, the buyer the volume risk. Another important clause in LT contracts were the destination clauses: the buyer was not allowed to redirect the bought gas into other national gas markets, creating indirectly competition to the seller in the LT contract. Oil-indexation facilitated the bankability of large gas investment projects while ensuring that the prices faced by consumers were in line with prices of alternative fuels (for instance where oil-heating was replaced by gas-heating). However, the market and therefore the risk ownership structure in the gas value chain has changed in which back-to-back selling at oil-linked prices is difficult (e.g. as indicated by Dincerler, et al., 2012.[5] Wholesale gas spot and forward markets developed, which offered gas buyers and consumers an alternative to the prevailing oil-linked long term contracts. As a result, midstream importing and wholesale companies got squeezed between gas bought upstream at oil-linked prices and gas sold downstream based on wholesale market prices. This is illustrated in Figure 3.

[5] Dincerler, C., C. Lins, and J. Schmitz. Long-term gas contracts – preparing for a new paradigm. Oliver Wyman, 2012.

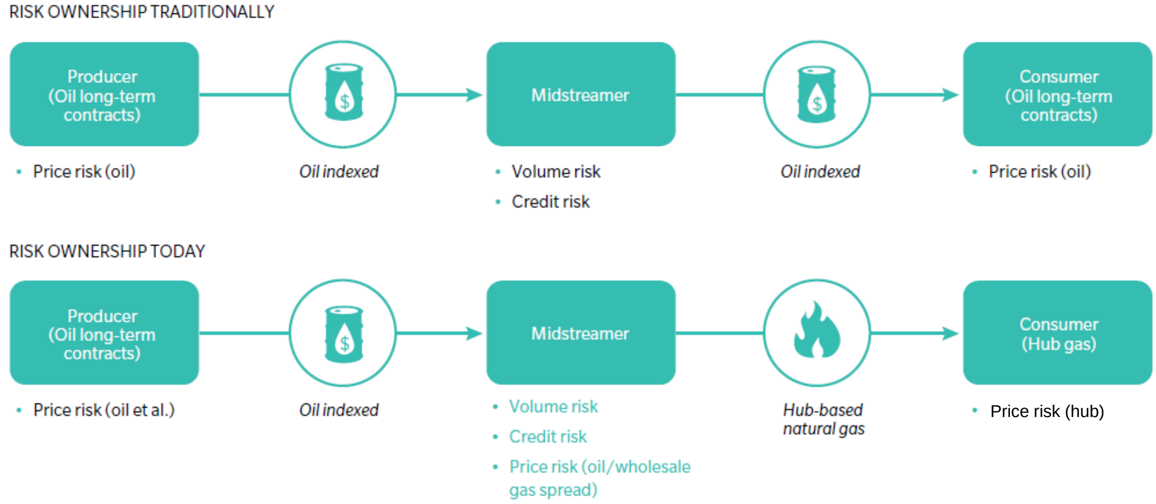

Figure 3: Changing risk ownership in the gas value chain

Source: Dincerler et al., 2012

A structural reason for the declining role of oil-indexed long-term contracted gas is the liberalization-push in Europe. EU policy and regulation towards energy market liberalization has led to consumer choice and more liquid wholesale gas markets. In addition, oil is hardly an alternative fuel for gas anymore, which is further demonstrated by the decoupling of the EU gas markets from the global oil market. Downstream in the gas value chain, market pricing is gaining importance, thus moving away from long-term contract pricing (still) used upstream.

3.1.2.1 Gas Delivery Between Producer and Wholesaler

Bros (2012 and 2013)[6] indicated that 58% and 57% of total European gas supply was long-term contracted under an oil-linked formula in 2011 and 2012 respectively, and is estimated to decrease further to less than 50% by 2014. Renegotiations of long-term contracts between the major producers/sellers and wholesalers/buyers are recognized as the main determinant for the reduction of oil-linked gas in Europe.[7]

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[6] Bros, T. European gas supply: on the verge of being mostly spot-indexed. Oxford Energy Forum, Issue 89, August 2012. Bros, T. presentation at Flame 2013.

[7] This argument is also supported by OIES and Reuters, see http://www.timera-energy.com/uk-gas/gas-indexation-in-europe-a-tipping-point/

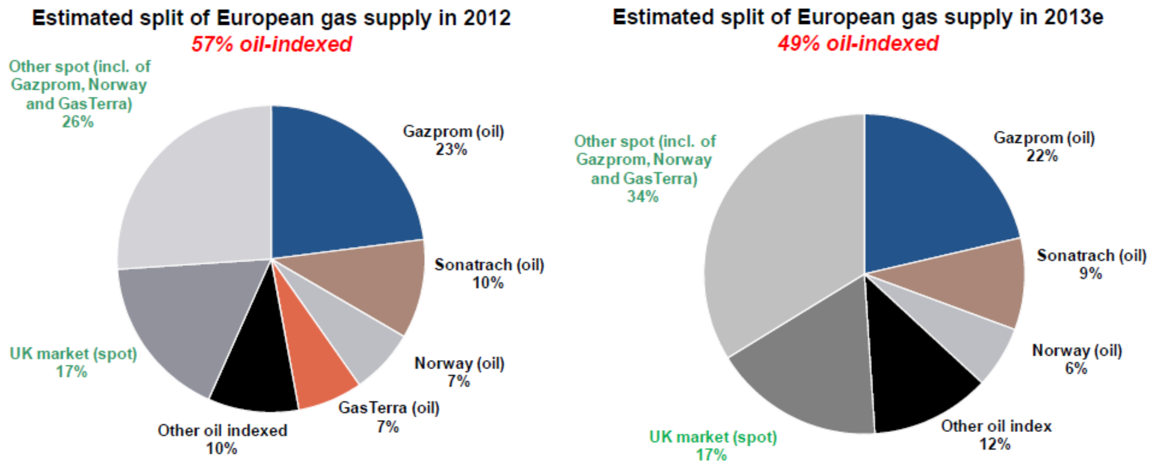

Figure 4: Pricing of European gas supplies

Source: Bros, Flame 2013

Major European gas wholesale companies, such as RWE, E.ON, GDF Suez and ENI have renegotiated (or are still in the process of renegotiating) their long-term gas purchasing contracts with producers (or sought arbitration). Given the dominance of Russian and Norwegian gas, the result of these negotiations will primarily depend on the approach that Gazprom and Statoil take on the adjustment of (i) absolute contract price levels and (ii) replacement of oil with gas hub indexation. Publicly available evidence indicates that Gazprom is willing to compromise on absolute price levels, but is not willing to let go of the oil-indexation. On the other hand, Statoil and GasTerra seem to have taken a more pragmatic approach to their long-term contract pricing. There is evidence indicating that they are willing to move away from oil-indexation in favor of gas hub pricing contract elements (and have done so in recent renegotiations).

As far as this is known, Statoil's modernization of contracts not only entails a shift to gas hub pricing[8], but it has also gradually reduced the amount of indexed contracts that are exposed to price reviews. It is reported that around 75% of its volumes were exposed to price reviews in October 2011, and this fell to less than 20% in January 2012.[9] Statoil's alleged strategy resulted in record gas sales into Europe and solid revenues in 2012, even though the EU gas market contracted. The additional volumes sold more than compensated the lower specific profit due to the new contract structure. Statoil is selling more in the UK and they are using more opportunities in hub markets, expanding their trading activities in e.g. the Netherlands and Germany.

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[8] For example, ICIS reported (20 November 2012) a new gas supply contract between Statoil and Wintershall for the delivery of 45 bcm over a period of ten years. Pricing of the contract is indexed to NCG and Gaspool, as well as to other European hubs.

[9] Platts, 18 February 2013. http://www.platts.com/news-feature/2013/naturalgas/eu-gas/index

At the same time, Gazprom's gas sales to Europe declined in 2012 while still appears to be adhering to oil-indexation and providing price discounts to their customers in retrospect. As a result, Gazprom had to refund $2.7 billion in 2012 and plans another $4.7 billion in potential price cuts in 2013 in order to keep its gas competitive with spot prices.[10]

In July 2012, Platts reported that Gazprom had completed talks on gas price cuts with most of its European customers, including GDF Suez, Wingas, Wintershall, SPP (Slovakia), Botas (Turkey), Econgas (Austria) and ENI (Italy). By November 2012 Gazprom and PGNiG (Poland) reached an agreement revising the terms of the Yamal contract to Poland[11] resulting in an estimated 18% lower price. Finally, in June 2013 an arbitration court ruled in favor of RWE that Gazprom has to base the price of its long-term supply to RWE on market prices.[12]

As an important supplier of gas to Spain, France and Italy, both via pipeline and LNG, Sonatrach also seems to hold on to its oil-linked prices and long-term contracts. Selling at spot prices occurs occasionally, e.g. with LNG cargoes. Export volumes to EU will, at best, remain flat in the coming years due to domestic gas demand in Algeria. Sonatrach's pricing policy is not expected to change, although it has shown some flexibility, e.g. in allowing customers to take less than the minimum contracted volumes (Gas Natural and Transgas in 2009). Since the exposure of Algeria's main customers to hub-priced supplies has been low, price revision requests in existing contracts have been limited.[13] However, this has already changed in Italy, where PSV (the Italian virtual trading point) has gained in importance and hubs on the Iberian Peninsula are likely to follow.

GasTerra in the Netherlands[14] has also shown flexibility in its gas sale contracting. Since the beginning of 2011 it has been offering gas with delivery at TTF (instead of delivery at physical points, unless the client asks for it). Almost all the gas marketed by GasTerra in the Netherlands is now offered via the spot market. Most popular contractual terms are for one or two years[15], but longer terms with flexible solutions are also possible. For example, in January 2012 Eneco and GasTerra closed a long-term contract (>5 years) for gas supply dependent on daily temperature and wind speed

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[10] Reuters, 8 February 2013. http://www.reuters.com/article/2013/02/08/gazprom-dividend-idUSL5N0B81T320130208

[11] Source: http://www.naturalgaseurope.com/russia-and-poland-agrees-on-gas-price-reduction

[12] http://www.reuters.com/article/2013/06/27/rwe-gazprom-dispute-idUSL5N0F32ZZ20130627

[13] Darbouche, H. Algeria's shirfting gas export strategy: Between policy and market constraints. OIES, NG 48, March 2011.

[14] GasTerra is not strictly a producer, but the company is marketing the majority of gas produced in the Netherlands.

[15] FD, 25 March 2013. Vrije gasmarkt oké, maar waar haalt Europa gas vandaan bij een volgend Fukushima?

(fostering dispatching of Eneco's gas-fired power generation portfolio versus wind power generation)[16].

Altogether, LNG imports to the EU seem to retain its own contracting and pricing dynamics. LNG contract prices traditionally are oil-indexed (e.g. Algeria and Qatar), but often contracts include an additional transportation element reflecting shipping costs whilst volume flexibility is believed to be lower than for pipeline gas deliveries.[17] However, after the delivery of LNG at the receiving terminal (as the contract requires), the buyer may divert the cargo to a higher priced market. LNG supply contract terms in the EU typically are 15 to 20 years, reflecting the traditional need to guarantee revenues to remunerate investments (both at the buying and selling side). Although only a limited number of new LNG import contracts are concluded for delivery to the EU,[18] an increasing share of EU LNG imports has been on a short and mid-term basis (1 – 15 years) with the option for diversion to other markets. Moreover, spot trade of LNG has grown gradually to some 15% of total European LNG import in 2012, with Qatar being the largest supplier of spot and short-term LNG volumes.

Since November 2011, LNG import volumes to the EU have decreased. LNG is diverted to Japan (because of demand increase after the Fukushima incident) and emerging LNG markets (e.g. China and India) where substantially higher prices are paid for LNG than in Europe. The diversion away from the EU even resulted in reloading at regasification terminals, especially in Belgium and Spain.[19] Utilization rates of existing EU regasification terminals have been very low which raises doubts as to whether new LNG projects planned will go ahead as scheduled or could even be stopped altogether.

3.1.2.2 Gas Delivery between Wholesaler and Local Supplier

The distinction between a gas wholesaler and supplier in the midstream section of the gas supply chain is not always obvious or relevant, and it can be one and the same company indeed. Large importers or wholesale gas companies are no longer simple intermediaries between producers and consumers; they have evolved to become energy trading companies with complex portfolios. Melling (2010)[20]

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[16] Another example on GasTerra's flexibility is found in its gas purchase contracts. GasTerra offers gas producers of the Dutch 'small fields' opt-out options: 100% or 20% of the volume, after 5 and thereafter each 3 years (and opt-in 3 years after an opt-out).

[17] Take-or-pay levels of 95 to 100% have been common in older LNG contracts, see Melling, A.J. Natural gas pricing and its future – Europe as the battleground. Carnegie Endowment for International Peace. 2010.

[18] GIIGNL reports a contract for 15 years between Qatar and Belgium concluded in 2012, and a contract for 3 years between Qatar and the UK in 2011. Two contracts for EU delivery were concluded in 2010: a 10 years contract between Iberdrola and the Netherlands, and a 1 year contract between Iberdrola and Spain.

[19] GIIGNL, The LNG Industry in 2012.

[20] Melling, A.J. Natural gas pricing and its future – Europe as the battleground. Carnegie Endowment for International Peace. 2010.

recognizes the growth of a ‘new breed of competitor’ which he calls the second-tier players. He argues that the second-tier players include not only the incumbent importers and wholesalers, but regional gas distribution companies, other utilities, consortia of industrial purchasers, and power generators as well. Hence, second tier players may be large incumbents themselves, however with reduced market shares in their home market and expanding into foreign, neighboring markets (joining the ranks of second-tier players abroad). The other group of second tier players are still the customers of large incumbents, but with more accessible and diverse gas supply sources.

The second-tier players have typically been relieved (or have gotten rid of) of their long-term obligations to incumbent wholesalers or the monopolist wholesaler. They are now able to buy gas directly from producers or at spot markets. They have developed supply portfolios with only a small part based on long-term contracts and/or oil-indexation and the remainder purchased short-term and spot. The required flexibility for their customers is obtained via hub purchases or contracts with storage operators, for example.

Whereas the major incumbent companies, i.e. E.ON and RWE in Germany, ENI in Italy, GasTerra and NAM (Shell and Exxon) in the Netherlands and GDF Suez and Total in France, still can be regarded as traditional importers and wholesalers in their home markets, the following list provides some examples of second-tier players in the larger European gas countries:

- France: Electricity utility EDF has major gas market interests in France. In addition, utilities from neighboring countries, upstream players and companies with LNG stakes (although the majority of LNG still lies with GDF Suez) have become important market parties: BP, Enel, ENI, Poweo and Statoil.
- Germany: Due to the sheer volume of the market and its central location in Europe, Germany is attractive to various gas competitors, including Verbundnetz Gas, Wingas, ExxonMobil, Shell and GDFSuez.
- Italy: Influenced by power liberalization, electricity producers and gas distribution and industrial consortia, as well as other European utilities gained important stakes in the Italian gas market: ENEL, Edison, A2A, Plurigas, GDFSuez, Sorgenia and Gas Natural.
- Netherlands: By mergers and acquisitions, Dutch utilities became second-tier players, together with some upstream and neighboring companies: Vattenfall/Nuon, RWE/Essent, Dong and E.ON.
- Spain: Power generators and oil companies yield the majority of second-tier players in the gas market, due to the rapid growth of gas-fired power generation and the displacement of LPG: ENI, Iberdrola, Endesa, Cepsa, Naturgas, Shell, GDFSuez and BP.

As indicated in the previous section, large gas importers and wholesalers nowadays are struggling with their take-or-pay commitments in a slightly oversupplied EU gas market. Small wholesalers and local suppliers partly experience the same squeeze in margins. However, they have also been able to renegotiate the pricing terms of (a large part of) their long-term gas purchasing commitments with producers and wholesalers. As a result, their exposure seems to be smaller (than exposure of large importers and wholesalers) since a larger part of their portfolio has already been diversified towards shorter term contracts and hub based prices.

3.1.2.3 Gas Delivery between Supplier and End-Consumer

"*Long-term gas contracts based on oil or other commodity indexes will be sustainable only if there is a natural demand for them.*" (Dincerler et al., 2012). With the opening up of the market driven by the EU energy packages and with growing liquidity of gas hubs, many consumers have seen hub prices as the basis for their gas contract. This process has started with large industrial customers, including power generators and then spread to SMEs and household customers who are now able to make an informed choice between gas suppliers. At the same time, consumers interested in diversifying their gas price risk may still demand long-term gas contracts which are indexed to other products (e.g. electricity, coal) or certain conditions (e.g. temperature, wind). The latter mainly consist of power generators and large industrial gas consumers. Dincerler et al. estimate that in the Continental European gas market the demand for non-gas indexed long-term contracts is between 17 to 30%. Thus, at least 70% would naturally be priced by gas-on-gas competition.

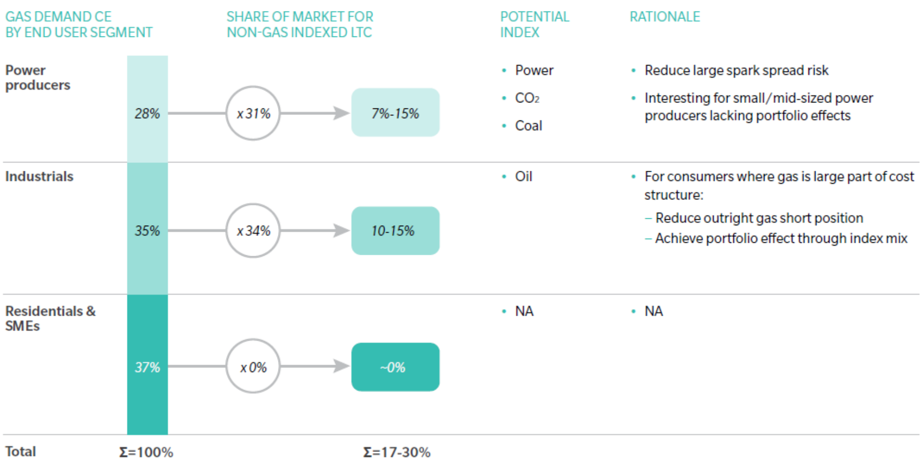

Figure 5: Assumed market share for non-gas indexed long-term contracts

Source: Dincerler et al., 2012

Especially in a liberalized electricity market, power producers have strong reasons to be uncomfortable with oil-linked gas contracts. With oil playing almost no role in electricity generation[21] or with take-or-pay obligations in gas, there is a structural risk that the power generator will be forced to take gas while power prices are too low to cover gas fuel prices. This spark spread risk is the largest

[21] The competitive fuel for gas mainly being hard coal.

for (small) independent power producers without a diverse portfolio of fuels and without substantial trading options. Power producers would want to reduce large spark spread risks and thus demand gas contract prices based on wholesale gas prices or indexed to power price (or coal and CO2 prices) in order to hedge their margins.

Large gas intensive industrials represent another group of consumers that may be interested in long-term commodity indexed gas purchase contracts. For example, the chemical industry or fertilizer producers would want to diversify their price risk in their gas purchasing portfolio which they can achieve by entering into structured gas contracts based on (a basket of) traded commodities. For the petrochemical industry this could even be oil since their product prices are related to the oil market. Fertilizer producers might for instance be interested in a urea indexed contract besides the generally more and more applied gas indexed contracts in this segment.

Residential gas consumers and smaller commercial consumers are likely to be more interested in the comfort of an uncomplicated gas supply. Their gas demand is largely driven by temperature and they expect gas to be constantly available (when needed). This means that individual supply should be very flexible, whereas demand is not very flexible and is rather price inelastic, especially in the short-term. However, with the increased number of options to choose and switch between suppliers, gas suppliers will increasingly have to compete on prices and services offered. With the emergence of second-tier players and new entrants in the gas retail business these prices will be more and more based on hub prices. Hubs provide easy access to gas supply for new retailers. Contract terms between retail suppliers and residential consumers are often annual or bi-annual, possibly with the option to step out any time. Some EU countries have defined standard or minimum standard contracts for residential gas consumption. Since residential and commercial gas consumers are not active in gas trading, transport and storage, their role will not be discussed further in the following sections.

3.1.3 Traded Gas Markets – OTC and Exchange

Typically in North America and the UK, gas sales take place in an environment of gas-to-gas competition without a direct gas to oil link. The market price indicators in those spot traded markets are Henry Hub in the U.S. and the National Balancing Point (NBP) in the UK. Both the Henry Hub and the NBP are widely used gas price indicators e.g. to monitor market developments but also in gas sales and purchase agreements as contract reference price or price escalator. Typically, in markets relying on competitive forces to determine prices, supply contracts only seldom have a duration of more than three years.

The Henry Hub is a major physical gas pipeline junction in the south of Louisiana that transports, or has interconnections that transport, much of the gas to the north and east of the U.S. Still most of the gas produced in the Gulf of Mexico region, as well as new shale gas production from Texas, Louisiana and Arkansas, flows through the Henry Hub. Apart from being a reference for physical traded gas, the Henry Hub also developed into a futures trading product on the New York Mercantile Exchange (NYMEX). Within the U.S. the difference between the Henry Hub price and the price in many other hubs is often used as a market indicator, reflecting the pipeline transportation costs between the Henry Hub and the other hubs, but also various market conditions. The market hubs at the East Coast and California are especially important since they tend to be the focus of premium-priced LNG imports to the U.S.

As opposed to the Henry Hub, the National Balancing Point (NBP) in the UK is a virtual trading point for the sale of natural gas in the UK. At the same time it is the pricing and delivering point for the gas futures contract of the Intercontinental Exchange (ICE). The NBP was effectively introduced by the Network Code in 1996 in order to promote the balancing mechanism detailed in the Code. The Network Code is the set the rules and procedures for third party access to the British gas pipeline grid. It created a system of daily balancing and thus a need for a short term traded market.

The principles of the European Union’s gas entry-exit system, as required by Regulation (EC) No 715/2009, are based on the UK example. EU Member States have established entry-exit systems, where for every entry point into and for every exit point out of the system network users are able to book capacities independently. A Virtual Trading Point (VP) is essential and intrinsic to an entry-exit system as it enables that gas can be traded independently of its location in the system. A VP offers users the possibility to bilaterally transfer title of gas and/or swap imbalances between network users. The VP is not tied to a physical point within the system and it is accessible without the need to book entry or exit capacities. With the VP, trading is enabled to move away from traditional trade at specified physical locations, traditionally at the flange of a system entry or exit point.

Heather (2010)[22] provides an overview on the reasons for trading natural gas. The primary reason to trade gas is to satisfy demand and supply needs, with volumes based on expected loads and production forecasts. The core intention is to physically deliver the gas on the agreed delivery date. Any time prior to the delivery date, changes in expected demand and supply, e.g. due to weather forecasts or technical outages of equipment, can be traded ‘away’ by buying and selling more or less gas for the day of delivery (physically optimizing or balancing the portfolio). This physical trading is done via bilaterally negotiated contracts, but also via OTC trading on the forward and spot market (as already explained above).

A second reason for trading is to financially hedge a future position with the intention of locking in the profit margin, i.e. to mitigate the price risk. It essentially means that the trader takes a futures position that is equal but opposite to a position held in the commodity (or cash) market. Such hedging, however, only works because future prices are closely correlated to commodity spot prices. [23]Gas

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[22] Heather, P. The Evolution and Functioning of the Traded Gas Market in Britain. OIES NG 44, August 2010.

[23] For example, suppose in the month of June a company needs (physical) gas in November, it is able to fix the price already. With a long hedge, i.e. buying November futures at 25 EUR/MWh in June it locks in the price. In case of a market fall by the time November is reached, it sells the futures for 20 EUR/MWh (at 5 EUR/MWh loss), but it is also able to buy physical gas at 20 EUR/MWh. In case of a market rise, it sells futures at 28

futures are usually traded at the established exchanges however OTC financial or paper trade is also possible.

Instead of a hedge on individual positions, in a broader perspective managing the risks of the total portfolio is also a reason for trading. Diversification between physical products (e.g. forward year, winter, monthly products), counterparts, clients, etc. would be part of such portfolio risk management strategy. Closely related to portfolio risk management is optimization of the overall trade portfolio in terms of physical and financial positions. The intention, however, is to create additional profit (instead of mitigating risks). Finally, proprietary trading is performed by market parties without any physical interest, simply to generate profit based on speculations on price changes in the market.

Another reason for (forward) gas trading is provided by Van Eijkel and Moraga-González[24] who state that apart from risk hedging, there are strategic reasons to trade gas in case there is some degree of oligopoly in the market. In that case, firms may sell gas forward in an attempt to gain competitive advantages in the spot market. The strategic advantages of forward trading relate to trying to change the strategies of rival competitors and to deter entry of new competitors. In an imperfect market, a firm wants to 'take' or fix a part of the market by selling (part of) its output in the forward market (such that its competitors can only take the remaining part of the market). However, since every firm has this incentive to use the forward market, the strategic advantage is less than expected by the individual firm (resulting joint output is higher and prices are lower). Thus the authors also provide arguments and circumstances in which such strategic trading is not effective in an oligopoly.

The emergence of hubs enabled gas exchanges to arise. Gas exchanges may offer spot trading on day-ahead and intra-day markets, forward markets as well as a variety of (financial) derivatives of physical markets. These include the various gas exchanges that have been established to further facilitate hub trades, e.g. Nord Pool Gas in Denmark, ICE-Endex Gas in the Netherlands or EEX in Germany (and many more). In contrast to bilateral trading, exchange trading is always anonymous whereby market parties (e.g. producers, suppliers, large consumers, brokers, traders) offer to sell or bid to buy gas. The exchange operator is the central counterparty and ensures clearing and settlement of all trades. Usually, short-term (day-ahead and within-day) physical products with delivery on the virtual hub are offered at the gas exchange. However, also futures contracts with delivery on the hub, or even purely financial contracts are sometimes facilitated by the exchange. In traded gas markets, the gas contracts are generally not flexible with standardized contracts being used which usually are for a flat product and negotiated at a fixed volume and price. However, liquid and transparent market places provide the excellent possibility to combine several contracts and products enabling market parties to build-up the required flexible or profiled product quickly. Thus flexibility is essentially found in the product range offered, in the continuity of trading and in market liquidity.

EUR/MWh (gaining 3 EUR/MWh) and paying 28 EUR/MWh for spot gas. In both cases, the company is effectively paying 25 EUR/MWh for the gas (20 spot + 5 loss or 28 spot – 3 gain).

[24] Remco van Eijkel and José Luis Moraga-González, Economic Implications of Forward Contracting. In: Gas Market Trading by C.J. Jepma (ed.), 2009.

In a liquid market, standard transactions can be executed quickly (immediacy) and large volumes per transaction can be traded without causing a significant change in prices (market depth). A key feature of a liquid market is that it has a large number of buyers and sellers willing to transact at all times (market breadth). Liquidity minimizes transaction costs and raises confidence among market participants.

In addition, market transparency is of major importance to liquidity. Real time or quick information and reporting on gas volume changes in supply and demand (e.g. production statistics) and on prices (price discovery) are essential for the emergence of a liquid market.

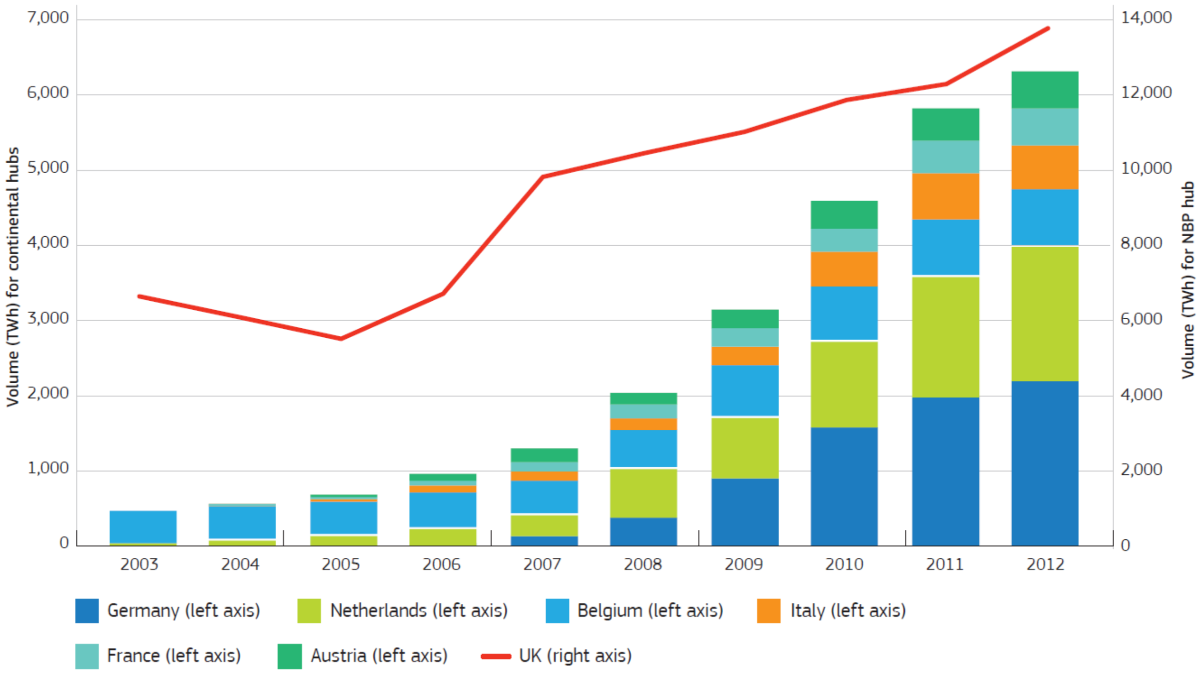

Figure 6: Traded volumes at selected European gas hubs

Source: Energy Market Observatory, Quarterly report on EU gas markets

The above figure provides an overview of the gas volumes traded at some established European gas hubs, showing an on-going trend towards an increase in traded volume. However, the figure does not show the complete picture as the majority of trades are OTC which are often not reported because they usually do not result in physical delivery and are therefore not nominated to the TSO.[25] At TTF, for example, total traded volumes are estimated to be more than three times higher than reported volumes shown in the figure.[26] For the same reason, volumes traded via organized exchanges are not always

[25] Note also that the gas volumes locked into long-term contracts are not represented in the figure.

[26] See “Explanation TTF volumes at http://www.gasunietransportservices.nl/transportinformatie/ttf-volume-ontwikkeling.

included in the (TSO operated) hub overviews. However, these represent relatively small volumes since market parties tend to prefer bilateral and brokerage trade rather than exchange trade.

It has been argued by Van Eijkel and Moraga-González[27] that market power by suppliers in the forward market, in combination with incentives for suppliers to price discriminate across buyers, may explain the preference (in terms of observed volumes traded) for bilateral trade over centralized exchange trade. In an oligopolistic market, the gas supplier (large wholesaler) can bargain a different price with buyers in order to gain extra profits when compared to the posted prices offered at the exchange. There is, however, a trade-off as bargaining may be costly, while participation in an exchange is relatively easy and inexpensive[28].

3.1.3.1 Traded Gas Markets - Producers

Gas producers in the UK, the Netherlands and Norway, as well as LNG suppliers, all have direct access to trading hubs in the EU. This has triggered producers, such as GasTerra and Statoil, to use virtual trading points for physical delivery within their contracts, but also to offer short-term, profiled and flexible products.

Gazprom has long been at a disadvantage as it had limited access to hubs and limited ability to provide supplies with sufficient flexibility[29]. Gazprom traditionally delivered at the flange, thus while having export capacity they had no import capacity at hubs. Of course, it has been Gazprom's own strategy to depend on long-term contracts. However, their situation is changing. With Nord Stream there is now direct access into North West European markets. In addition, Gazprom is actively building storage (e.g. Bergermeer, Haidach, Rehden, Peißen) and marketing position in Europe, further supporting its ability to compete at EU gas trading hubs. It seems unlikely that Gazprom is seeking to sell a large share of their gas at hubs or at hub prices (with evidence indicating rather an interest in keeping long-term oil-indexed contracts). However, the current development leads to the conclusion that Gazprom is interested in asset backed trading and will use hubs for marketing and portfolio optimization purposes.

Whereas existing gas supplies remain within long-term contracts (albeit with renegotiated prices and conditions), incremental gas supplies from existing producers are likely to be sold directly at the hubs or via contracts with hub-indexed prices, since they are complementary to the existing contracts and market. Third party access to pipelines also enables producers to market the gas via hubs, especially when moderate volumes are concerned.

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[27] Remco van Eijkel and José Luis Moraga-González, Economic Implications of Forward Contracting. In: Gas Market Trading by C.J. Jepma (ed.), 2009.

[28] This also provides a reason for keeping access and transaction fees for gas exchanges low.

[29] Because of characteristics of their production fields and long transport distances.

We see that the major gas producers all are active at traded markets. For example, at the ICE ENDEX gas exchange, GasTerra (Netherlands and UK), Statoil, Sonatrach Gas Marketing (only UK) and Gazprom Marketing & Trading are trading members on the spot gas markets of the Netherlands, the UK and Belgium[30]. Not surprisingly, Gazprom M&T is also active at the Austrian CEGH gas exchange, whereas Statoil only is a passive member there, while Sonatrach is a market participant at GME's M-gas spot market in Italy.

3.1.3.2 Traded Gas Markets - Importers, Wholesalers and Local suppliers

Large gas wholesalers, small wholesaler and local gas suppliers are likely to be the largest group of traders active on gas hubs and exchanges. As Heather[31] states: "*Wholesale energy companies are no longer simple 'intermediaries' between producers and end-users and have evolved to become energy trading companies with complex* […] *portfolios.*" They not only are active on gas hubs and exchanges to buy and sell gas for their direct requirements and clients, but also to balance their portfolios, to financially hedge their exposures, to optimize their businesses and even for proprietary trading. Midstream companies are therefore likely to cover and use the full range of available products and trading options at gas hubs and exchanges.

Many wholesale and supply companies have suffered from decreasing gas demand since 2008. They face declining earnings due to the worsening balance between gas procurement prices under long term contracts and gas selling prices in Member States with more mature markets. The traded markets have been used to resell part of take-or-pay volumes in order to at least cover part of the costs. Contract renegotiations and new contracting for gas have been towards more hub-based pricing, and thus taking the price risk from the buyer (he may have faced under oil-indexed contracts).

3.1.3.3 Traded Gas Markets - Consumers

Gas-fired power producers and gas intensive industrial gas consumers would want to manage their exposure to the market and have become active parties in the traded gas markets, either directly or indirectly via their banks or brokers. Trading activities of large gas using companies are mainly for purposes of gas sourcing for their own needs, physical and financial trading for portfolio balancing and hedging, and procurement tailored to the needs of business partners (daughter companies, projects, etc.). Melling[32] already signaled that "*Spot markets give generators more freedom, not necessarily to make a profit, but at least to avoid generation during loss-making periods.*"

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[30] Only recently they acquired shipping contracts in both German hubs, and became member at EEX (which does not necessarily mean that they are active shippers).

[31] Heather, P. Continental European Gas Hubs: Are they fit for purpose?, OIES NG 63, June 2012.

[32] Melling, A.J. Natural gas pricing and its future – Europe as the battleground. Carnegie Endowment for International Peace. 2010.

3.1.4 Transport Capacity

Whilst the previous sections described the situation with regard to gas trading along the value chain, we will now turn to capacity contracts, first transport capacity, and second storage capacity (c.f. section 2.1.5).

Traditionally with integrated companies, building transport capacity was directly related to the gas delivery contracts. If explicitly contracted, contract durations for transport were aligned with the durations of the gas delivery contracts. Vertically integrated companies had an integral planning with respect to volumes and capacities. With liberalization in Europe the unbundling process came alongside gradually: Firstly the administrative unbundling, secondly the legal unbundling, which in NW Europe is more and more ultimately followed by ownership unbundling. In line with third party-access requirements, this has led to explicit contractual relationships between trading companies and TSOs with respect to transport capacity (and/or the SSO with respect to storage capacity, as is further discussed below). Compared to the emergence of the gas sector in the EU, the widespread use of transmission contracts is a fairly recent development. The length of transmission contracts – dependent on the regulatory regime – may differ from the delivery contracts. We may distinguish between long distance transport from production sites outside the EU to the EU border, and gas transport capacity within the EU when discussing the rationale for contract durations in the transport business. In addition, there may be a difference between contracts for newly built transport capacity and contracts for allocating existing capacity.

3.1.4.1 Large Investments

New gas transport capacity within and towards the EU is often backed by long-term relationships, i.e. by long-term contracts with anchor shippers (e.g. sold in open seasons) or vertically integrated constructions, in order to secure the financing of such projects. Nord Stream and South Stream (for which FID has been given) are examples for the latter. Both projects have Gazprom as driving force with own gas resources and willing to invest in transport (i.e. vertical integration) with market parties from EU taking smaller ownership stakes. At the same time, the competing Nabucco project seems to have failed since partners lack sufficient own gas to fill the pipeline and the Shah Deniz consortium producing gas in Azerbaijan, which was supposed to provide the necessary volumes decided to go ahead with the Trans Adriatic Pipeline project instead.

The importance of long-term contracts and/or vertical integration for these large projects becomes clearer with a closer look on some examples. For instance 70% of Nord Stream was financed by banks (and 30% equity financed by the shareholders), part of these loans are backed by the earnings from transportation contracts. Contracts underlying Nord Stream for gas delivery from Gazprom include: Wingas (9 bcm/yr for 25 years), DONG (2 bcm/yr for 20 years, while DONG supplies 0.6 bcm/yr to Gazprom Marketing & Trading in the UK), E.ON (4 bcm/yr), and Gaz de France (2.5 bcm/yr). The

GATE LNG terminal may serve as another example, where long-term throughput agreements provide revenues for the terminal to finance the investment.

Another example is Medgaz between Algeria and Spain with shares and transmission fully aligned at the time of FID (Q4-2006): 36% for Sonatrach and 64% divided over four European energy companies (Cepsa, Iberdrola, Endesa, GDF SUEZ). For the BBL between the Netherlands and the UK we see a mixture of long term contracts and anchor shippers. Three shippers (GasTerra, E.ON Ruhrgas and Wingas) have concluded long-term transportation contracts with BBL-company, owned by Gasunie (60%), E.ON Ruhrgas (20%) and Fluxys (20%). While E.ON Ruhrgas' position can be explained from vertical integration, Wingas has a pure anchor shipper role. At the time of establishing BBL-company in 2004, GasTerra was still part of Gasunie, so their role may also be seen from a vertical integration perspective.

Nevertheless, part of the capacity in such large infrastructure projects may (and will) be sold on a short-term basis. Regulation may require that part of entry/exit capacity should be short term. Moreover, short-term contracts can help the profitability of the project. In the course of time, incremental investments can be made to increase capacity at relative low specific investment costs, for instance by installing additional compressor capacity. For example, while BBL operations started in 2006, an additional compressor has been taken into operation in the course of 2011, increasing capacity by more than 20% from 17 GW towards 20.6 GW. The additional capacity was offered in an open season, but not completely sold. Between 2011 and 2016, 20% to 50% of the incremental capacity was not sold and as from 2016 around 10% of the capacity is still for sale.

In principle, the EU gas regulations require third party access to all transport capacity. However, under certain conditions new gas pipelines and LNG terminals may be exempted from the general requirements for third party access for a limited period of time.[33] For example, the exemption for the BBL pipeline may not exceed the period of the initial contracts for capacities that resulted from the open season procedure for allocating the new capacity. This means an exemption for the period 2006-2016 for one contract and for the period 2007-2022 for the capacity in another contract.

The Network Code on Capacity Allocation Mechanisms in gas transmission systems will apply to non-exempted capacity once it has passed the comitology procedure likely in September 2013. The Network Code defines a standardized auction procedure including the standard capacity products to be offered. Moreover, it describes how cross-border capacity will be allocated in a bundled manner. The latter also reveals that shippers with existing (long-term) capacity contracts shall make best efforts to reach agreement on the bundling of capacity so that, in the future, gas will be delivered at hubs instead of at cross-border interconnection points.

[33] In general, exempted infrastructure projects are regarded as merchant pipeline, LNG or storage activities for which regulated tariffs, regulated third party access and unbundling will not provide a profitable business case. The exemption may be limited to certain aspects or bound to pre-defined conditions.

Transport of LNG requires capacity in the form of ships or charters to bring the LNG to EU terminals, as well as regasification (and storage) capacity. Shipping terms of LNG delivery are usually free-on-board (FOB) or delivery ex-ship (DES).

- In case of FOB, the buyer of LNG takes ownership of the LNG when it is loaded on the ship at the export facility. The buyer is responsible for LNG delivery, either on its own ships or ships chartered by the buyer. The contracted sales price does not include transportation costs.
- With DES, the buyer takes ownership of the LNG at the receiving port. The seller is responsible for LNG delivery, and the contracted sales price includes insurance and transportation costs.

Buyers of LNG increasingly favor FOB since it provides control over the cargoes and the ability to divert the cargo in order to manage demand variations. It also puts them in a position to trade LNG (cargos).

Traditionally LNG terminals have been developed by buyers for their own unloading, storage and regasification use. Third party use used to be limited and only partial, for example due to spot ex-ship trades. However, in the past decade we can observe a trend towards more LNG terminal owners providing terminal services to multiple parties or customers. As with pipelines, the EU regulations require TPA to LNG terminals in general, however a lot of LNG terminals have been granted an exemption from TPA requirements.

3.1.4.2 Preferences of Market Parties

Long-term gas transport capacity contracts are primarily attractive for gas producers and large importers and wholesalers, i.e. mostly for incumbent shippers with a higher ability to predict future capacity needs and to absorb changes in a larger portfolio. However, long-term certainty can be an important aspect in capacity booking for new entrants as well, e.g. as a hedge against the risk of congestion.

Long-term contracts, typically with a duration of 10 to 15 years, are also prevalent in open seasons, organized by the TSO or capacity investor. The open season is organized for determining the additional capacity to be built. A 10 to 15 year duration secures a significant portion of the pay back of the investments to be made.

Generally speaking, the availability of short term capacity contracts with a duration of one year (and less) is essential for new entrants (especially for small wholesalers and local suppliers) which may be reluctant to commit themselves to a long-term multi-annual contract if they do not have the matching purchase or supply contracts in place as well, and if the absence of congestion implies that capacity can most probably not be sold easily on secondary markets in case of non-utilization.

Short-term capacity contracts allow shippers (small wholesaler and local suppliers mainly) to better match their capacity portfolio with their supply and demand profile. This may be in particular relevant for those shippers that want to react to short-term trading opportunities. Day-ahead (and if future within-day) capacity is an important tool to optimize the use of available capacity by facilitating short-term trading and arbitrage, both of which are beneficial to the overall market.

Given that sufficient physical capacity is available, prices of neighboring hubs will converge at least to the level where the difference between the prices is equal to the short-term transportation costs (e.g. determined by the regulated tariffs). However, regardless of the actual price of short-term capacity, the availability of short-term capacity in the first place is important for market functioning and fostering liquid cross-border trade. Indeed, it is important to note that the mere possibility to react to short-term trading opportunities (availability of free capacity and access to it) may sometimes be already sufficient, as potential competition can already have an effect on market players' behavior.

In addition, where transmission lines connect two liquid trading hubs with diverse means of supply, the scarcity of transmission capacity poses only a financial risk of not being able to source gas from the cheaper hub, with the price difference also setting the maximum for the value of the transmission capacity. In such market environment, also transmission capacity may become a financially traded product, simply entitling the holder of such a financial transmission right to receive the price difference between the two connected markets. Similar instruments are well known in some electricity markets, e.g. in US market areas using nodal spot pricing.

3.1.5 Gas Storage Capacity

Apart from transmission capacity, gas storage capacity is another is a crucial infrastructure requirement in order to fulfill end-consumers demand for gas. Gas storage is a midstream activity, providing a service to match demand and supply of gas in general, i.e. it is one of the elements in the chain from upstream (producer) to downstream (consumer). Normally the supply pattern at the upstream side of the storage is more flat (base load) compared to the downstream side of the storage (profiled). A storage offers the possibility to swap gas over time by injecting gas at times the demand for gas is less than the regular supply and withdraw the gas later as demand for gas is more than the regular supply.

Storages can be distinguished along several characteristics: i) Physical characteristics of the storage, ii) Typical duration of the storage cycle, and iii) Service provided. Taking the physical characteristics of storage into account one can distinguish underground storage (UGS) facilities such as depleted gas or oilfields, aquifers and salt caverns and above ground storage facilities such as gas holders, LNG storage tanks and pipe storage. The possibility of the first type depends on geology, the second type can in principle be constructed anywhere.

The duration of the storage cycle can be year-on-year storages ("strategic storage"), seasonal storage, short term storage (monthly/weekly), diurnal storage (within day) and peak service (withdrawal capacity much higher than injection capacity). Given the CAPEX and OPEX of the different storage facilities, economic evaluation leads to a general relationship between the physical type of facilities and their use. This is presented in the table below.

	Year-on-Year	Seasonal	Monthly	Weekly	Diurnal	Peak service
UGS depleted field	✓	✓	✓			
UGS aquifer	✓	✓	✓			
UGS salt cavity		✓	✓	✓	✓	
Gas holder				✓	✓	
Pipe storage					✓	
LNG peak shaver						✓

Table 1: Typical storage usage by storage type

LNG storage typically is only available for parties having contracted regasification capacity at the LNG terminal. For example, Elengy in France offers an Early Send-Out Service and Send-Out Postponement Service to their customers having booked regasification capacity. This service differs from the LNG peak shaving tank mentioned in the table, which describes a facility with a high send out capacity (peak service) and a very low send in capacity, due to the liquefaction capacity needed at the site itself.

Specific storage contractual terms will be discussed below for the main actors in the gas chain.[34]

3.1.5.1 Producers

The following provides some examples of producers who are active in storage, by investing in storage facilities as well as booking storage capacity. Producers will normally only be active in storage in the neighborhood of the customers they serve, because of the transportation costs attached to the production from the storage. Storage facilities far upstream will – due to the additional transportation cost – not be competitive against storage facilities near the customers.

- Gazprom has many storage facilities in Russia to provide the required swing for its domestic customers in Russia and it has equity stakes in several countries in Europe, such as the Netherlands (Bergermeer; part of functionality as quid pro quo providing cushion gas for the

[34] Please not that neither storage that enables the TSO to fulfill his transport duties (e.g. to balance their network) nor storage that is contracted for emergency situations (peak service, strategic reserve) is taken into account.

duration of the storage license of Taqa; current end date 30-06-2050[35]). Gazprom is also active for instance in Germany (Astora, the former Wingas Storage) and Austria (Haidach) and along transportation routes from Russia to Central- and Western Europe, with Serbia (Banatski Dvor) serving as example.

- Statoil owns part of storage capacities located at Etzel in the North of Germany from the early 90s. It started with 500 mcm in salt caverns (originally used as oil storage) to provide back-up in case of production or offshore transport problems. Later on it has predominantly been used to compensate for seasonal fluctuations in demand. Today, however, they are also used as a flexible means of optimizing supply, as a reserve in the event of supply problems, and on an hourly basis to counterbalance surpluses and shortfalls. Furthermore Statoil was one of the three launching customers of the Bergermeer storage, with a contract duration between 4 and 10 years.
- GasTerra[36] has long-term storage contracts in the Netherlands (Norg, Grijpskerk, Alkmaar), owned and operated by producers NAM (Norg, Grijpskerk) and Taqa (Alkmaar). These storage facilities compensate the decrease in flexibility/capacity from the Groningen field and facilitate the possibility for Dutch Small Field to deliver at a flat rate. Note that in 2011 third party access at Grijpskerk and Alkmaar was cancelled when APX-ENDEX introduced a virtual seasonal storage product of around 2 bcm working volume on behalf of GasTerra.
- Centrica Energy is amongst others active as producer in the UK, Norwegian and Dutch part of the North Sea. As Centrica Storage it operates the storage facility Rough in the UK.

It becomes clear from the above that the large producers have acquired equity stakes in gas storages, pursuing a strategy of vertical integration into storage, which is obviously a long term strategy (covering the economic lifetime of the storage facility). If commercial storage contracts are applicable, contract durations entered into by producers are still long-term (15 - 20 years).

3.1.5.2 Large Importers and Wholesalers

A lot of the wholesalers[37] active in the EU gas market have invested in storage facilities in the past, to balance supply and demand in their portfolio. Today, the storage activities of these wholesale companies are mostly (if not all) executed by legally separated companies. The capacity from these storage facilities is offered under negotiated or regulated TPA regimes. A significant part of the

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[35] Source:
http://www.nlog.nl/resources/Jaarverslag2012/VergunningenOpslag_Overzichten2012NL_20130101.pdf

[36] Although GasTerra is a wholesale company, as seller of the Groningen gas (produced by NAM) we see GasTerra as representative of the "producers" in this overview.

[37] Some of the companies mentioned in this section are also active as producer, however less prominent compared to their wholesale role.

storage capacity is being contracted by the sister/mother trading company. To get an impression of the contract period for wholesale companies contracting storage capacity themselves, we looked at the available capacities for the German storages. We assume the last year with booked capacity as the last year the corresponding mother/sister wholesale company has contracted storage functionality. For the RWE storage facilities three locations are fully available as from 2017, one from 2015 and one is still (partly) booked until 2018. Based on that we assume a contract periods of 3 to 5 years as typical for RWE as a wholesale company.

Another example of a wholesaler contracting storage capacity is Vattenfall. Vattenfall was one of the three launching customers of the Bergermeer storage, with contract duration between 4 and 10 years[38]. The Astora storage facility in Jemgum, currently for offer, uses a 10-year contract period. This contract period is one-to-one related to the contract duration in open season for incremental transportation capacity. We have indications that wholesale companies are part of the customer base.

E.ON Földgáz Storage in Hungary offers seasonal storage with contract durations of 1, 2, 3 or 4 years. Nafta in Slovakia offers contracts with a duration of 1 year or shorter.

Based on the above we come to the conclusion that storage contracts for wholesale companies vary between 1 and 10 years, with a focus on contract durations around 5 years.

3.1.5.3 Small Wholesalers and Local Suppliers

Smaller wholesalers and retail gas suppliers will contract storage services to balance their portfolio. For the delivery contracts we have seen 3 to 5 years as contract period on the purchase side (with the large wholesalers) and on the sales side a variety between less than 2 years (residentials and SME) and 3 to 5 years (power and industry). These suppliers normally book storage not exceeding the contract periods for the delivery contracts. This implies contract durations for storage by suppliers of 1 year for a part of supplies, and up to 5 years for the other part.

3.1.5.4 Consumers

Large industrial customers and power generation companies on the one hand rely on (full-service) delivery contracts with their suppliers. On the other hand some larger companies act like a supplier (of their own needs) with an own portfolio management and sourcing department. The latter companies also book storage capacity to balance their portfolio and to hedge against seasonal price spreads, typically with a contract duration between 1 to 5 years.

[38] http://www.ebn.nl/en/Actueel/Pages/Announcement-Bergermeer-Launch-Customers.aspx

3.1.6 Summarizing Overview of Current Contractual Terms in Europe and Conclusions

In the figure below we have summarized the analysis from the earlier sections.

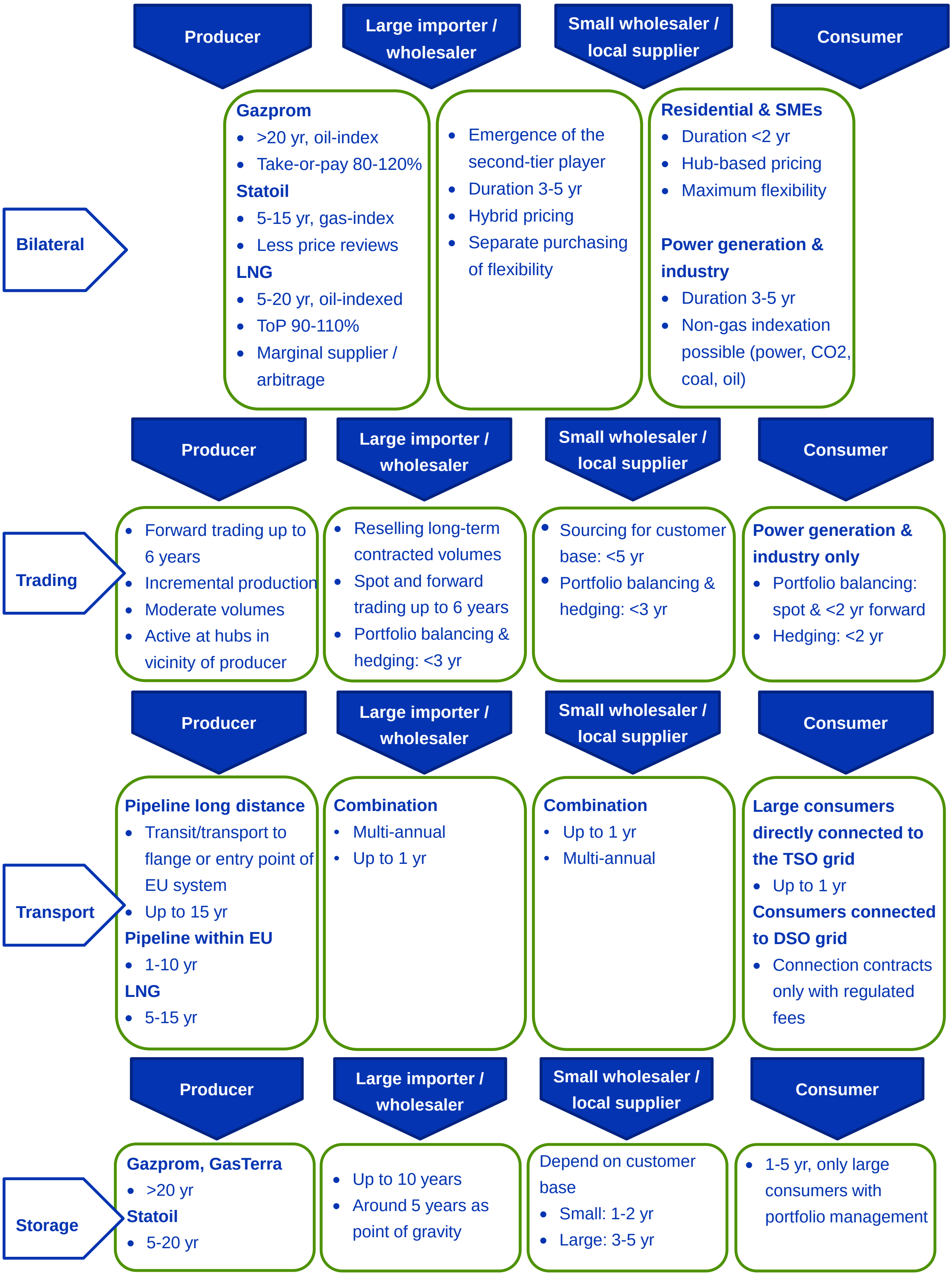

Figure 7: Overview of current contractual terms in Europe

From the descriptive overview in this chapter we come to the following observations and conclusions with respect to the contract structures in the EU gas sector:

1. The pricing terms, the length of the contract and the volume flexibility are the basic elements in any gas contract or trade. These elements are interrelated. Pricing at oil-index or fixed, high take or pay levels and long-term durations are at one side of the spectrum; pricing at the hub or gas indexed, low or no take or pay levels and short term duration are at the other side of the spectrum. We observe a general trend to more flexible and more short-term oriented contracts on all levels of the value chain.

2. While producers Statoil and GasTerra seem to be willing to gradually or fully convert towards hub indexation, Gazprom, Sonatrach and Qatargas seem to cling to oil indexation in their long-term gas export contracts with EU partners. However the producers are confronted with downward price claims, ultimately honored in long lasting renegotiations and/or arbitrations.

3. The further across the gas value chain, the shorter the contract durations. At the upstream side contracts tend to be long-term with durations for new contracts often in the range of 10 to 15 years, while at the downstream side contracts are typically more short-term oriented with durations typically below 5 years. Transport contract durations are generally comparable or somewhat shorter than the contract duration of the gas delivery contracts. Contract durations for gas storage tend to be comparable to transport contract durations.

4. For large investments in infrastructure in and towards Europe we see these projects with back up by vertical integration and/or anchor shippers in order to ensure bankability of these projects. However, in light of the availability of these instruments as back-up it is hardly possible to say whether infrastructure investments would have gone ahead also without this back-up. In general, where mature markets exist, demand seems to be reasonably secure and (sufficiently) well predictable. In those markets, together with market-based pricing, long-term contracts provide little added-value.

5. In developed market systems with liquid hubs there is less need for long-term transportation capacity to serve as physical back up for the commodity business. Long-term transport capacity booking serves as a hedge against the transportation congestion cost risk. Comparable to the pricing mechanism for storages (tariff indexed to summer/winter price differentials) we could imagine some TSOs to propose transportation tariffs related to locational price differentials (as will also be further elaborated below).

3.2 Competition

Market conditions on the EU gas market have dramatically changed over the last years. As a result of the on-going financial and economic troubles, gas demand growth has stalled and in some countries we can even speak of demand destruction. At the supply side, diversified and increasing (LNG) supplies in combination with the unprecedented shale gas developments in the U.S. have driven the market in an oversupply situation with relatively low gas prices.

The increased role and liquidity of gas hubs has enabled market parties further down the gas value chain to offer competitive prices and conditions to end users compared to the incumbent wholesale companies. This has led to several developments.

Most noteworthy is the reopening and renegotiating of several long-term gas supply contracts to be adapted to spot market conditions or being replaced by shorter term contracts. Given the present conditions on the oil market, the large wholesalers importing gas under long-term oil-indexed contracts are unable to maintain their competitiveness, unless their purchase price is linked (explicitly by changing the index or implicitly by price level) to the hub price. While most cases have been settled rather quietly, in at least one case the arbitration case was taken to the end: Recently (summer 2013) the arbitration between RWE and Gazprom resulted in a ruling of the International Court of Arbitration in Vienna deciding that RWE had a fair claim for ex-post reimbursement and a change in pricing structures, i.e. including a move towards spot-based pricing.[39]

Furthermore, this trend has led market players to refocus on their business. Some players move away from downstream activities and focus on upstream activities (where the profit margins allegedly are more attractive), whereas some large gas producers and exporters are more and more entering midstream and downstream gas markets to secure demand. Examples for upstream activities of traditional import companies (being either direct consumers or suppliers) are:

- E.ON Ruhrgas swapping an equity participation for a participation in the Yushno Russkoje field,[40]
- BASF swapping its stakes in the joint venture Wingas with Gazprom in exchange for a 25% participation in the Nowy Urengoi field,[41]
- Bayerngas invested via its subsidiary Bayerngas Norge into two gas fields in the North Sea,[42]
- AXPO (EGL) invests into the TAP pipeline to source Caspian natural gas.[43]

Power generation plays a dominant role in the (future) demand situation in Europe. The main drivers are the development of renewable energy sources and the inter-fuel competition between coal and gas fired power generation. The role of oil as fuel in the power generation has become negligible.

We have divided the discussion on the role of short-term (and long-term) contracts for competition in the gas market into four parts:

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[39] C.f. http://www.reuters.com/article/2013/06/27/rwe-gazprom-dispute-idUSL5N0F32ZZ20130627

[40] http://www.eon.com/en/business-areas/exploration-and-production/russia.html

[41] http://www.basf.com/group/pressrelease/P-12-511

[42] http://www.bayerngas.de/english/03_upstream_e/upstream_e.html

[43] http://www.trans-adriatic-pipeline.com/news/news/detail-view/article/3/

1. The first part describes the impact of a development towards shorter term contracts on liquidity and competition (see chapter 3.2.1).
2. The impact of an increase in short-term contracts on the role of gas exporters and utilities in downstream markets is addressed in chapter 3.2.2
3. Section 3.2.3 describes the role that long- and short-term contracts play in the competition between coal and gas in power generation.
4. Finally in chapter 3.2.4 some political and strategic impacts on competition and contracts are discussed

This section concludes with an overview of the benefits attached to short-term contracts with respect to competition in Europe.

3.2.1 **Liquidity and Competition**

In markets where competition already exists or is emerging, short-term contracts will ease market entry (and exit), thereby enhancing competition. An increase in short-term contracts will thus have a positive impact on liquidity by increasing the number of market parties. In addition, an increase in short-term contracts will provide additional room for traded volumes, hedging and paper trade, thus increasing total volumes traded on (short-term markets). While parts of the gas volumes may be under oil-indexation or coal-indexation, spot markets will provide transparent (price) signals and will offer consumers a choice as to from where and how they can source gas.

A liquid and competitive market fostered by increasing number of market parties as well as increasing trading volumes provides robust price signals. In such a market both buyers and sellers are price takers in that any volumes they offer or bid for will not have a visible effect on price. We have seen the impact of such markets developed in the EU on revenues of gas importing companies and as a consequence on the existing contracts with prices linked to e.g. oil or coal. Contracts have been or are the process of being renegotiated in order to align e.g. pricing terms and volumes. Note that also in case of prolonged lower oil-indexed prices than hub prices, such renegotiations would probably have taken place (induced by the producer / seller of gas), e.g. resulting in producers selling larger volumes directly at the hub and/or are entering the downstream market to take part of the downstream margins.

The move towards more short-term contracting and more short-term elements in long term contracts has an impact on competition in several ways as discussed in the following subsections.

3.2.1.1 **Shift of Flexibility**

The flexibility needed in long-term contracts is shifted towards short-term trade. This trend is illustrated in the figure below. Traditionally, long-term supply contracts often include some of the flexibility needed to balance seasonal demand fluctuations. The original demand pattern is given at the left, showing the daily fluctuations within a year. With traditional long-term contracts being replaced by more flexible arrangements, part of the deliveries may be fixed at certain volume levels with prices linked to the hub (some of these may still be contracted over longer-terms). This is shown in the middle of the figure below where roughly half of the volume is supplied by stacking yearly, quarterly and monthly products. The remaining flexible part (green part, to be sourced on spot markets) is compared with the original demand pattern in the bottom chart. The resulting flexible pattern peaks at approximately 1300, while the original pattern peaks at 2600. Hence, the maximum flexibility required in the portfolio has declined as a result of fixed volume blocks procured and will be traded on a short-term basis.

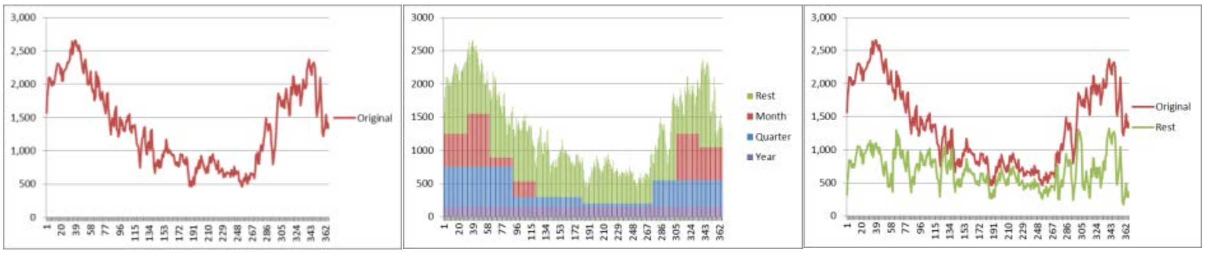

Figure 8: Change of flexibility demand under changing procurement strategy

3.2.1.2 Point of Delivery

Short-term contracting and some contract renegotiations have led to a change in delivery location.[44] In new contracts the point of delivery is often the hub, i.e. typically the virtual trading point, resulting in sourcing flexibility for the seller and sales flexibility for the buyer. For instance, a producer originally intends to deliver the gas under a supply agreement at the hub. However, if he has problems at his production site or the opportunity to sell to another buyer at a better price, he may want to deliver less gas at the originally agreed hub. As his original or contracted buyer still needs the gas as originally agreed, the producer may source the required volumes at this hub at hub price. This is what is called “sourcing flexibility”. On the other hand, the buyer originally may intend to sell the delivered gas to his customers in his portfolio. If the portfolio becomes smaller than the buyers’ commitment to the producer then the buyer has the possibility to sell the overcommitted volumes at the hub at the market reflective price, i.e. “sales flexibility” without facing a loss.

3.2.1.3 Contracts for Commodity Versus Capacity in the EU

As we have argued above, the current trend towards trading more flexibility on short-term basis and using hub-based pricing enables further trade opportunities and boosts market liquidity. The question remains how differences in contract structure and durations impact the relation between contracts for commodity and transportation capacity.

[44] The sunset clause in the proposed network code on capacity allocation mechanisms also assumes bundling of contracted capacities, implying gas delivery at the hub.

In the developed gas markets in the EU a clear trend towards more short term contracts can be observed. With virtual points emerging, market parties can easily trade at these hubs, providing the necessary flexibility in their portfolio. Furthermore, capacity access has become more flexible, both on the primary market (e.g. day ahead products at the TSO/SSO, auctions) and the secondary market (e.g. capacity trading, bulletin boards).

In these developed market systems there is no need for long term capacity to serve as physical back up for the commodity business. Long term transport capacity booking serves as a hedge against the transportation congestion cost risk.

This is demonstrated in the following example. In this example a commodity contract for gas is assumed from Entry 1 and is going to be delivered at Exit 2. Entry 1 is connected to hub VP1 and Exit 2 is connected to hub VP2.

The first option for arranging the transport is to conclude a long-term transport arrangement between VP1 and VP2, for instance via a 10 year contract as a result of an open season. With such a contract the shipper knows he will pay the transportation tariff as applicable in the primary market for transport capacity. However, as changes in the regulatory framework and/or tariff methodology may occur during the long-term contract period, the actual tariff level may change during the contract period. Thus, a risk on the transport price level will remain for the shipper.

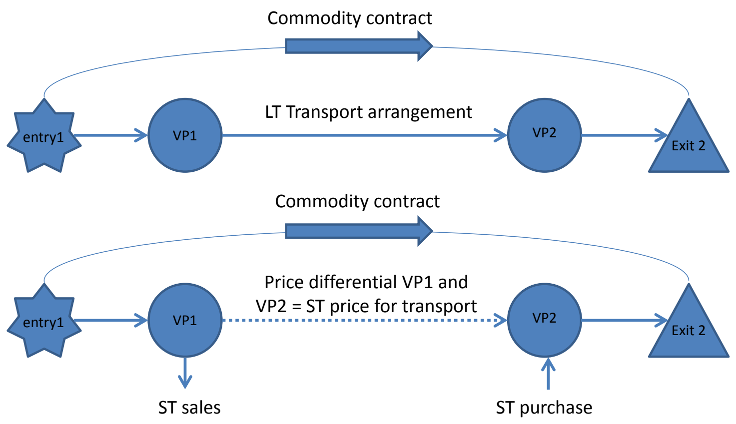

Figure 9: Relation between commodity and transport capacity contracts

The second option is to arrange transport in the short-term. Dependent on the scarcity (and the regulatory regime) of transport capacity between VP1 and VP2, the price for this short-term transport can deviate from the price for the long-term transportation contract. If the short term-transport capacity is booked with the TSO and the TSO uses the same tariff for the long-term and short term transport contracts (e.g. yearly booking), the prices of short-and long-term transport can be equal as well.

The third option in a developed gas system with sufficient liquidity on both sides is to simply swap the gas: Gas from Entry 1 initially meant to be transported from VP1 to VP2 is sold at VP1 at the respective commodity (spot) price, while at the same time a corresponding amount of gas is bought at VP2 at the respective (spot) price, to serve the need of the client at Exit 2.

In a well-developed system the second and third options will result in equivalent prices, i.e. the price for the short-term transport from VP1 to VP2 is equal to the commodity price differential on both hubs. In case of congestion or capacity scarcity between VP1 and VP2 this commodity price differential (i.e. the short-term transport price) will deviate from the long-term transportation contract.

If market parties expect scarcity between VP1 and VP2, and therefore high short-term prices for transport, they can hedge these costs by arranging a long-term transport contract with the TSO. Moreover, if the scarcity lasts for a prolonged period, in which short-term transport prices remain high, this may be seen as a price signal for investment by the TSO. As soon as investments have been made and the transportation capacity is enlarged, the short-term transport prices will come down again (even to levels below the long-term transportation price levels).

Market parties in a developed gas system will take hub prices as important drivers for their business. Similar to the pricing mechanism for gas storages (tariffs indexed to summer/winter price differentials) we expect shippers to lobby for transportation tariffs for long-term contracts related to locational price differentials, i.e. price differences between hubs. TSOs are reluctant to accept such suggestions due to the risk of a potentially insufficient recovery of capital costs since price differentials between the major North West European have been diminished due to a far reaching price conversion. Price differentials below a transport tariffs derived from the current regulatory asset based level would lead to a lower income for the TSOs potentially affecting their willingness to invest in new transport infrastructure. On the other hand, applying reserve prices in the capacity allocation may lead to an incomplete arbitrage between hubs if average price differentials are below the reserve price.

3.2.1.4 **Less Developed Market Environments**

For developed market environments short-term contracts result in more gas hub-indexed prices, more market traded products and more market liquidity. Thus, the effect of the contractual changes outlined above is most significant in the most developed (mostly Northwest) European markets. Yet, not all European markets show similar behavioral aspects. If we take the convergence of hub prices as a proxy for market maturity (at least as to show the coupling between different markets), one can get hold of the extent by which EU’s less developed markets follow Northwest European examples. The Mediterranean countries are rapidly catching up, as can be illustrated by the convergence of the hub price evolution at the PSV and the NWE market in 2012.

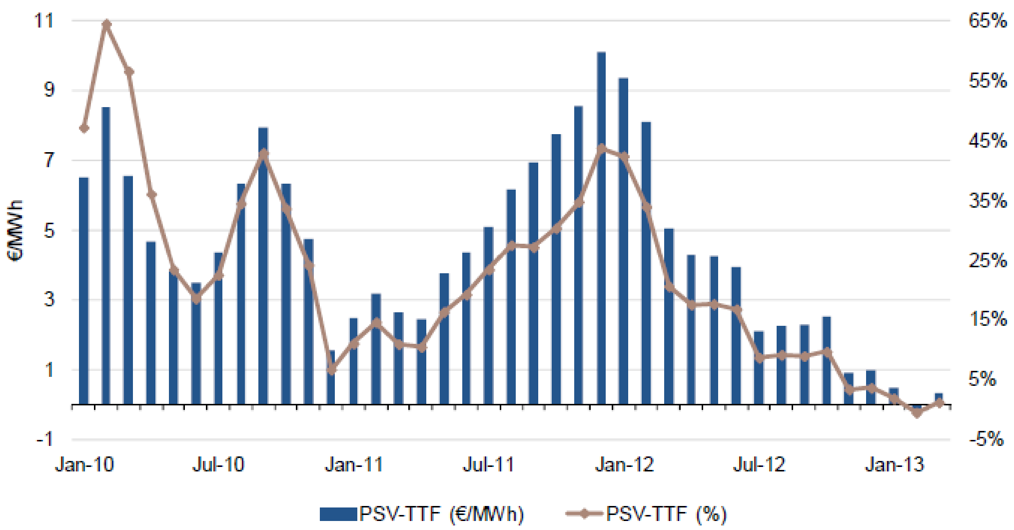

Figure 10: Increased convergence between PSV and TTF

Source: Bros, 2013[45]

However, this does not apply to all EU countries, as illustrated in the figure below, showing the pricing of gas across Europe. We observe that the hubs in North West, South West and South Europe are quite aligned, although there are also non-hub prices ('other prices') that differ from hub prices. On average, those other prices are 2.5 EUR/MWh above hub levels. From West to East we see increasing price levels with roughly 8 EUR/MWh as the value for the transportation costs between West and East.

Despite the vast improvement in recent years, gas market liberalization and a significant amount of competition remains difficult to implement effectively in Eastern European countries. Traded gas markets and new suppliers have not yet developed properly and interconnectivity (including reverse flows) remains a problem, for example in the Baltic States. Thus promoting shorter term contracts and spot trading would likely improve competition and liquidity in those markets, as well as the concept of reverse flows giving the opportunity to link Eastern European prices to the Western European developments. Please note, however, that short term contracts will not be a sufficient condition for competition to develop, for instance in countries with a single supplier and no connection to other markets.

[45] Thierry Bros. World Consequences of the US Shale Gas Revolution, April 2013. Societe Generale.

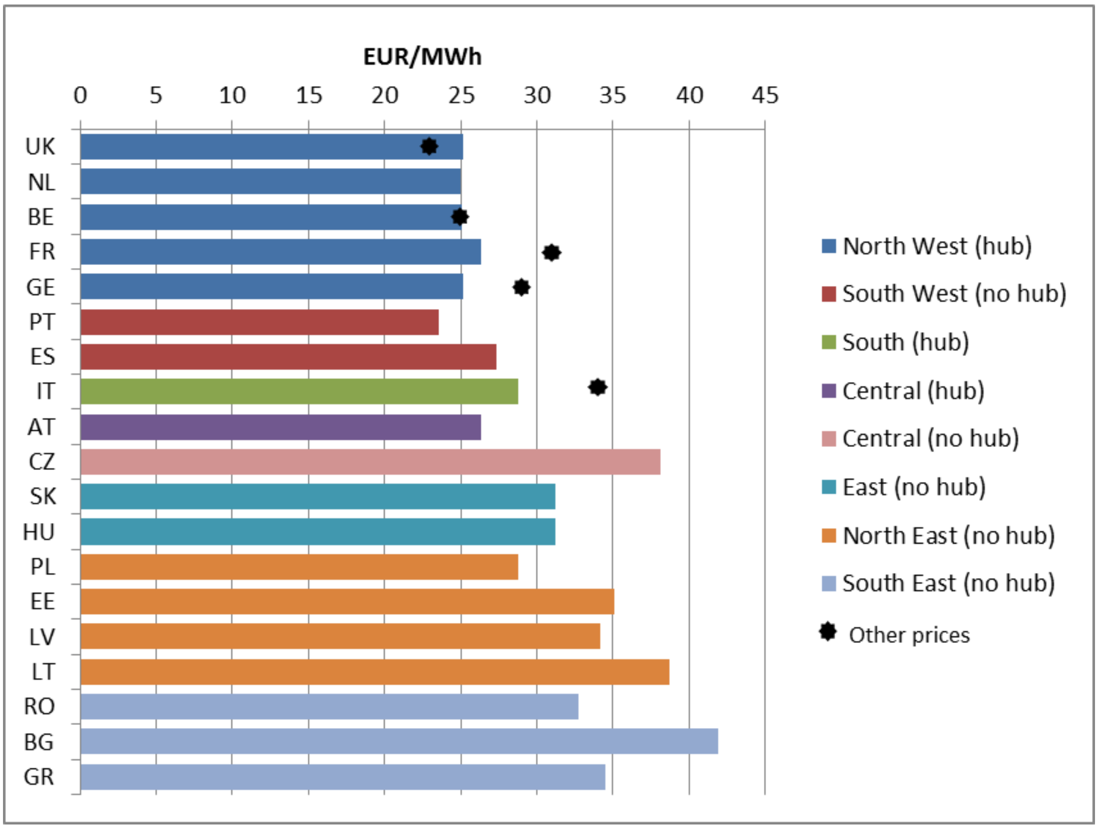

Figure 11: Overview Market Prices EU

Source: DNV KEMA, based on Quarterly Report on European Gas Markets (Q1 2013) by Market Observatory for Energy (DG ENER) with wholesale prices; figure 21

If interconnectivity is improved for these "isolated" countries and shorter-term contracts and spot-trading is promoted then we believe that, in the end, the countries in the eastern part of the EU may follow the same pathway, i.e. hubs will be established and prices will align, with price differentials representing the short-term cost for transport between the hubs.

3.2.2 Exporters Moving Downstream

As downstream markets fall away in terms of total volume and long-term or fixed contracts, and with persistently lower hub prices (i.e. lower than oil-indexed price levels), gas wholesalers and suppliers have changed their procurement strategies. This has allowed large producers and exporters to consider becoming active at downstream markets themselves as well, in an attempt to secure the volume in their portfolio. If their wholesale customers take less volume, the exporters can compensate these lower sales by selling additional gas themselves downstream, directly to end customers plus a balancing amount at the hub. Below we describe the position of the most important exporters in the downstream market:

- We have found no indication that GasTerra is moving further downstream abroad in the EU. However, within the Netherlands itself GasTerra sells a large part of its portfolio on the hub.

From the total GasTerra sales in the Netherlands (34.8 bcm) the larger share (27.3 bcm or 78%) was sold at the hub. On the total GasTerra portfolio of 83.4 bcm this 27.3 bcm is equal to 33%. This was partly due to the requirement as set out by the Dutch regulator for GasTerra to supply at TTF instead of the physical gas stations in the system.

- Gazprom is active downstream via Gazprom Marketing & Trading and by its stake in Wingas (having around 13% share in Germany). GM&T report 85 bcm sales in 2011.This volume is equal to 17% of overall Gazprom production of 513 bcm in 2011. In the UK's industrial and commercial gas market GM&T has shares of 6.3% of daily metered and 11.1% of non-daily metered markets. They have 3% of the industrial and commercial gas market in France and 3% in Ireland (approximately 18% based on usage). In 2012, downstream activities have begun in the Netherlands as well, and for 2013 these activities are expected to commence in Belgium. In Germany Gazprom is involved in several gas activities: the sales business is operated via WINGAS, while Astora is marketing storage capacity. Gas transportation activities run via GASCADE, NEL and OPAL. In the Czech Republic, Serbia and Turkey Gazprom is active in storage
- The majority of the gas marketed by Statoil[46] in Europe - about 80% to 90% - is sold under long-term contracts to large European gas utility companies and suppliers. Statoil also trades gas in the spot market, and the company is active in the emerging liquid trade markets for gas in Europe. In addition, Statoil sells natural gas directly to major end-users in Belgium, the Netherlands, France and the UK.
- Italy and Spain are Sonatrach's most important export countries, provided via long term contracts, largely with the incumbents ENI and Gas Natural respectively. As Sonatrach has also own transmission rights in pipelines crossing the Mediterranean Sea (2 bcm/a in Transmed and 3 bcm/a in Medgaz), Sonatrach has the possibility to offer short-term gas to the market as well and has made public statements announcing that it will do so.

Both Statoil and Gazprom sell between 10% and 20% of their total production directly in the downstream markets. Sonatrach downstream activities are expected to be below these levels, while GasTerra sells 33% of its portfolio on the local hub in the Netherlands[47] and only limited amounts, if any, directly abroad. Those four producers all have long-term contracts, with the buying party having flexibility in determining the actual amount. As those producer companies also have their own outlet for gas, we conclude that they are using this outlet to balance their portfolio, i.e. if demand under the long-term contracts is less than expected, they can sell more gas directly downstream and vice versa. However, for the companies mentioned their share in direct sales further downstream (and abroad) are

[46] http://www.statoil.com/en/ouroperations/gas/pages/market.aspx

[47] As already indicated, this is largely due to regulatory requirements.

rather limited (only slightly above 10% or less). So, in fact, these companies bring further diversification in the downstream markets, which can be judged as positive with regard competition.

By volume alone, there is a threat that producers may influence market prices. (Soft) manipulation of gas price is believed to be possible by some of our interviewees. Although competition authorities are in a better position to study market manipulation, in the public domain DNV KEMA did not find any evidence for such manipulation. On EU level, gas supply could be described as diverse and most markets are sufficiently well interconnected.[48] Morbee and Proost[49] for instance conclude that the Russian market power is limited, because demand is not completely inelastic even in the short run. Finon and Locatelli[50] concluded that Gazprom's direct involvement in a market can have a positive effect on competition, provided that Gazprom is not taking over the dominant national player (on wholesale level). However, in particular CEE countries the situation may be different.

To limit the risk of (potential) manipulation, it certainly helps if there is competition among producers, in other words, further diversification between upstream supplies. It is expected that LNG receiving terminals, U.S. LNG exports, as well as new gas field developments in e.g. Israel, Cyprus, Mozambique and Tanzania will provide such competition. Those new gas sources would not have to delivery into the EU physically; the mere 'threat' of additional gas in the market may already support competition.

As we do not have found proof for (soft) manipulation of market or did find evidence that this could be the case in future, we conclude that large gas exporters moving downstream will most likely have a positive effect on competition as they bring further diversification in these downstream markets (joining the ranks of the second-tier players), provided their market shares in the downstream market remain modest.

3.2.3 Competition Between Coal and Gas

Assuming equal and abundant availability (in terms of volumes and transport capacity) of gas and coal for EU power producers, current (and prolonged) cheap coal and low carbon prices make coal the fuel of choice for power production in Europe (at present) at the expense of gas, meanwhile undermining carbon policy. Essentially, in the long-run the relative price between coal and gas (including CO_2) determines which fuel is used for power generation. Whether the fuel is available through long-term or short-term contracting seems to be of minor importance. Generators will only use gas from long term contracts to generate electricity if the spark spread (i.e. in simplified terms the difference between the

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[48] It should be noted however that this is not equally the case for all Member States.

[49] Morbee J. and Proost S. (2008) Russian Market Power on the EU Gas Market: Can Gazprom do the same as in Ukraine?

[50] Finon, D. & Locatelli, C. Russian and European gas interdependence: Can market forces balance out geopolitics? (2007)

gas and electricity spot price adjusted for the efficiency of the power station) is positive or at least more favorable than an alternative usage of the gas (e.g. selling into the spot market). In general, power producers in the EU seem to prefer spot markets and short-term trading enabling to be able to flexibly procure the fuels required and (temporarily) stop generating or switch between fuels. Traded electricity markets are incompatible with long-term oil-indexed contracts in power generation and the presence of liquid traded gas markets is likely to help the development of gas-fired power generation (whereas long-term ToP commitments have higher risks associated for power generators). Moreover, in a market where gas fired stations are – at best – only marginally in the money and only dispatched for peak supply, flexibility of gas contracts is requested. As gas market mechanisms support flexible nominations of power generation, the preference for spot markets seems logical. Therefore, "*the spread of liquid gas markets in Europe should be a positive driver for the development of new CCGT plants.*"[51]

Where current price levels for coal and gas fired electricity generation clearly favor coal fired stations, from a system perspective there is a strong need to increase the share of gas-fired generation in Northwestern Europe. Various studies evaluate the increasing need for flexible power answering the large penetration of intermittent renewables like wind (around the North Sea) and solar PV (predominantly in Germany). As (especially old) coal fired stations cannot meet the ramping rates required to balance fluctuations at minute timescale, gas stations are required for balancing purposes. For this reason, various (power) TSOs (and regulatory authorities) are at present exploring the possibilities to further incentivize operation of gas fired stations for providing balancing capacity. At the same time, TSOs are faced with an increasing number of gas fired stations being mothballed by their owners. In this arena, flexibility of gas supply is an essential requisite to foster that a certain share of gas fired production capacity is kept online.

In order to gain more certainty with regard to gas demand from power producers, several interviewees have suggested that market parties should not limit themselves to oil-based versus hub-based pricing, but to be more inventive with respect to the design of pricing mechanisms in long-term contracts. Linking the gas price for power generation to a basket for instance of coal, CO_2 and electricity prices as well development of GDP and inflation in contracts with a duration of 8 to 15 years could provide stable and growing gas volumes in this segment. Such a linkage may lead to differences between the gas price for power compared to other gas using segments. It is expected that these types of contracts will be mainly structured by vertical integration and/or tolling agreements.

3.2.4 Strategic and Political Arguments With Respect to Competition

It should be considered that market behavior by market players are not based on economic drivers alone. Strategic and political arguments may play an important role to understand the market behavior.

[51] Melling, A.J. Natural gas pricing and its future – Europe as the battleground. Carnegie Endowment for International Peace. 2010.

Hence, from an economic perspective, markets function in an imperfect way, and the contractual choice (long-term or short-term) is not necessarily driven by economic arguments.

As an example we observe Qatargas still delivering the UK with LNG, while netback prices from spot LNG sales towards Asia would be considerable higher than from their UK sales. The background for this may be the wish of Qatargas to be a reliable exporter to the EU in view of potential future increase of LNG deliveries, in which Qatargas wants to play an important role (and due to a worldwide market, netback prices may potentially differ less than nowadays). Qatar supplies to the South Hook terminal are the only ones to the UK that are based on a long-term contract. The contract price is however linked to the NBP and the contract contains ample flexibility. Already back in 2009 it was expected that Qatar would avoid a purely commercial approach to the terminal.[52]

Another example of this is Nord Stream which initially did not bring additional gas volumes to the EU, but only a shift in routes from Ukraine to directly controlled pipelines. The strategic argument is twofold: besides the direct control on the pipeline it also gives Gazprom the possibility to increase deliveries quite easily, i.e. transportation infrastructure is in place, so to optimize their overall supply portfolio. On the same page, many parties (at the supply side) involved with South Stream and TAP pipelines seem to have also non-economic motivations to participate.

3.2.5 Conclusions on Competition

In this section we will revert on the three research questions as addressed in Chapter 1.3.1.

What is the impact of shorter term contracts on liquidity and competition?

As explained above, in markets where competition already exists or is emerging, short-term contracts will make market entry and exit easier, thereby enhancing competition. More short-term contracts will have a positive impact liquidity, as it gives additional room for volumes, hedging and paper trade. While parts of the gas volumes may be under oil-indexation or coal-indexation, well-functioning spot markets will provide transparent and robust (price) signals and will offer consumers a choice where from and how to source gas. In general, a transparent market is beneficial for smaller players and new market entrants.

If interconnectivity is improved for the more “isolated” Member States and shorter term contracts and spot-trading are successfully promoted, we believe that in the end – taken the developments of PSV in 2012 taken into account and the alignment in earlier years for NCG/Gaspool/PEG with TTF/NBP – the Member States in the eastern part of the EU may follow the same pathway, i.e. hubs will be established and prices will align, with price differentials representing the short-term cost for transport between the hubs.

[52] http://www.icis.com/heren/articles/2009/01/23/9309296/first-q-flex-vessel-to-commission-south-hook-lng-in-next-few-weeks.html

What is the impact of shorter term contracts on the role of gas exporters in downstream markets?

The impact of shorter term contracts may be that large producers and exporters consider becoming active at downstream markets as well in order to secure part of their demand (volume) and preserve a part of their profit (although downstream margins are believed to be rather low compared to upstream margins).

As we do not have found proof for (soft) manipulation of gas markets and equally found no evidence that the potential may increase in future, we conclude that large gas exporters moving downstream will have a positive effect on the competitiveness of gas markets, as they will bring further diversification to downstream markets (provided their market shares in the downstream market remain modest).

Which role do long and short term contracts play in the competition between coal and gas in power generation?

In general, power producers in the EU prefer spot markets and short-term trading enabling to flexibly procure the fuels required and along increasingly flexible plant operations. Traded electricity markets are not compatible with long-term oil-indexed gas contracts in power generation and the presence of liquid traded gas markets is likely to help the development of gas-fired power generation (whereas long-term ToP commitments have higher risks associated for power generators).

The competition between coal and gas in power generation is driven by the relative fuel prices, not by long-term or short-term contracts as such. Innovative pricing terms in long-term gas contracts to power producers may however improve the position of gas in the competition with coal. It may also lead to more vertical integration and/or tolling agreements.

3.3 Security of Supply

The concept of security of supply encompasses the reduction of dependence on external suppliers, enforcement of production and transport infrastructure including gas storage facilities and diversification of gas supply. In this report we focus on the more long-term aspects of supply security, i.e. secure and reliable external supply flows to EU markets, encompassing both the availability of gas volumes to meet demand and the availability of transport capacity to move volumes to the market.[53]

Promoting interconnectivity and competition in the EU gas market is part of a strategy to diversify gas supply sources and routes. The most straightforward way to reduce import dependence is to reduce the use of gas and providing room for alternative fuels (also serving environmental and carbon policies).

[53] We have excluded immediate mitigation of sudden disruptions in supply (e.g. due to an accident in a major pipeline) or extreme demand peaks (e.g. due to cold weather conditions). The provisions in the EU Gas Security of Supply Directive (2004) and Regulation (2010) basically address these short term issues sometimes described as ‘operational security’ or ‘systems security’.

However, if a stable demand is assumed the declining domestic gas production in the EU has to be replaced by sources from outside. Thus the discussion is usually focused on geographical diversification by means of LNG and new pipelines (connecting new gas sources).

There is a need for assuring that gas will be available for buying or importing in order to satisfy demand at all times. One way to minimize this security of supply risk is to lock in a percentage of the requirement by forward buying, preferably from different sources. Long-term contracts for gas provide such a lock in, but also on various EU gas hubs (both virtual and physical) forward contracting is possible, albeit usually with shorter delivery times (e.g. 3 years forward instead of the 20 years we see in traditional long-term contracts).

The central question addressed in this section is whether the movement towards more short-term contracting and spot trade in Europe is impacting security of supply. The notion often heard is that with a general move to short-term contracts security of supply could we weakened. Therefore, to put the research focus in other words: Are long-term contracts required to maintain a secure gas supply to Europe? In the following we argue that there is no substantial risk for gas security of supply to be weakened in having more short-term contracting and trading because:

- More competition and liquidity will attract more competitors and more gas to the market when the price is right (see also previous section).
- From the perspective of investments in infrastructure, existing long-term contracts have shown to provide no firm financial guarantees anyway in the current market.
- There already is sufficient infrastructure capacity available (including those investments for which FID has been taken) to supply the EU market in the coming decade at least.

These arguments will be further elaborated in the subsequent sections.

3.3.1 Competition and Security of Supply

The role of and liquidity on several gas hubs across the EU is increasing. Providing an outlet for producers and a source for suppliers, without the necessity of these market parties having a contractual relationship with each other (via an exchange), these hubs can help security of supply, with the resulting price level based on demand and supply. Short-term, spot and futures trading provides for virtually any flexibility the market parties would require. In liquid and mature gas markets, optionality (both on the supply and demand side) is high. Supply difficulties will immediately be reflected in the gas price, triggering supply and demand responses required. Forward contracting ensures also that supply is secured in the longer term (i.e. at least within the range of forward markets). Moreover, forward prices provide investment signals in the sense that prolonged high forward prices may trigger new investment, thus providing access to new gas sources. Forward contracting may also be a basis for securing an investment project, although investment lead times in natural gas are usually longer than the forward market can provide (up to 6 years in some markets, but usually less and with low liquidity). It seems obvious to assume that once investments are in place and new sources are connected, deliveries will be available also beyond the initial range of forward contracts.

Security of supply problems in short-term markets may however occur in stress situations, e.g. during cold spells in winter, when immediate (large) demand increases and/or supply dips lead to price spikes, triggering the market to react. Such price volatility could for instance be observed in the UK during last winter (beginning of 2013). During such scarcity situations, the EU will be in competition for gas on a global level; it will need to pay e.g. spiking LNG prices during demand peaks. Indeed this is normal market reaction while a new demand-supply equilibrium price is found. While prices may increase in such situations, the existing (even if limited) price elasticity will incentivize consumers to reduce their demand where economically efficient. With an increase in short-term contracts more consumers will directly affected by price spikes and thus subject to such incentive to reduce consumption. Therefore, it can be argued that with more short-term contracts the resilience of markets faced with immediate scarcity situations will improve. There would only be a problem when there is no gas or capacity available (on a global, EU or country level) anywhere to relieve the market; prices will then stay high for a prolonged period, triggering long-term changes in gas supply and demand (e.g. investing in new fields or fuel shifts). Despite any direct impact this may have for market parties, in the longer run security of supply may again be improved.

Longer term security of supply is hardly affected by short term scarcity, as overall EU gas consumption is declining. An example, provided by one of our interviewees, refers to Centrica which very recently was selling seasonal storage capacity at the lowest price since 2005[54]. Thus, the market seems to be long in seasonal storage capacities, despite short-term occurrences of scarcity.

3.3.2 Infrastructure Investments

Two, more or less opposing views prevail in the discussion on the necessity of long-term contracts for large infrastructure investment projects, including upstream gas field development as well as pipeline and LNG projects. Some parties believe that long-term contracts are needed to back capital intensive investments. The argument thus is to make the projects bankable when project financing is concerned. It may be more difficult (i.e. more costly) to get any external financing when the business case is not backed at least partly by some capacity usage and/or volume guarantees provided by long-term contracts and the like. Since pipelines (and LNG infrastructure and gas production fields) represent long-term sunk costs with little or no value of alternative use, they provide a classical case for the hold-up problem that users of the pipeline may change their mind once it is built. In such cases, long-term contracts or vertical integration are used to avoid opportunistic behavior and internalize the investment risk. As we have seen, in the past these instruments were usually used to set-up large investments.

[54] http://www.centrica-sl.co.uk/index.asp?PageID=22&NewsID=165

Other parties believe that, in a liberalized and mature market, long-term contracts that serve as a 'demand security' tool are no longer required to secure investments into developments of new fields and infrastructure. As Westphal[55] puts it: "security of supply cuts both ways", implying that it also entails security of demand. The question however is whether the gas supplier/producer would need security of demand in the rather mature EU gas market. Gas demand does not need to be newly developed but is reasonably 'secure' for a large part, although additional demand is hardly expected, unless maybe at specific locations and in specific sectors such as power generation. However, demand for gas in the power generating sector has also been under pressure due to the competition between coal and gas as the fuel of choice (negative spark spread in the market) and the volatile production of renewable electricity for which gas-fired generation serves as back-up. In the current market with a perspective of stagnating or even declining gas demand, gas producers and exporters may have a case for demand security and thus for long term contracts.[56] On the contrary, in simple economic terms, without the security of demand tradition long-term ToP commitments offer, the risk for investors increases. In order to accommodate this, a higher rate-of-return, adjusted for the risk, may be the result. There seems to be no reason to believe that investments will not be made under a more short-term oriented contractual landscape. However, it seems likely that costs (for financing) could increase and investment decisions would be more dependent on actual market signals. The result would be that many investment decisions would probably only be taken once a certain level of scarcity occurs. Thereby, the gas sector would in general become a bit more prone to economic cycles as observed in many other markets. Short term contracting and price volatility may give rise to boom and bust cycles. However spot prices react immediately on changes in the demand – supply equilibrium and provide precise signals to adjust investments on the supply side. Without this signal function of spot prices, over-investments into the supply side are sustained for longer periods of time and may led to substantial stranded investments.

3.3.2.1 Long-Term Contracts are no Guarantee

Long-term contract commitments have been particularly appealing to the long-term security of supply objectives in Europe. According to the original intention of long-term take-or-pay contracts with oil-indexed prices, the gas producer bears the price risk whereas the gas buyer/importer takes the volume (or market) risk, i.e. the buyer takes the risk of failing to sell the quantity of the project. However, in view of the market situation in the last years, with lower levels of gas hub prices than oil-linked prices, profitability of EU gas wholesale companies has been under pressure, thus implying also a price risk for the wholesaler.

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[55] Westphal, K. Security of Gas Supply. Four political challenges under the spotlight. SWP Comments 17, June 2012.

[56] Policy makers may have a role to play here by setting clear targets, e.g. on the role of gas as transitional fuel or as fuel for the transport sector, taking away part of the uncertainty in demand developments and therefore also taking the argument away for long term contracts.

As we have seen in the beginning of this chapter, most large importers of gas have now renegotiated their gas contracts with the major producers, resulting in lower absolute prices, but more importantly also in a pricing based on spot and indexed gas. Moreover, various arbitration and court cases by large importers have been started in an attempt to get a larger share of contracted volume indexed to spot prices.[57] The most notable example is the RWE case against Gazprom, where the arbitration court ruled that the price formula should be adapted to include market pricing and that payments made since May 2010 should be reimbursed.

With the changing pricing structures in long-term contracts towards hub prices, gas producers increasingly become price takers for the gas volumes delivered and for the capacity sold. Within the limits provided by the contract, the contracting parties have the option to buy and sell at the market place (gas hub). Thus, provided that there is a competitive and liquid gas hub, the role of long term contracts in supporting the bankability of large projects, and thus in supporting a secure gas supply, is diminishing.

The crucial prerequisite for this is the existence of a developed gas hub. However, in several EU Member States traded gas markets and new suppliers have not yet developed properly and interconnectivity remains a problem. In those markets the above argument is not (or less) valid, i.e. long-term contracts may still be needed to ensure security of supply.

Gas hubs will not develop automatically. In order to develop mature gas hubs with decent liquidity a couple of prerequisites are needed. Developed and liquid gas hubs require an ample supply of gas, a large number of diverse market players and a well-developed transport infrastructure[58]. This does not hold true for the majority of the CEE states with the exception of Romania. Subsequently, political measures aim (1) at a diversification of supplies to the CEE countries by additional transport infrastructure and to enlarge small national gas markets by market integration. These measures will take time and will only provide a framework for the development of a liquid gas hub. In the meantime, the CEE countries are intrinsically tied with the traditional sole supplier of gas. The existing long term contracts serve for CEE countries as risk allocation tool as long as the prerequisites are in place. A pre-mature abolition of long term contracts in those countries would probably deteriorate the security of supply.

[57] Thierry Bros, Oxford Energy Forum, August 2012 provides some examples.

[58] As for example reflected in the MECO-S gas target model as proposed by Glachant et al. Glachant identified the following conditions as essential for a “functioning wholesale gas market”: the HHI of gas selling wholesalers should be lower than 2000, the gas market should be supplied at least from three different supply sources (either domestic or from abroad) and the gas market should be large enough (i.e. in excess of 20 bcm) to attract a large number of market participants.

3.3.2.2 New Major Investment Not Required

The contracting choice with respect to security of gas supply is related to the prevalent market circumstances determined by the demand and supply situation. The EU gas market is more or less saturated. There is not much option for demand growth, while interconnectivity within the market and between 'mature' markets is good. The figure below shows the largest EU gas consuming countries, illustrating that most gas markets are indeed mature. Moreover, the figure puts the security of supply issue into perspective. The 12 largest gas countries together represent more than 90% of the total EU market. Countries in Central and Eastern Europe, including the Baltic countries, represent only a small part and are, therefore, less attractive for competitors, making them vulnerable to the security of supply risk.[59]

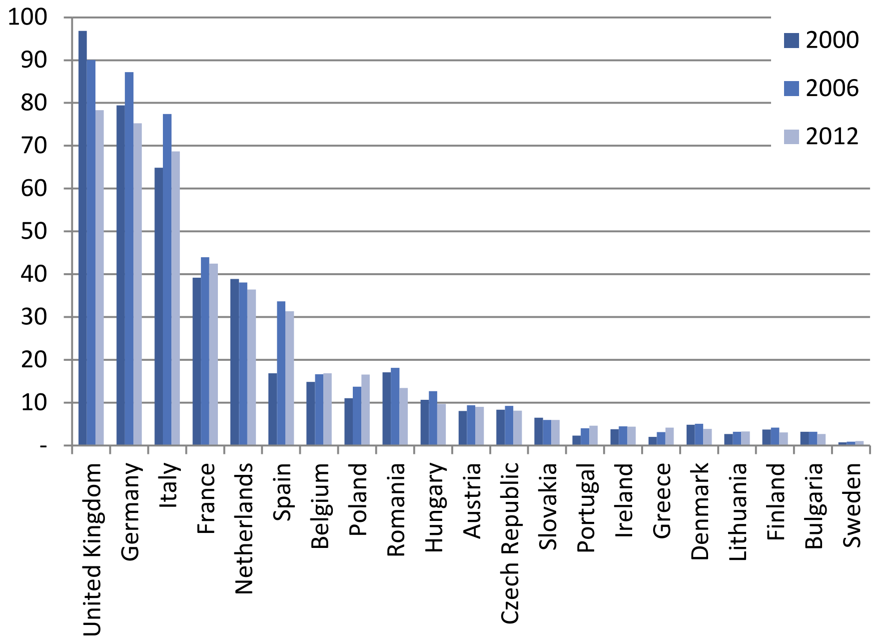

Figure 12: Development of gas consumption (bcm) in EU countries

Source: DNV KEMA based on BP, 2013[60]

On the supply side of the EU market, gas is sourced mostly from existing producers and sources, via existing pipeline and LNG infrastructure. The costs of incremental gas supply are mainly determined by operating costs and small investments. It entails either using idle capacity at production and in

[59] Parmigiani, L. The European Gas Market – A Reality Check. IFRI, May 2013.

[60] BP Statistical Review of World Energy 2013.

transport infrastructure, or relatively small investments in increasing capacities, e.g. including enhanced recovery or new wells (near) existing fields.

In the figure below the classification of the demand and supply sides of the gas market is illustrated, while providing the rationale for the use of long-term and short-term contracts with respect to gas security of supply issues.

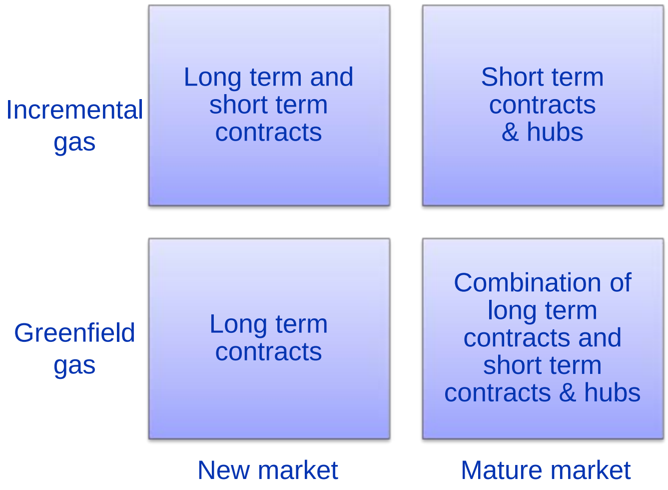

Figure 13: Classification of gas markets

The majority of largest gas countries in the EU can be classified as developed and mature markets with competitive and liquid gas hubs (i.e. North West Europe, including Austria, Italy and Spain: refer also to Figure 11 and Figure 12).

Based on the current information on infrastructure built (including FID) and estimated production and demand figures as shown in Table 2, we conclude that the total gas supply potential is sufficient until the mid-2020ies.[61] The EU LNG regasification terminals will probably show high utilization rates towards the end of this period. LNG will be the marginal supply and with short-term contracts only, the LNG will come to EU markets, if short-term prices are high enough to compete with the demand areas in other parts of the World.

Given a positive balance towards 2025, as shown below, and a lead time of some seven years for large gas infrastructure investments, this implies that until 2018 no additional infrastructure decisions have to be made from a security of supply perspective. Hence, even if one believes that, in the extreme case with only short-term contracts, there will be no appetite for investing in infrastructure towards Europe, security of supply is not affected in the coming years.

[61] Thierry Bros supports this balanced gas situation in Europe at least until 2018. See World Consequences of the US Shale Gas Revolution, April 2013. Societe Generale.

2025	Region	Infrastructure Capacity bcm/yr Directed to Europe (incl. Turkey)	Production Capacity bcm/yr Directed to Europe	Estimated Contribution Min – Max Case	References / Remarks
Pipeline Gas	Russia	192 [1)]	198 to 232 [2)]	190	1) .... NTSOG
	Norway	120 [3)]	120 [4)]	120	2) Russia's natural gas export potential up to 2050; Sergey Paltsev, MIT, Cambridge USA
	Algeria & Libya	69,5 [5)]	60	60	3) Gassco
	Caspian region, Kazakhstan, Middle East through South Stream / TAP / White Stream	10 to 32	partly Russian gas diverted from other routes; no volumes commissioned yet	10	4) Norwegian petroleum directorate, facts 2013, chapter 7, figure 7.1 5) Oxford Inst. of Energy studies; Sonatrach
Domestic Production	Europe	n.a.	170 + possibly 55 shale gas	170 – 225	
LNG	World	Regasification capacity EU 193 to 222 [6)]	World market; far above regas capacity EU	100 - 200	Capacity seldom fully utilized; estimated 50% used in minimum case 6) GIIGNL, The LNG industry 2012
Total Potential Supply				650 – 805	Sum of above amounts
Total Demand				600 [7)]	7) Oxford Inst. of Energy studies
Balance				50 – 205	

Table 2: Assumed gas supply-demand situation in 2025

3.3.3 Conclusions on Security of Supply

In this section we have argued that short-term contracting, and thus competition, generally has a positive impact on security of supply. More competition and liquidity will attract more competitors and more gas to the market when the price is right, thus supporting diversified supplies. In a competitive market (a deep and liquid spot market) scarcity situations are handled through price signals. The market will serve as a supply for last resort, as well as an outlet for (new) large supply projects and incremental gas. Moreover, future markets enable future delivery, contracting, and price discovery, supporting longer term investment signals.

At the same time, security of supply also helps competition. A comfortable supply situation creates trust in the market, so that market parties can rely on the market to solve imminent (short term) supply issues, albeit probably at some price risk. We should however also be aware that competition cannot fully replace or solve security of supply risk. In some cases the market will not be able to address supply issues. For example, there probably is no business case for keeping enough gas available to cope with extremely cold days. For such events, political and regulatory interference is required to protect gas customers (and as has been used already in the past).

From the perspective of investments in infrastructure, we also conclude that the movement towards more short-term contracting is not detrimental for security of supply. The argument that long-term contracts are required for the bankability of projects has been weakened by the development of gas hubs and competition. Long-term contractual terms are subject to regular renegotiation between the contracting parties related to changing market conditions. Renegotiations provide contracting parties to exploit the options at the traded markets and hubs and, as a result, financial guarantees of these contracts are, in reality, not as firm. The existence of a competitive and liquid gas hub is however a prerequisite.

In addition, the current and expected gas market situation in the EU, with sufficient gas volumes and capacity available, makes long-term security of supply a less important issue for the coming year. As a consequence, more short term contracting will not affect investments in large gas projects.

Moreover, governmental and political interference also affects the market and security of supply. Major gas projects currently supplying the EU market have not always been based on pure business or economic considerations, or on the role of long-term or short-term contracts. Political arguments are not always transparent and opaque from an economic perspective, and they are most probably not affected by a move towards short-term contracting.

4 TASK 2: INTERNATIONAL COMPARATIVE ANALYSIS OF THE TEMPORAL STRUCTURE IN OTHER LARGE MARKETS

4.1 Overview

The overall goal of the second task of the project was to take stock of the temporal contract structure of four other large gas markets, i.e. USA, Australia, Japan and China, and to assess the existing long- and short-term contractual relationships with the aim of distilling lessons-learned and the potential impact the development in these countries may have on the EU gas sector. As a result, we have provided a comparative analysis of the selected countries identifying and explaining the reasons and drivers for the temporal structure as it is.

We have divided this task into three parts.

1. The first part contains case studies for the four selected countries, focusing on the research foci described in chapter 1. Each case study is complemented with a concluding assessment of the current issues and future development
2. Subsequent to the country-by-country analysis, we have provided a comparative analysis, showing the key differences and also the key similarities between the countries and thereby assessing how certain contractual structures observed (as well as differences and similarities) can be explained by a countries situation
3. In the last part we conclude with the key findings from the analysis of other large gas markets and the conclusions drawn in relation to the EU gas sector

4.2 Case Studies

4.2.1 US Gas Sector

4.2.1.1 Structure of the US Gas Sector

The US natural gas sector has a long history of liberalization and regulatory intervention. The US gas sector is well developed and characterized by the availability domestic resources. Traditionally dominated by production in the Gulf region, but also in other regions natural gas was available for production. In addition, pipeline imports from Canada and Mexico were easily available. The soaring success of shale gas further drove and is still driving the development of the natural gas sector in the US. By now, the USA is the world's largest natural gas producer, while also being the largest consumer with an annual consumption in 2012 of approx. 720 bcm.

The US gas pipeline network is mostly privately owned and operated and

- consists of 210 pipeline systems,
- with a total length of more than 480,000 km, which connect
- more than 500,000 producing gas well,
- approx. 400 underground natural gas storage facilities,

- 49 cross-border import/export pipeline connections,
- 8 LNG regasification plants, and
- 1 LNG liquefaction plant under construction (Cheniere Energy's Sabine Pass LNG plant).[62]

The following picture provides an overview of the US pipeline network. The pipeline density clearly shows the traditional centers of the natural gas sector in the South.

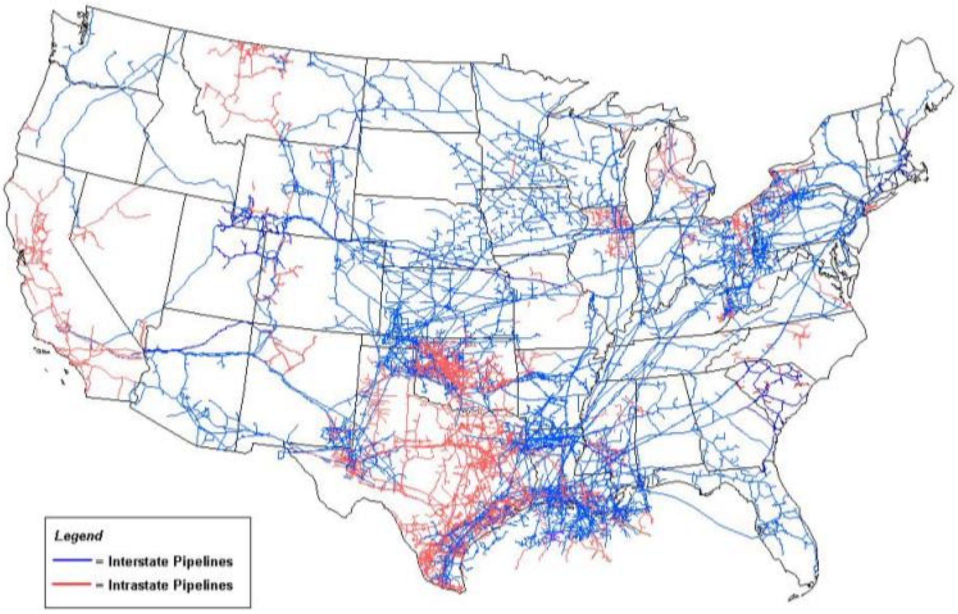

Figure 14: US natural gas pipeline network

Source: EIA

The existing pipeline network and the large number of gas producers facilitate a highly dynamic and competitive market. With more than 30 market centers (hubs), Henry Hub in Louisiana being the most prominent (physically located at an important intersection of large interstate pipelines close to the traditional gas productions areas in the Gulf region). Price differences between hubs are largely determined by transport costs between them. Henry Hub is the reference point for futures contracts traded at NYMEX. Trading evolved since 1985 when FERC[63] opened the interstate transmission level for third-party access, which has been strengthened further in 1992 (as is further explained below). Until then the gas sector was characterized by long-term contracts and an integration of transport and commodity ownership along the value chain. Producers sold to pipeline companies, which sold to distribution companies, which then finally sold the gas to retail customers.

[62] Based on U.S. Energy Information Administration (EIA), Global LNG Info and Cheniere Energy

[63] Federal Energy Regulatory Commission (FERC) is an independent federal agency, responsible for regulatory matters on federal or interstate level, e.g. regulating interstate pipelines and LNG terminals.

Until spot trading emerged during the second half of the 1980ies, long-term contracts were usually based on oil-prices. At present, there is no regulation applied on wholesale prices anymore. Gas is traded either at market hubs or NYMEX with prices naturally set by market forces, or – where gas is traded OTC – prices are derived from market prices, for instance by choosing an indexation based on Henry Hub prices, while oil-price indexation seems to play no role at all anymore.[64] Neither seem long-term commodity contracts play a role anymore on the domestic market (and where they are used, they are linked to spot prices). Large gas volumes are also traded along the forward curve, seldom using contract durations of more than three years.[65]

The shift to more short-term oriented trading started – among others – with the establishment of Henry Hub as the first spot market in 1988. In 1990 futures were already being offered at NYMEX, based on delivery at Henry Hub. With FERC Order 636 requiring unbundling for interstate TSOs, the pipeline companies themselves, and their traditional model of gas supply under long-term contracts and vertical integration went out of business. The increased flexibility for distribution companies as to from where and how they could source gas seems to have led to decrease in demand for long-term contracts. Meanwhile the volume of spot and futures trading quickly gained momentum, as the following figure shows. Today, NYMEX reports on average a daily volume of around 400,000 contracts traded in Henry Hub Natural Gas Futures.[66]

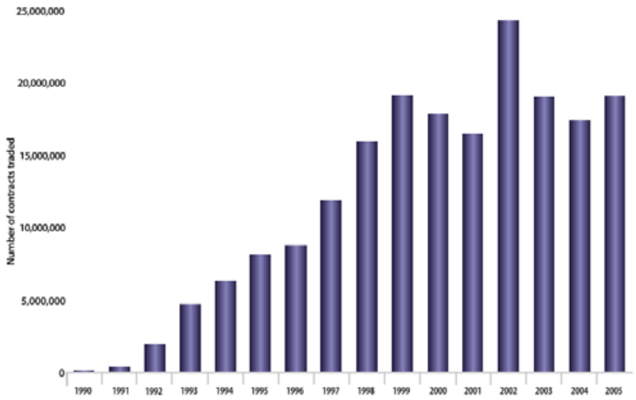

Figure 15: NYMEX trading volume 1990 - 2005

Source: NYMEX, LEXECON[67]

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[64] Cf. IGU, Wholesale Gas Price Formation, June 2011, p. 34

[65] However, given the current dynamics on the US gas market, this may change again in the future, as is further explained below.

[66] C.f . http://www.rbnenergy.com/henry-the-hub-i-am-i-am-understanding-henry-hub

[67] Understanding Natural Gas Markets, http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/natural-gas/~/media/9D1859A08BE44BBFAF5264148AE8ACF6.ashx

As Costello argues, the changing market environment also reduced the need to have long-term contracts in order to back-up investments in production and transport.[68] In addition, distribution companies are experiencing competition and uncertainty with regard to future demand and thus have been less willing to enter into long-term contracts.

As the following figure shows, the US gas sector is largely self-dependent. Domestic production covers approx. 90% of the demand. Additional volumes are imported by pipeline from Mexico and Canada and only a very small fraction of demand was imported through LNG terminals.

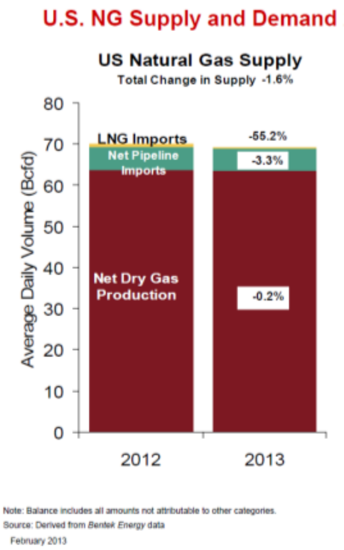

Figure 16: US natural gas supply and demand

Source: FERC

After a continuous decline of US gas production, an increase in US import dependency was expected earlier this century. This resulted in several LNG regasification terminal projects, mostly originating in the traditional production region around the Gulf of Mexico, but also at the Mexican Pacific Coast and in the Northeast of Canada.

[68] C.f. Costello, Ken, Going “Long” with Gas: Considerations for State Regulators, September 2010

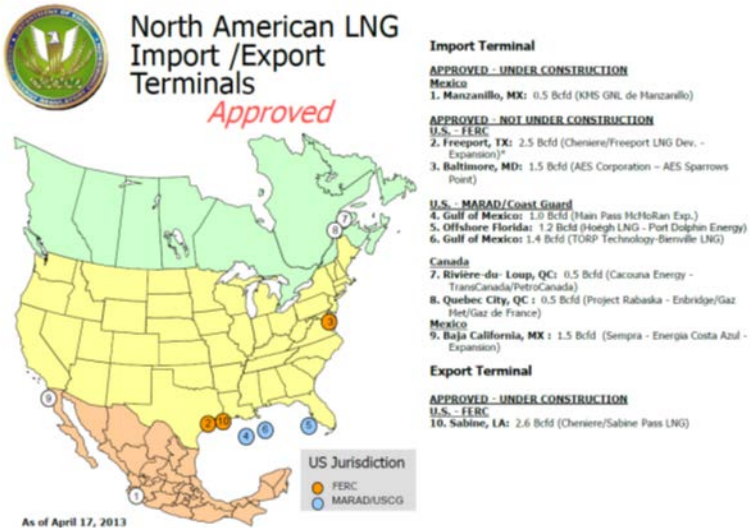

Figure 17: Approved LNG terminals in North America

Source: FERC

Earlier IEA projections were expecting US LNG imports to reach around 70 bcm in 2010-2012.[69] However, due the soaring success of shale gas, the US gas production has managed to compensate production declines from more mature conventional production and to steadily increase gas production throughout the last years. Today unconventional gas (i.e. shale gas and coal-bed methane) makes up for more than 25% of US gas production.

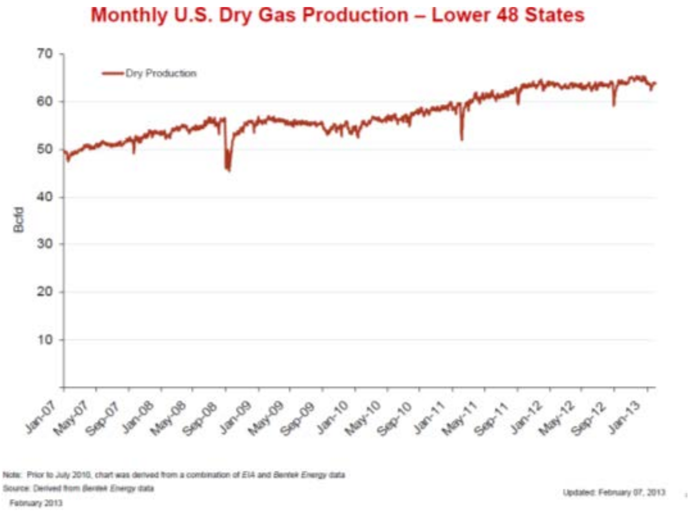

Figure 18: Monthly US dry gas production since January 2007

Source: FERC

[69] IEA, Annual Energy Outlook 2007

US gas production is distributed all over the country, featuring a total of more than 6,000 producers of natural gas, of which around 20 are considered to be major companies. Whereas, the large majority of these producers are only very small enterprises. Such a production landscape is, among others, promoted by the specifics of US mining law.[70]

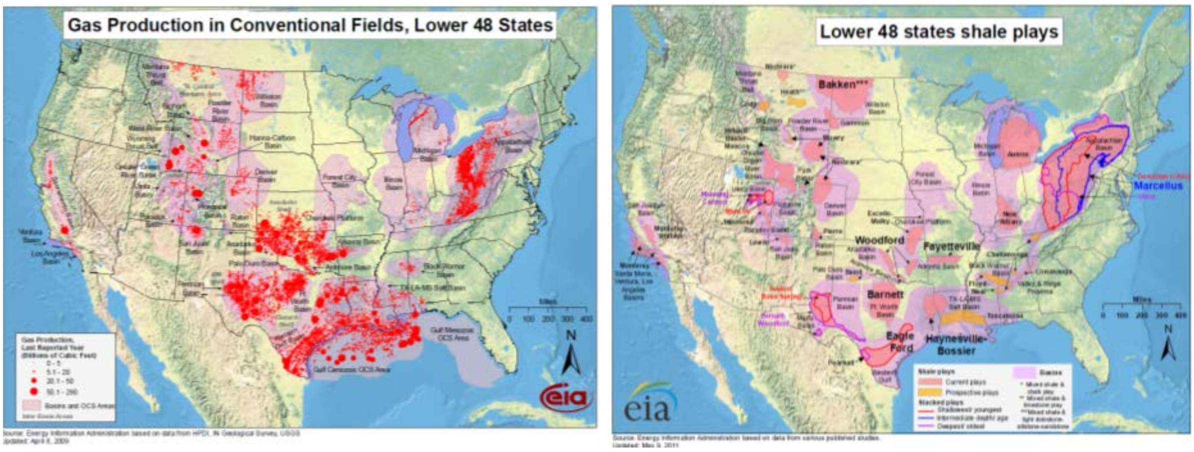

Figure 19: Distribution of gas fields in the US

Source: EIA

At the same time, domestic gas production recovered and the LNG import terminals became obsolete. Although LNG is imported into the US until today, utilization of regas capacities is far from installed capacities, as the following figure shows. At the same time, the availability of LNG cargos, originally contracted for the US market for diversion to other markets, was part of what shaped the situation of EU gas markets during the last years (as discussed in the previous chapter).

[70] In the US, landowners also own the right to all minerals buried in the ground. In comparison, in many other countries, mineral rights belong to the state which awards concessions (allowing for exclusive exploration and production) to companies and gathers royalties in return.

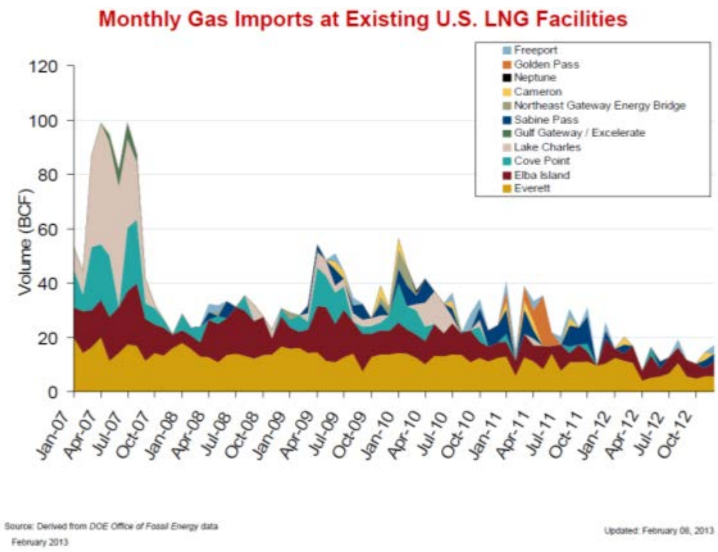

Figure 20: US LNG imports

Source: FERC

Since the role of shale gas increased in the US gas sector, gas prices have evolved independently from EU gas prices, as the following figure shows.

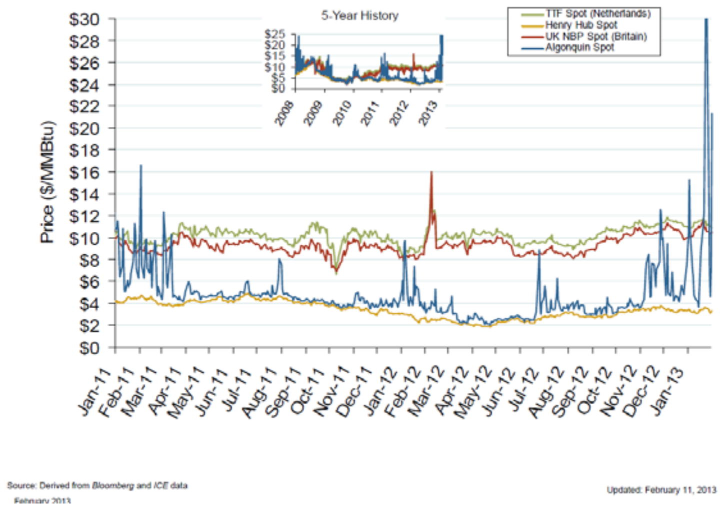

Figure 21: Comparison of US and EU gas prices

Source: FERC

In particular since 2011, US gas prices have remained on a price level significantly below EU gas prices. As can be seen in the above figure, the Henry Hub Spot price, taking it as an index for gas prices, close to production is stable with showing little seasonality. However, where import constrained load pockets exist price peaks may occur, as the curve for Algonquin Spot market shows.

The Algonquin spot price is the city-gate price for the Boston region in New England, which suffers from transmission congestion.[71]

While the already existing LNG import facilities could be considered as stranded investments (on account of the low utilization and weak outlook for future demand for imported gas), the low gas prices in the US compared to comparably high gas prices in Europe and Asia-Pacific, lead to various effort from market participants to enable gas export from the US. While the discussion of the potential impact of gas exports on the US economy and also construction, as well as export permits, are still pending (as is further explained below). This then resulted in a multitude of projected/proposed LNG liquefaction and export terminals.

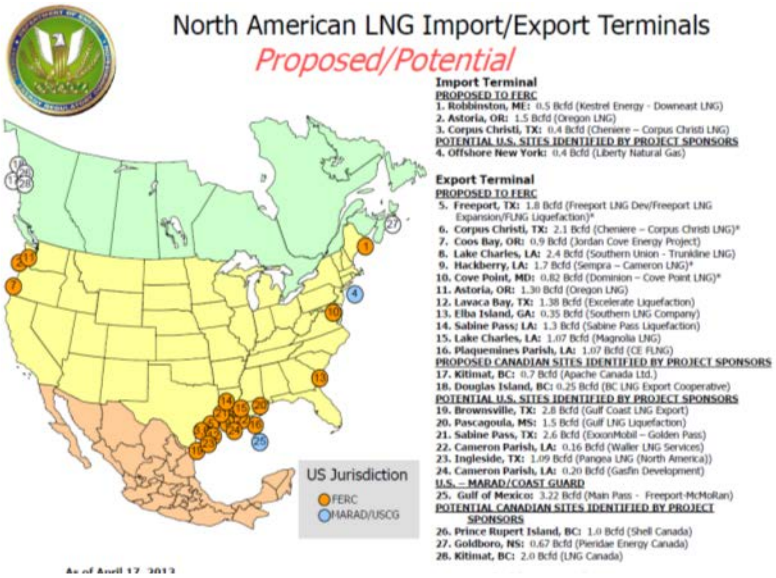

Figure 22: Proposed/Potential LNG export terminals in North America

Source: FERC

Similar to the development of import terminals before, the bulk is concentrated in the Gulf region. In addition, in particular with Asia-Pacific as a promising gas demand region, a number of export terminals is also planned along the Pacific coast.

Similar to many European countries, natural gas plays a role as energy carrier in various sectors. Industrial demand covers around 30% of the overall demand and power generation even 40%.[72]

[71] The Boston region also used to be supplied with LNG. It is argued however that the overall low gas prices in the US increase the reluctance of LNG importers and thus aggravate the situation for the Boston region during peaking demand (c.f. http://www.rbnenergy.com/the-mighty-algonquin-supplying-new-england-the-eskimos)

Commercial and residential demand (mainly for space heating) make up the remaining 30% (disregarding a very minor share of gas used as vehicle fuel), with residential demand making up around 12% and commercial demand at 14%.

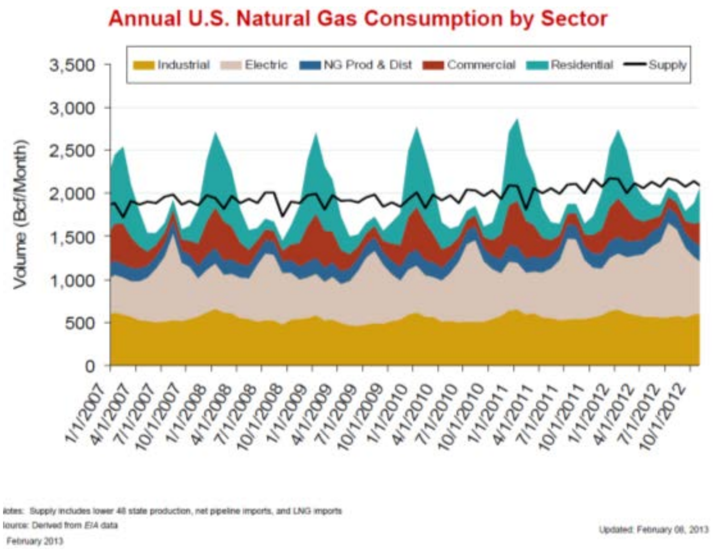

Figure 23: US gas demand by sector

Source: FERC

At present, the US gas market could be described as slightly oversupplied. In early 2012, storage inventory levels were unusually high and only a strong gas demand for power generation kept oversupply at bay during 2012. With the beginning of the winter season 2012/2013 additional production volumes became available on the market.[73] As data reported by FERC seems to indicate, the market still seems to be able to absorb the ever increasing dry gas production as prices have increased slightly as well. At the same time, LNG import volumes in 2012 have reached a 5-year minimum.[74]

[72] In particular the demand for gas in power generation has increased during the last years, mainly due to the low gas price improving the position of gas fired power plants in the merit order.

[73] Cf. Fahey, Jonathan, U.S. Natural Gas Market Bursting At The Seams, available at http://www.huffingtonpost.com/2012/04/08/natural-gas-market_n_1410851.html, and REUTERS, Analysis: Waking giant-Marcellus Shale bullies U.S. gas market, available at http://www.reuters.com/article/2012/10/15/us-energy-natgas-marcellus-idUSBRE89E12B20121015

[74] Cf. FERC, National Gas Market National Overview, February 2013, available at http://www.ferc.gov/market-oversight/mkt-gas/overview/2013/02-2013-ngas-ovr-archive.pdf

4.2.1.2 Regulation of the US Gas Sector

The US gas sector is subject to regulation by various agencies. Interstate pipelines ,as well as offshore production, import and export, are subject to federal jurisdiction whereas intrastate pipelines, onshore production and supply are mainly falling under state jurisdiction.

Interstate pipelines are regulated by FERC. Interstate pipelines have to offer open third party access to their systems and have to comply with certain unbundling requirements. However, full ownership unbundling is not required. Transmission tariffs are regulated as price caps based on a cost-plus approach. Pipeline companies are free to offer their services below the regulated rate and – as pipelines are in competition[75] with each other – frequently do so. In all cases, offered tariffs have to be non-discriminatory.

Intrastate pipelines and distribution companies are regulated by authorities of the States in which they are located (the Public Utility Commissions, PUC). In many States, a high degree of vertical integration persists. Often distribution companies are municipally owned and have a local monopoly on gas distribution and retail. However, in recent years, more and more states have started to liberalize the final consumer sector, allowing free choice of suppliers.

Historically, the US gas industry was characterized by a certain separation at each level of the supply chain. Producers of gas were often independent and sold gas at the wellhead (or rather the gas treatment facility) to transmission pipeline companies. These pipeline companies then transported the gas on their assets to the city gates, where gas was sold to distribution companies. Distribution companies took over the gas at the city gate and transported it through their systems to their retail customers. Despite being separated along the supply chain, many companies thereby integrated gas trading and supply with asset ownership. During the second half of the last century, it has been attempted to regulate prices at all these three points, wellhead, city-gate and at the "burner-tip" (i.e. the retail price). Currently, there is no price regulation on the production and wholesale level anymore. These earlier attempts to regulate wellhead prices were abandoned in 1978 after having proved to be impractical and sub-optimal. In many States retail prices are still subject to State regulation.

Starting in 1985, FERC (order 436) attempted to liberalize the gas markets, enabling (interstate) pipeline companies to market their transportation capacities by setting up a framework for regulated transport fees and preventing discrimination of transport-only customers against customers still being delivered gas. With Order 436 FERC opened the interstate transmission level for third-party access. However, while many consumers used the opportunity to find new ways to source (cheaper) gas, pipeline companies suffered severe problems from take-or-pay obligations under their contracts with producers. In order to facilitate further unbundling of (interstate) pipeline companies, FERC allowed pipeline companies to buy-out from these take-or-pay obligations. In 1992, legal unbundling of

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[75] It should be noted that competition between pipelines cannot be easily isolated, as there is also competition on the production side. Often, the question for a supplier may thus be not which pipeline to use to transport the gas but rather from where to source the gas.

intrastate pipelines became mandatory, requiring a separation of pipeline and gas trading/sales activities and full open third-party access regimes (FERC Order 636).

4.2.1.3 New Infrastructure

As federal regulator, FERC is responsible for reviewing applications for construction and operation of (new) pipelines. New pipeline constructions are mostly driven by the need of producers to establish a physical link with areas of consumption. Traditionally, many of the new pipelines served to transport gas from production centers in the South and West to the load centers in the East. At present, the production and transportation capacities from the Marcellus Shale located in the Northeast are expected to shift the situation around with gas from the Marcellus Shale displacing gas transported from the West and South as well as from Canada. In general, the boom of shale gas leads to a huge demand for new pipeline capacities, as new production centers emerge. In some cases, however, changing flow patterns may also lead to the underutilization of existing pipes.

New pipeline investments are subject to a mandatory open season procedure. Usually, pipeline companies will already hold the open season prior to submitting the application for the investment project to FERC. The investment decision for a new pipeline is typically dependent on an anchor shipper booking a large part of the pipeline capacity in advance during the open season with contract durations of 10 years and more. For instance, in advance of building the Rockies Express Pipeline, one of the largest pipelines in the US stretching over almost 2,700 kilometers from the Rocky Mountains to the border between Ohio and West Virginia, more than 65% of the capacity was sold under precedent agreements during the open season.[76]

LNG terminals are exempted for the requirement to provide open third-party access. Apart from technical regulations[77] which will not be discussed in detail here, the aspect of main relevance is assumed to be the regulation of imports and exports as such (either LNG or through pipeline), as is described in the following section.

4.2.1.4 USA as Gas Exporting Country

Import and export requires an authorization from the Department of Energy (DOE). Two types of authorizations can be distinguished: (1) for short-term imports/exports up to two years, and (2) for

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[76] Rockies Express Pipeline LLC, Open Season Results, January 12, 2006, available at http://www.kindermorgan.com/business/gas_pipelines/divested/rockies_express/OSP_Rockies_Express_Results_01-12-06.pdf

[77] The responsibility to set and to oversee compliance with technical regulations lies with FERC. FERC has the sole authority to approve or deny an application for siting, construction, expansion and operation of LNG terminal facilities onshore and in State waters. Responsibility for installations in Federal waters belongs to the Coast Guard.

long-term imports/exports ranging above two years. Apart from the already approved Sabine Pass LNG terminal, ten export terminals are currently proposed to FERC, one to the Coast Guard and several more are considered by project sponsors. [78] The DOE currently has received applications to export LNG of altogether more than 800 mcm/d. In almost all cases export to FTA (free trade agreement) countries has already been approved, while export to non-FTA countries is still pending.[79] Until know only the Sabine Pass liquefaction project (trains 1 – 4) and the Freeport liquefaction project received a DOE permit to export to non-FTA countries. While the Sabine Pass project already received the non-FTA export permit in May 2011 (which was then finalized in August 2012), the non-FTA permit for Freeport was granted in May 2013. The current market development is the main force behind the development for the USA to become a gas exporter, not only to Mexico and Canada but – through LNG – also to the rest of the world.

However, the possibility of the US becoming a major natural gas exporter triggered an intense debate over possible impacts for US industry and consumers due to price increases on the domestic market. It is quite obvious that the existence of major export capacities will factually lead to a convergence of US and world market prices (minus liquefaction and transport costs, though) and therefore could have a significant impact for US gas consumers. At the same, with gas prices still being at the lower end raising doubts whether gas production is still in the money, gas producers and investing/financing parties have strong incentive to push for export capacities.

The US Energy Information Administration (EIA) prepared a report, assessing the impact LNG exports will have on prices, supply and demand,[80] serving as input for the discussion. EIA expects a short-term price increase of up to 36% (above reference case) in the short run, if additional exports are ramped up fast to a high level, and up to 28% in case of a slower ramping up of exports. However, EIA also expects a strong resilience of the US gas market, bringing prices back down to below an increase of 20% in the high export scenario (12 bcf/d = 0.34 bcm/d) and 10% in the low export scenario (6 bcf/d = 0.17 bcm/d).

[78] Cf. FERC, North American LNG Import/Export Terminals – Proposed/Potential, available at http://www.ferc.gov/industries/gas/indus-act/lng/LNG-proposed-potential.pdf

[79] Department of Energy, Summary of LNG Export Applications, March 2013, available at http://www.fossil.energy.gov/programs/gasregulation/reports/summary_lng_applications.pdf

[80] EIA, Effect of Increased Natural Gas Exports on Domestic Energy Markets – as requested by the Office of Fossil Energy, January 2012

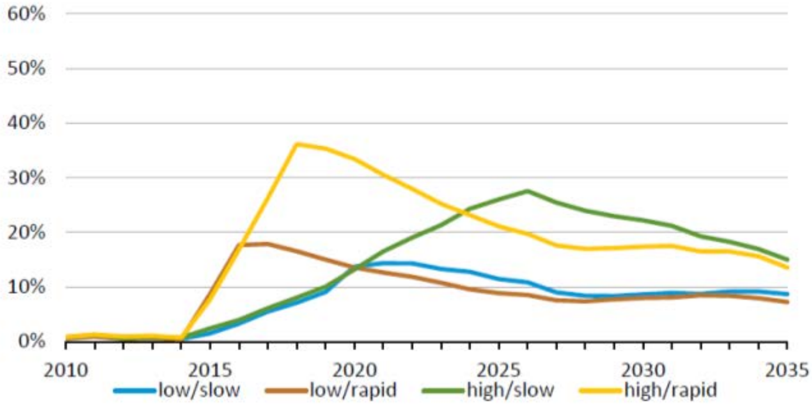

Figure 24: Impact of increased LNG exports on US wellhead prices

Source: EIA

The EIA concludes that increasing exports will lead to higher prices but also to higher production volumes, decreasing gas consumption and increasing imports from Canada. As the above figure shows, the initial price increase is expected to be followed immediately by a downturn of the price levels. The explanation is of course quite simple. Firstly, increased prices will lead to renewed efforts in gas exploration and production. With the current price level, gas production has come under pressure, as is also shown by the decreasing rig count over the last two years. A price increase will bring more projects into the economically feasible range. Secondly, given the price-elasticity of some consumers, a price increase will lead to a decrease of gas consumption. EIA expects this mainly to result from less gas used in power generation, replacing gas with coal and renewables. While the export will thus lead to increased expenditures of consumers for gas and power, producers of natural gas will benefit from higher production volumes and higher prices, with a net benefit for the US economy.

The EIA study's results were further detailed by NERA, taking into account interdependency with the world gas market and the macroeconomic impact in the US.[81] NERA confirms that across all scenarios and cases, the net benefit from US LNG exports is positive. Welfare gains across all scenarios are ranging between 0.0038% and 0.0291% for the time horizon 2015 until 2035, with GDP increases of around USD 10 to 20 billion per year.

According to Cheniere Energy, the owner of the Sabine Pass terminal[82], long-term (20 years) supply agreements have been signed with BG Gulf Coast LNG, Gas Natural Fenosa, KOGAS, GAIL and Total Gas & Power North America over a total of approx. 18 million tons LNG per year.

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[81] NERA, Macroeconomic Impacts of LNG Exports from the United States, December 2012

[82] One of two terminals which to date has been granted a non-FTA export permit.

~18 mmtpa "take-or-pay" style commercial agreements
~$2.6B annual fixed fee revenue for 20 years

	BG GROUP BG Gulf Coast LNG	gasNatural fenosa Gas Natural Fenosa	KOGAS Korea Gas Corporation (1)	GAIL GAIL (India) Limited (1)	TOTAL Total Gas & Power N.A.(6)
Annual Contract Quantity (MMBtu)	286,500,000	182,500,000	182,500,000	182,500,000	104,750,000
Annual Fixed Fees (5)	~$723 MM	~$454 MM	~$548 MM	~$548 MM	~$314 MM
Fixed Fees $/MMBtu (2)	$2.25 - $3.00	$2.49	$3.00	$3.00	$3.00
Term (4)	20 years	20 years	20 years	20 years	20 years
Guarantor	BG Energy Holdings Ltd.	Gas Natural SDG S.A.	N/A	N/A	Total S.A.
Corporate or Guarantor Credit Rating (3)	A2/A	Baa2/BBB/A-	A+/A1	Baa2/NR/BBB-	Aa1/AA
Fee During Force Majeure	Up to 24 months	Up to 24 months	N/A	N/A	N/A
Contract Start Date	Train 1 + additional volumes with Trains 2,3,4	Train 2	Train 3	Train 4	Train 5

(1) Conditions precedent must be satisfied by December 31, 2013 for KOGAS and GAIL (India) Ltd. or either party can terminate. CPs include financing, regulatory approvals and positive final investment decision.
(2) A portion of the fee is subject to inflation, approximately 15% for BG Group, 13.6% for Gas Natural Fenosa and 15% for KOGAS and GAIL (India) Ltd.
(3) Ratings may be changed, suspended or withdrawn at anytime and are not a recommendation to buy, hold or sell any security.
(4) SPAs have a 20 year term with the right to extend up to an additional 10 years. Gas Natural Fenosa has an extension right up to an additional 12 years in certain circumstances.
(5) BG will provide annual fixed fees of approximately $520 million during trains 1-2 operations and an additional $203 million once trains 3-4 are operational.
(6) Total has agreed to purchase 91,250,000 MMBtu of LNG volumes annually plus 13,500,000 MMBtu of seasonal LNG volumes upon the commencement of train 5 operations. Conditions precedent must be satisfied by June 30, 2015 or either party can terminate. CPs include financing, regulatory approvals and positive final investment decision.

9 CHENIERE

Figure 25: Sabine Pass liquefaction sale and purchase agreements

Source: Cheniere Energy

Where price clauses are reported in more detail, the purchase price is given as indexed to the monthly Henry Hub price plus an additional fixed component.[83] Specific details are known for a supply agreement between Cheniere and Centrica on 1.75 million tons per year: The contract duration is 20 years, starting in 2018, and includes the option for a 10 year extension. Again, a fixed-price component and a Henry-Hub-based component are used. The fixed component is USD 3/mmbtu plus 115% of the relevant Henry Hub price, delivery is 'free on board'.[84] In addition, as above figure shows, annual fixed fees are applied.

Contractual parties of Cheniere for Sabine Pass capacity have used or may use this to resell the gas, for instance between Total and KOGAS.[85] As far as is known, the design of these LNG sale and purchase contracts as tolling agreements leaves full diversion rights with the client.

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[83] Cf. Cheniere Energy press releases, eg. http://phx.corporate-ir.net/phoenix.zhtml?c=101667&p=irol-newsArticle&ID=1767719&highlight=, http://phx.corporate-ir.net/phoenix.zhtml?c=101667&p=irol-newsArticle&ID=1638424&highlight= and http://phx.corporate-ir.net/phoenix.zhtml?c=101667&p=irol-newsArticle&ID=1621715&highlight=

[84] Cf. Centrica news release 25.03.2013, available at http://www.centrica.com/index.asp?pageid=1041&newsid=2693

[85] Cf. Total news release 13.09.2012, available at http://www.total.com/en/about-total/news/news-940500.html&idActu=2863

Freeport LNG, the other export terminal which already has been granted a non-FTA export permit, is planning to install liquefaction capacity of around 13.2 million tons per year (with three trains) at an estimated investment of USD 10 billion. For the first two trains, Freeport LNG already has signed 20-years liquefaction tolling agreements:[86]

- Train 1: 20-year liquefaction tolling agreement with Osaka Gas and Chubu Electric Power for 4.4 million tons per year
- Train 2: 20-year liquefaction tolling agreement with BP Energy for 4.4 million tons per year

For another pretty well developed liquefaction project (FERC permits are expected for 2013, export to FTA countries is already approved by DOE), Sempra's Cameron LNG terminal, development contracts with Mitsubishi, Mitsui and GDF Suez are in place, including mandatory negotiations of 20 years' worth of supply agreements based on pre-defined terms.[87]

4.2.1.5 Current and Future Developments

Given the quite distinct result of both, the EIA's and NERA's assessment (see above) of a generally positive impact on the US economy from LNG exports and in light of the very recent (May 2013) non-FTA export permit granted to Freeport LNG, there is little doubt that he US are becoming an important gas exporting future in the coming years. However, taking into account the impact this will have on consumer's welfare, it remains unclear at which pace and to which extent gas will be exported. It seems reasonable to assume that policy makers will try to limit the negative impact for consumers by trying to avoid ramping of exports too fast in order to avoid price spikes.

For the years 2012 and 2013, a strong decrease of the number of active gas rigs can be observed. At the same time, the number of active oil rigs has strongly increased. This seems due to the quite low gas prices while high oil-prices persist. One could argue that it is a rather gradual shift. Basically, when gas production is the focus of exploration efforts, the drier the gas, the better, as this limits treatments costs. With a constellation of high oil prices and low gas prices, the associated liquids may become a rather important part of a gas field's value proposition, which in effect could mean that wet gas plays are preferred. From this point, there seems to be only a minor step from gas production with associated liquids to oil production with associated gas. In the US, the shale gas boom seems to have become a shale oil boom. For the past years an annual growth rate of shale oil production of around 25% is observed.

If LNG exports lead to higher gas prices, it is obvious that there is a high probability that if a certain level is achieved, financial, technical and human resources may well be directed into (shale) gas exploration and production again. As already explained above, in its report of the impact of gas

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[86] Cf. Freeport LNG, http://www.freeportlng.com/Liquefaction_Project.asp

[87] Cf. Sempra LNG, http://cameron.sempralng.com/liquefaction.html and http://sempra.mediaroom.com/index.php?s=19080&item=127918

exports, the EIA expects a high level of resilience of the US gas market, in particular over the longer term.

The expectation of higher prices at the same time also leads to considerations which may lead to a renaissance of long-term contracts in the US market. As already described, the market is currently based on spot and short-term trading with usual contract durations below three years. Nevertheless, utilities do take measures to hedge against price increases or general price volatility, mainly by using financial instruments. As a report published by National Regulatory Research Institute shows[88], the topic is on the agenda of utilities and regulatory authorities. Despite the fact that currently long-term contracts are rather not used, it is discussed whether they could serve to protect consumers against potential price fluctuations because of LNG exports. The report observes that both, natural gas producers and utilities are interestedly looking into the possibility of using long-term gas supply contracts. Current arguments for long-term contracts also refer to stability of prices achieved by the shale gas production, leading to more trust into (the predictability of) the future market development and therefore easing the resistance against long-term contracts. In addition, gas producers may have interest in long-term contracts to ensure stable off-take volumes and cash-flows over a longer period. And also investors in for instance gas-fired power generation may have an interest to ensure availability of gas on pre-agreed terms.

As final consumer prices remain regulated in many States, Public Utility Commissions (PUC) play a major role in shaping the future development. In many cases there is no explicit PUC position in favor or against long-term contracts, but rather long-term contracts proposed by utilities are evaluated and approved on a case-by-case basis. Three PUCs already have set-up a framework actively promoting long-term contracts as a means to ensure stable consumer prices.

Given the various reasons for long-term contracts, it remains unclear how price-formulas will eventually look like. At the moment some form of hub-price indexations seems most likely. But hub-indexed contracts will not ensure low prices if the general market development is taking an upward direction. Here it will depend on specific clauses, e.g. floors and caps, etc. In particular, for power generators some form of indexation along power prices may be interesting.

4.2.2 **Conclusions US Gas Sector**

Based on our research we come to the conclusion that the US gas market is very much short-term oriented. Gas is sourced at a plethora of market centers or in OTC trades based on spot prices. Although there is a futures market, trading seems to get very illiquid beyond three years into the future. Actually, much of the forward trading is purely financial, providing rather hedges for the gas sources at or under spot prices. The whole gas sector focuses on Henry Hub (or one of the other

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[88] Costello, Ken, National Regulatory Research Institute, Survey Responses of State Utility Commissions on Long-Term Gas Contracting and Hedging, July 2012

market centers) as reference point for pricing. Due to the availability of liquid financial markets, market parties are able to hedge remaining price risks effectively.

There is no evidence of oil-indexed contracts playing a role in US gas price formation anymore. Wholesale prices are not regulated and also regulation of transmission tariffs could be described as light-handed, rather with competition determining transmission tariffs than the ceiling rate set by FERC.

Apart from commodity markets, long-term contracts seem to prevail where heavy infrastructure investments are required, i.e. for transmission pipelines where agreements concluded during open seasons usually have a duration of 10 years and more, and LNG terminals, where those export terminal projects which currently are comparably mature and where those details are known are typically backed up with 20 years supply and purchase agreements. It seems reasonable to assume that any other US LNG export contracts in place, or any to be expected for the future, will be rather similar in their nature, i.e. there are

- Annual fixed fees, already covering a quite large portion of the investment costs,
- Variable fixed fees per mmbtu covering liquefaction costs,
- Mark-up of the Henry Hub price.

For instance, the already mentioned Sabine Pass liquefaction terminal has a total annual capacity of 18 million tons for trains 1 to 4. The known supply agreements (see above figure) for the first four trains result in USD 2.273 billion fixed annual fees, while Cheniere reports a total EPC[89] price of USD 7.74 billion. Liquefaction costs are known to be in the range between USD 0.9 and 3 per mmbtu, therefore they should be covered by the agreed fixed fees.

With prospects of US gas prices increasing because of LNG exports, it seems though, as if long-term contracts could more attention in the US in future in order to ensure stable consumer prices – at least this topic seems to be on the agenda of Public Utility Commissions. However, based on our research we believe that whatever form these long-term contracts will take, there will be no return to oil-price indexation. In particular if the rationale for long-term contracts would be to lock in low gas prices, fixed prices would be the logical result.

4.2.3 Australian Gas Sector[90]

4.2.3.1 Structure of the Australian Gas Sector

The Australian gas market started to develop in the 1970ies, when larger gas reserves were discovered and gas production started. At present, the domestic annual demand for gas is in the vicinity of 35 to

[89] Engineering, Procurement, Construction

[90] The main research interest for Australia was the country's role as exporter of LNG. Therefore, the domestic Australian gas market is only briefly described in the following sections.

40 bcm[91], while roughly the same amount of gas is exported (with an increasing tendency of 3% p.a. expected for domestic demand and a strong increase of exports expected for the years to come).[92] The Australian gas sector is geographically segmented into three areas (North, West and East). Gas is transported through a transmission network of altogether more than 20,000 kilometers. The largest pipeline company, owning two thirds of the transmission company, is APA where Petronas was a major founding shareholder, but recently divested its 17.3% share. The second largest pipeline owner is Singapore power, indirectly holding a portfolio of several smaller transmission companies.

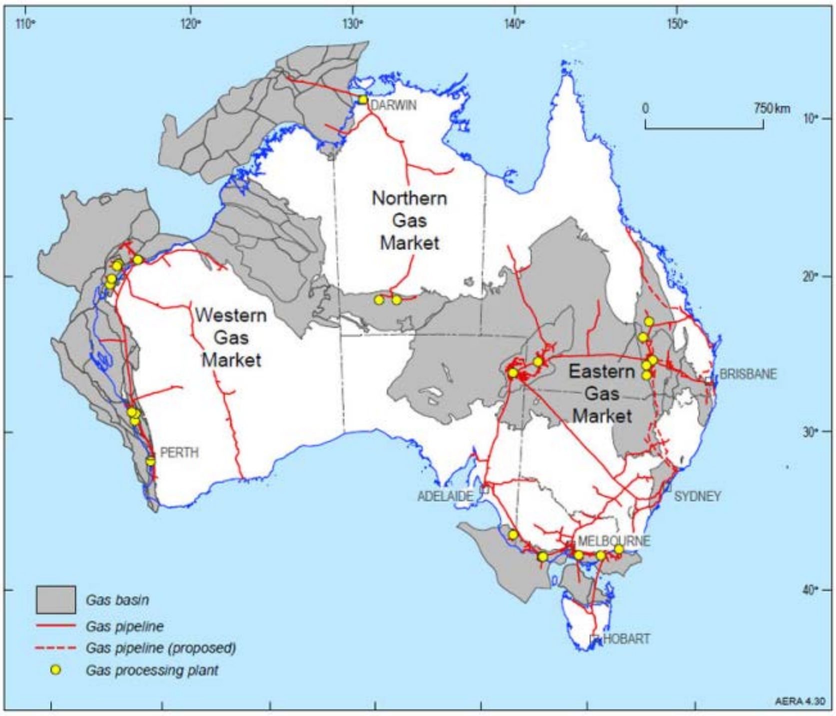

Figure 26: Australian gas basins and transmission network

Source: Geoscience Australia

Gas supply for the domestic market historically took place under confidential long-term contracts. The Australian Energy Regulator (AER) reports that in some parts of the country arising export opportunities put pressure on domestic prices as exporters have started to secure volumes to support their export contracts, partly also due to gas field developers falling back behind projected drilling targets.[93] The domestic markets are further impacted as the majority of traditionally used long-term contracts is due for renegotiation during the next five years, with higher pressure on prices to be

[91] Of which gas used as energy source in the liquefaction process has a significant share.

[92] Cf. Bureau of Resources and Energy Economics, Gas Market Report, July 2012

[93] Cf. Australian Energy Regulator, State of the Energy Market, 2012

expected. Over the last decade, wholesale spot markets emerged at several market hubs. According to the IGU, the prevailing pricing mechanism in Australia is market-based pricing (gas-on-gas-competition).[94]

For export, 3 LNG terminals are in operation, 7 more are under construction and 6 terminals are currently reported as planned.[95] Current export projects would provide an export volume of (only) 63 million tons in 2016/17, the terminals currently under consideration could increase the export capacity to over 100 million tons per year (more details are provided below).[96]

4.2.3.2 Regulation of the Australian Gas Sector

Transmission pipelines are not generally regulated. The Australian system distinguishes three types of pipelines:

- "Covered" (by the Natural Gas Law) pipelines under full open-access requirements, including (ex ante) regulated price-caps
- "Covered" pipelines under "light" regulation, requiring non-discriminatory open-access and applying price-monitoring
- Un-regulated pipelines only offering negotiated third-party access

A pipeline may be considered as a covered pipeline either subsequent the pipeline company applying for approval of its access regime by the regulator or by a third party applying for the pipeline to be regulated (with the final decision then taken by government). Light regulation is applied where the effort of a full regulatory regime including price-control may not be justified. During the last years, several pipelines were released from being covered and only one newly built pipeline is regulated.[97]

Apart from a legal requirement in Western Australia to reserve 15% of the production volume of new offshore LNG project for the domestic Western Australian market, gas can be traded and exported without specific restrictions.

4.2.3.3 New Infrastructure

As is already mentioned above, compared to the liquefaction capacities already under operation, there is significant new build of LNG terminals projected (6 plants) or already ongoing (7 plants). The new

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[94] Cf. IGU, Wholesale Gas Price Formation, June 2011, p. 38

[95] Global LNG Info, World's LNG Liquefaction Plants, January 2013, available at http://www.globallnginfo.com/World%20LNG%20Plants%20&%20Terminals.pdf

[96] Cf. Bureau of Resources and Energy Economics, Gas Market Report, July 2012

[97] Cf. Australian Energy Regulator, State of the Energy Market, 2012

LNG terminals are reported to be faced with severe problems with regards to soaring costs and subsequent delays, though (see below).

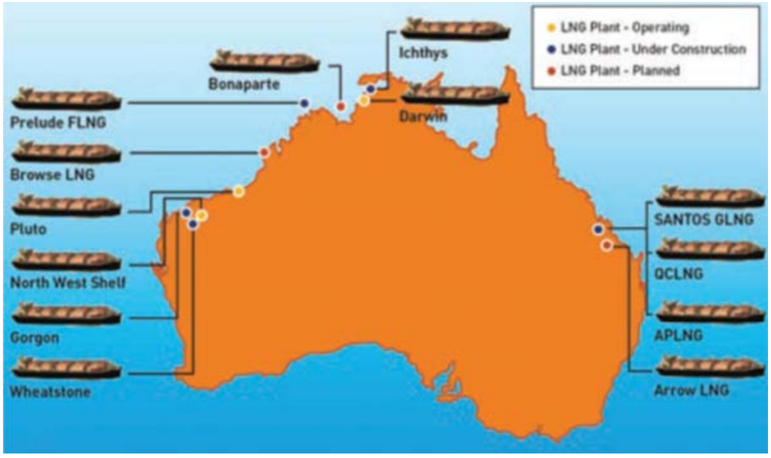

Figure 27: Australian LNG plants: Existing, planned and under construction[98]

Source: LNG Journal

Name	Owner(s)	Capacity (mtpa)	Cost (bn AUD)	Status
Darwin	Conocophillips, Eni, Inpex, Santos, TEPCO, Tokyo Gas	3.24	1.5[99]	Operational
North West Shelf	BHP Billiton, BP, Chevron, Japan Australia LNG , Shell, Woodside	16.3	50	Operational
Pluto	Woodside, Tokyo Gas, Kansai Electric	4.3	15.3	Operational
Arrow LNG	Petrochina, Shell	16		Planned
Australia Pacific LNG	Conocophillips, Origin, Sinopec	9	24.7	Under Construction
Bonaparte LNG	Santos, GDF Suez	2		Planned
Browse LNG	Woodside	12	50	On Hold
Fisherman’s Landing LNG	LNG Ltd			Planned
Gladstone LNG	Santos, Petronas, Total,	7.8	18.5	Under Construction

[98] Three more projects which are reported as planned by Global LNG Info (as of January 2013) are not included in the map, Fisherman’s Landing in Northeastern Queensland, Sunrise off the Northern coast, and Scarborough off the Northwestern coast.

[99] 2005 AUD

	KOGAS			
Gorgon LNG	Chevron, Exxon, Shell, Osaka Gas, Tokyo Gas, Chubu Electric	15	52	Under Construction
Ichthys LNG	Inpex, Total, Osaka Gas, Toho Gas	8.4	34	Under Construction
Prelude FLNG	Shell, KOGAS, Inpex	3.6	11-12	Under Construction
Queensland Curtis LNG	BG Group	8.5	20.4	Under Construction
Scarborough LNG	Exxon, BHP Billiton	6.6-7.7	18-24	Planned
Sunrise LNG	Woodside, Conocophillips, Shell Osaka Gas			Planned
Wheatstone LNG	Chevron, Shell, Apache	8.9	29	Under Construction

Table 3: Australian LNG Plants: Existing, planned and under construction

Source: Various sources[100]

4.2.3.4 Australia as a Gas Exporting Country

Australian LNG exports are directed mainly to Asian countries. There, prices are dominantly based on oil-price indexation.[101] In particular exports to Japan are known to be priced in accordance with the development of Japanese oil import prices. In many cases a so-called S-curve is applied, which leads to somewhat higher gas prices when oil prices are low and softens the impact of strong oil-price increases.[102]

LNG exports are taking place – where such information is known – under long-term contracts.[103] For example Chubu Electric (Japan) is known to have contracted a supply from Chevron's Wheatstone terminal (still under construction) for 20 years. Japanese demand has been the basis for Australian

[100] http://www.globallnginfo.com/World%20LNG%20Plants%20&%20Terminals.pdf, http://www.theaustralian.com.au/national-affairs/high-costs-kill-off-woodsides-50bn-browse-lng-plant/story-fn59niix-1226619543660, http://www.reuters.com/article/2013/04/02/us-exxon-bhp-lng-idUSBRE9310C920130402, http://www.rigzone.com/news/oil_gas/a/122878/LNG_Ltd_Fishermans_Landing_Costs_Remain_on_Budget_at_11B, http://abarrelfull.wikidot.com/lng-terminals-in-australia as well as various company websites

[101] Cf. Chen, Michael Xiaobao, Gas Pricing in China, in: Stern, Jonathan (Ed.), The Pricing of Internationally Traded Gas, Oxford, 2012

[102] However, this may change in the future. As will be explained further below, global market dynamics put severe pressure on oil-indexation also in Asia-Pacific and thus would also affect gas exports from Australia.

[103] It seems to be fair assumption that in general long-term contracts are backing up the investments in liquefaction plants.

LNG exports for more than 20 years. It is reported that companies Woodside Petroleum, Shell and Chevron have contracts with 10 Japanese utilities. [104] Apart from long-term supply contracts, companies from LNG importing countries take a substantial stake in the new LNG plants in Australia (together with domestic and large internationally active companies):

- The new Ichthys terminal with a planned output of 8.4 million tons per year is owned by Inpex together with Total, Tokyo Gas, Osaka Gas, Chubu Electric and Toho Gas
- Kogas and Petronas participate in the Gladstone project (planned production capacity of 10 million tons per year)
- Sinopec is one of the shareholders of the Australia Pacific LNG terminal with a planned output of 9 million tons per year
- The planned Arrow project with a planned output capacity of up to 18 million tons per year is partly owned by Petro China

Apart from taking stakes in the liquefaction step of the value chain, companies from LNG importing countries also take an interest in the production side, as the following table shows:

[104] Cf. LNG Journal, Asian LNG market set for overhaul for Australian and American volumes, May 2012

COMPANY	CARNARVON (WA)	BROWSE (WA)	PERTH (WA)	BONAPARTE (WA/ NT)	AMADEUS (NT)	SURAT-BOWEN (QLD)	COOPER (SA/QLD)	CLARENCE MORTON (QLD/NSW)	GUNNEDAH (NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	HUNTER (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	36.9															19.1
Shell	17.2	14.8				8.9										13.2
ExxonMobil	14.1												45.7			8.6
BG						25.6										7.1
Inpex		55.4		2.1												6.9
Woodside	11.4															5.9
Origin			63.7			13.0	12.9							37.1	42.5	4.1
Total		23.4				3.7										3.9
Santos	1.1			2.1	89.2	4.6	64.3		80.0				5.3	16.6		3.8
ConocoPhillips				10.4		12.6										3.6
BHPB	3.8												45.7	15.2		3.4
PetroChina						9.8										2.7
Sinopec						8.4										2.3
BP	4.2															2.2
Apache	3.6															1.9
MIMI	3.1															1.6
AGL						3.1				100.0	100.0	100.0				1.5
Petronas						3.7										1.0
CNOOC	1.1					1.2										0.9
Kogas		2.2				2.0										0.8
Eni				83.8												0.7
Kufpec	1.1															0.6
Osaka Gas	0.7	0.9														0.5
Mitsui						1.1								6.5		0.3
Metgasco								96.2								0.3
Beach							20.3							0.1		0.3
EnergyAustralia									20.0							0.2
Kansai Electric	0.4															0.2
Toyota Tsusho						0.5								2.8	11.3	0.2
Nexus													3.3			0.1
Benaris														15.3		0.1
AWE			36.3											6.5	46.3	0.1
Other	1.3	3.3		1.6	10.8	1.8	2.5	3.8								1.7
TOTAL (PETAJOULES)	72 456	17 384	41	1123	138	39 055	1758	445	1426	669	142	142	4124	847	249	139 998

Notes:
Based on 2P reserves at August 2012.
Not all minority owners are listed.
Source: EnergyQuest 2012 (unpublished data).

Table 4: Market shares in proved and provable gas reserves Australia

Source: EnergyQuest, taken from: Australian Energy Regulator, State of the Energy Market, 2012

4.2.3.5 Current and Future Developments

Many gas plays under development are ridden with technical challenges, either because they are deepwater offshore gas fields or unconventional gas fields such as coalbed methane. In addition, many of the new gas plays are neither connected to the existing pipeline system nor to an existing LNG terminal. As in particular LNG export promised a good value proposition, many of the new gas plays are planned to provide gas directly intended for liquefaction and export. Thereby, for offshore developments, not even an onshore connection may be planned, using floating liquefaction vessels instead.[105] Subsequent to the often technically very challenging exploration and liquefaction projects, many Australian LNG projects are experiencing difficulties to remain within originally planned budget limits. In April 2013 it became known that for instance Woodside decided to put its Browse project (off the Northwestern coast) on hold because – according to Woodside – price increases were resulting in the project to have lost commercial feasibility. It is reported that originally planned costs of

[105] As is for example planned for Shell's (together with KOGAS and Inpex) Prelude project off the Northwestern coast of Australia.

AUD 30 billion had increased to at least AUD 50 billion.[106] Though not yet officially put on hold, other Australian LNG projects are reported to face similar problems.

We did find only little evidence with regards to export contracts from the new LNG terminals. Apart from the vertical integration and the participation of oil&gas majors, long-term contracts are used to back-up the investments. As is shown further below in sections 4.2.5.3 and 4.2.7.3, there are several long-term contracts with Japanese and Chinese buyers, mostly in the range of 20 years but also with durations of up to 25 years. Existing contracts will also be a major driver for some projects to go ahead despite soaring cost. With regard to pricing, there is no evidence that the traditionally used principle of oil-indexation has yet been given up (whilst there is also no proof of the opposite). With the US emerging as supplier for the Asia-Pacific region using Henry Hub as price reference and with the development away from oil-indexation in Europe, buyers from Asia-Pacific seem to be keen on moving away from oil-indexation as well (as is also discussed below in the sections on Japan and China). Taking into account competing gas supplies to the Asia-Pacific region not only from US but also from Russia and new gas plays in Eastern Africa, it may be concluded that oil-indexed pricing will come under considerable pressure,[107] affecting LNG exports from Australian terminals. If there will be general change of pricing in the Asia-Pacific region, Australian producers will (have to) move along.

4.2.4 Conclusions Australian Gas Sector

In Australia it can be observed that with regard to LNG exports, long-term contractual relationships seem to prevail. Apart from formal supply contracts, many companies of Australia's customer countries take a step further and took a stake mainly in production and liquefactions, thereby vertically integrating important parts of the value chain. Such a form of vertical integration can be considered as an even stronger bond than long-term contractual relationships. LNG customers may take a higher financial burden in order to achieve a higher level of security of supply while at the same time also hedging against price increases.

In many cases, oil-indexation still seems to be the prevailing pricing mechanism. However, known pricing details are very thin and do not justify a general assumption. Many LNG export projects have come under considerable pressure from cost inflations. Together with a potential move away from oil-indexation, this may dampen the outlook for the Australian gas sector.

[106] Cf. The Australian, High cost kill off Woddside's $50bn Browse LNG plant, April 13, 2013, available at http://www.theaustralian.com.au/national-affairs/high-costs-kill-off-woodsides-50bn-browse-lng-plant/story-fn59niix-1226619543660

[107] Cf. The Sydney Morning Herald, LNG execs looking for scapegoat, November 19, 2012, available at http://www.smh.com.au/business/lng-execs-looking-for-a-scapegoat-20121119-29ldz.html

4.2.5 Japanese Gas Sector

4.2.5.1 Overview

Demand and Supply

Japan was traditionally the largest natural gas-consuming market in Asia-Pacific, only recently overtaken by China. The power sector represents the biggest share (approx. 65% in 2011) of the total natural gas demand and companies operating gas-fired power plants dominate the LNG imports. Before Fukushima approx. 18% of Japan´s energy requirements were met using natural gas. Points of demand are centered on major metropolitan areas (as mountain areas account a large proportion of the national land). Before the Fukushima accident, Japan was considered a quite mature natural gas market. The outlook for the market and demand in Japan heavily depends now on the political position on nuclear power. It is expected that natural gas demand will increase considerably in the medium-term requiring significant infrastructure investments.

As Japan has a very limited domestic production approx. 90% of the country´s natural gas needs are imported from various countries, such as Southeast Asia, Australia, Qatar, and Russia etc. Given the island nature of the country´s geographical location and the lack of pipeline connections to other markets, the import takes the form of LNG which makes Japan the largest LNG-importing economy in the world.

Market Structure

The Japanese natural gas market has a considerable number of LNG importers (seven power companies, eight gas companies and several industrial importers), however the import is dominated by the four major utilities (Tokyo Gas, Tepco, Osaka Gas and Chubu Electric) importing approx. 68% of total LNG deliveries in 2012. Beside their dominance on the import side the major utilities also handle regional monopolies in the distribution and sales operation. The approx. 200 local (small and medium sized) gas utilities active in selling natural gas to end consumers have limited market power, as these companies purchase their gas from the larger gas and power companies importing LNG. Trading activities are limited by the high degree of vertical integration within the market. Remaining trading activities are largely bilateral. In the retail market natural gas is traded on the basis of a contract between the consumer and the private gas company, with a gas fee regulated by the Gas Business Act and other related laws.

In line with the traditional focus of government policy on energy supply security the Japanese government is actively involved in the supply of natural gas at almost every level of the value chain. The upstream development is, for example, carried out by a state-owned company (JOGMEC). The de facto nationalization (for ten years initially) of the power company Tepco, which is a considerable LNG importer for its power plants, strengthens also the public involvement in the natural gas sector.

According to the Japanese government an LNG futures market will be created setting a price based on supply/demand factors. Listing on a commodity exchange should start as early as April 2014.

Gas Infrastructure

The gas infrastructure has been developed by each local gas utility independently, which resulted in a less developed, very limited infrastructure with gas pipelines that interconnect major cities and LNG terminals. This leads in fact to a situation that gas cannot be transported over boundaries between regions.

The Japanese natural gas transport and distribution infrastructure is owned and operated by vertically integrated gas and power companies. Although a functional unbundling is required, legal unbundling is not an obligation. Therefore regulation has limited effect on separating decision-making for transport and sales. General gas utilities and pipeline service providers have an obligation to grant access to their pipelines to third party gas suppliers since 2004. Access to natural gas infrastructure is organized on a contractual basis between the parties. Each pipeline owner is required to put in place its own set of transportation service terms and conditions for use with any third-party access. Due to relatively high third-party usage fees, however, third party usage of pipelines seems uncommon.

Due to its geological conditions Japan disposes only of limited underground storage facilities.

4.2.5.2 Import Infrastructure

The following table summarizes the existing and planned LNG receiving terminals in Japan.

Terminal	Investor(s)	Send out capacity (Bcm/y)	Start-up
Negishi	Tokyo Electric, Tokyo Gas	15.64	1969
Senboku 1	Osaka Gas	2.94	1972
Sodegaura	Tokyo Electric, Tokyo Gas	41.60	1973
Chita Kyodo	Chubu Electric, Toho Gas	9.74	1978
Senboku 2	Osaka Gas	15.70	1977
Tobata	Kitakyusyu LNG	10.28	1977
Himeji LNG	Kansai Electric	11.00	1979
Chita	Chita LNG	14.78	1983
Higashi Niigata	Nihonkai LNG	11.60	1984
Higashi Ogishima	Tokyo Electric	18.00	1984
Himeji	Osaka Gas	6.40	1984
Futtu	Tokyo Electric	26.00	1985
Yokkaichi LNG Center	Chubu electric	8.68	1988
Yanai	Chugoku Electric	3.10	1990
Oita	Oita LNG	6.27	1990
Yokkaichi	Toho Gas	2.00	1991
Fukuoka	Saibu Gas	1.10	1993

Sodeshi	Shimizu LNG	3.90	1996
Hatsukaichi	Hiroshima Gas	1.15	1996
Kagoshima	Nihon Gas	0.30	1996
Kawagoe	Chubu Electric	6.69	1997
Ogishima	Tokyo Gas	12.40	1998
Chita Midorihama	Toho Gas	9.20	2001
Nagasaki	Saibu Gas	0.20	2003
Sakai	Sakai LNG	8.70	2006
Mizushima	Chugoku electric, Nippon Oil	1.30	2006
Sakaide	Sakaide LNG	1.64	2010
Joetsu	Chubu Electric	2.50	2011
Total		**252.57**	

Table 5: Existing LNG receiving terminals in 2011

Source: IEEJ, Natural gas situation and LNG supply/demand trends in Asia Pacific and Atlantic markets, January 2010, Tokyo Gas Investors´ Guide 2012;GIIGNL, The LNG Industry in 2011

The first LNG terminal was built jointly by Tokyo Electric and Tokyo Gas in 1969, followed by several other LNG investments in a short time. At the beginning investments were mainly carried out by the big power utilities.

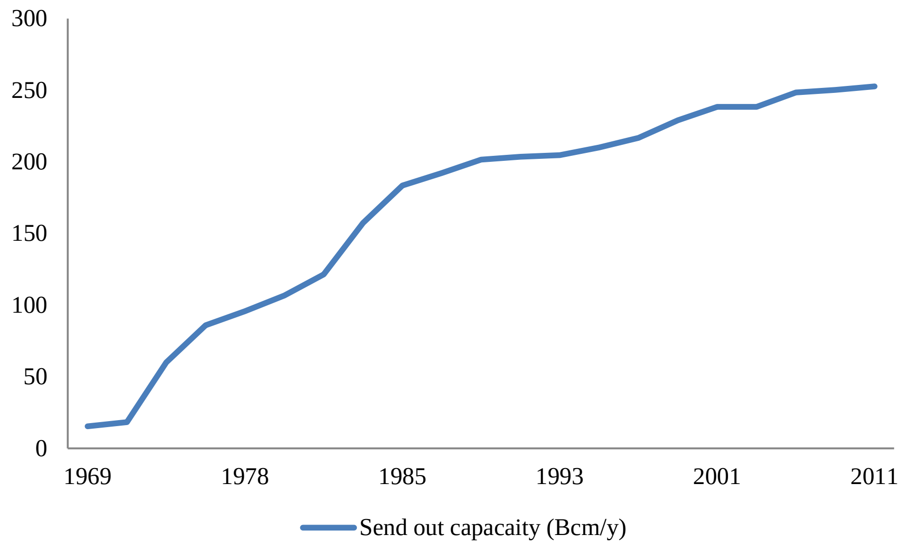

Figure 28: Send out capacity of LNG terminals

Source: IEEJ, Natural gas situation and LNG supply/demand trends in Asia Pacific and Atlantic markets, January 2010

The LNG import capacity increased rapidly by exceeding a total send out capacity of 100 bcm by 1979 which again doubled in the following ten years. The growth in the number of LNG terminals particularly marked between 1972 and 1985 slowed down at the end of 80s and picked up speed slowly after 1997. In order to meet expanding demand several new LNG terminals are in the planning stage or under construction at the moment, as shown in the following table.

Terminal	**Investor(s)**	**Start-up**[108]
Yoshinoura	Okinawa Electric	2012
Joetsu	Chubu Electric, Tohoku[109]	2012
Ishikari	Hokkaido LNG[110]	2012
Naoetsu	INPEX	2014
Hibiki	Hibiki LNG	2014
Hitachi	Tokyo Gas	2015
Hachinohe	JX Nippon Oil & Energy	2015
Shinsendai	Tohoku	2016
Toyama Shinminato	Hokuriku Electric Power	2018
Wakayama	Kansai Electric	2022

Table 6: LNG receiving terminals in the planning stage or under construction (at the end of 2012)

Source: IEEJ, Natural gas situation and LNG supply/demand trends in Asia Pacific and Atlantic markets, January 2010 and Tokyo Gas, Investors´ Guide 2012

In order to ensure flexibility Japan´s annual import capacity of around 250 bcm significantly exceeds the current level of national natural gas consumption (as of 123 bcm in 2011),. In case all planned terminals come into operation, Japan´s total receiving capacity will be increased by almost 25% by the end of 2022.

LNG re-gasification facilities are owned mainly by electric and gas utilities. The ownership structure of LNG terminals shows a fairly high concentration: The three biggest operators dispose approx. of 56% of the send-out capacity, while the top eight companies control more than 85% of the send-out capacity.

There is no mandatory functional unbundling for LNG infrastructure. The revised Gas Utility Law foresees third-party access to LNG terminals and access to LNG facilities should be organized on a contractual basis between the parties. However, the establishment of third-party access at LNG import

[108] Expected commencement of operation as of at the end of 2012

[109] Total capacity of Chubu Electric: 540 thousand kl, total capacity of Tohoku: 240 thousand kl

[110] Hokkaido Gas and 8 gas firms in Hokkaido

terminals has been proven to be difficult, as these are developed to fit an importer´s specific supply portfolio and subsequently the sales portfolio requirements in the hinterland.

4.2.5.3 Import Gas Delivery – Negotiated Contracts between Producers and Wholesale

Total LNG import in 2012 accounted to 83.18 million tons. Similar to the infrastructure side, the import is also dominated by the big electric and gas utilities. The four biggest companies (Tepco, Chubu Electric Power, Tokyo Gas and Osaka Gas) represent almost 70 % of the total LNG imports into the Japanese market and only 14% of national demand was covered by other players in 2012.

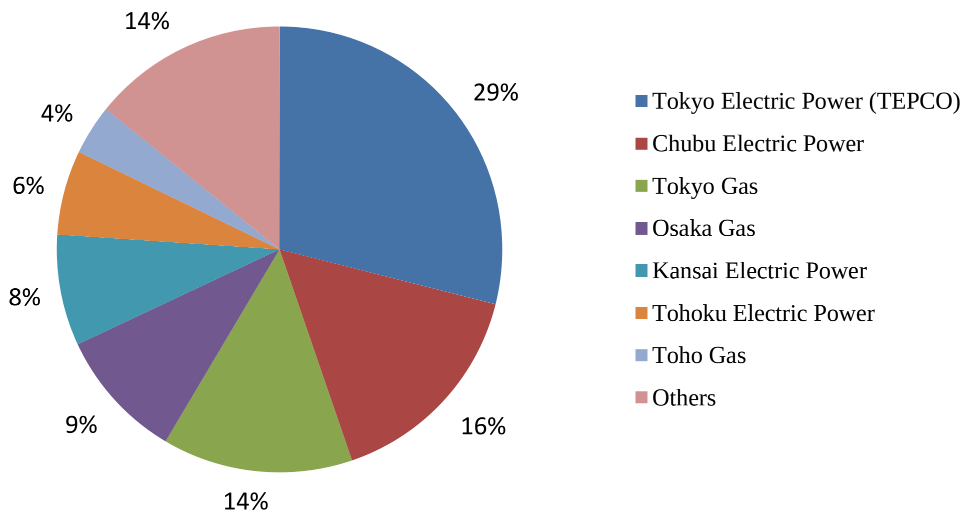

Figure 29: Japanese LNG import by utilities in 2012

Source: Tokyo Gas, Investors´ Guide 2012

Due to the relatively high number of LNG importers coupled with the nevertheless high concentration on the import market, henceforward we will assess LNG import into Japan by analyzing the import activities of three of the main importers (Tepco, Tokyo Electric and Osaka Gas) covering more than 50% of Japan´s LNG need. It is important to note that as the selected companies, similar to other big players in the Japanese gas market, are vertically integrated, their production, LNG procurement, transport, supply and sale activities often belong to the same business unit, resulting in a limited number of publicly available information with regard to import contracts.

Tepco after developing the first LNG terminal in Japan was the first company importing LNG into the Japanese market in 1969. Currently, Tepco imports LNG from 9 LNG projects to cover the fuel supply of about 70% of the company´s total thermal power generation. Previously Tepco also sold part of the imported natural gas on the wholesale market, however since 2008 the company´s import activities solely aim to secure fuel supply for own power production. Tokyo Gas imports more than 11 million tons of LNG per year from 11 projects in six countries based on long-term contracts. The Osaka Gas procured 7,980 thousand tons of LNG in 2012.

Contract duration – Long-Term vs. Short-Term

Currently Japan imports LNG mainly under long-term contracts and only a smaller part of the country´s LNG demand is covered on spot and short-term contract basis. Japan´s existing long-term LNG contracts date from the 1970s and 1980s, and are set to expire over the next decade, providing importers with the opportunity to renegotiate the terms of the supply agreements. The contract information for the three companies selected for a more detailed assessment are provided in the following table. Only the basic data for these contracts is known whereas information on volume flexibility, e.g. take-or-pay levels, re-opening clauses and pricing details was not found.

Project * **	Importer	Quantity (mtpa)	Period (years)	First shipment	Expiration	Contract type
Brunei	Tokyo Gas	1,24	20 +20	1972	2013	Ex-Ship
Brunei	Osaka Gas	0,74	20 + 20	1972	2013	
Brunei	Tepco	4.03 (2.03)	20 + 20 +10	1973	2023	
Das	Tepco	4,3	17 + 25	1977	2019	
Malaysia I	Tokyo Gas	2,6	20 + 15	1983	2018	Ex-Ship, FOB
Satu	Tepco	4,8	20 +15	1983	2018	Ex-Ship, FOB
NWS	Tokyo Gas	0,53	20 + 8	1989	2016	Ex-Ship
Bontang	Osaka Gas	1,27	19	1994	2013	
Indonesia	Tokyo Gas	0,92	20	1994	2013	FOB
Malaysia II	Tokyo Gas	0,8	20	1995	2015	Ex-Ship
Malaysia II	Osaka Gas	0,6	20	1995	2015	
Bontang	Osaka Gas	0.4	19	1996	2015	
Qatar	Tokyo Gas	0,35	25	1997	2021	Ex-Ship
Qatar	Osaka Gas	0,35	23	1998	2021	
Qatar	Tepco	0.2 + 0.8	25 + 10	1999	2021	
Bontang	Osaka Gas	3.00	11 + 9	2000	2020	
Oman	Osaka Gas	0,66	24	2000	2024	
NWS	Osaka Gas	1	30	2004	2034	
NWS	Tokyo Gas	1.073	25	2004	2029	FOB
Malaysia III	Tokyo Gas	0,34	20	2004	2024	Ex-Ship, FOB
Darwin	Tepco	2	17	2006	2022	FOB

Darwin	Tokyo Gas	1	17	2006	2022	FOB
Malaysia III	Osaka Gas	0,12	18	2006	2024	
Qualhat	Tepco	0.8	15	2006	2020	
Sakhalin II	Osaka Gas	0,2	23	2008	2031	
not specified	Tepco	0,3	8	2009	2017	
NWS	Osaka Gas	0,5	6	2009	2015	
Malaysia	Osaka Gas	0,8	15	2009	2024	
Qualhat	Osaka Gas	0,8	16	2009	2025	
Sakhalin II	Tepco	1,5	22	2009	2029	
Sakhalin II	Tokyo Gas	1,1	24	2009	2031	FOB
Pluto	Tokyo Gas	1.5-1.75	15	2012		Ex-Ship, FOB
Brunei	Tokyo Gas	1	10	2013		Ex-Ship
Papua New Guinea	Osaka Gas	1,5	20	2013	2033	
Papua New Guinea	Tepco	1,8	20	2013-2014		
Gorgon	Osaka Gas	1.375	25	2014	2039	
Gorgon	Tokyo Gas	1,1	25	2014		FOB
QC LNG	Tokyo Gas	1,2	20	2015		Ex-Ship
Ichthys	Osaka Gas	0,8	15	2017	2032	
Ichthys	Tepco	1,05	15	2017	2031	
QC LNG	Tokyo Gas	1,05	15	2017		FOB
Wheatstone	Tepco	3,1	20	2017	2037	
Wheatstone	Tepco	0,7	20	2017	2037	
Wheatstone	Tepco	0,4	20	2017	2037	
Cove Point LNG	Tokyo Gas	2,3	20	2017	2037	na
Cameron LNG	Tepco	2	20	na		

* Blue text indicates that delivery has not yet been started.

** Text highlighted in green indicates that the importer is taking part in the investment project by acquiring a minority stake.

Table 7: Long-term LNG contracts of the three main LNG importers subject to assessment

Source: Company Data

The first LNG imports were concluded between large Japanese vertically integrated gas and power companies with the aim to secure the supply of their end consumers and LNG operators aiming at safe recovery of the investment through off-take commitments. It was the interest of both parties to establish long-term and stable relationships taking the form of long-term import contracts.

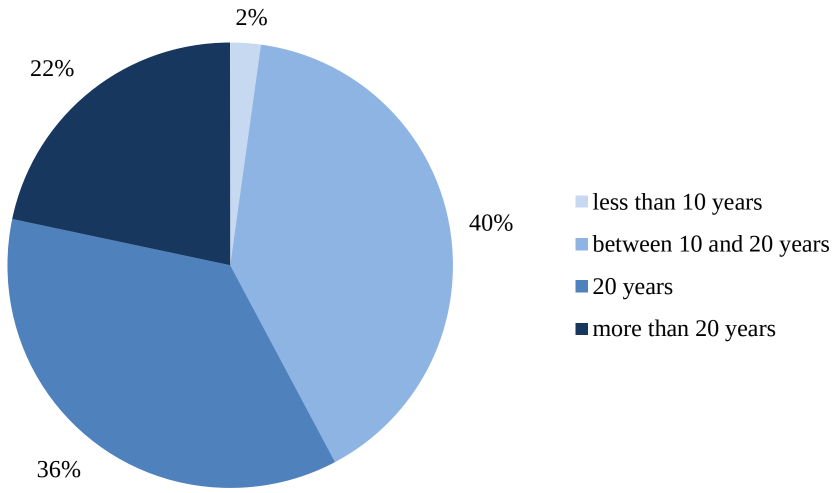

Figure 30: LNG contract duration

Source: Company Data

Because of the high degree of import dependence Security of supply has always been top priority in the Japanese energy policy and due to the expansion of global energy demand long-term stable supply remains a key driver for utilities when establishing contractual terms. The concern on stable resource supply explains that companies continue to secure LNG volumes under long-term contracts. Certainty on meeting the obligations toward end customers is especially crucial for providers of city gas, obliged by the law to supply gas safely throughout their districts.

Due to security of supply consideration, as explained by market experts and also communicated by Tokyo Gas in its mid- and long-term planning, long-term contracts will remain the main bulk of supply and long-term duration will remain the preferred basis for gas procurement. The main part of the recently concluded deals by Osaka Gas, Tepco and Tokyo Gas are 20-year import contracts and even the shortest contracts have duration of 15 years. This implicates that with respect to durations of long-term contracts, no shift towards shorter durations can be observed.

However, in addition to the persistence of long-term contracts, the share of gas purchased under short-term contracts (including spot) in the import portfolio is increasing.

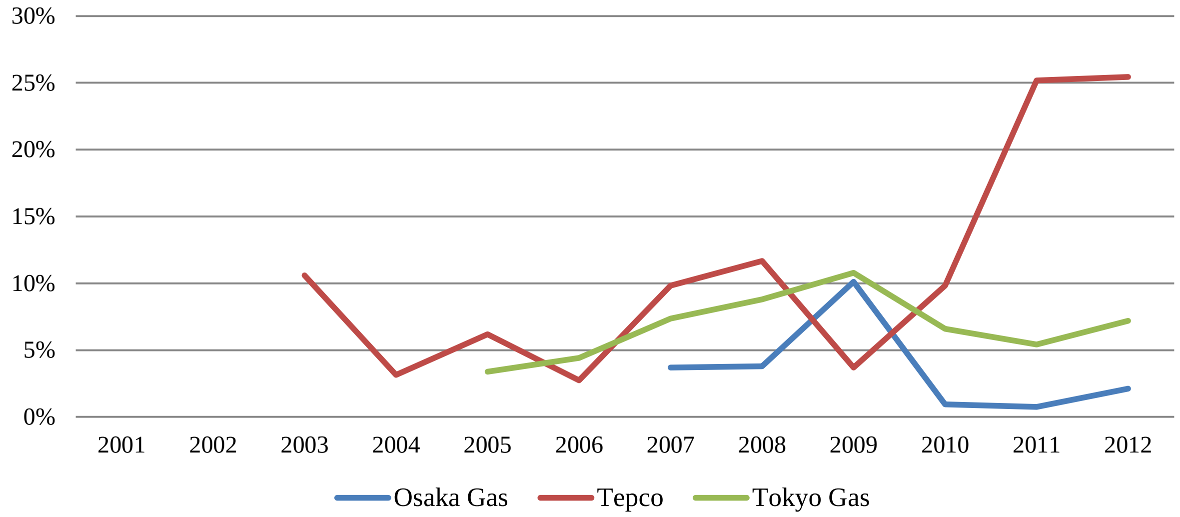

Figure 31: Share of short-term/spot contracts in the purchase portfolio

Source: Company Data

As shown in the above figure, big importers started to purchase LNG under short-term contracts only during the last decade. Short-term contracts reached relatively rapidly a share between 5 and 10% in the purchase portfolio. The hike between 2008 and 2009 can be assumed to be driven by the shale gas boom in the United States leading to a significant amount of cargos available for relatively low prices on the LNG spot market. Short-term contracts are mainly driven by the fluctuations in demand as they increase the companies´ flexibility. Besides that, the share of short-term contracts in the supply portfolio is also a strategic decision of a company. According to official company communication, despite having the bulk of their supply under long-term contracts, importers aim to contract more LNG under medium- and short-term basis or procure it on the spot market in the future as well. Tepco already purchases 25% of the imported LNG on the spot market and Osaka Gas also targets to increase the share of medium- and short-term contracts in its portfolio in the near future.

Based on these observations it can be concluded that whilst importers are (still) relying on long-term contracts of 15 and more years to procure the bulk of their demand, short-term contracts (including) spot will have an increasing role in providing flexibility to react on changes in demand and supply. With short-term contracts having a substantial share in the importers' portfolios which can easily be in the 25% range, spot and short-term trading is certainly not only used at the margin anymore .

The assessment of the importers´ procurement strategy revealed a further important trend. As indicated in the table 13 with the green color, utilities do not only secure gas supply by concluding long-term contracts with developers of new upstream infrastructure but also take stakes in these investment projects. This development is further investigated in chapter 3.2.3.4.

LNG prices

Traditionally, Japanese LNG long-term supply contracts use oil-indexation. As the main alternative fuel to natural gas used to be oil and its price was rather stable, the first LNG volumes were purchased under oil-fixed prices. After the second oil shock in 1980 most LNG contracts applied the Government Selling Price ("GSP") as an index in the pricing formula. In the 1990s, the generally low oil price environment led to the introduction of the so-called S-curve pricing mechanism. The LNG price development in Japan is demonstrated through the example of two main importers. The figure below shows the average LNG prices paid by Tokyo Gas and Osaka Gas compared to JCC[111] during the period from 2005 to 2012.

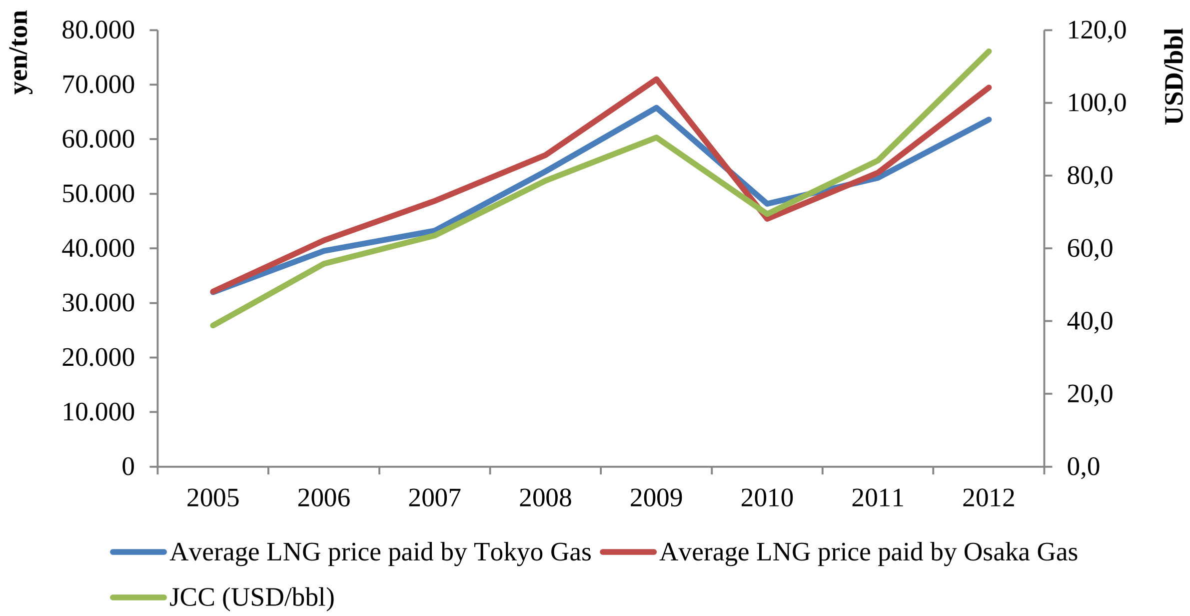

Figure 32: Average LNG prices

Source: Company Data

Due to the vertically integration of the companies the amount of publicly available information on the pricing structure of import contracts is limited. According to Tokyo Gas´ communication the company pays oil-related prices for the imported LNG. Based on our assessment and as indicated by Figure 32 we assume that Osaka Gas also imports LNG under oil-indexed long-term contracts.

Traditionally, Japanese gas and power utilities have paid for their LNG imports more than European and North American buyers. Historically, this was mainly due to their traditional preoccupation with

[111] JCC (Japan customs-cleared crude) is the average import price for crude oil in Japan published by the government, sometimes referred to as Japanese Crude Cocktail. In many newer LNG contracts, JCC is used instead of GSP.

supply security and the ability to pass the costs of added security on to their customers as Japanese end user prices have been regulated on a cost plus basis. Japan´s LNG import prices ranged between USD 15 and 18.11/MMBtu in 2012 and were at a level of USD 14.53/MMBtu in April 2013.[112]

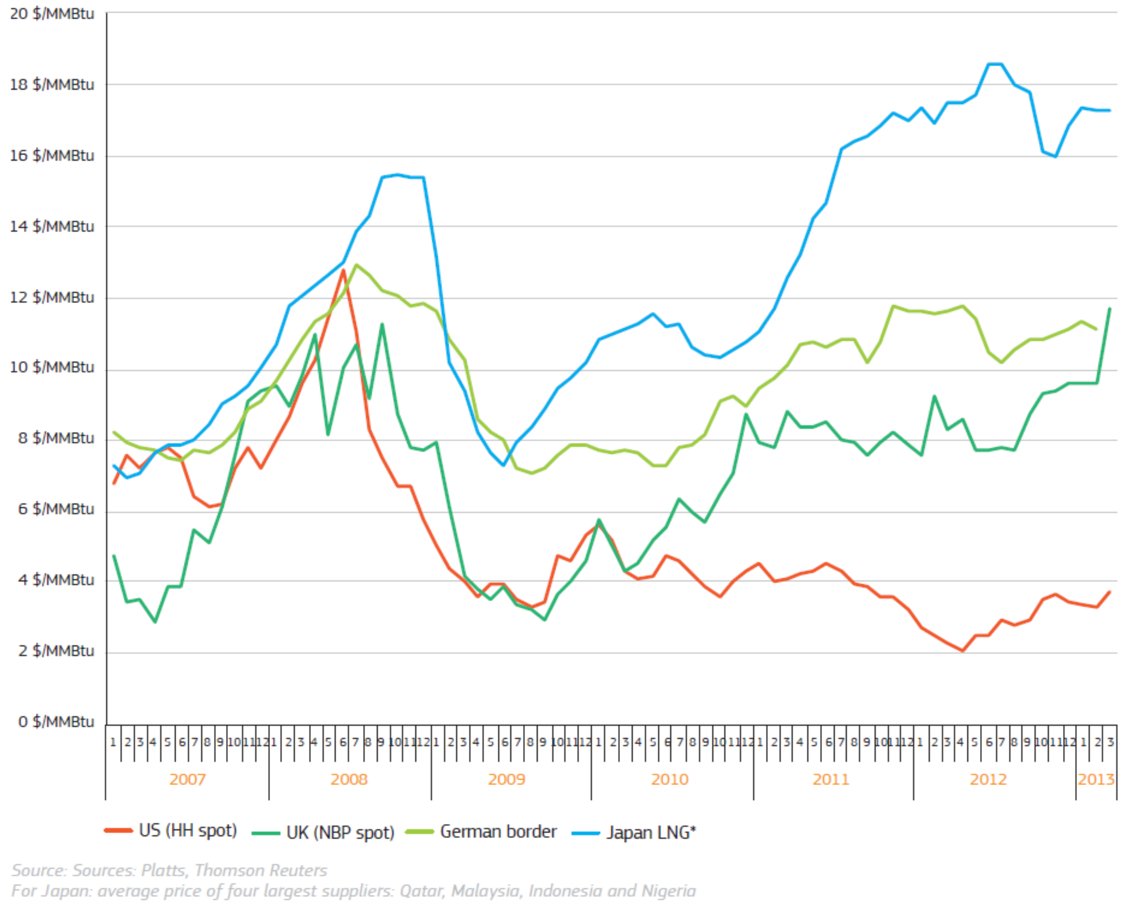

Figure 33: International comparison of wholesale gas prices

Source: Market Observatory for Energy, Quarterly Report on European Gas Markets, Q1 2013

The price level of LNG into Japan has always been above the US and EU spot prices, however the development of wholesale gas prices in these regions showed a convergence over the last five years until 2011 when the shale gas boom in the US kept down prices on the domestic market and prices in the EU and Japan started to evolve independently from the US prices. Since, the spread between wholesale prices in Japan and the EU and US increased significantly. In 2013, Japanese LNG buyers paid almost four times the spot prices in the US and around 140% of the NBP spot price.

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112 http://ycharts.com/indicators/japan_liquefied_natural_gas_import_price

The price difference is mainly caused by the different pricing structure: while Japan buys the main part of LNG under oil-indexed prices, the natural gas contracts in the US are linked to Henry Hub prices. And as over the past 10 years, the price of crude oil almost quadrupled whereas the prices at Henry Hub fell by about a third, LNG cargoes are sold in Asia four times higher than the US benchmark price. As minimizing purchase costs is high on the agenda of the importers the focus is now on lowering prices towards European and United States´ price levels. Japanese gas importers, including Kansai Electric Power, Tokyo Gas and Osaka Gas are trying to move away from oil-linked prices in order to reduce their costs.

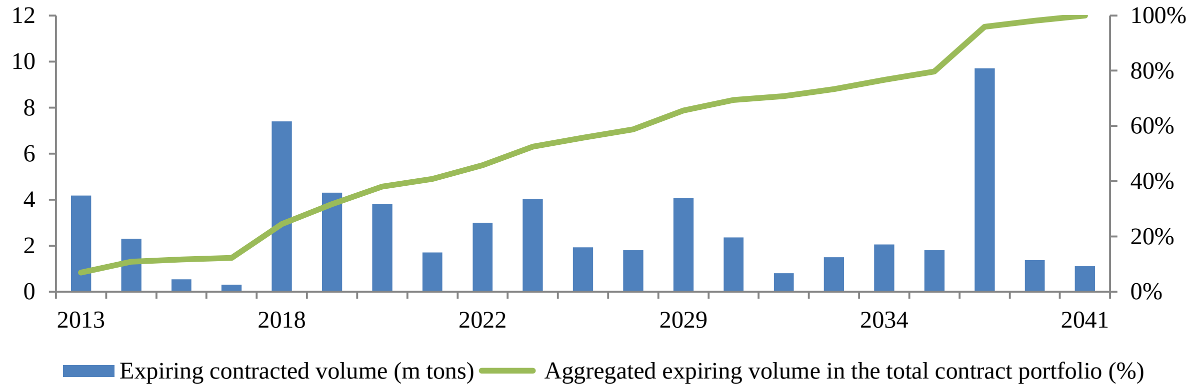

Figure 34: Expiration of contracted volumes

As shown in the figure above, almost 40% of the LNG volumes under contract today will expire by the end of this decade and Japan will have only one quarter of its LNG need of today covered under contracts by the end of 2030. The expiration of significant part of old oil-indexed contracts gives importers the possibility to renegotiate the terms and conditions. The focus of the negotiations will probably remain on new pricing structures other than oil-indexation, take-or-pay obligations and volume flexibility.

In addition to adapting the terms of existing long-term contracts at the time of expiry importers try to contract new LNG volumes under hub-based pricing. Tepco (through intermediaries Mitsui and Mitsubishi) has just managed to link the gas price of a contract recently signed with Cameron LNG to Henry Hub gas price rather than the price of oil.[113]

4.2.5.4 Overseas Natural Gas Upstream Investments

Osaka Gas was among the first "pioneers" participating in overseas upstream investment projects. The company acquired a 33.43% share in the Indonesian Universe Gas & Oil LNG project back in 1990. This first overseas acquisition was followed by several rather smaller stakes mainly as from 2000.

[113] http://www.tepco.co.jp/en/press/corp-com/release/2013/1224596_5130.html

Since 2008 other big Japanese utilities have also been progressively investing in upstream projects overseas. The participation typically consists of taking a minority interest of around 1-5% in large-scale projects. However, small and medium-scale LNG projects are also starting to become part of Japanese companies´ overseas investment portfolio. In these projects Japanese companies are even willing to take larger percentage interest of around 20–30% or a majority stake. Tokyo Gas sees this approach as a key element to reach its declared strategic goal of LNG procurement diversification. To that end Tokyo Gas signed a Heads of Agreement on participation with an interest of 25% in the Senkang project in Indonesia in 2010.

In the 2000s the investments focused mainly on Asia and the Arab peninsula. Since then, preferences with regard to geographical location have been somewhat changed. Driven by the shale gas boom in the USA and the expansion of LNG development in Australia a shift towards these geographical locations can be observed.

Country	Project	Company	Stake	Entering the Project	Start of Operation	Main Features
Canada	Cordova natural gas development project	Osaka	7.50%	2011	2009 / 2014	Estimated reserves: 100-160 million tons in LNG equivalent Production: 3.5 million in LNG equivalent per year
		Tokyo Gas	3.75%	2011		
USA	Shale Gas and Liquids Development Project	Osaka	35.00%	2012	na	
Australia	Darwin	Tokyo Gas	3.07%	2003	2006	
Australia	Gorgon LNG project	Tokyo Gas	1.00%	2009	2014	
		Osaka	1.25%	2009		Estimated reserves: 800 m tons in LNG equivalent Projected output: 15 m tons/year
Australia	Ichthys LNG project	Tokyo Gas	1.58%	2012	2016	The gas will transported through the Darwin LNG terminal, with a liquefying capacity: 8.4 million tons per year
		Osaka	1.20%	2012		
Australia	Pluto LNG project	Tokyo Gas	5.00%	2008	2012	Once the project fully goes on stream, LNG production capacity is expected to reach 4.3 million tons per year.
Australia	Queensland Curtis LNG Project	Tokyo Gas	na	2010	2015	coal bed methane
Asia	Crux Condensate Field	Osaka	15.00%	2007	na	Estimated reserves approx. 60 m bbl condensate
Asia	Sanga Sanga Gas Field	Osaka	4.38%	1990	na	
Indonesia	Senkang	Tokyo Gas	25.00%	2010 HOA	na	
Indonesia	Universe Gas & Oil	Osaka	33.43%	1990	na	

	LNG project					
Oman	Qualhat LNG terminal	Osaka	3.00%	2006	na	Liquefaction capacity: 3.3 m tons/y
	North Sea Oil Field	Osaka	49.49%	2005	na	Estimated reserves: 0.8 million boe (barrels of oil equivalent)
	Sunrise Gas Field	Osaka	10.00%	2000	na	Estimated reserves: 110 m tons natural gas (LNG equivalent), approx. 230 m bbl condensate

Table 8: Overseas upstream investments of Japanese companies[114]

Source: Company Data

The strategy of Japanese companies focuses on ensuring a stable procurement of gas resources. Going beyond the conventional approach of procuring resources from sellers on the basis of long-term contracts, seeking participation in overseas resource development projects and investments also allows companies to achieve this goal. In addition to stabilization of fuel procurement, acquiring upstream interests serve as a natural hedging mechanism against fluctuations in crude oil prices and exchange rates thus resulting in lower procurement prices which represents the second pillar of Japanese companies' procurement strategy. Entering the market of unconventional resource development opens up new possibilities to procure more competitive resources and thus to minimize purchase costs. Furthermore, upstream investments can lead to more diverse terms of trade, including pricing. All this suggest that the significance of participation in upstream investments will continue to rise in the future. This view has also been supported by different market experts during the background discussions conducted.

4.2.6 Conclusions Japanese Gas Sector

Japan is the largest LNG importer in the world. Currently, Japan imports LNG mainly under long-term contracts with oil-indexation. Due to the expansion of global energy demand long-term stable supply will continue to play a major role in Japanese companies´ import activities. To that end it can be expected that long-term durations in the range of 20 years will remain the preferred basis procuring the bulk supply. However, at the same time, the role of short-term contracts in the purchase portfolio is increasing. In the future Japanese importers are aiming to contract more LNG under medium- and short-term basis, mainly to provide a flexible complement to long-term contracts. Short-term contracts are mainly used for risk hedging and covering fluctuations in demand.

In addition to securing supply via long-term contracts, Japanese importers also safeguard stable supply with vertical integration which further supports long-term commitments. Japanese companies acquire

[114] Please note, that this is a selected list of projects and it is not exhaustive.

primarily minority stakes in overseas upstream investments, but they also consider taking larger percentage interest of 20-30% or even majority stake in small- and medium-scale LNG projects.

Traditional Japanese import contracts use oil-indexed prices. Due to the wide spread between prices of LNG cargoes sold in Asia and the US benchmark price, Japanese companies are trying to move away from oil-linked prices (with first successes made by hub-based pricing in contracts with US exporters). With the expiration of a significant part of existing oil-indexed portfolio over the next decade Japanese importers will have the possibility to renegotiate the contract terms with the suppliers. The focus is expected to primarily remain on new pricing structures, take-or-pay obligations and volume flexibility.

4.2.7 Chinese Gas Sector

4.2.7.1 Overview

Demand and Supply

The Chinese gas market barely existed two decades ago, and even in 2000 natural gas consumption accounted only for 26 bcm. Since then the natural gas demand increased more than fivefold, growing to around 130 bcm in 2011 and making China the fourth largest gas user in the world. Natural gas is used also in power generation; however gas-fired power generation represents only around 2% of total power production.

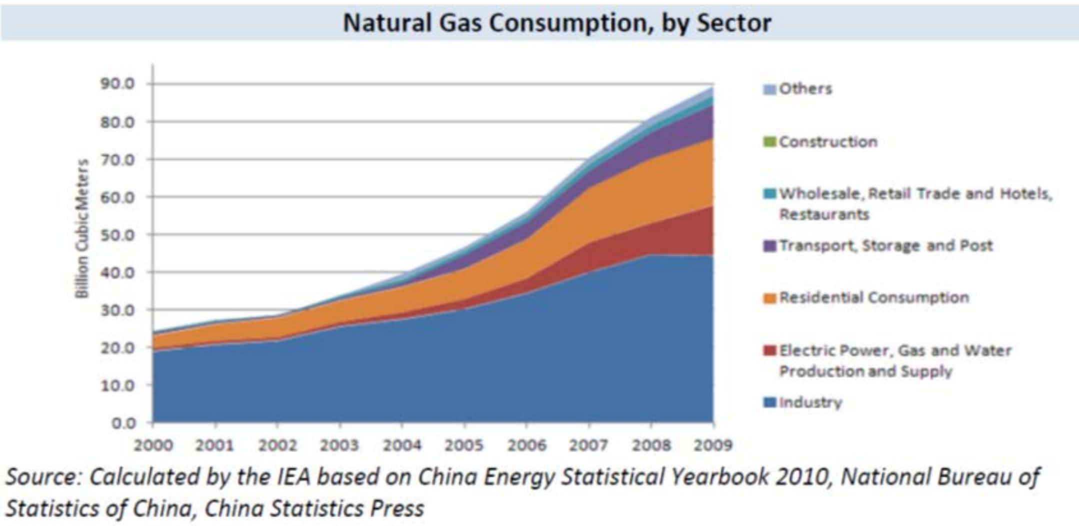

Figure 35: Natural gas consumption by sector

Source: IEA

In its current 12th Five-Year Plan (2011 to 2015) the Chinese government plans to almost double the share of natural gas in the primary energy consumption and reach consumption levels up to 260 bcm by 2015. Regarding the use of natural gas, each sector (residential, industry and power) is expected to consume roughly one-third of total natural gas demand by 2017.

The first and most important source of gas supply is domestic production. Only one quarter of Chinese natural gas demand is covered by pipeline gas from Turkmenistan and LNG imports from various sources.

Although indigenous production is no longer expected to grow at the same pace as demand, it will remain the bulk of supply. The additional demand for natural gas will be mainly covered by growing LNG imports (new Australian LNG is expected to start by 2014 to 2015), which makes China to be increasingly exposed to global gas dynamics. Furthermore, the increasing import requires new infrastructure development with high capital costs investments leading to a widening spread between cheaper domestic gas production and expensive LNG import.

Furthermore, China disposes of important unconventional gas quantities and is cited as one of the three regions where significant shale gas production can be predicted.[115] The Chinese energy policy has also recognized the potential arising from the development of own shale gas resources and sets a production target of 6.5 bcm/year by 2015. The shale gas development, however, will require substantial pipeline investments in the underdeveloped gas network. Moreover, many of the shale basins are located in regions characterized by scarcity of water resources which raise serious environmental concerns related to shale gas exploration in China.

[115] Navigant Consulting, prepared for: Department of Energy and Climate Change (DECC), Unconventional Gas, The potential impact on UK Gas Prices, 2012

Figure 36: Water access issues in China 9

Source: Navigant Consulting (prepared for DECC), Unconventional Gas, The potential impact on UK Gas Prices, 2012

Market Structure

China has already partly moved away from the vertically-integrated approach, though the market is not yet at a liberalized stage. The Chinese gas industry is characterized by an oligopolistic structure dominated by three state-owned energy companies (so-called the big three, namely CNPC, CNOOC and Sinopec). Although the import infrastructure has a relatively diversified ownership structure, the three big companies dominate on the LNG side and CNPC on the pipeline import side by owning and operating both international pipelines connecting Myanmar and Central Asia and 90% of the domestic natural gas transmission pipelines. The production of natural gas is dominated by the big three as well. Although there are several smaller natural gas producers active in the regions, they depend on transport facilities provided by the big three (especially, CNPC).

The domestic natural gas prices are regulated in China. The current regulatory regime consists of three controlled price elements: a) ex-plant price; b) transportation tariff; c) end-user price. The ex-plant prices are set by the central government based on the domestic production cost of natural gas. The city gate price is also calculated based on a cost-plus approach, and it is the sum of the ex-plant price and the transportation tariff, which is also centrally regulated. The ex-plant and city gate prices differ depending first on the gas supply source, and second on the final gas use (e.g. residential, commercial, industry or fertilizer). The end-user prices are determined by each local government by taking into account the distribution costs, alternative fuel prices and other market policy factors. [116] As the current cost-plus price regulation takes only domestic production costs into account, companies supplying their customers via imported natural gas with a significantly higher price than domestic production costs incur significant losses. With the increasing gas imports the urgency of a shift toward a net-back given approach in price regulation becomes larger. Some regions experiment with new pricing mechanisms linking city-gate prices to a basket of fuel oil and LPG, which could lead to replacement value pricing scheme down to the end-consumer level. Furthermore, the government has recently announced a gas pricing reform indexing new volumes (both imported and domestically produced) to oil and LPG prices. According to expert estimates the new regulation will lead to significant price increases in the Chinese market which again should one make cautious about the implementation and success of the reform.

Gas Infrastructure

Due to the fragmented nature of the pipeline infrastructure China is not one integrated gas market. Despite of the significant import infrastructure investments in both pipelines and LNG terminals, the transmission/distribution network is still rather limited. However, the network expansion is continuously ongoing. An additional LNG import capacity of 23 bcm has been under construction as of early 2012 in addition to the existing LNG capacity of 29 bcm. The 12th Five-Year Plan ambitious target of significant increase in domestic natural gas use requires further significant investments on the midstream and downstream sides.

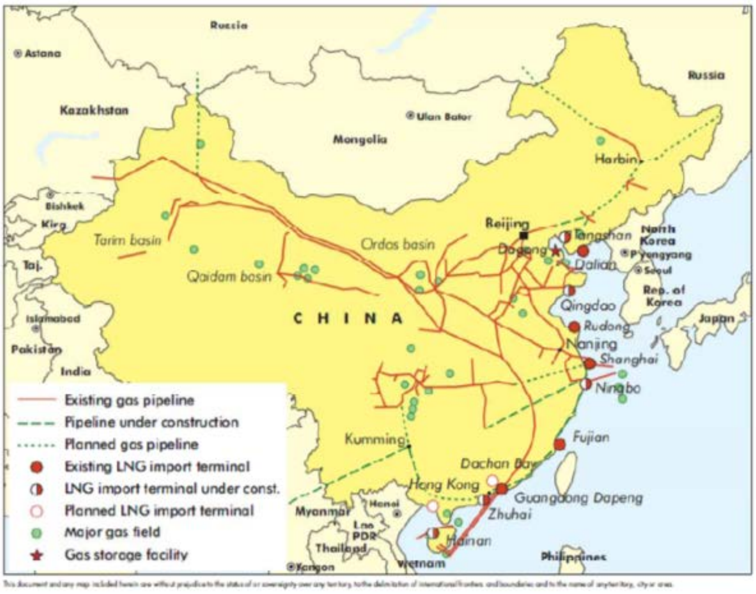

Figure 37: Natural gas infrastructure map in China

Source: IEA

[116] IEA, Natural gas in China – Market evolution and strategy, June 2009

The geographical fragmentation of the Chinese infrastructure leads to multiple regional markets that traditionally have received supply from different production areas at different costs, with different prices as a result.

4.2.7.2 Import Infrastructure

The demand which cannot be covered by national production is supplied via the import infrastructure consisting of LNG terminals and gas pipelines. The rapid growth in national consumption led to several important infrastructure investments in the past year.

LNG Terminals

The table below summarizes the existing and planned LNG receiving terminals by indicating their ownership structure.

LNG terminal	Bcm/year	Date	Companies
Dapeng	9.0	2006	CNOOC 33%, BP 30%, others
Fujian	7.0	2008	CNOOC 60%, Fujian Dypt and Investment Corp 40%
Shanghai	4.1	2009	CNOOC 45%, Shanghai Shenergy Group 55%
Liaoning	4.1	2011	Kunlun 75%, Dalian Port 20%, Dalian Const, Inv. 5%
Jiangsu	4.8	2011	Kunlun 55%, Pacific Oil and Gas 35%, Jiangsu Guoxin Inv. 10%
Dalian	8.4	2011	CNPC
Zhejiang	4.1	2013	CNOOC 51%, Zhejiang Energy Company 29%, Ningbo Power 20%
Zhuhai	4.8	2013	CNOOC 25%, Guangdong Power 35%, others
Yuedong	2.7	2013	CNOOC
Shandong	4.1	2013	Sinopec, Huaneng Group
Tangshan of Hebei	4.8	2014	PetroChina 51%, Beijing Inv. Holding Company 29%, Hebei Construction Inv. Company 20%
Yangpu	2.7	2015	CNOOC 65%, Hainan Development Holdings 35%

Table 10: LNG Terminals, Existing and Planned/Under Construction

Source: Company Data; IEA, Gas pricing and regulation – China´s challenges and IEA´s international experience, 2012

The first LNG imports to China arrived in 2006 when the Dapeng LNG receiving terminal started operation. This was followed by the development of further terminals which lead to a significant increase in China´s LNG receiving capability reaching 29 bcm/year by the end of 2011.

The first phase of the Dalian project developed by CNPC became operational at the end of 2011 to supply natural gas to the Northeast and North China. The construction has been started in 2008 and as shown by the completion of the first phase the work is getting on according to plan. By accomplishing the second phase the terminal will reach a total receiving capacity of 6 Mt/a and deliverability of 8.4 bcm/a.

In March 2011 CNPC kicked off the Tangshan of Hebei LNG project which has a planned capacity of 10 million metric tons per year. Feasibility studies and preliminary design have been completed and according to CNPC communication the project is due for completion in July 2013. The terminal is planned to serve as a new source of natural gas supply to Beijing, Tianjin and Hebei.

The Jiangsu LNG project has been launched by CNPC in 2004. In the long-term the terminal will dispose of a receiving capacity of 10 Mt and deliverability of 13.5 bcm per year. It is planned to fill LNG cargoes for export purposes as well as to supply gas into the Chinese market. The phase-I was put into trial commission in May 2011 t, with a maximum unshipping capacity of 267,000 cubic meters per day. This is CNPC’S first independently designed, built and operated LNG project.

The Shandong LNG project developed by Sinopec and the Huaneng Group is expected to be put into operation in 2014.

Sinopec is also planning to develop an LNG receiving terminal. The Quingdao LNG project has been approved by the NDRC in 2010.

In case all LNG terminals reported to be under construction/expansion, become operational, China´s total LNG regasification capacity would increase from around 29 bcm to over 50 bcm in a few years.

Gas Pipelines

CNPC dominates the pipeline side of the import infrastructure by owning and operating both international pipelines connecting Myanmar and Central Asia and 90% of the domestic natural gas transmission pipelines. CNPC´s gas pipeline infrastructure has a length of 3,822 km. It transported 17.76 bcm of natural gas in 2011 and includes the following main pipelines:

- Second West – East Gas Pipeline
- Central Asia – China Gas Pipeline
- Kazakhstan – China Gas Pipeline
- Russia – China Gas Pipeline

The 8,704 km long Second West – East Gas Pipeline was the first pipeline in China to import overseas gas resources. Its designated transport capacity is 30 bcm/year. The pipeline connecting to the Central Asia-China Gas Pipeline allows import from Central Asian countries to the Pearl River and Yangtze River delta areas and the central west part of China. The construction began in February 2008 and the whole trunk was completed and put into operation in June 2011.

Gas transport from Turkmenistan, Uzbekistan and Kazakhstan to China comes via the 1,840 km-long Central-Asia – China gas pipeline consisting of three lines. The Chinese part is developed by CNPC, while the pipeline in the two transit countries is developed by two joint venture companies between CNPC and Uzbekneftgaz and KazMunigas respectively. The construction started in 2008 and line A had a startup in 2010. The line B was upgraded in 2011 to reach a deliverability of 23 bcm/year and transported already 15.86 bcm in 2011. Furthermore, in 2011 CNPC signed an agreement with Uzbekneftgaz and KazMunaigaz on the construction and operation of line C with a designed capacity of 25 bcm per year which will run parallel with line A and line B. According to CNPC press release the Central Asia – China gas pipeline will reach 55 to 60 bcm per year by 2015. Overall by putting the Central Asia – China Gas Pipeline and the Second West-East pipeline into operation in 2011 CNPC doubled its gas import into China.

The Kazakhstan-China Gas Pipeline is also owned and operated by CNPC. The agreement between CNPC and KazMuniGaz signed in 2007 provided the basis for the construction of the 1,300 km long Kazakh-Chinese section of the pipeline. The work started in 2008. End of 2010 the second phase of the Kazakhstan-China Gas Pipeline started construction to meet natural gas demand in southern Kazakhstan. It is developed in two stages; first a line with an annual capacity of 6 bcm is constructed followed by the second stage with the design of a pipeline with an annual capacity of 10 bcm, which can be expanded to 15 bcm. According to the press releases of CNPC the second phase was planned to become operational in 2012. The third part of the Kazakhstan-China Gas Pipeline (line C) is expected to start gas delivery in early 2014. In addition to the pipeline construction the agreement between CNPC and KazMuniGas foresees the joint development of the Urikhtau gas condensate field.

In 2011 CNPC started the construction of the Myanmar-China Oil and Gas Pipelines. The gas pipeline has a designed annual delivery capacity of 10-13 bcm. The project is due to be completed and is expected to become operational in 2013.

A Russia – China gas pipeline has been under discussion for a long time. Connecting the two countries by a gas pipeline would allow China to diversify its supply sources and assure security of supply by adding incremental import gas to the country´s portfolio. The project would allow Russia to diversify its export routes and get access to a market with a fast growing natural gas demand at the same time. Several transit routes are under consideration at the moment. One of them is the Altai project which has the big advantage that no transit countries are present en route. The lead time of development contracts is becoming shorter; however, there is some skepticism among market experts that the final deal will be concluded by the end of this year, if at all. At present, it looks as if a competing gas supply route in the far east would materialize (also further discussed below).[117]

Ownership of and Third Party Access to Infrastructure

The description of the import infrastructure elements clearly reveals that although the import infrastructure has a relatively diversified ownership structure, the three big (CNPC, CNOOC and Sinopec) dominate on the LNG side and CNPC on the pipeline import side. The import facilities (LNG terminals and pipelines) are mostly built in accordance to the import plans and sales strategies of the three big players and thus having a regard on the fact that the major stake in these companies is state controlled, assumed to be fully in line with the governmental plan for further development of the gas sector.

[117] http://online.wsj.com/article/SB10001424127887324557804578376510628682312.html#

The access to infrastructure is not regulated either in terms of tariffs or other conditions. Third parties can get access to infrastructure based upon bilateral negotiation and agreements. For LNG there are some cargoes from one company arriving to another in case of shortages, but the general rule here again similar to gas pipelines is that there is no open third-party access. Furthermore, it should be pointed out that access to LNG terminals only enhance market entry if gas pipeline necessary to transport LNG to customers is accessible as well.

The lack of access to infrastructure prevents the entry of new suppliers delivering LNG or pipeline gas to end-users or to gas distribution companies, thus limits the competition and maintains the oligopoly/monopoly structure of the wholesale market.

New Infrastructure

As natural gas demand is expected to continue growing in the future further infrastructure investment projects are in the planning stage or already under development. As energy security plays a key role in the country´s energy policy, the government realized the need for legislative measures supporting new import infrastructure investments. At the same time however, the regulatory requirement of the Commission´s approval for new import infrastructure might in fact lead to delays in the constructions.

4.2.7.3 Import Gas Delivery – Negotiated Contracts between Producers and Wholesale

China started importing natural gas in 2007. Since then the imported volumes have significantly increased. As the growing demand cannot be covered solely by indigenous production, the role of import is continually gaining significance. This first necessitates large investments in the gas pipeline network and LNG terminals and second, filling with gas the new import capacities (i.e. security of supply de facto requires the delivery of the volumes). Due to the absence of full open access to infrastructure, in general the owners and operators fill the import capacities with gas. Furthermore, new import infrastructure is subject to the Commission's approval which is granted upon secured supply. This regulation gives another boost to project developers to secure gas delivery themselves through their pipeline.

This section assesses the contractual situation between gas producers and importers in China. It should be stressed that this is the solely interface of the value chain with deregulated prices.

- CNPC imports gas from Turkmenistan via the Central Asia – China Gas Pipeline based on the sale-and-purchase agreement signed in 2007 that envisages annual deliveries of 30 billion cubic meters of gas for 30 years under oil-related prices. The price paid for the Turkmen gas in January 2013 was around USD 11/MMBtu.[118] According to a study prepared by IEA in 2012[119] China and Turkmenistan signed a deal to increase the import volume to 65 bcm per

[118] Interfax, Global Gas Analytics, Issue 6, March 2013

[119] IEA, Gas pricing and regulation – China´s challenges and IEA´s international experience, 2012

year. 17 bcm/year are expected to be delivered from a joint production of the two companies, while 13 bcm/year has to be provided by Turkmenistan from other fields. As no date has been officially mentioned in the preliminary agreement and taking into consideration the technical and other challenges of the project, the delivery date of these additional volumes can be perceived as being rather uncertain.

- In addition to the import from Turkmenistan, China purchases 10 billion cubic meters of natural gas through the Central Asia – China Gas Pipeline from Uzbekistan based on a framework agreement between CNPC and Uzbekneftegaz. In January 2013 the price for these imports amounted to around USD 9 MMBtu.[120]

- Based on a 30-year purchase agreement signed in 2008 between CNPC and the South Korean conglomerate Daewoo International gas will be imported to China also from Myanmar. The agreement forms the basis for the currently on-going pipeline construction between China and Myanmar. The work is due to be completed in 2013. However, there are still some doubts on whether or to what extent the whole pipeline capacity of 10-13 bcm would be filled due to the lack of finding sufficient identified supply in Myanmar.

- The discussion on potential natural gas import from Russia to China has been ongoing already in 2003 when a first feasibility study has been prepared on a natural gas supply from Kovykta Gasfield in Russian Irkutsk to China and Korea. Although this pipeline (Altai pipeline) has not been built yet, the dialogue between China and Russia continued. In 2010 than, Gazprom and CNPC signed a supply agreement which sets out the major terms and conditions of the natural gas supplies from Russia to China by determining the volumes and timeframe of deliveries, the take-or-pay level, the supplies build-up period and the guaranteed payment level. First supplies were planned for late 2015. The contract period would be 30 years and the supply volume would account to 30 million cubic meters a year.[121] Whilst the Altai project seems to be slowed down, deliveries to China in from Russia's far east have become more probable.[122] So far no final agreement has been reached on pricing the import volumes from Russia, as Gazprom insists on oil-indexation while China opposes this. However, it may be assumed that Gazprom is willing to concede to deviate from pure oil-indexation in favour of securing gas exports to China. As China is expected to be short of gas as from 2018, Gazprom may rely on this. At the same time, Gazprom is planning an LNG terminal at the Pacific coast (at Vladivostok) which could provide an alternative means to export the gas in case the supply to China will not materialize.

[120] Interfax, Global Gas Analytics, Issue 6, March 2013

[121] http://www.gazprom.com/about/production/projects/pipelines/altai/

[122] http://online.wsj.com/article/SB10001424127887324557804578376510628682312.html#

Company	Source	Pipeline	Term	Volume (bcm/year)
CNPC	Turkmenistan	Central Asia – China Gas Pipeline	30 years	30 - > 65
CNPC	Uzbekistan	Central Asia – China Gas Pipeline	na	10
CNPC	Myanmar	Myanmar – China Oil and Gas Pipelines	30 years	10-13
CNPC	Russia	Russia – China gas pipeline	30 years	30

Table 11: Gas pipeline import agreements

Source: Company Data; IEA, Gas pricing and regulation – China´s challenges and IEA´s international experience, 2012

LNG Gas Import

China concluded its first LNG import contracts in 2005 and the first LNG shipment arrived one year later in 2006.

In China, 90% of the LNG is estimated to be imported under long-term contracts; the main ones are summarized in the table below.

Company	Source	Signing Date	Term (Years)	Volume (mtpa)	First Cargo
CNOOC	Australia – North West Shelf Project	2003 Dec	25	3.3	2006 June
	Indonesia – Tangguh LNG Project	2006 Sep	25	2.6	2009 May
	Malaysia – Tiga	2006 Jul	25	3.0	2009
	QatarGas II	2008 Jun	25	2.0	2009
	Australia – QC LNG	2009 May	20	3.6	2014
CNPC	Shell (Australia – Gorgon +)	2008 Nov	20	2.0	2011
	Quatar – Quatargas 4 LNG project	2008 Apr	25	3	2011
	Australia – na (Woodside Energy Ltd)	2007	na	Na	na
	ExxonMobil (Australia – Gorgon)	2009 March	20	2.0	2014

Table 12: LNG supply sources and import agreements

Source: Company Data; IEA, Natural gas in China – Market evolution and strategy, June 2009

- CNOOC sources LNG from the North West Shelf Project in Australia and the Tangguh LNG Project in Indonesia. The gas is secured via long-term supply contracts and is sold to various customers in the Asia-Pacific region, including LNG Terminals in Guangdong Dapeng and Fujian Putian, China.

- PetroChina, a holding company of CNPC supplies yearly 2.25 million tons of LNG from Gorgon Gas Field in Australia to China based on a 20-year agreement worth USD 41 billion and signed in 2009 with ExxonMobil. ExxonMobil holds a 25% portion of the output of Gorgon Gas Field.
- CNPC signed a binding LNG sales and purchase agreement with Qatargas and Shell for the annual supply of 3 million tons of LNG for 25 years from the Qatargas 4 project in Qatar. The gas is to be shipped to CNPC´s LNG receiving terminals upon the commencement of their commercial operations.[123] At the date of signature the Qatargas 4 LNG project was still under construction and is a 70-30 partnership between Qatar Petroleum and Shell.
- CNPC purchases annually 2 million tons of LNG from Shell International Eastern Trading Company. The agreement foresees a delivery over 20 years starting from 2008.
- Without disclosing any specifics, in 2011 CNPC reported having secured resources for its LNG projects in Dalian and Jiansu through close partnerships with international LNG suppliers.
- CNPC buys LNG from Australia's Woodside Energy Ltd. The sale-and-purchase agreement was signed in 2007; details of the contract are not disclosed.

According to estimations, only 10% of LNG is bought on the spot market. The LNG spot market is mainly driven by additional demand for LNG cargoes (peak in demand), especially in the winter season. Spot LNG prices for China reach even USD 20/MMBtu which is several times higher than the current city gate price.[124]

Apart from the three big companies only a few private companies can import gas. By granting import and export rights to a private company (ENN Energy) the monopoly of import and export of natural gas was officially abolished in 2006. However, as open third-party access is not required and ENN does not have own receiving infrastructure, the company is not in the position to exercise his import and export rights. To that end the opening of the import and export natural gas market is still outstanding. According to the IEA study[125] not a single case has been reported where a company other than one of the big three has sold imported gas into the Chinese market.

[123] The Qatargas 4 LNG project is a 70-30 partnership between Qatar Petroleum and Shell, and was expected to become commercially operational in 2011.

[124] IEA, Natural gas in China – Market evolution and strategy, June 2009

[125] IEA, Gas pricing and regulation – China´s challenges and IEA´s international experience, 2012

Prices

The big gas companies in China are vertically integrated and so their marketing and production activities are not split from the pipeline, LNG and storage business units. To that end, the amount of publicly available information on import activities is very limited.

According to an IEA study[126], the CNOOC's contracts for LNG in the early 2000s lay down DES prices in the USD 3.00-3.70/MMBtu price range reflecting oil price ceilings of USD 25 and USD 38 per barrel, respectively. From 2007 to 2008, driven by growing national demand, Chinese companies (NPC or Petrochina, CNOOC) started aggressively buying LNG at international prices. Oil indexation seems to remain the basic price setting principle for Chinese LNG imports, as shown by CNOOC's and Petrochina's more recent deals with Petronas, Woodside and Qatargas which still apply a crude oil parity pricing.

Each of the big three companies imports natural gas from overseas upstream projects with own interest. In that way, prices realized from own production overseas can be regarded as import prices. However, information in this regard is only disclosed to a limited extent. Even if companies publish sales prices, gas prices are either not split from oil prices or they are not locationally differentiated and only one general average price for the whole overseas production is reported, regardless whether the gas was sold into the Chinese market or into other markets. Furthermore, as the main importers are vertically integrated companies, the interface between wholesaleers and suppliers often happens between legal entities belonging to same parent company.

In the following paragraphs, however, we attempt to give an insight into the import activities of the Chinese companies. To that end and based on the company profile and the publicly available information we selected CNOOC for further assessment. CNOOC covers all its natural gas sales by own production in China and overseas. Its net production in 2012 was of 342.4 million BOE while the sales volume reached 322.6 million BOE. In 2012, CNOOC became aware of an increase in average gas prices of 12.0% (from USD 5.15/mcf in 2011 to USD 5.77/mcf in 2012).[127] According to the company´s information this was mainly due to (i) higher price for natural gas from oil and gas fields that have commenced production recently; (ii) higher sales price for certain production of Tangguh LNG in Indonesia in the spot market.[128] The following two tables summarize the realized sales volume and prices by CNOOC in 2012.

[126] IEA, Gas pricing and regulation – China´s challenges and IEA´s international experience, 2012

[127] Please note that the average sales price includes all sales activities, both wholesale and retail.

[128] CNOOC

Production	Net Production (Bbls/Day)	Average Sales Price (USD/Mmcf)	Average Production Cost (USD/BOE) (oil+gas)
Offshore China	663.1	6,019	9.28
Overseas	308.6	5,232	16.45
Asia	157.8	7.752	23.58
Oceania	101.1	3,171	9.26
North America	49.7	1,426	23.80
Total	971.7	5,769	10.58

Table 13: CNOOC´s production volumes, production costs and realized prices in 2012

Source: Company Data

Natural Gas	2010	2011	2012
Revenues (Rmb in millions)[129]	10,576	12,576	12,949 (+5.2%)
Net production (m BOE)	66.0	73.3	70.6 (+20.6%)
Average net realized price (USD/mcf)	4.49	5.15	5.77

Table 14: CNOOC´s natural gas production volumes, realized prices and revenues in 2012

Source: Company Data

CNOOC negotiates sales prices bilaterally with its customers. In general, CNOOC concludes long-term gas sales agreements, which normally provide a periodic price adjustment mechanism. Furthermore, a typical CNOOC´s contract includes provisions for periodic resets. These contractual terms lead to sales price fluctuations linked to international oil prices and inflation rate, which clearly affects CNOOC's profitability.

As shown in the above tables the costs of domestic production are in general far below the costs of overseas production. In Asia and North-America, the difference is almost twice and a half. The significant spread between domestic and overseas production costs point to the pronounced tension related to current price regulation leading to significant losses of gas importers. The recently announced pricing reform linking gas prices to oil and LPG will significantly leaven the profitability of Chinese LNG import activities. The new regulation represents an end to the separation of domestic prices from internationally traded LNG prices and thus foster LNG imports. At the same time, it also

[129] Includes the sales from CNOOC´s subsidiaries in Indonesia, Australia, Nigeria, Trinidad and Tobago.

boosts inland production as higher end prices render the development of marginal fields economically viable. Furthermore, the price hike might also accelerate the shale gas exploration in China.

4.2.7.4 Overseas Natural Gas Upstream Investments

As energy security is one of the key elements of the country´s energy strategy, China also secures the increasing domestic demand through overseas natural gas resource acquisitions. The big three, active in the whole value chain starting from exploration, development, production and sales of natural gas, are making effort to gain upstream access overseas. They often produce their own gas and import it into the Chinese market. In geographic areas where the companies have limited experience, they tend to plan infrastructure investments as alliances or partnerships with companies possessing the required expertise.

CNPC´s overseas production (CNPC´s share) reached 12.57 bcm in 2011. The main projects are summarized in the table below. In addition, CNPC also realizes joint projects in Indonesia and South Africa.

Country – Project	Date of Contract	Joint Investors
Turkmenistan – Amu Darya project	2008	
Iraq - Halfya oil field	2009	Total, Petronas
Kazakhstan – Urikhtau gas condensate field	2008	KazMunaiGas
Kazakhstan – Zhanazhol Oil & Gas Processing Plant	2007	
Uzbekistan – five onshore exploration blocks	2006	Uzbekneftegaz
Quatar	2010	Shell,
Mauritania - No. 20 oil & gas field		Baraka
Canada	2010	Shell, Qatar Petroleum
Australia – LNG	2011	

Table 15: Overseas upstream investments of CNPC (realized and planned)

Source: Company Data

- CNPC produces its own gas in Turkmenistan. The construction of the first Gas Processing Plant of the Amu Darya natural gas project in Bagtyiarlyk started in 2008 and first exploration was due in 2009. At the end of 2011 the No.2 Gas Processing Plant had its ground breaking ceremony. The project has a designed capacity 8 billion cubic meters per year.
- A consortium of CNPC, Total and Petronas exploit the Halfya oil field in Iraq based on the service contract awarded at the end of 2009.

- CNPC developed the Urikhtau gas condensate field in close cooperation with KazMunayGas. The first agreement between the two companies signed in 2008 was followed by a second one dating from 2011 which sets out the development of the Urikhtau gas field through a joint venture on equal equity.
- The first phase of the Third Zhanazhol Oil & Gas Processing Plant was completed and put into operation at the end of 2007. According to CNPC´s press release this plant can process 2 billion cubic meters of natural gas a year.
- CNPC took over all the assets of PetroKazakhstan in 2005 when "unconditional" final order has been granted by the Queen's Bench Court, Calgary, Canada completing the transaction.
- According to memorandum signed in 2010 between PetroChina, a holding company of CNPC and Shell the two companies should carry out an integrated oil and gas project in Canada.
- Since 2006, CNPC explores five onshore blocks in Uzbekistan based an agreement between CNPC and Uzbekneftegaz. In 2009 the two companies signed an agreement on reinforcing oil and gas cooperation.
- According to an Exploration and Production Sharing Agreement signed in 2010, CNPC, Shell and Qatar Petroleum (QP) will jointly explore natural gas in Block D in Quatar during the agreement term of 30 years.
- CNPC and the Australian Baraka company jointly prospect and develop the No.20 oil & gas field along the coast of Mauritania.
- Following an equity acquisition of 19.9% of the shares of Australia's LNG Limited by a subsidiary of CNPC, the company also active in the Australian LNG market since 2011.

The other two main Chinese LNG importers have also gained upstream access overseas. Sinopec is involved through its subsidiaries in oil and gas exploration projects in Russia (Taihu), Kazakhstan (CIR) and in Columbia (Mansarovar), while CNOOC realizes oil and gas investments in Indonesia, Australia (North West Shelp project), Nigeria, Trinidad and Tobago and in the US and Canada (Eagle Ford project and Niobara project). The overseas investments represent an integral part of the companies´ assets. For example, CNOOC´s overseas net production and net proved reserves accounted for approximately 22.0% and 31.0% , respectively, of the company´s total net production and net proved reserves and overseas oil and gas sales revenue accounted for 14.7% of CNOOC´s total as of at the end of 2012.

Overseas upstream investments play an increasing role in the companies´ supply strategy. In most cases they are developed in the form of a joint venture with a company of the host country and often linked to pipeline investments and LNG projects, plus backed-up by long-term import contracts.

4.2.8 Conclusions Chinese Gas Sector

China is one of the biggest gas consumers in world. At the moment China´s import dependency is less strong as three quarters of demand is covered by national production. However, the import dependency is expected to increase in the future as national demand is expected to be doubled by 2015 and the additional volumes are planned to be supplied through import. Due to the related environmental concerns we do not expect that shale gas exploitation will be a game changer in terms of imported volumes soon and it is not expected that it will redirect current trends on the import side in the near future.

In general, it can be concluded that the market fundamentals essentially shape the current contract structure in China. The fragmented nature of the gas infrastructure leads to the fact that China is not one integrated market. The import side is dominated by state-controlled vertically integrated companies with supply obligation. The lack of competition and the strong public influence leads to investment and import decision driven by security of supply questions rather than competitiveness. The role of competitiveness is farther undermined by cross-subsidization along the value chain by granting high IRR to investments allowing companies to recover losses resulting from import activities. However, the recently announced pricing reform will significantly improve the recovery of import activities and make domestic off-shore production as well as shale gas exploration profitable and thus facilitate related infrastructure investments.

In order to deliver the additional volumes, significant import infrastructure investments are required. Most new pipeline and LNG terminal developments are carried out in the form of a joint venture of a Chinese company and partners in the relevant countries and are often linked to joint gas field development projects and import contracts. Currently new import infrastructures are subject to the Commission´s approval which is granted upon secured supply. This regulation urges investors to conclude long-term supply contracts. Chinese importers secure supply not only with long-term contracts (typically in the range of around 20 years) but also by taking mostly minority stakes in overseas upstream investment projects.

With regard to new supply sources the possible import from Russia should be pointed out. China and the EU are probably not competing for gas resources but for infrastructure investments. The economic downturn experienced during the past few years seems to lead to Gazprom revising its capital-intensive investment strategy and to focus on major export-oriented, economically viable projects. To that end, it can be assumed that Gazprom's ability to shoulder the development of gas fields destined for exports to the EU and China at the same time because of limited resources in terms of financing, qualified labor force (e.g. experienced project managers) and technical equipment (e.g. drilling rigs, pipeline laying equipment) – at least not on short notice. If the investments for exports to China will really go ahead without even a firm long-term contract reached between Gazprom and Chinese companies, it seems as if Gazprom considers China as a very promising gas export destination for the future. If Gazprom would concede to the Chinese demand to use pricing different from oil-indexation, further pressure would be put on the concept of oil-indexation in the Asia-Pacific region in general, but also Gazprom in relation to its efforts to maintain oil-indexation as the preferred pricing mechanism.

As security of supply can be regarded as the main driver for the establishment of contractual terms, long-term contracts are expected to remain providing the bulk of supply. However, it may be assumed that the pricing structure will experience a shift from the historically applied oil-indexation toward more market-based pricing. With the persistence of long-term contracts, the role of short-term contracts is increasing at the same time as they allow for portfolio optimization. Spot contracts are providing flexibility and are mainly used to cover additional demand driven by seasonal fluctuations and until now it seems that they are of less relevance in terms of competition in the market.

4.3 Comparative Assessment

In light of the main research question of this study, i.e. what are driving forces shaping temporal structures of contractual relationships, the following sections aim at providing insights by comparing the four selected countries with regards to a couple of key characteristics:

- Import dependency
- Infrastructure
- Regulation
- Market development
- Temporal contract structures

The following table summarizes the country specifics along the selected aspects. In order to show the existing similarities, i.e. differences between the EU and the assessed countries the EU has also been incorporated in the comparison.

Aspects	Australia	China	Japan	USA	EU
Import Dependency					
Country profile	Exporter	Importer	Importer	Importer[130]	Importer
Share of import/export in national consumption/production in 2012	50%	25%	90%	10% import	65.6 %
Imported/expor ted volume of gas in 2012	~ 25 bcm	~ 32 bcm	~ 120 bcm	~ 72 bcm	~ 320 bcm
Interconnectivity with other markets	LNG	LNG + gas pipeline	LNG	LNG + gas pipeline	LNG + gas pipeline
Expectations	LNG export capacity reaching 100 million tons/year by 2016/17	Natural gas demand doubled by 2015 (reaching 260 bcm). Additional demand mainly	LNG import capacity increased by 25%, reaching more than 300	Possible important LNG exporter in the future (as a result of the shale gas boom)	Decreasing domestic production will necessitate additional supply

[130] While in future, the US will most likely become a net exporter, it is currently still considered an importing country.

		covered by LNG imports	bcm by 2022		from import
Gas Infrastructure					
Degree of development	Less developed	Less developed	Less developed	Well developed	Well developed
National infrastructure	Segmented	Fragmanted	Fragmanted	Interconnected	Interconnected
Regulation					
TPA to import/export infrastructure	Bilaterally negotiated	Bilaterally negotiated	Bilaterally negotiated – third party usage not common due to high third party usage fees	Open access	Full open access, excemptions only granted to new infrastructure
Special regulation with regard to import/export	Western Australie requires 15% of the prodcution volume to be made available to the domestic market.	New import infrastructure development is subject to the Commission´s approval upon secured supply	None	Import and export activities are subject to regulatory authorization	None
Price regulation	None	All prices regulated except import prices (domestic production, transportation and end-user prices regulated on a cost-plus basis)	None	No price regulation on the production and wholesale side (transportation tariffs and retail prices are regulated)	Transmission and distribution price regulation and some remaining regulation of end users prices
Market Development					
Level of development	Liberalized	Not fully liberalized - vertical integration	Liberalized	Not fully liberalized – vertical integration	Liberalized
Wholesale market	Competition	Oligpoly	High concentration	Strong competition	High concentration
Retail market	Competition	Low competition[131]	High concentration	Monopoly/ Competition[132]	Competition[133]
Existence of (a) gas hubs	Several	None	None	Several[134]	Several
Contract Structure					
Prevailing contract type	Long-term	Long-term	Long-term	Short-term LNG export contracts: long-term	Long-term and short-term
General contract	20 years	20-30 years	15-20	10-20 years	

[131] The Chinese downstream market is characterized by various domestic suppliers each dominating in its given geographic area. They are private companies or owned by the local government and face an increasing competition from the Big Three.

[132] Retail liberalization is ongoing on state level, however in many cases regulated distribution monopolies prevail.

[133] The level of competition varies from Member State to Member state.

[134] More than 30 gas hubs exist in the US, inter alia Henry Hub which serves as a reference for price setting in case of many gas contracts.

duration of LT contracts					
Prevailing pricing mechanism	Oil-indexed (export)	Oil-indexed	Oil-indexed	Market-based	Oil-indexed / Market-based

Table 16: Summary of the comparative assessment of the analyzed gas markets

Import Dependency

Similar to the EU, two of the assessed countries are qualified as importing counties (China, Japan) and the other two are looked at as (future) exporting countries (Australia and USA). This fact is certainly an important aspect to consider when taking a closer look at the situation in each of these countries.

The situation for Japan and China as importing and import dependent countries is quite similar. Both countries rely to a certain extent on gas imports (although China has also significant domestic resources). Natural gas plays an important role in the Japanese and Chinese economy, and the two countries are important players in the worldwide natural gas market by representing the two largest gas consuming market in the Asia Pacific. Due to Japan´s geographical location, the natural gas import takes the form of LNG making the country the biggest LNG importer in the world. In Japan, subsequent to the Fukushima disaster, import dependency even increased because of the reduction of nuclear power generation (replaced by gas-fired power generation). The role of natural gas in the years to come will be driven by the political decision on the future of nuclear power which is one of the main fuel alternatives for power generation. In China, the import dependency at the moment is less strong, with domestic resources covering three quarters of demand. The soaring economy of China unfolds a tremendous need for energy though,. Despite China having also plenty of coal resources, it faces massive environmental and air quality problems leading to positive outlook for future gas consumption. In addition, China has significant shale gas resources. Although production of shale gas in China will be ridden with costly environmental issues, in particular because of water demand for shale gas exploration (i.e. for hydraulic fracturing), it may unfold unforeseen dynamics with regards to shale gas production if conditions for gas imports were considered as less economical or despite its problems, more coal could be used instead. Overall, it is assumed that China will become more import dependent in the years to come, as the expected strong increase of gas demand will most likely be covered largely by imports).

Australia, as an exporting country is in a completely different situation. As a country rich with energy resources it faces no scarcity and many of the export projects are developed on the basis of gas plays locked for the domestic Australian market, as there is no infrastructure connecting these (rather remote) gas plays to major demand centers. Although the Australian domestic gas sector (market as well as regulatory oversight) is quite well developed, it does not really influence the developments with regard to Australia's role as a gas exporting country.

The US have first and foremost a large and very well developed domestic market and domestic gas production based on a large amount of rather small fields to supply this market. The large number of domestic producers represents a significant difference to the gas production in the EU. And while a few years ago, it was expected that the US would become an importer of LNG it is now at the brink of becoming a gas exporting country. In any case, it can be safely assumed that the US will not become a gas importing country again in the foreseeable future. [135] Nevertheless, in comparison with its domestic gas demand, exports play only a limited role and the political debate on price increases which are expected from gas exports will perhaps lead to certain limitations of the overall export volumes. However, once regulatory approval is given to broader gas exports it might change the landscape of the worldwide natural gas market having significant implications for importing countries by affecting LNG prices and available (incremental) volumes on the market gas. This may in particular affect global pricing of LNG, as first contracts in place rely on hub-based pricing instead of oil-indexation.

The EU is one of the main gas importers. This results in the fact that, similar to that seen in Japan and China, energy markets are rather focused on security of supply and not on security of demand. Although the EU is well interconnected to supply countries, both via pipelines and LNG, one of its main important external suppliers Gazprom, leading to the discussion of supply sources' diversification in energy policy, as is the case in China and Japan.

Moreover, it should be pointed to the interrelation between the countries. The export situation in Australia and the US affects and influences the import situation in Japan, China and the EU and so vice versa.

Gas Infrastructure

The existing infrastructure is one of the major fundamentals of the country´s natural gas sector. The pipeline network in the US, just as in the EU, is well developed and connects all parts of the country and thus creates one single gas market. However, an important difference between the US and EU gas infrastructures can be observed with regard to the distance gas has to travel from the supply source. At the same time the Chinese and Japanese infrastructure has a less developed, fragmented nature, resulting in separate geographical markets without interconnections between them. The same applies also to the Australian gas infrastructure, which is segmented into three regions. Moreover, gas fields dedicated for export are not connected to the major Australian domestic market. The shape of the gas infrastructure not only determines the integrity of the gas market and thereby allows for competition in the market, but also drives future investment needs.

Need for Investment

The outlook for natural gas demand shape the investment needs in the future. In order to deliver the additional volumes to China and Japan, significant infrastructure investments are required in the pipeline infrastructure and/or LNG receiving terminals. The same applies to the exporting side, i.e. liquefaction terminals in Australia and the US need to be built in order to export natural gas.

[135] This is neglecting the existing import/export relationships with Canada and Mexico, but only focused on relationships outside of North America.

Investments are easily in the range of USD 5 to 10 billion for a large liquefaction terminal in the US. Investments required for Australian export projects regularly include also the field development, as the gas would be only produced to be delivered to and exported through the respective terminal and can be in the range of up to USD 40-50 billion. As some of this gas fields are for instance deep-water offshore projects and would require floating liquefaction vessels, total investment volumes are easily three to five times than in the US. In addition, the nature of gas production is largely different in Australia and the US: In particular with shale gas, exploration and production investments are significantly less lumpy in the US than in Australia. Total drilling and completion costs for a shale gas well are typically in the range below USD 5 million. Furthermore, with the widespread availability of producible gas resources and a well-developed transportation network, gas production and liquefaction terminals are independent of each other. Moreover, it should be pointed here to the specific regulatory measures with regard to infrastructure investments which have also an impact on the contractual framework in the countries. In China for example new import infrastructure development is subject to the regulatory approval which is granted upon secured supply. Furthermore, the cross-subsidization along the value chain in China (e.g. losses from import activities are covered by relatively high IRR granted to investment projects) leads to the situation where both investment and import decision are not taken under business conditions.

All the future developments in the assessed countries can have an interesting implication for the EU. The growing demand in China poses the questions whether the EU will have to stand in competition for Russian resources with the largest gas consumer in the Asia-Pacific region. During the background discussions conducted in the frame of the project, several market experts expressed their view that the EU may experience a competition with China for incremental volumes and new infrastructure developments, however, Asia's rising hunger for natural gas will not affect the quantities currently delivered to Europe. All interviewees see current EU demand for Russian gas safe of risk, since netback is secured and infrastructure is in place.

Market Development

Market development is determined by the level of liberalization. Main stages to be completed to reach a competitive and efficient market structure have been determined by Pollitt[136] as the followings: (i) privatization of publicly owned assets; (ii) the opening of the market to competition; (iii) the extension of vertical unbundling of transmission and distribution from the generation and retailing; (iv) the introduction of an independent regulator. Furthermore, key regulatory aspects of the opening of the market to competition are third-party access and price regulation. Disparities in the level of liberalization lead to irreconcilable differences in market structures.

[136] Pollitt MG (2009) Electricity liberalizatiom in the EU: a progress report. University of Cambridge, working paper in economics, 0953

Whilst Australia, the US and the EU have taken all the necessary measures to accomplish these four stages and thus developed mature gas markets, China and Japan are still on their way of the liberalization.

Although both the US and the EU have liberalized and mature gas markets where regulation (such as full open access to infrastructure) foster new market entry and competition, some fundamental differences remain. While in the US producers are almost exclusively private companies with low political interferences, the production of gas consumed in the EU is characterized by few companies, most of them located outside the EU and partly driven by a "political agenda". Furthermore, while in EU the import side is still dominated by some big players, in the US a very high number of market participants are active all along the value chain in the US, resulting in an inherent dynamic potential in the market. Despite the political influence the US government takes on the US gas sector, the sector seems to be free to dynamically pursue all kinds of different developments.

The natural gas markets in the other assessed countries are less mature than in the US. In Australia in the exploration, production and export segment, and in Japan and China in the import segment, we see only a handful of large, often governmentally owned (in Japan and China), companies. Gas markets are either small, dominated by said companies or quite isolated, or everything at the same time. In addition, full open third-party access is not provided in China and Japan. Bilaterally negotiated access to infrastructure and high third-party usage fees hamper market entry of new players and conserve the oligopolistic/concentrated nature of the market. Furthermore, due to current price regulation in China demand and supply are not reflected in the prices, leading to market distortions.

A further important aspect of market development is the existence of trading hubs. In that aspect the EU shows similarities to the US, both having several, well-established trading points. At the same time, trading hubs in the Asia-Pacific region have yet to be established (the Australian domestic market has several hubs, but with little to no impact on Australia's gas export). This leads to a situation where prices mostly do not reflect actual demand-supply balance.

In general, as long as market players cannot get access to the market (inter alia due to the lack of an effective open third-party access regulation) the contract duration has little influence on enhancing competition.

It can be assumed that a liberalized, mature and competitive market environment, will inherently also foster more dynamic contract characteristics.

Temporal Contract Structures

Temporal contract structures in the EU have been assessed and described in detail in chapter 2, therefore here we focus on the four selected markets.

Apart from commodity contracts in the US domestic market, long-term supply contracts in a range of about 20 years are the prevailing contract type in all four countries.[137] In Australia, China and Japan the long-term contracts are mostly still linked to oil prices, while US LNG export terminals apply tolling agreements with hub-based prices.

At the same time, on a secondary level, the role of contracts with shorter durations is increasing. That is for example the case for spot LNG supplies which have gained significance in Japan during the last years and are also used by Chinese companies. Such spot LNG cargos are often subject to firm long-term contracts in the first place, but as they are either no longer needed at the originally intended destination, or offer better value if diverted elsewhere (or never were meant for a particular destination), they are offered short-term on the market.

Though, it should be noted though that in the US long-term commodity supply contracts may face a renaissance. There is at least some evidence pointing into the direction that long-term contracts are assessed as instrument in order to ensure stable consumer prices.

In general, similar to the EU, where costly infrastructure is needed, the investment is usually backed-up with long-term contracts in all four countries. In addition, to long-term contracts gas field developments and export terminals are in many cases also safeguarded by vertical integration, when Japanese and Chinese importers take usually a minority stake in the investment projects in the US and Australia in order to ensure supply.

4.4 Key Differences in Economics

A pattern that could be repeatedly seen during the research is that of where significant investment is required, in most cases a long-term commitment of the investor – in particular if the assets are sunk – have been used, with durations up to the economic asset lifetime. Such investments typically are the exploration and production investments required to start the operation of a gas field, as well as transport infrastructure like gas pipeline and LNG terminals. In many cases the investment costs are largely sunk.

When assessing other gas markets, it becomes clear that long-term contracts are used to different extents. Long-term contracts were (and still are) typically used in the EU gas sector (at least in relation to producers) and for transport and liquefaction capacities (the latter holds also for the US). On the contrary long-term contracts play no role in the domestic US gas market (i.e. for commodity contracts). Therefore, one of the questions which arose during the project is the matter as to whether there are differences in economics driving possibly the need for long-term contracts.

[137] I.e. without having a closer look at supply contracts between utilities and consumers which typically are of a shorter-duration. However, liberalization and free choice of suppliers is not even possible in all US states and factually, a residential consumer investing in a gas-fired appliance will indirectly have a long-term relation with its supplier.

The willingness to such long-term commitments by investors is shaped by the expected market development as well as the economics of their investment. Thus, apart from the expectation of the volume to be sold into the market and at which price, the investment decision may also take into account the following issues:

- Lumpiness of the investment
- Project size in comparison with overall market size
- Flexibility in production/operation later on
- Associated investment needs

Lumpiness of the investment and project size

Natural gas wellhead development costs largely vary between the regions. While production costs in the US range between 3 and 7 USD/MBtu, investors in Europe face production costs of 5 to 10 USD/MBtu and in Qatar one MBtu can be produced for something between 0 and 2 USD.

Natural gas well-head development and production costs (USD/MBtu)	USA	China	Russia[138]	Europe	Qatar
Conventional gas					
Low	3	4	3	5	0
High	7	8	7	9	2
Shale gas					
Low	3	4	-	5	-
High	7	8	-	10	-

Table 17: Natural gas well-head development and production costs in 2010

Source: IEA, WEO 2012 - Special Report Golden Rules for Golden Age of Gas

As clearly disclosed by the figures in the table above, the production costs for both new conventional and shale gas are estimated to be in the same range in a specific region. The reason behind is the cheaper large conventional onshore locations are fairly depleted and new developments are only possible in more expensive onshore and offshore locations where production costs converge to those of shale gas production.

[138] Costs for projects in new onshore and offshore regions are indicated in the table. Development and Production costs for existing traditional production regions range between 0 and 2.

Shale gas production costs in Europe exceed by more than 60% those in the U.S. mainly due to stricter environmental legislation and the location and nature of the fields. The European shale gas plays are deeper and have a more complex geological structure, and they are located in areas with greater population density. All these factors result in significant higher development costs.

The geographical characteristics of Chinese shale gas are also different of those in the U.S. and necessitate more complex extraction technology which again leads to higher production costs. As China has so far no shale gas production the uncertainty regarding the different cost projections is rather high. Therefore the numbers should be looked at with some precautions. The figures presented in the table are IEA estimates which indicate the same cost range for both conventional and shale exploration. However, Kushkina[139] projects average productions cost for shale gas significantly higher than the production costs of conventional gas in Sichuan ranging between 4.4 and 5.7 USD/MBTu. For shallower shale wells (such as Sichuan shales) they predict costs between 6.6 and 12 USD/MBTu and for deeper wells 30-80% higher, excluding above ground costs which could increase the costs by an additional 30-50% due to the mountainous location.

When we compare these numbers to the costs of gas export projects in Australia, we see much lumpier investment costs. Investment costs for the (now stopped) Browse project were reported as around USD 4 billion per capacity of 1 mtpa (including the cost for the gas production investment), with total costs estimated at USD 50 billion.

Shale gas development has the advantage compared to conventional exploration that the individual incremental investment is rather small and production can be flexibly scaled up and down. The recent development with a strong decrease in gas rigs and a simultaneous increase in oil rigs shows this flexibility. Although the investment costs for one shale gas well are in general lower than for one conventional well, they can significantly vary depending on the geographical location. In 2011 experts estimated productions costs for a well upwards of two to three million dollars[140]. The actual drilling and completion costs for a single shale gas well in the U.S. are below USD 5 million, while in China first drills amounted to expenses of USD 8.2 million for each well. With respect to shale gas production in Europe, higher costs are even to be expected.

By looking at the production costs, one important aspect should not be forgotten with regard to the exploration of shale reservoirs, namely that the presence of liquids can change the dynamics of the project assessment. An analysis of Core Energy Group[141] revealed that the breakeven prices for

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[139] Kushkina, Ksenia, <<Golden age>> of gas in China, available at http://www.irex.ru/files/Gaidarfellowship/2012/Kushkina-Eng.pdf

[140] Hefley, et al. 2011cited by Ryan J. Duman, Economic viability of shale gas production in the Marcellus shale, 2010

[141] Core Energy Group, Gas Production Costs, August 2012

different Australian wells can be almost twice in case liquids are excluded from the assessment than in the case they are included. As investment decisions are rather taken by looking at the overall profitability, revenue flows from byproducts can change the overall project economics. Besides, there is no universal standard regarding cost allocation between main product and byproducts, therefore shale gas production costs need to be looked at with prudence and as they might not be comparable one to one.

Associated Infrastructure Investment Needs

Furthermore, shale gas production requires more than just wells. Adequate pipelines need to be in place to transport the drilled gas to either the consumption area or LNG terminals. The network infrastructure is mostly there in the U.S. Even for the new liquefaction facilities, at least network infrastructure and harbor facilities are already there (from the now obsolete regasification terminals built a couple of years ago). On the contrary, in China, the shale gas development will require substantial pipeline investments in the underdeveloped gas network due to a lack of pipeline capacity. The situation is somewhat similar in Australia where the lack of infrastructure is one of the key drivers of higher productions costs, besides the labor costs and lack of drilling technology.

Flexibility with regard to the Sales Market

In addition, flexibility with regard to sales market is a further important aspect of project´s economics. Many projects have little flexibility in Australia, while in the US a gas producer has plenty of option where to bring and how to sell the gas, with a liquid market (still) absorbing the production. At the same time, an exporter has plenty of flexibility from where and how to source the gas. Due to the developed nature of the gas market in case of new LNG terminals business decisions are in general not linked to gas field development. On the contrary, in Australia there are now mutual interdependencies between production and export investments. Gas fields are in most cases developed jointly with LNG terminals and costs are not necessarily split up between the two parts of the project which makes a comparison with development costs of LNG terminals in other regions, such as US where investment costs are in the range USD 0.4 to 0.5 billion per million tons per year[142] difficult.

In general, gas projects in Australia are characterized by rising investments costs, often exceeding planned budget making them up to 30% more expensive than similar projects in the U.S. For example the costs of Gorgon LNG project rose by approx. 20% and reached a total sum of USD 52 billion at the end. A recently published report written by the Australian Council of Learned Academies[143] found that relatively high gas prices are required to render shale exploration in Australia profitable.

[142] For terminals like Cheniere's Sabine Pass

[143] Acola, A study of shale gas in Australia, May 2013

According to the report´s findings the breakeven price for an Australian shale gas project would be around 6 to 9 USD/GJ which is somewhat above the price level of current domestic wholesale long-term contracts (as of 6 USD/GJ) but below the current netback price of gas exported to Japan (10 USD/GJ).

4.5 Conclusions

In general, we see long-term contracts currently applied in all four of the assessed countries, with significant differences though.. To date, where costly large scale investments are required, long-term contracts of 10 years and more (often 20 years) seem to be applied on a rather general level, with the exception of US gas production investment. Alternatively (or additionally), companies tend to hedge their positions with vertical integration along the supply chain. Similarly where strategic considerations are playing a major role, for instance in order to secure gas supplies for an import dependent market. As the current US debate on long-term supply contracts for utilities shows, not only the absence of a market may promote long-term contracts but also stable market conditions (as then the risk of having a long-term contract is also reduced, in particularly where long-term contracts include short-term elements, e.g. market-indexed pricing).

For the time being, it seems that the traditional model of long-term contracts will be continued to be used at least in relation to large investments, as for instance the example of the recent LNG export agreements for US terminals shows. This conclusion was further substantiated by the interviews with market experts conducted during the project. However, it seems to be a rather general belief that even while we still see also 20+ year contracts, the future contract durations may be more in the area of 10 or 15 years. For EU market players it can be assumed that with increasing exposure to the world gas market (e.g. due to decline of domestic resources) their contractual structures are also shaped by the competitive environment on the world gas market. Therefore it seems likely to assume that whilst a general tendency to a decrease in contract durations is observed, the typical contract durations related to imports into the EU may still be around 8 to 12 years for commodity and up to 20 years for capacity (e.g. in an exporting LNG terminal).

In general, it can be observed that the market fundamentals essentially shape the contract structure. The characteristics of the gas infrastructure and the regulatory measures such as third-party access and liberalization determine the level of competition in a country. In a liberalized integrated gas market such as the US, the establishment of contractual terms and their change over time, was and is among others driven by changes of the market environment (either by endogenous development or pushed by the regulatory authorities) which have led or at least have allowed for to a much more important role of short-term contracts with durations of less than three years. In import-dependent China (and to similar extent in Japan) where the market is characterized by an oligopolistic structure and state-owned companies with supply obligations dominate the import side, the investment and import decisions are rather steered by security of supply questions (import costs are of less importance when monopolistic positions ensure cost coverage in an case). The lack of competition results in the fact that import companies are less exposed to volume risk associated with long-term contracts. The main bulk of demand is covered by long-term contracts and spot-term contracts aim to serve mainly as a flexibility tool to supply additional demand.

By assessing the selected countries a clear pattern evolves with regard to motivation toward long-term contracts: while the gas exporting market actors rather focus on securing cash-flow from their investments (secured return, increased bankability of the project), gas importers concentrate on securing stable supply for their domestic demand. Thus, on world market level exporting and importing parties meet which have strong interest in stable long-term relations. However, an increasing variety of exporting and importing parties, as well higher transparency and increased optionality, is likely to lead to resolving the mutual interdependency between exporters and importers.

For the EU that would mean that longer-term contracts (as described above) will – for the time being – mainly be found on a primary level at the interface between production companies in gas exporting countries and importing companies, as these companies will be stronger affected by the approach used also by other player on a world market level and will likely need to conform to a large extent to the requirements of production and infrastructure companies in order to secure access to gas supplies. On a secondary level, i.e. companies on the EU market getting gas from importers and supplying it onwards and trading on the internal market will much less bound by such constraints. Their activities will be much more shaped by the situation on the EU gas market with a strong competitive pressure. As for the importing companies the EU demand as such is not likely to shift away, there is also less pressure to have agreements with companies on the secondary level to match their agreements on the outside interface. Therefore, it seems likely that contracts on a secondary level will tend to be shorter than on the primary level. With regard to infrastructure, where public consultations and regulatory approval is replacing traditional methods like open seasons in order to facilitate investment decisions, contract durations may also have the tendency to be more short-term oriented. In the longer run, with changes towards shorter and more flexible contract models expected also on the world market level, this may easily lead also to a change of contract structures for the EU market parties, while at the same time, changes on the EU market will increase the momentum for the development towards more flexible contracts structures on the world market.

However, it remains crucial how contracts are designed. Gas supply contracts of 10 years and more which are not bound to oil-price development but to gas market prices (thus containing short-term elements), as used for the tolling agreements contracts for US LNG export facilities, bear less risk for the buying party that at some point in time the gas will be too costly to be competitive on the world market. Still, parties of course bear a volume risk, but this is just similar to directly investing into infrastructure.

The recent developments have shown also for market players in Japan and China that oil-indexation is not the only possible solution to price gas. With supply contracts for the US based on gas hub price development, this opens a whole new debate and unfold a dynamic development (partially) away from oil-indexation, already showing in discussion with regards to Russian exports to China or in Australian gas exports. All in all, the research of Asian-Pacific markets indicates that these markets have achieved a state quite similar to that of the EU market 7 to 10 years ago: Buyers are realizing that they can get gas at prices lower than under the traditionally used oil-indexed contracts, either by unlocking new sources and suppliers or by renegotiations with existing suppliers.

Nevertheless, it seems quite safe to assume that, on a primary level, 8 to 12 (at least) year contracts will prevail for the time being, though with different pricing formulas perhaps. Oil-indexation will prevail very likely for a certain time as well, but maybe only as one element in pricing formulas, because of the security of supply concerns in countries like Japan (and also South Korea) putting low prices a bit more backward on the agenda. Long-term contracts will be sought for by those companies (and their capital providers) investing in large-scale field development of transport infrastructures. On the one hand, national concerns about securing necessary gas volumes could further strengthen the interest of parties involved in firm long-term contracts. On the other hand, potential competition among suppliers on the world gas markets could strengthens buyers' positions in their demand for new contract models. The contracts for US LNG exports could become a reference point for future gas supply contracts with other gas suppliers, i.e. either existing players such as Russia, Australia or Qatar or newly emerging supplies like East African or Mediterranean countries, such as Mozambique, Cyprus or Israel.

5 TASK 3: CROSS-SECTOR COMPARATIVE ANALYSIS OF THE TEMPORAL STRUCTURE IN OTHER RELEVANT COMMODITY MARKETS

5.1 Overview

The following sections provide a cross-sector comparative analysis of the evolution of the temporal contract structures in other relevant commodity markets. It is the aim of the analysis to derive any insights in relation to the impact an increase in short-term contracts may have on the EU gas sector.

As already explained in chapter1, we have chosen the following commodity markets for the cross-sector comparison: Brent crude oil market, Atlantic steam coal market, EU electricity market represented by the examples of Germany, Italy and UK.

Firstly, in the following sections, we have provided description of the development of the three selected commodity wholesale markets in the past. The descriptions are provided along a structure elaborating on the markets, the market actors and typical contracts used. The maturity of wholesale markets is thereby different and the drivers that led to different developments in the three commodity sectors were different either, in brief:

- Brent crude oil market: the analysis period covers the time period from the second oil crisis (1979 / 1980). This is crucial to understand the evolution that the crude oil market has undergone since. From vertical integration and long term contracts before the second oil crisis, over the netback pricing (80ies), the physical (wet) spot trade in the 90ies to the liquid paper wholesale trade of the new millennium, the important phases and transitions in crude oil markets are described and evaluated.
- The international trade in steam coal picked up after the phasing out of the domestic steam coal production. This phasing out started as early as the 60ies in the Netherlands and has not fully come to an end. The liberalization of electricity markets (at the end of the 90ies) created additional risks for the steam coal consuming market participants. The period from the beginning of the 90ies until now will be of major interest.
- The wholesale electricity markets developed between the beginning of the 90ies (United Kingdom) and the end of the 90ies (EU liberalization affecting Germany and Italy). The markets are thus less mature and developed than the crude oil market and similar to the steam coal markets.

Secondly, after the description of the individual markets, we have provided a comparative assessment of contract structures and drivers for this development. Thirdly, we provide an assessment of lessons-learned and insights gained in relation to the EU gas sector. At the end of this chapter, we will briefly elaborate on the key differences in economics across markets, drawing also on insights gained in the previous tasks, as these economics (i.e. investment costs and transport costs, fixed and variable costs) seem to have a strong influence on contract structures.

5.2 Case Studies

5.2.1 Atlantic Seaborne Steam Coal Trade

5.2.1.1 Development of the Steam Coal Trade

Historically steam coal was domestically produced in EU Member States close to the place of consumption of the steam coal – thermal power plants. The dominating structure was the so called mine mouth power plant. The power plant was generally located close to the coal mine and transport was done by means of conveyor belts, small scale train transport and similar means of short distance transport. The production costs of domestic steam coal exceeded increasingly the import costs of steam coal plus the associated domestic transport costs. Gradually EU Member States stepped out of the domestic production of steam coal. The following figure shows the gradual decline of production. An important exception of the general trend is Poland, which lowered its steam coal production significantly only after the end of the cold war.

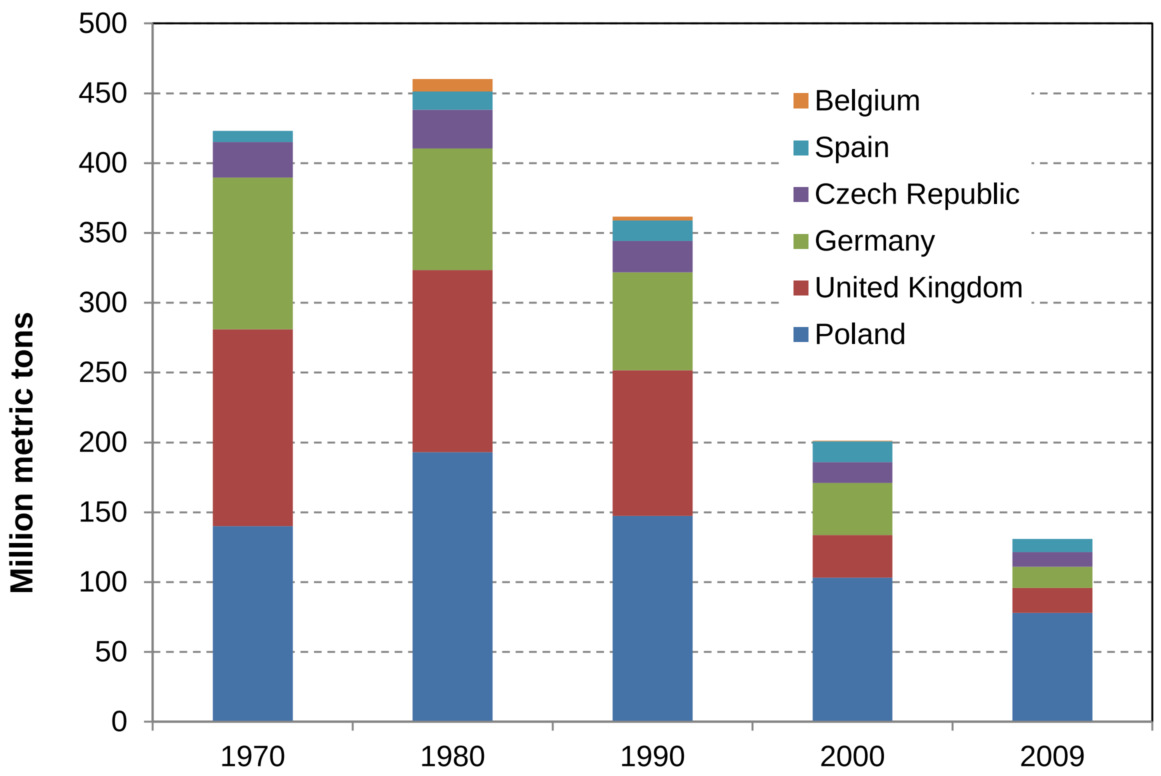

Figure 38: Development of domestic steam coal production in selected EU countries in million metric tons

Source: Bundesanstalt für Geowissenschaften und Rohstoffe, 2009

The reduction of domestic coal production left a significant share of existing steam coal fired power plants with a substantial residual lifetime without fuel supply and would have rendered these assets stranded (and subsequently would endanger the reliability of the electricity supply. Other countries had historically operated steam coal fired power plants relying from the onset on imported coal (e.g. Sweden, Denmark and Italy). The import needs of countries without domestic production and of the countries terminating their domestic production was met by imports. The imports stemmed partially from countries historically already being significant coal producers (e.g. USA[144]), from countries with – until then – a limited domestic coal production (e.g. Australia, South Africa) and countries with no previous coal production at all (e.g. Indonesia, Columbia and Vietnam). The following figure shows the development of the production in selected steam coal exporting countries.

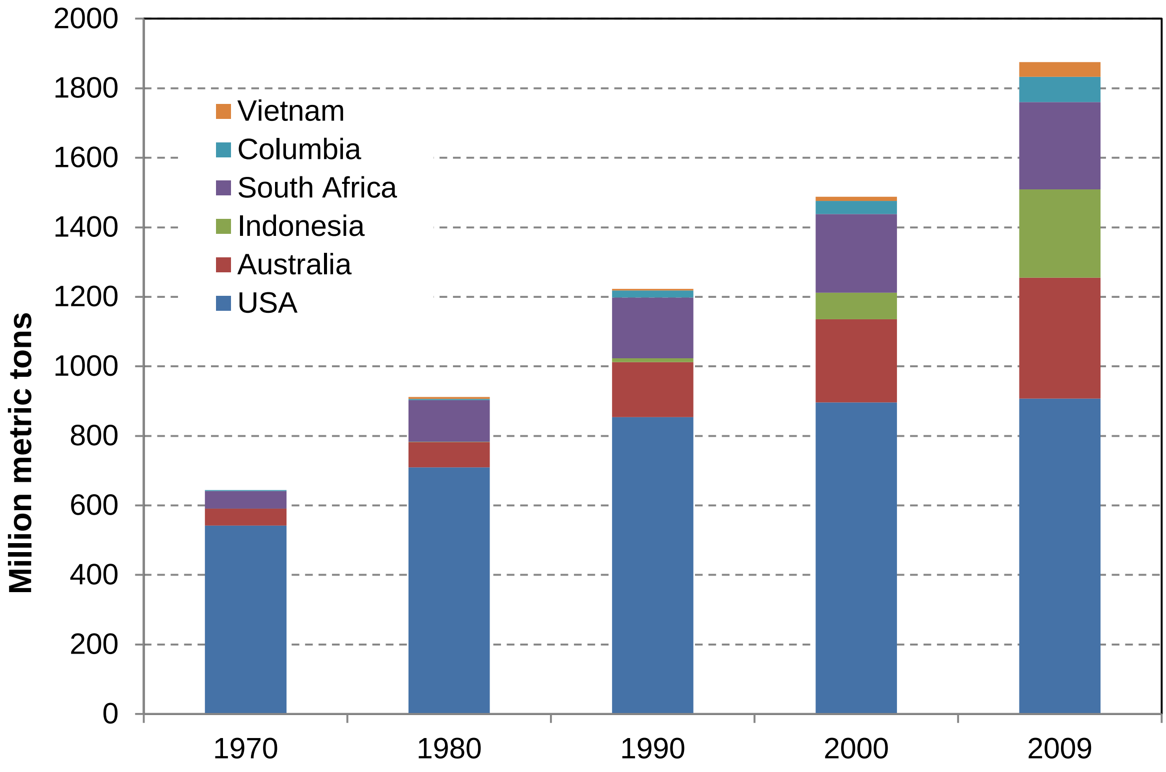

Figure 39: Development of steam coal production in major exporting countries in million metric tons

Source: Bundesanstalt für Geowissenschaften und Rohstoffe, 2009

The international steam coal trade can separated into the Atlantic and Pacific seaborne steam coal trade and some limited international land transport. The pacific steam coal market is approximately

[144] The USA acts in the international steam coal trade as a so called swing supplier. The USA is both producing and consuming large amounts of steam coal. Depending on the market situation the USA will export additional coal volumes above their domestic consumption at times of high coal prices and vice versa in times of low coal prices. The strong increase of shale gas production in the USA and subsequent decline of natural gas prices has and will lead to stronger US exports onto the international steam coal markets.

twice as big as the Atlantic market (driven by the large coal imports of Asian countries such as China, India, Japan, South Korea and Taiwan. The Pacific and Atlantic markets are tightly connected to each other.

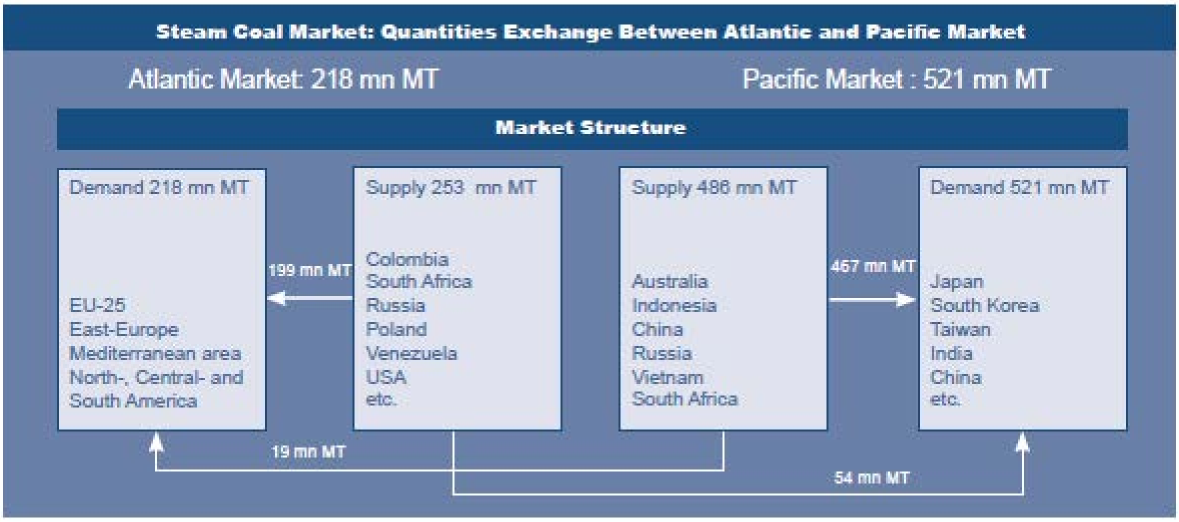

Figure 40: Trade flows in the Atlantic and Pacific steam coal trade 2011

Source: Bundesanstalt für Geowissenschaften und Rohstoffe, 2009

The markets

The Atlantic steam coal market consists of a physical layer and a derivative layer. The physical layer is primarily a bilateral market between coal producers and coal consumers with or without insertion of intermediaries. Intermediaries in the physical layer may match potential buyers and sellers (i.e. pure brokerage) or offer additional added value services such as sea transport, insurance, storage and blending. Steam coal is a rather inhomogeneous commodity with a high variability of quality standards (e.g. ash and sulfur content, heat rate, moisture). This limits the scope for standardization of physical coal transactions. The physical market is thus a more bilateral market with only a few multilateral trading facilities (GlobalCoal is the dominating physical market place for steam coal). The churn factor is low meaning that the title in the commodity between production and consumption will only change a few times, if at all. The most important physical markets for the Atlantic seaborne steam coal trade are:

- Richards Bay, a South African export harbour,
- Newcaste, an Australian export harbour, and
- Amsterdam-Rotterdam-Antwerpen: these represent the most important trade places for imports from the above exporting markets.

The aforementioned market places are used to derive spot market prices indices to settle derivative hedging instruments (see below).

The consumers of steam coal (i.e. power generators) are exposed to heavy inter-fuel competition (see section on electricity wholesale markets). Subsequently a need to hedge against the price differential between the steam coal and electricity prices occurred. This led to a large increase of derivative instruments being applied for the hedging the future steam coal prices. There are three important spot price indices that the derivative market will be settled against:

- **API#2**: the volume weighted average of monthly spot cargos in the Amsterdam-Rotterdam-Antwerpen area
- **API#4**: the volume weighted average of monthly spot cargos in the South African export harbor Richards Bay
- **Newcastle FOB**: the volume weighted average of monthly spot cargos in the Australian export harbor Newcastle

The churn factor between the physical steam coal trade and the nominal derivative paper trade was 3.5 in 2010. The factor in the Atlantic basin is even higher due to the large dominance of the API#2 index. The dominating market for derivative transactions is the standardized OTC market facilitated by brokers. Second to it is the exchange based derivative steam coal market of the Intercontinental Exchange (the ICE), followed by smaller exchange based markets such as the European Energy Exchange (EEX) or the already aforementioned Global Coal (being primarily a physical market with derivative market being only an extension. The following figure shows the explosive increase of derivative transactions since 2000.

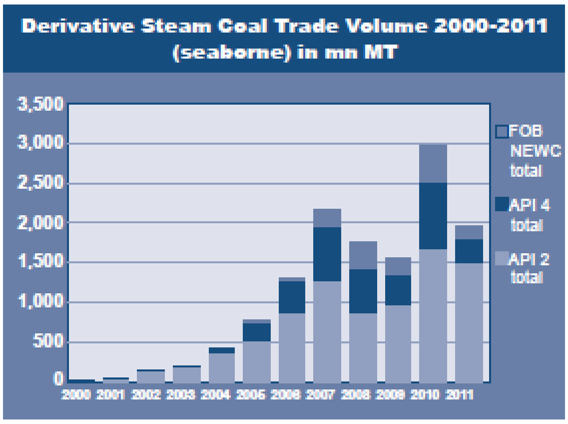

Figure 41: Derivative steam coal trade since 2000

Source: Verein der Kohleimporteure, Jahresbericht 2012

The actors

The coal producing companies are large operators of mostly open cast steam coal mines and a good infrastructure to nearby export harbors. The most important export countries for the Atlantic market are in descending order Colombia, Russia, the USA and South Africa.

The intermediaries and market operators can be broken down into two distinct classes of service providers. On the one hand "pure" brokerage companies are bringing together buyers and sellers. The important steam coal brokers are GFI, ICAP, Spectron, TFS and Tullet Prebon. On the other hand added value service providers are providing additional services such international and domestic transport, storage and blending. These can be producing companies such as BHP Billiton or Glencore, consuming companies such as Peabody or pure service companies such as RAG Trading. The service providers may or may not take a title in the commodity. The market operators are mainly the Intercontinental Exchange and smaller market places such as the EEX and Global Coal.

The traders: can be broken down into the market participants with a physical interest or pure speculative players. Most often physical players are either producing companies (e.g. BHP Billiton, Glencore, Peabody) or consuming companies (e.g. RWE, EDF, E.ON). In the derivative market the same players are active as in the physical market. Additionally several investment banks have entered the derivative steam coal trade (e.g. Goldman Sachs, Deutsche Bank, Societe Generale).

Contracts – structure, products and duration

Physical layer: Most of the physical transactions are spot related meaning that the buyer and seller will agree on the terms and conditions for a single sea vessel cargo of steam coal. These spot transactions are often done under a single contract. More seldom framework contracts are applied, which determine general contractual conditions such as force majeure, termination rights, credit support and so forth; they generally do not determine the price and volume of the steam coal. Framework contracts can have indefinite contract durations, but as they do not require the conclusion of a particular transaction, they will leave the full flexibility for the market operators. Framework agreements in physical coal trading are for example:

- The **Standard Coal Trading Agreement (SCoTa)**, developed by Global Coal,[145] changed the nature of the contract from a single-transaction contract to a framework agreement. The SCoTa is a widely (> 2000 licensed users) used physical trading agreement and mainly applied to international transactions. Until version 7 it was a single-transaction contract.
- The **Master Coal Purchase and Sale Agreement** was developed by the Coal Trading Association and is used primarily for US domestic coal transactions.

Due to the inhomogeneous product characteristics of steam coal several definitions have to be agreed between seller and buyer before actual delivery. These include inter alia caloric values, moisture, ash and sulfur content and grain size.

As mentioned earlier, both transactions under a single agreement or under a framework agreement concern single cargoes for a prompt delivery.

Derivative layer: The derivative contracts are highly standardized. Bilateral OTC derivative transactions are almost exclusively concluded under the ISDA framework agreement. The ISDA is

[145] Standard Coal Trading Agreement, Ver. 8, 16.09.2011, Global Coal

normally a financial framework agreement and does not foresee a physical component. The ISDA contracts can be used to trade several commodities (e.g. crude oil, metals, natural gas, soft commodities) but also for other financial transactions (like FOREX or interest rates). In order to trade steam coal under an ISDA agreement, a dedicated schedule for steam coal needs to be agreed upon the contract partners. Once a framework agreement has been agreed upon, derivative trade can be done anonymously. The bilateral transactions are Swaps, meaning that they have a so called fixed leg (i.e. the agreed contract price) and the floating leg (the spot index). Only the difference between the contract prices is settled between the partners. The spot indices are the aforementioned API#2, API#4 and Newcastle FOB. These swaps may be cleared bilaterally or centrally by means of a clearing house.[146]

The organized market places (e.g. ICE, EEX) require a membership in the exchange and the associated clearing house. The future products traded in the organized market places are highly similar to those SWAPS traded in the bilateral OTC market. Both are cash settled during the delivery period between the market participant and the clearing house. The difference is the margining to account for the volatility of contract prices prior to the actual delivery. In order to protect the clearinghouse against credit risks, the market participants will have to deposit an initial margin and have to provide a variation margin. The variation margin can represent cash flows in both directions.

The derivative products traded on the OTC markets and the exchanges are highly similar:

- Months,
- Quarters (three consecutive months / i.e. Jan.-Mar.),
- Seasons (six consecutive months / i.e. Jan.-Jun.),
- Calendar years (i.e. Jan.-Dec.)

Steam coal can be traded up to six years ahead (meaning that in theory transactions can be concluded for the period 2018 / 2019). However, liquidity and open interest is highly focussed on the short end of the “forward curve”.

5.2.1.2 **Investments in Production**

Case Study USA: Coal mining in the US is centered in three regions: The Appalachians, the “Interior” and the Powder River Basin. Steam coal is used in electricity generation domestically and partially exported. The US used to act as a swing supplier. Due to the recent shale gas “revolution” in the US, steam coal has lost ground against gas in power generation. The replaced steam coal is instead being marketed. Historically, most exports were in the direction of the Atlantic market, but US exporters are increasingly trying to export in the faster growing Pacific market.

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[146] In the US, derivative commodity transactions have to be cleared centrally by a clearing house due to the Dodd-Frank Act. In the EU this requirement will be introduced 2014-2015 through the recently enacted EMIR regulations.

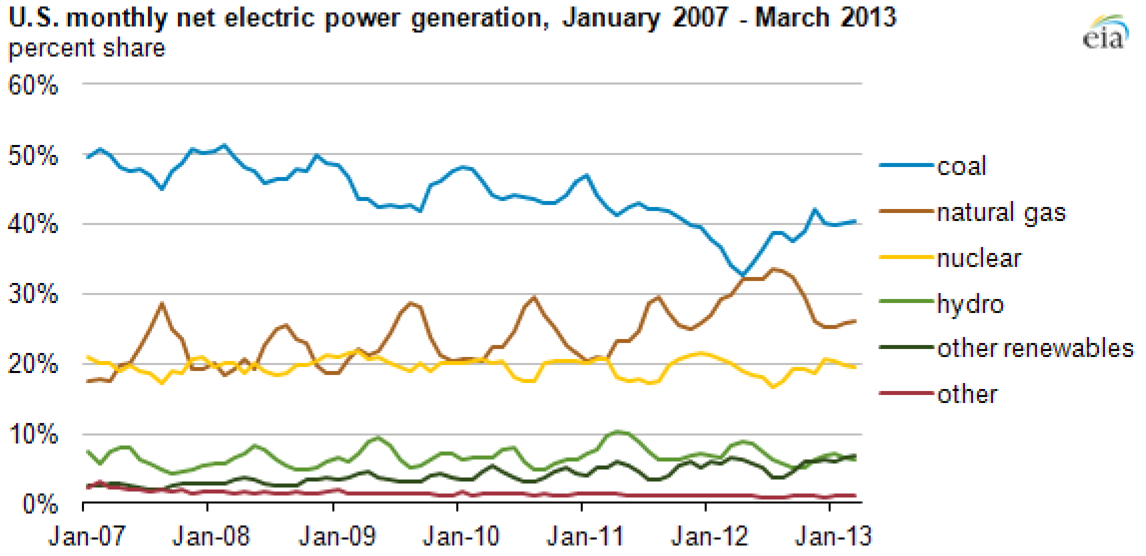

Figure 42: Evolution of the fuel mix in US electricity generation

Source: US Energy Information Administration, Electric Power Monthy, April 2013

The US mining industry is highly fragmented. However, the largest three mining companies account for more than 40% of all coal production in the US.

Mining Company	Thousand tons	Share
Peabody Energy Corp.	188,002	18.9%
Arch Coal Inc.	145,403	14.6%
Alpha Natural Resources LLC	105,591	10.6%
Cloud Peak Energy	86,723	8.7%
Consol Energy Inc.	30,209	3.0%
Others	555,928	55.9%
Total	**993,937**	**100.0%**

Table 18: Major US coal producing companies

Source: US Energy Information Administration, Annual Coal Report 2011

The Appalachians is the oldest coal mining area of the US. The coal is partially produced in open cast mines and partially in underground mines. The coal is partially consumed domestically and partially exported. The export volumes of the Northern part of the Appalachians is exported via the export terminals in Norfolk and Baltimore, the export volumes of the Southern part of the Appalachians via harbors in New Orleans and Mobile.

The Powder River Basin is the largest coal mining region in US accounting for 40% of overall production. Located in Wyoming and Montana, coal is mainly used domestically. The coal mining area is characterized by large open cast mines. The high quality of the coal and the worsened competitive position of steam coal in US electricity generation have triggered ideas to build a railroad from the Powder River Basin to the Pacific Northwest coast in order to enable exports to Asia. There are five export terminals under consideration.

The interior coal mining area combines coal mining in Texas, Eastern Interior (Illinois and Indiana), Western Interior (Oklahoma, Missouri and Kansas), and Mississippi (Mississippi and Arkansas). Coal production in the interior region is declining.

Figure 43: Coal mining in the US and export harbors

Source: based on DOE- EIA information

The figure above shows the coal mining areas and the export harbors and export volumes for 2011.

Investments in the mining sector have been limited in recent times and were meant to maintain current output levels. Notable recent investments were the Bear Run coal mine in Indiana and the extension of the existing Twentymile mine in Colorado. The Bear Run Mine was opened in 2010 is located in Indiana and serves primarily local power stations. The investment of USD 400 million is backed by 17 year long-term contracts with power generators. At the maximum annual production of 8 million tons, the proven and probable reserves would allow operation of this mine for 35 years. The Twentymile extension will allow meeting obligations to deliver 40 million tons in long-term coal supply agreements beyond the lifetime of the existing Twentymile mine. The existing Twentymile mine and extension are backed by long-term contracts with the nearby Hayden power station of XCel Corp.

Case Study Colombia: the largest coal mine in Columbia is El Cerrejon, representing more than 40% of the total Colombian coal production. The mine is jointly owned by BHP Billiton, AngloAmerican and Xstrata. The mine is located in the North of Colombia and the production is transported via a railway to the export harbor Puerto Bolivar. Almost the complete production is exported to the Atlantic market. In August 2011, a decision to invest 1.3 billion was taken to increase the annual from 32 to 40 million tons. Construction is expected to be completed this year. Afterwards the production will progressively ramped up until 2015.

The domestic Colombian steam coal market is rather small. The bulk of production is being exported. Exports are spot related and not backed up by long term contracts.

Case Study South Africa: coal is the dominating primary fuel in South Africa. Coal is being used to generate electricity (93% of electricity generation stems from coal), to produce gasoline (30% share of synthetic refined products). Around 25% of the South African coal production is being exported (almost exclusively to the Atlantic market). The steam coal being used to generate electricity by state owned electricity generator ESKOM is purchased under long-term contracts with either fixed prices or cost plus pricing formulas. The resulting prices are expected to be way below the world market prices of steam coal. Coal mining companies have thus a high incentive to export free volumes to the world market. The export is hampered by a lack of export infrastructure.

One of the most recent investments is the Zibulo mine, owned by AngloAmerican (73%) and Inyohi Consortium (27%). The investment in the Zibulo mine has been taken in 2007, construction started shortly thereafter and in Q3 / 2009 the first production and full production was achieved in Q4 / 2011.

The investment of around USD 500 million is partially backed by domestic sales to generator ESKOM (3 million tons p.a.), the remainder will be exported. The export will be via the Richards Bay export harbor. The export facilities in the Richards Bay harbor are fully contracted via long term contracts. AngloAmerican has existing capacity rights in the export harbor.

The case studies show that investments in coal mining are backed partially by long-term contracts. This observation holds true especially for the mines which are located in remote placed with generally only one or two local customers, generally being electricity generators. The long-term contracts serve in this case as risk mitigation measures for both the seller and the buyer. The seller will have a stable sales basis and the buyer a stable fuel supply. The tight link between sellers and buyers is becoming weaker the more choices sellers and buyers have. A good export infrastructure and favorable domestic transport facilities from the mine to the export harbor will allow the mine owner to make investment decisions without at least a partial backing by long-term contracts. The export mine El Cerrejon in Colombia without any backing of long-term contracts is thus rather the exemption than the rule.

Another important driver for investments is obviously the level of wholesale steam coal prices. Investments tend to be decided in phases of high steam coal prices as being shown in the figure below.

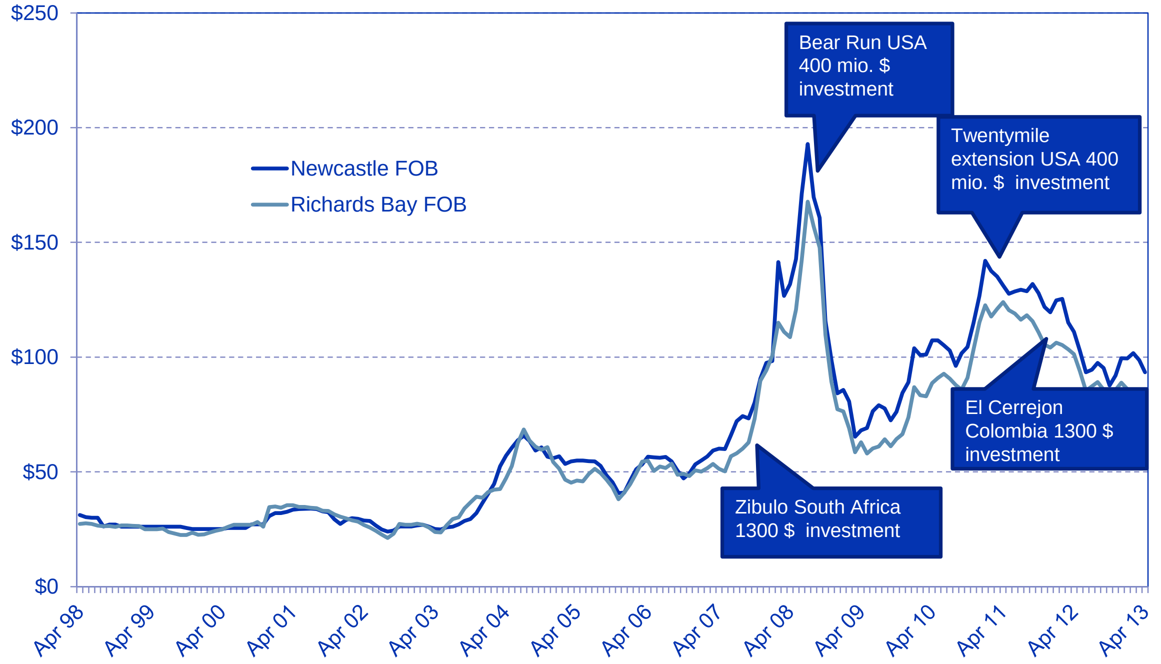

Figure 44: Steam coal export prices and investment decisions

Source: IHS McCloskey, annual reports and company news

5.2.2 Conclusions Atlantic Steam Coal Trade

The Atlantic seaborne steam coal trading developed gradually to replace the domestic European steam coal production. Historically, the steam coal production in Europe was tightly linked to the main consumption sector electricity generation; either by means of vertical integration of mining and electricity generation (e.g. SNET / Charbonnages de France, Steag / Ruhrkohle) or by mandatory cost based off-take obligations of steam coal generating companies. Usage of steam coal for space heating was gradually replaced by heating oil and natural gas based systems. Cheaper import coal required the subsidization of the uneconomic domestic production. The need to subsidize the domestic coal production motivated the closure of coal mines in Europe.

During the 90ies electricity markets both in the US and Europe (e.g. UK 1990, Norway 1991) were liberalized and steam coal producers were exposed to interfuel competition with other primary fuels for electricity generation. The competitive wholesale electricity markets led to price risks, which needed to be hedged. The introduction of financial derivatives for steam coal allowed to hedge price risks from the electricity markets. The instruments for risk hedging resemble thereby in their contract structures to a large extent the structures of the wholesale electricity markets. The time horizon of forward / futures trading, the duration of standard contracts and liquidity along the forward curve are very similar. The development of the steam coal trade follows the development of the wholesale electricity trade.

Vertical integration of steam coal production and electricity generation is today rather the exemption than the rule. The reason for the missing link by means of corporate integration or long term contractual relations is attributable:

- to the long distances between production and consumption centers,
- the vast number of coal producers and electricity generators as potential sellers and buyers,
- the rather low specific seaborne transport costs.

Vertical integration by corporate ownership or long term contracts applies in cases, where transport costs are prohibitive to transport over long distances with rather expensive transport means (i.e. rail transport). A practical example from the case study is the Powder River Basin in the Northwest US.

The backing of investment decision is done based on long term contracts if producers and consumers are intrinsically linked to each other. This is generally the case if mine and power plant are remotely located and neither the producer nor the consumer are in position to bypass the other due to a lack of alternative infrastructure (i.e. no domestic transport infrastructure). Different to the comparable situation of lignite almost no vertical integration can be observed between coal producers and consumers. Long-term contracts are often based on cost plus formulas or fixed prices. Provided both sellers and buyers have several different options to sell or purchase the steam coal, long term contracts are not applied. Investments in coal mining are based on the anticipated demand and supply balance. If demand is high, prices for steam coal (both spot and forward quotations) tend to increase and investment decisions are taken. Steam coal mining is in this respect a typical boom and bust industry.

5.2.3 Brent Crude Trade

5.2.3.1 Development of the Brent Crude Trade

Historically the exploration, production, refining and marketing of refined products were done within vertically integrated companies (e.g. EXXON, Shell, BP etc.). Due to the vertical integration no significant trade in the production chain took place. The so called oil multinationals produced crude oil in concessions granted by national governments and paid royalties in return to these governments. Starting in the 50ies and lasting until the beginning of 70ies, several national governments nationalized the crude oil reservoirs and created own exploration and production companies. These former fully integrated oil companies lost partially their production base. The oil producing countries formed a cartel known as the OPEC to agree on production quotas and target price levels. The cartel produced in this way the first oil crisis as of 1973. Pricing of crude oil was a complicated structure of so-called “posted prices”, “official selling prices” and “buy-back prices” and was so cumbersome for OPEC to control and administer that the system broke down during the 70ies. The roaring crude oil prices led to increased exploration efforts to find new reserves in other places in the world. Among the places with increased exploration efforts were the North Sea (particularly the British and Norwegian shelf). The exploration proved to be successful (the Brent oil field to be discovered first, followed by several others) and the new reserves were discovered and prepared for production (Brent was discovered in 1971 and started production in 1976). In order to align short-term fluctuations between production and consumption a short-term physical Brent crude trade emerged in the 80ies first among the physical players. The price index used was the 10day Brent market index (see below). The Brent crude oil field reached its production maximum in the mid 80ies and declined thereafter. In order to preserve the function as a price marker, additional oil fields were added to the price index. The first additional field to be added was the Ninian field (UK) in 1990, the Forties (UK) and Oseberg (Norway) fields in 2002 and the Ekofisk field (Norway) in 2007.

The markets

The BFOE (Brent, Forties, Oseberg, Ekofisk) spot market is the lowest physical layer of the Brent crude oil trade. This market represents the spot market with physical delivery 25 days after the transaction date. Above this physical layer the first derivative level is the 21-day BFOE trade. Forward Brent is a forward contract that specifies the delivery month, but not the particular date when the cargo will be loaded. The 21-day Brent can be either cash-settled or physically delivered. In case of cash-settlement the price differential between the contract price and the spot price will be settled between the contract partners. The 21-day Brent market is a closed shop of only a few market participants, but inhibits a large liquidity. The low number of participants in this physical market can be explained by the need to have access to physical assets (in particular transport assets as the Brent system, a pipeline system connecting 20 offshore oil-fields with a landing terminal in Sullom Voe on the Shetlands).

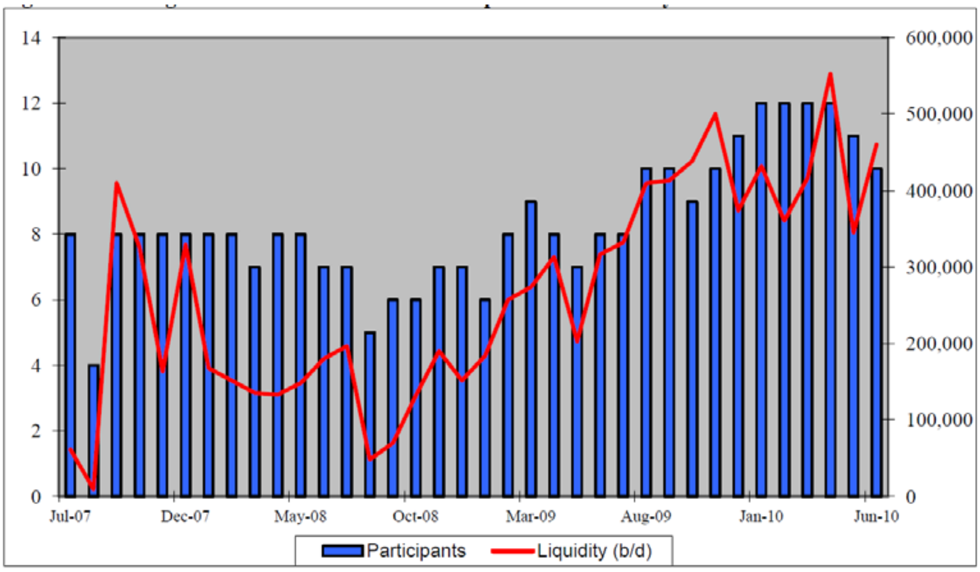

Figure 45: Number of participants and liquidity in the 21-day Brent trade

Source: the Oxford Institute for Energy Studies, An Anatomy of the Crude Oil Pricing System, Bassam Fattouh, 2011

The next derivative layer is the bilateral OTC market and the organized exchange trade on the Intercontinental Exchange (ICE). In the bilateral OTC market derivative Brent swaps are traded among oil producers, oil consumers (i.e. refining companies, if different from the producing ones), traders (both physical oriented companies such as Vitol and pure paper traders such as investment banks) and hedgers (parties with a need to hedge a crude oil price risk). The trade is generally done based on an ISDA framework agreement. The swaps contract prices are settled against the Brent crude oil price index. More important than the bilateral OTC trade is the exchange based trading at the Intercontinental Exchange. The Intercontinental Exchange started trading oil futures in 1988 as the International Petroleum Exchange. Crude oil trade in the Intercontinental Exchange increased dramatically over the next twenty years. In 2010 the average trading volumes in the ICE were 400 million barrels per day, five times the physical worldwide consumption. The large success of the crude oil trading in the ICE is the vast number of market participants. In OTC trading in order to trade framework agreements (in this case the ISDA contract), dozens, if not even hundreds of ISDA contracts were needed to be entered into in order to avoid opportunity costs (potential trading partners with an interesting offer has no framework contract). In an exchange traded environment only a contract with the exchange and a contract with clearinghouse have to be entered into.

The actors

The **crude producing companies** are the operators of onshore or offshore oil fields in the vicinity of the North Sea.

The **intermediaries and market operators** can be broken down into two distinct classes of service providers. On the one hand "pure" brokerage companies are bringing together buyers and sellers. The important crude oil brokers are GFI, ICAP, Spectron, TFS and Tullet Prebon. On the other hand added value service providers are providing additional services such transport, storage and blending. The service providers may or may not take a title in the commodity. The market operator is represented by the Intercontinental Exchange[147].

The **traders** can be broken down into the market participants with a physical interest or pure speculative players. Most often physical players are either producing companies (e.g. BP, Shell, Statoil, Total) or refining companies (basically the same as the producing companies). Next to the major oil companies, physical traders are arbitrageurs, who move crude oil one place to another to exploit price differentials (e.g. Vitol, Trafigura). There even some investment banks active in the physical crude oil trade. In the derivative market the same players are active as in the physical market. Additionally several investment banks are active in the derivative crude oil trade (e.g. Goldman Sachs, Deutsche Bank, Societe Generale). In the ICE alone more than 150 participants are admitted to trade Brent crude oil derivatives.

[147] There are other exchanges in the world with crude oil trade as the NYMEX (WTI trade) or DUBAI Exchange, but the ICE is the only important exchange for the crude oil trade.

The Contracts – structure, products and duration

Physical layer: As explained above, the physical Brent crude oil trade is a “closed shop” with a very limited number of participants. Access to physical infrastructure (in particular pipelines and terminals) is a prerequisite for participation and creates large barriers to entry the market. The 21-day Brent market is a spot related market for deliveries for the next three months. Delivery is mainly physical, but cash settlement can be arranged among the market participants. Due to the low number of market participants, no standardized, published framework agreement exists for the trade in this market. However, the bilateral agreements in place are presumably very similar in order to avoid incompatibility issues in back-to-back transactions.

Derivative layer: The derivative trade can be broken down in the OTC trade and the exchange based trade. Similar to the steam coal trade, the OTC trade in crude oil in done via the ISDA framework agreement. A schedule for Brent crude oil is added to the framework agreement in order to account for the specifics of the crude oil trade. The transactions are SWAP based; the price differential between the contract price and the Brent price index is cash settled. The OTC transactions may foresee bilateral margining (to protect against credit risks) or not. In the future, these OTC transactions will need to be cleared centrally (see section on steam coal trade).

The futures traded in the ICE are similar to the Swaps traded in the OTC market but not identical (in contrast to the steam coal products, which are almost identical). There is a substantial basis risk between an OTC Swap and an ICE future, which do not allow changing an OTC position into an exchange position and vice versa.

Monthly futures can be traded in the ICE until 2016 (for each month), thereafter the months June and December can be traded until 2019. No quarterly, seasonal or annual futures exist. The futures can be transformed into physical trading obligations (Exchange of futures for physical).

5.2.3.2 Investments in Offshore Exploration and Production

Case Study Sonangol / Angola: Angola is largest crude oil producer in Africa and surpassed Nigeria in 2007 in this role (being the 8th largest oil producing country in the world). Exploration and production of crude oil (both onshore and offshore) is vested with the state owned holding *Sociedade Nacional de Combustíveis de Angola (***Sonangol***).* Sonangol invites major oil producing companies for the exploration and subsequent production of (onshore and) offshore fields. The foreign companies provide technical knowhow and capital to develop the fields and are entitled to a share of the crude oil production output (Production Sharing Agreement[148]). Sonangol tries increasingly to become independent from the foreign field operators and is building up expertise also in deepwater offshore crude production. The ultra deepwater fields 31 to 34 are located in water deeps of more than 1200 m

[148] http://www.sonangol.co.ao/wps/wcm/connect/790e270047e2f8a19ec4dfd5ee7fe2c3/bid07_cpp_KON11_KON12_cabindaCentro_en.pdf?MOD=AJPERES&CACHEID=790e270047e2f8a19ec4dfd5ee7fe2c3

and are currently developed. Production of crude oil started in Block 31 in January 2013. The table and figure below show the concessionaires of the fields with their production shares and the location of the offshore fields.

	Block 31	Block 32	Block 33	Block 34
Sonangol	45.0%	20.0%	20.0%	20.0%
Total	-	30.0%	58.7%	-
BP	26.7%	-	-	-
ESSO	-	15.0%	-	
Statoil	13.3%	-	-	50.0%
Marathon	10.0%	10.0%	-	-
Petrobras	-	-	-	30.0%
China Sonangol	5.0%	20.0%	-	-
Others	-	5.0%	21.3%	-

Table 19: Production shares in Angolian deepwater offshore fields 31 to 34

Source: Sonangol [149]

[149] http://www.sonangol.co.ao/wps/portal/!ut/p/c1/04_SB8K8xLLM9MSSzPy8xBz9CP0os3hDl5AQUzN_QwMDwyBTA09DR2djAy8XYwMzE6B8JLJ8gIUbUN4_MMDHx9XQwNyUIt1mBHSHg1yLVwWaPIr57u5GeOUNzM0JyJsSkDeDyBvgAI4G-n4e-bmp-sEFJfoFuaERBpmemQHpjooAMnGmrA!!/dl2/d1/L0lHSkovd0RNQU5rQUVnQSEhL1lCWncvZW4!/

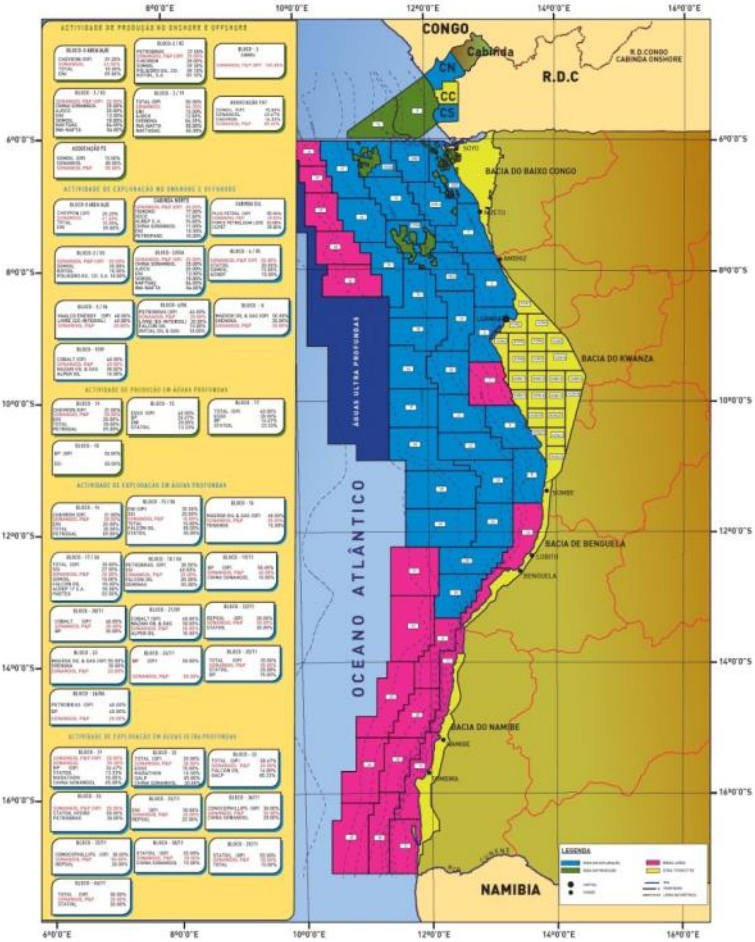

Figure 46: Concession areas in the Angolian onshore and offshore fields

Source: Sonangol [150]

The integrated oil companies being partner to Sonangol in the E &P activities are adding the crude oil production to their respective portfolios. Sonangol markets their crude production share via sales offices in London, Houston and Singapore in wholesale markets. Angola itself has only a very small refinery and needs to import refined products from the world market. Sonangol is therefore building a refinery complex in Lobito. This will allow to meet the domestic demand for refined products and to sell the surplus products on the market.

Sonangol markets the output from these fields without backing of long term contracts.

[150] http://www.sonangol.co.ao/wps/portal/!ut/p/c1/04_SB8K8xLLM9MSSzPy8xBz9CP0os3hDl5AQUzN_QwMDwyBTA09DR2djAy8XY4NQc6B8JLJ8gIUbUN4_MMDHx9XQwNyUIt1mBHSHg1yLW4WZCbo8ivnu7kZ45Q3MzQnImxKQN4PIG-AAjgb6fh75uan6BbmhEQaZnpkB6YqKAKcvJ6g!/dl2/d1/L2dJQSEvUUt3QS9ZQnB3LzZfMURUVDU2TzEwMDFSNTBJMUFDMzBKRDMwVTI!/

Case Study Petrobras / Brazil: Petrobras is the leading integrated oil company of Brazil. It is a privately owned and stock listed company. Petrobras operates along the oil value chain and is active in E&P, refining and marketing of refined products.

In 2006 the deepwater (> 2000 m) offshore Lula oil field was discovered in the Santos basin by Petrobras. The Lula oil field is one of the largest oil fields discovered in the last 30 years. Block BM-S-11, of which the Lula field is part of, is operated by Petrobras. Petrobras holds a 65% stake of the oil field and the rest is held by BG Group (25%) and Galp Energy (10%). The first 4 production wells were drilled in 2012. The field will reach its final production capacity in 2017 and is expected to produce 1.4 million barrels per day.

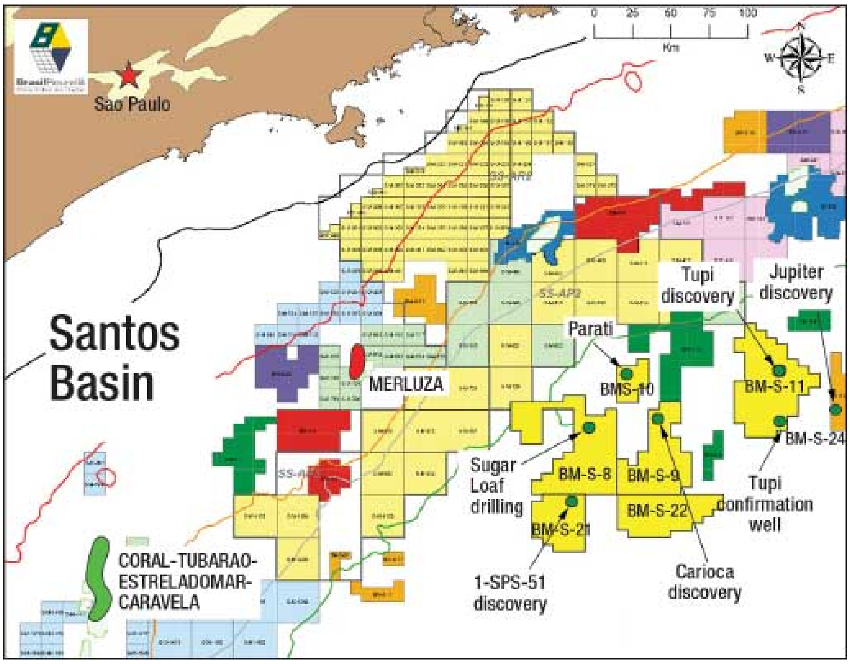

Figure 47: offshore fields in the Brazilian Santos basin including BM-S11 (Lula field)

Source: National Agency of Petroleum, Natural Gas and Biofuels, Brazil[151]

Investments in crude oil exploration and mining are backed partially by vertical integration. Vertical integrated companies are able to mitigate price risks at least partially by their downstream activities. But also companies with very low own downstream activities are marketing their crude oil production without long term contracts as risk mitigation measures. Apparently the sharp increases of crude oil prices since the millennium have meant for E&P oriented companies a high upside potential and only a limited downside potential. The increases have been interrupted only temporarily by a price collapse following the financial crisis (see figure below). The long-term outlook is also rather stable and

[151] http://www.brasil-rounds.gov.br/ingles/mapas_de_concessoes.asp

positive for E&P companies. Long-term contracts with a different price base than one of the leading price indices could itself create certain risks. Another important factor to consider in the explanation of a lack of long-term contracts is the lack of a long term exposure of typical end consumers of crude oil products. Consumers from the traffic sector for example show only a very limited future exposure to crude oil prices. The forward price exposure exists for most consumer types only to the next one-two years. Subsequently, these consumers are unwilling to hedge non-existent open risk exposures.

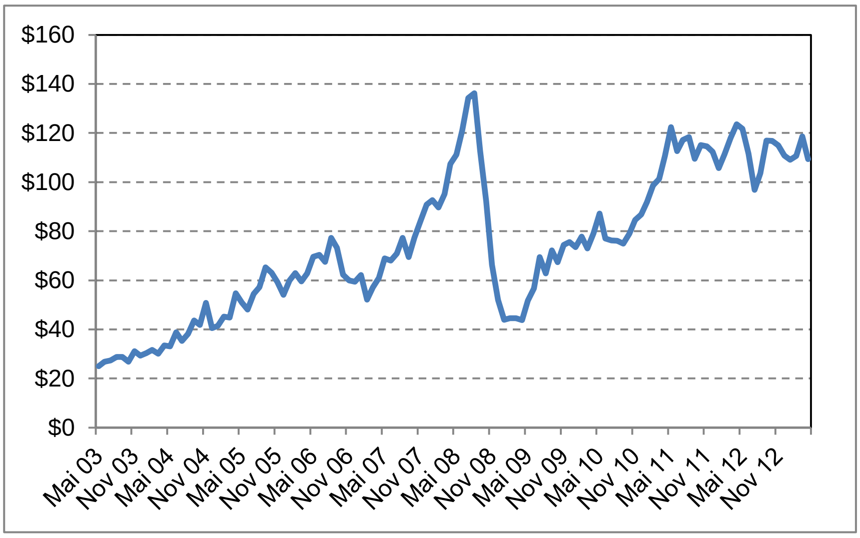

Figure 48: Brent crude oil price development

Source: Platts

5.2.4 Conclusions Brent Crude Oil Trade

Brent crude oil was the first commodity market relying strongly on standardized wholesale trading. The wholesale trading emerged outside the traditional vertical integration and / or long-term contracts as a result of new emerging independent oil producers. This development occurred in two steps. Vertical integration was historically the dominating principle in crude oil production and consumption (consumption representing the downstream / refining sector). The nationalization of exploration and production in large areas of the world led to a breakup of this vertical integration. The vertical integration was replaced by a system of administered prices set by the OPEC cartel countries. New crude producers outside the OPEC offered their production outside this administered system into a spot market. Lower prices in the spot market than the administered OPEC prices led to decline in the OPEC market share. Finally the current 'commodization' of crude oil trading emerged. However, vertical integration from the well-head to the steam cracker is still a dominating organizational principle of the petroleum industry.

After the emergence of the crude oil spot markets at the end of the 80ies / beginning of the nineties, more and more market participants entered the crude oil market. With the advent of pure financial players, financial trading in crude oil gained more and more importance. Today, standardized crude oil trading (in particular Brent) represents the single most important hard commodity sector. Daily derivatives trading in Brent alone exceeds the daily worldwide consumption by five times.

Investments in crude oil exploration and production are done without the backing of long term contracts. Integrated oil companies with activities in upstream and downstream will incorporate the output of successful explorations into their existing portfolios. Companies with minor downstream activities market their output on the world spot markets for crude oil. However, there is a trend among oil producing companies without own substantial downstream activities (e.g. oil producing companies from emerging and developing countries) to integrate vertically into the downstream sector in order to absorb part of the price risks.

Current investments in crude oil production and exploration are driven by fast increasing prices. Crude oil prices only increased in the new millennium from a low level until the financial crisis. Current prices have recovered. Locking in prices by exploration and production companies at current forward market prices could potentially leave any upside potential unexploited. Provided, spot market prices are not expected to fall considerably below current spot market levels, the downside potential of leaving future production unhedged is limited compared to the additional income potential from future spot price hikes. Another important reason for the lack of long term contracts is the lacking price exposure of final consumers of refined products. Their forward price exposure is limited to 2-3 years, which can be easily hedged by means of standardized short term contracts.

5.2.5 Electricity Trade

5.2.5.1 Electricity Trade Italy

Development of the wholesale electricity trade

The Italian electricity supply industry was nationalized in 1947 and a statewide monopoly for the generation, transmission and distribution created: ENEL (Ente nazionale per l'energia elettrica). Due to the complete vertical integration within one national monopoly, no domestic trade with electricity took place. ENEL only traded with foreign market participants (notably EDF of France and Swiss electricity companies, as they had access to Italian interconnectors). Due to the Italian step out of nuclear generation in the 80ies, Italy was for more than two decades highly dependent on imports.

Following the liberalization of the European electricity markets, the Italian state monopoly ENEL was broken down via the so-called Bersani decree. ENEL was split up into several different legal entities:

- TERNA: owner of the transmission system, TERNA remained a wholly owned subsidiary of ENEL until 2004,
- GRTN: in order to provide a level playing field albeit TERNA being a part of ENEL, an independent grid operator was created, who was not owner of the transmission assets, but responsible for the operation of the transmission system and granting access to it.

- In distribution, ENEL had to transfer concessions for distribution to the major cities (Rome, Milano, Brescia, Torino, etc.) and subsequent creation of new distribution companies,
- In generation ENEL had to divest 15.000 MW of generation capacity, which were organised in three new generation companies and subsequently being privatised (they were basically sold to foreign companies and the newly formed municipalities)

The markets

Cornerstone of the new Italian wholesale electricity market was the Gestore del Mercato Elettrico (GME), which is nowadays called Gestore Mercati Energetici, since it is has been given also the responsibility for the operation of the natural gas exchange. The GME is a power pool with compulsory participation for traders, generators, load serving entities and direct consumers (i.e. industries). The GME matches the complete offer of and demand for electricity for the next day. The matching is done for the 24 hours of the next day. The bidding into the pool by generators is done in six different generation zones (North, Centre-North, Centre-South, South, Sardinia and Sicily) and by importers into five import zones (France, Switzerland, Austria, Slovenia and Greece). The prices in these zones differ from each other. For load serving entities and direct consumers only one national electricity price exists: the Prezzo Unico Nazionale (PUN)**.** The PUN is volume weighted average of the different generation and import zonal prices.

Due to the compulsory character of the GME, the spot market represents almost the complete Italian consumption (with the exception of autoproducers). At the time of the creation of the wholesale pool it was assumed that similar to the United Kingdom, a liquid derivative market would develop around the GME spot market. Swaps (or contract for differences as they were referred to in the United Kingdom after creation of the power pool) would be cash settled against the PUN (or potentially against the zonal generation prices). However, the development of derivative instruments around the GME developed only very reluctantly and with major delays compared to the creation of the spot market. However, gradually a bilateral derivatives market developed during the period 2000 – 2006/7. Before that liquidity was low due to a lack of incentives for those market participants with generation and / or import opportunities. Italy was heavily import dependent and allowed the generators and importers / exporters to squeeze the market. Roaring wholesale prices way above generation costs and comparable wholesale prices in other European countries allowed them to generate large profits. They did not had an incentive to increase liquidity in the derivatives market as a means of price risk hedging. The high wholesale price levels created incentives to build new generation capacity (mainly gas-fired CCGTs). The more balanced demand / supply situation had a depressing effect on wholesale price levels and suddenly generators encountered also a downside price risk.

The dominating derivatives market is the bilateral OTC market. Electricity trading is done under the EFET electricity framework contract. The EFET framework contract is similar to the ISDA framework contract. Normally the EFET contract foresees physical delivery of the electricity traded (prevailing in the most EU countries), but in Italy this is not possible due to the mandatory character of the power exchange. Therefore the transactions are pure financial deals. The OTC transactions under the EFET contract are cash-settled against the PUN supply price (contract price as the fixed leg, the spot price the floating leg. The liquidity is heavily concentrated on the front end of the forward curve (next month, quarter, calendar year).

Besides the bilateral OTC market an exchange for cash settled derivatives has been developed by the Borsa Italiana in 2007/2008. The futures are settled against the PUN. The so called IDEX offers trade in the following three months, four quarters and one calendar year. The liquidity in the IDEX is very low due to the requirement to have a license as a financial services provider.

The actors

Generators have to sell their whole physical output to the pool on a day-ahead basis. They can hedge their price and volume risks only by means of the derivatives market. Initially they did not have large incentives to hedge risks as the upside potential outweighed the downside potential by far. Nowadays with more balanced supply / demand balance they increasingly active in the derivatives hedge market.

Load serving entities have to buy the whole supply volumes for their customers in the wholesale spot market. Due to the low liquidity of the derivatives market and especially the lack of liquidity for medium to long term in the forward curve, they started increasingly to hedge themselves physically by building new generation capacity. The subsequent alignment of Italian wholesale prices to other European prices diminished the appetite for own generation. The load serving entities are active in the derivatives hedge market.

Traders are only active in the derivatives market as they are not admitted in the GME spot market.

Importers / exporters: The importers are price takers, the importing zones are too small to provide a benchmark for derivatives and the import zone prices differ too strong from the PUN to provide them incentives to enter into hedge transactions. Exports from Italy northern adjacent countries are seldom, they occur generally during off-peak hours in the winter.[152]

Contracts – structure, products and duration

Spot market: The 24 hours of the following day are cleared by matching supply and demand in a double sided auction. Participation in the GME requires a contract setting out the communication requirements, the financial securities and responsibilities. There are no other products traded than the day-ahead hours (8760 hours a year).

Derivatives market: Due to the compulsory nature of the spot exchange, all derivatives are cash settled. The most prevailing swap is against the nationwide supply price (PUN). Locational risks for generators have to be accepted. Derivative contracts are used as monthly, quarterly and annual

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[152] Low domestic electricity demand and high demand in France and other Northwest European countries allows to arbitrage between the markets

contracts. The fixed price of these contracts is settled against the average of the PUN prices over the contract period.

Summarizing the situation on the Italian wholesale market in brief:

- The compulsory character of the day-ahead electricity wholesale electricity market (the pool) in combination with the high import dependency of Italy provided initially only limited stimulus for the development of liquidity.
- The upstream vertical reintegration of load serving entities and other investors balanced better the demand / supply structure in Italy. The more balanced upside and downside potentials created stronger incentives to rely on hedging instruments.
- Liquidity and maturity of the Italian wholesale electricity market is still limited compared to other European electricity wholesale markets (notably NW Europe, Scandinavia, United Kingdom).
- Liquidity in the Italian electricity wholesale market is also hampered by the lack of a liquid natural gas market[153].

5.2.5.2 Electricity Trade Germany

Development of the wholesale electricity trade

Trading in electricity developed gradually after the liberalization of the German electricity market. In 2000 two electricity exchanges were formed to offer spot trading in the German market. The European Energy Exchange (EEX) was created in 2000 and offered initially continuous spot trade in block products. The block products were the day-ahead baseload (flat delivery over the 24 hours of the next day) and peakload product (flat delivery over the 12 hours of the next day from 08:00 to 20:00) and week baseload and peakload products. The weekly peakload product covers only Monday to Friday. The choice of products was heavily influenced by generation companies, who preferred the option to sell block products instead of hourly products[154]. The competing Leipzig Power Exchange (LPX) offered a day-ahead auction for the 24 hours of the day ahead similar to the power exchange concept applied in the Scandinavian Nordpool since 1991 (starting in Norway). The hourly day-ahead auction was preferred by load serving entities, traders and direct consumers, as it allowed better to modulate the typical daily load patterns than the two block products. Subsequently liquidity developed faster in the LPX than in the EEX. However, there was no room for two exchanges in the long run. Therefore the two exchanges merged in 2002 under the name of the European Energy Exchange. The new exchange combined the former auction and block trading design features of both exchanges.

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[153] Natural gas is the dominating primary fuel for electricity production in Italy.

[154] Baseload powerplants cannot modulate on an hourly basis. Baseload power plants require at least a few to several hours from a warn start to reach nominal rate plate capacity.

Since then the spot exchange has developed very fast and liquidity in the spot market represents nowadays around 25% of total consumption. Due to the EU target to create a pan-European electricity market, the spot market of Germany was coupled with the spot markets of France, Belgium and the Netherlands in 2010. Austria is already part of the German spot market from the beginning due to a lack of cross-border transmission bottlenecks and for Switzerland, the EEX operates a separate day ahead auction since 2007. In 2009 the spot markets of the EEX and the French Powernext merged. The merged spot exchange EPEX spot resides in Paris and is responsible for the spot markets of Germany / Austria, France and Switzerland.

High spot electricity prices in the years 2006 – 2008 created incentives to vertically reintegrate upstream. Load serving entities developed plans to establish own generation to generate profits from the high wholesale prices.

Parallel to the development of the spot trade a liquid forward market developed. Supported by brokerage companies, physical forward trading picked up in 2000 and has developed expontially ever since. Today around 6-8 times the physical consumption is being traded in the German OTC forward market.

The markets

The exchange based spot market: The EPEX spot is the major cornerstone of wholesale electricity trading in Germany. It is a widely accepted price benchmark for exchange traded, cash-settled futures, but is also the price marker for physical bilateral OTC forward transactions (see below).

The OTC spot market: Early after liberalization most spot trading was based on bilateral OTC trading. The OTC spot trade was based on the concept of a continuous block trading and hampered therefore from the same drawbacks than the exchange based block trade in the original EEX. Today almost no OTC based spot trading exists anymore due to the comparable high transaction costs.

The OTC forward market developed parallel to the spot trading. Therefore the OTC based trading today is based on physical delivery rather than cash settlement. The products traded are peakload (Mo.-Fr.; 08:00 – 20:00) and baseload (Mo.-Su.; flat). Turnover in the OTC market is very high and churn factors are 6-8. The high liquidity in the German OTC forward market can be attributed to the central position of Germany in Europe having direct borders to 9 other countries.

The Exchange futures and options market: The exchange based trade in futures was always somewhat in the shadow of the OTC based forward trading. Lower trading fees and the lack of clearing fees in OTC trading led to lower transaction costs. The financial crisis of 2009 and a deteriorated financial solvability of market participants led to a stronger interest in exchange based trading. The need to centrally clear OTC transactions from 2014-2015 in accordance with EMIR has led to more balanced level playing field between the exchange and the OTC market.

The actors

Generators: All German electricity generators are at least active spot market participants irrespective of their level of vertical integration. The optimization of the generation and supply portfolio allows avoiding any opportunity costs. Participation in wholesale forward / futures markets in contrast depends stronger on the level of vertical integration (sales as a natural hedge for generation and vice versa).

Load serving entities: The situation of load serving entities mirrors the situation of generators. Even fully balanced vertically integrated suppliers will optimize their generation / supply portfolio against the spot market. The level of engagement in wholesale forward / futures markets is stronger linked to the level of vertical integration for the same reasons than generators.

Traders: Traders try either to arbitrage between different commodity markets (e.g. between primary fuel markets and electricity markets) or different locational markets (e.g. between Germany and the 9 adjacent galvanically connected electricity wholesale markets).

Hedgers: Often market participants are trading in derivative German wholesale electricity instruments without any physical position and without the intension to speculate. They are trying to hedge physical positions elsewhere by German hedge positions. Even if these attempts are far from perfect hedges, the will lower the risks compared to unhedged positions, since correlation between Germany wholesale electricity markets and other electricity markets is rather high.

The Contracts – structure, products and duration

Exchange futures market: Baseload and peakload contracts can be traded for:

- the months of the current year,
- the quarter years until early 2016,
- the calendar years until 2019.

These products are futures and are cash settled against the spot price reference index. They are centrally cleared and require initial margins and variation until maturity of the contracts. Liquidity is centered around the short end of the forward curve.

The **OTC forward market** resembles almost fully the contract structure of the exchange traded futures products. The major difference is physically delivery obligations of the OTC forwards. However long daisy chains are the rule and churn factors in the German electricity wholesale markets are high despite the physical character of delivery. Due to the EMIR regulation, these transactions need to be centrally cleared with a central clearing house. This will lower the attractiveness of the OTC forward trade in comparison to exchange based trading.

Long term power purchase agreements: The construction of power plants (in particular hard coal fired ones) is a capital intensive business. Investors with an interest to leverage equity / debt ratios and exploit interest differences need to assure the financing banks, that long term investments in power plants is a low risk business. Therefore power plant projects are often linked to long term power purchase agreements. Often these power stations are built jointly by load serving entities. These are buying the output of the station on a long term basis based on indexed purchase prices. The PPAs can be of financial nature and meant as a hedge only or they can serve to physically supply the investors.

5.2.5.3 Investments in Power Plants

Case study steam coal plant Wilhelmshaven GDF Suez: In 2007 French-Belgian integrated energy company GDF Suez raised plans to build a coal fired power plant in the harbor region of Wilhelmshaven. GDF Suez had previously bought into the German distribution companies of Saarbrücken, Gera and Wuppertal. However the sales basis of these distribution companies is rather small and GDF Suez was seeking partners for this power plant project. GDF Suez was successful in this search and BKW FMB AG of Switzerland participated for 33% in the project and WSW Energie & Wasser AG participated for a further 15%, leaving GDF Suez with a stake of 52%. The construction of the power plant began in 2008. The power plant representing an investment of more than 1 billion € is expected to assume commercial operation in the course of 2013. The commercial architecture is slightly more complicated than the pure ownership structure. The power plant is operated by GDF Suez Kraftwerk Wilhelmshaven GmbH & Co KG, which is turn owned by the three respective shareholders. The operator has a tolling agreement[155] with GDF Suez, who takes all the generation output and sells part of the generation then to BKW FMB AG and WSW Energie & Wasser AG. These power purchase agreements are not known in detail, but existing information indicate that the contracts are inter alia linked to the primary fuel prices.

Case study steam coal plant Trianel Lünen: Trianel is a cooperation company of German municipal distribution companies jointly owned by them. Trianel builds together with some its shareholders (more than 10 German municipal utilities) a coal fired power plant in Lünen. The power plant represents an investment of 1.4 billion €. The power plant was ordered in 2007, construction began in 2008 and commercial operation is expected in 2013. The project is debt financed to a large extent. Major financing bank is WestLB as leader of a financing consortium. The construction and later operation is rind-fenced by the dedicated operator company Trianel Kohlekraftwerk Lünen GmbH & Co. KG.

Besides risk mitigation strategies there in form of physical co-ownership as explained by the two case studies, there is another form of risk mitigation in form of a virtual ownership. These virtual power plant stakes are long-term contracts, which mimic physical part-ownership of a power plant. Duration of these contracts is usually in the range of 10 to 20 years and resembles the characteristics of a real power plant. The advantage of these virtual power plant stakes is the lack of large up-front investments. The buyer pays a fixed capacity fee over the duration of the contract in order to contribute to the capital requirements.

Larger integrated electricity companies build new power plants not in form of a project financing (bank loans directly linked to an investment object), but as part of the generation portfolio. Financing

[155] A tolling agreement involves the physical delivery of the primary fuel to the tolling agent and the receipt of generated electricity at the agreed capacity by the tolling customer. The tolling agent receives a fee for the generation of electricity.

is on a corporate level. Optimal gearing ratios are achieved by corporate loans instead of project loans and most often debt is collected using bonds tenders. Price and volume risks are then mitigated within the overall supply and generation portfolio of the integrated companies.

Summarizing the situation on the German wholesale market in brief:

- The German electricity market is the most important electricity market in continental Europe. It is being used not only to hedge German price and volume risks, but also corresponding risks in adjacent countries with a high correlation to German electricity prices.
- The development of the German (and other EU) electricity wholesale markets creates a need for market participants to hedge also primary fuel prices (notably steam coal and natural gas).
- Vertical integration represents a means of a natural hedge both for load serving entities and generators.
- Due to the strong penetration of renewable energy sources and the associated merit order effect the appropriateness of inter-fuel hedges deteriorates[156].
- Investments in power stations are financed for smaller investors via project financing. Project financing (debt part) is provided by Banks, who in turn receive ownership of the operator company as collateral. Larger integrated electricity companies finance new power plant projects as part of their overall investment portfolio. The power plant specific investment is then done based an overall corporate financing. The price and volume risks are then mitigated by the existing generation and consumer portfolio of the particular integrated company.
- Investments in power generation are largely driven by anticipated wholesale price developments. Most recent and current investments in German power plants were planned and ordered prior to the collapse of wholesale electricity prices. All potential investments, which had not reached the final investment decision stage, are currently on hold.

5.2.5.4 **Electricity Trade United Kingdom**

Development of the wholesale electricity trade

Wholesale trading in the United Kingdom emerged immediately after the breakup of the monopolies in generation and transmission (the Central Electricity Generating Board was solely responsible for electricity production and transmission in England & Wales) and distribution and sales (there were twelve regional distribution monopolies in England & Wales). Wholesale trading centered on a compulsory power pool. All generators had to sell into the pool and all suppliers had to buy from the

[156] Wholesale electricity prices may drop even if all other primary fuel prices are rising. Long term hedging becomes meaningless.

pool. Companies active in generation and sales had to sell the generated electricity into the pool and to buy electricity they were selling to final customers from the power pool. This system ensured a high liquidity in the spot market (the spot market represented thus nearly 100% of the total generation except for small scale generation and industrial autoproduction).

The historic separation of generation from supply activities led to the emergence of derivatives trading on the one hand and a vertical re-integration on the other hand. So called contract for differences were cash-settled against the pool price. Gradually a brokered OTC market developed for these derivatives. On the other hand, generation companies and supply companies tried to reintegrate vertically in order to mitigate the price risks from the spot market[157]. The mandatory character of the power pool created incentives to artificially manipulate the spot price by e.g. withholding generation capacity. Wholesale pool prices constantly being above the marginal generating costs triggered a political decision to abandon the pool system and to replace it with the so called New Trading Arrangements (NETA) in 2001. Under NETA companies were free to sell and buy electricity to whomever they wanted without using the pool. Cornerstone of the NETA system was a close-to-real-time balancing system administered by a central balancing and settlement administrator – ELEXON. Wholesale trading was based solely on bilateral OTC transactions both for spot and forward trading. The OTC market was mainly a brokered market relying on voice and screen based trading.

The markets

The exchange based spot market: The OTC market lacked any form of organized spot or derivatives exchange. This situation changed between 2008 and 2010. The lobby organization of the wholesale electricity market participants Futures and Options Association[158] tendered for the introduction of an organized wholesale power exchange already operating on the continent. Three interested exchanges were shortlisted (Nordpool Spot in cooperation with NASDAQ Commodities, APX and EEX) and finally Nordpool Spot and NASDAQ Commodities were chosen as the preferred operator. The spot exchange N2EX started operations finally in 2010. In parallel, Dutch exchange APX decided to operate a spot exchange in competition to the N2EX.

The OTC spot market: Besides the spot exchange there is still OTC based spot trading facilitated by brokers. However the bulk of spot transactions shifted to the spot exchanges N2EX and APX (UK). Transactions in the OTC spot market are generally governed by the so-called Grid Trade Master Agreement (GTMA), which is similar in its structure to the EFET contract applied for example in Germany and Italy.

[157] National Power for example, one of the newly created generation companies bought regional distribution company Midlands Electricity in 1998. The other important generation company PowerGen bought the regional distribution company East Midlands Electricity in 1998.

[158] More precisely the Power Trading Forum under the auspices of the FOA

The OTC forward market: Forward trading in the UK is dominated by brokered OTC transactions. These generally foresee physical delivery and are governed by the GTMA. Besides the trade under the GTMA, there is some trading governed by the ISDA and EFET contracts as well. Transactions under ISDA can be physical or financial. Liquidity in the wholesale OTC market is low compared to other liquid wholesale markets such as Scandinavia or Germany and triggered efforts by the electricity regulator OFGEM to enhance liquidity[159] (the churn factor is around 2, indicating that the electricity is traded twice before it is delivered to the final customer).

The Exchange futures and options market:

NASDAQ OMX, one of the operators of the N2EX spot exchange operates a derivatives exchange for UK power. The exchange offers futures, which are settled against the N2EX spot price. The exchange has yet not gained wide acceptance and subsequently liquidity is very low.

The actors

Generators: After the initial breakup of the central generation and transmission monopoly, initially unbundled generation companies are today completely vertically reintegrated. An exemption is British Energy, who operates the UK nuclear power plants and is owned since 2008 by EdF.

The load serving entities initially unbundled from generation activities have been reintegrated into vertically integrated companies. This development was triggered by volatile spot wholesale prices, which were difficult to hedge due to the liquidity of forward wholesale trading.

Traders: Besides the physical parties referred to above, financial entities like investment banks and hedge fonds are active in wholesale trading and take speculative positions.

Hedgers: Hedging of open positions is motivated by lack of complete vertical integration of combined generation and supply companies and temporary surpluses / deficits in the generation / supply portfolios.

The Contracts – structure, products and duration

Exchange futures market: Baseload and peakload contracts can be traded for:

- the months of the current year,
- the quarters until early 2016,
- the calendar years until 2019.

Liquidity in the organized exchange is neglectably low.

The **OTC forward market** has similar contract structures as the forward exchange. Liquidity in derivatives is almost exclusively concentrated on the OTC market. The churn factor of OTC transactions is around twice the physical consumption (in 2011).

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[159] See OFGEM: Retail Market Review: Intervention to enhance liquidity in the GB power market, 22.02.2012

Long term power purchase agreements were used to hedge the production of generation companies being long in power production. With the takeover of British Energy and a subsequent sale of 20% in British Energy to Centrica led to nearly balanced generation and supply portfolios of the major portfolio generation and supply companies. Subsequently, long term contracts diminished in their importance.

Summarizing the situation on the UK wholesale market in brief:

- The privatization and liberalisation of the UK power market in 1990 was one of the two landmarks (next to the liberalisation of the Norwegian electricity market in 1991) in the competitive opening of the European power market. The UK model (based on a central mandatory power pool) was one of the two main organisational models for all other EI electricity markets to be liberalised.
- The privatization and liberalisation of the UK power market led to a far reaching breakup of the bundling of different activities along the value chain. However, after some time entities along the value chain (especially supply companies) started to reintegrate vertically as a means to hedge price risks. This was a result of a lack of long term standardized hedging instruments on the wholesale market.
- The compulsory character of the power pool was prone to market squeezes. Hoarding (withholding available capacities from the power pool) of generation capacities allowed to raise the pool price above the "true" marginal system price. Subsequently the power pool was abandoned in favour of an "open" wholesale market based on OTC trading (so called **Ne**w **T**rading **A**rrangements) with a central balancing operator to assure a system wide balancing, reconciliation and settlement of the system.
- A highly volatile liquidity in the OTC derivatives market triggered demands to augment the system with a voluntary power exchange based on day ahead market (auction) for each hour of the next day. Several continental exchanges tendered for the operation of the exchange and a joint venture of Nordpool Spot and NASDAQ Commodities was finally the preferred exchange operator. A second very similar exchange is operated by the Amsterdam Power Exchange. The exchanges have attracted some liquidity in the meantime, but have not yet reached the importance of other continental power exchanges.
- There are some concerns regarding the current levels of liquidity of the derivatives wholesale markets. However, the UK power forward market is still among the more liquid wholesale markets.
- The UK power market today is very similar to other power markets on the continent. Markets, contracts and contract structures and durations resemble those from the continent to a large extent.

5.2.6 Conclusions Electricity Trade

The traditional vertical integration of the electricity supply chain either by corporate ownership or long-term contracts was abolished during the competitive opening of electricity markets end of the 90ies. Privatization and unbundling of generation / supply activities from grid operations (e.g. split up of the CEGB into National Power, Powergen, British Energy and National Grid the UK, spun off of Terna from Enel, creation of GRTN) was he dominating form in the case studies UK and Italy, whereas in Germany the abolition of franchised regional monopolies was deemed sufficient to boost competition.

The dominating organizational model for electricity trade in Europe is centered around a spot market based on a voluntary power exchange (e.g. Germany, France, Benelux, Scandinavia), however the other dominating organizational model is a spot market organized as compulsory power pool. The compulsory character of power pools leads to a highly liquid spot market (representing nearly 100% of the liquidity), but does not create incentives to develop liquid forward markets. The lack of a liquid forward market in power pools has motivated many market participants (mainly load serving entities) to integrate upstream into generation. But also in electricity markets organized in form of power exchanges with voluntary participation incentives to integrate vertically are present as being observed in the UK and Germany.

The competitive opening and subsequent development of the EU electricity wholesale markets created a need for market participants to hedge also primary fuel prices (notably steam coal and natural gas). The steam coal market followed thus wholesale electricity markets in form of products and term structures. The strong penetration of renewable energy sources and the associated merit order effect renders inter-fuel hedges meaningless.

Investments in power stations are financed for smaller investors via project financing. Project financing (debt part) is provided by Banks, who in turn receive ownership of the operator company as collateral. Larger integrated electricity companies finance new power plant projects as part of their overall investment portfolio. The power plant specific investment is then done based an overall corporate financing. The price and volume risks are then mitigated by the existing generation and consumer portfolio of the particular integrated company. Investments in power generation are largely driven by anticipated wholesale price developments. Most recent and current investments in German power plants for example were planned and ordered prior to the collapse of wholesale electricity prices. All potential investments, which had not reached the final investment decision stage, are currently on hold.

5.3 Comparative Assessment

The analysis of the Brent crude oil, the Atlantic steam coal and the EU electricity markets has been undergone in order to understand why and how temporal contract structures evolved in these commodity markets over time and what potential lessons could be learned for the future development of temporal contract structures in the EU gas market. Important factors, which triggered the temporal evolution of contract structures, are:

- Market structure (number of producers / generators and supplier / consumers and traders)
- Level of vertical integration,
- Network dependency,
- Transport distances between production (generation) and consumption and related transport costs,
- Age and maturity of the wholesale market,
- Capital intensity of production (or generation) investments and transport infrastructure.

The following table summarizes the aforementioned factors for the other relevant commodity sectors. In order to highlight the similarities and differences between the other commodities and the EU gas sector, the EU gas sector has been added as well. The EU gas sector addresses only the import level.

	Steam coal	**Crude oil**	**EU Electricity**	**EU Gas**
Market structure				
Level of vertical integration[160]	Almost none	Still substantial, ambiguous developments	Medium to high	Very low
Number market participants	Many producers and consumers, several intermediaries and financial players	Limited number of production and downstream companies, very large number of hedgers and financial players	Large number of market participants in wholesale markets	Very limited number of production and import companies
Wholesale market maturity	Low to medium	High	Medium	Low
Wholesale market liquidity	Medium	Very high	Medium to high	Low
Networks and transport infrastructure				
Network	None	None	Very high	High (but

[160] Vertical integration is here meant as integration between production activities on the one hand and refining, generation and wholesale supply activities on the other hand.

dependency			(almost no technical storage capability)	diminishing on the large-scale import level due to LNG)
Network topology	n,a.	n,a,	Highly meshed	For import pipelines point to point
Transport distances	Medium to high	Medium to high	Low	Medium to high
Transport costs	Low (to medium)	Low (to medium)	Low	High
Capital intensity				
Of production	Medium	Low to high	High	High
Of transport infrastructure	Low (dry bulk transport) High (export terminals)	Medium	Low[161]	Very high

Table 20: Summary of the comparative assessment of the analyzed gas markets

Market structure

The analysed commodity sectors are highly in-homogenous in their market structure. The degree of vertical integration ranges from almost none in the steam coal sector (seaborne trade) to an increasing and already high level in electricity markets. Vertical integration has merits in areas, where buyers and sellers are intrinsically linked to each other and are not able to bypass each other. This is a typical situation in the coal sector for geographically remote areas, where (land) transport costs are prohibitive to transport the steam coal over large distances (i.e. railroad transport). A similar low degree of vertical integration is present in the EU gas sector (on the import level), but for different reasons. However, the situation is changing (e.g. see the recent announced acquisition of the BASF / Wintershall stakes in Wingas by Gazprom). The degree of vertical integration in the crude oil sector was historically high, but the nationalisation of production assets in several countries has broken up

[161] The transport infrastructure in electricity consists of the transmission and distribution level. The specific cost of this infrastructure is considerable in comparison to the commodity electricity itself, but costs of connecting a power plant to the transmission level is rather low compared to the investment costs of a power plant. The cost of the main transmission and distribution grid is generally passed through to the ultimate consumers by means of a so-called “postage stamp tariff”, The allocation of transmission costs to power plants in form of a G-component in EU electricity markets represents only a very minor fraction of the total transmission costs, if applied at all.

this vertical integration. Today an ambiguous development can be observed. Former vertically integrated companies leave the downstream sector (in particular the refining sector) due to low margins in this particular sector of the value chain. Exploration and production companies from emerging and developing countries with own large downstream activities fill this gap to hedge against potential price volatility. In the electricity sector, vertical integration either by corporate ownership or by long term contracts in combination with franchised supply area monopolies was historically high. In the liberalisation process, this link was broken also through legislative measures. Today a trend towards a vertical reintegration is observable.

Very large differences exist in the number and diversity of market participants in the different commodity sectors. The steam coal and electricity markets are characterised by a large number of physical market participants. The investments in coal mines and power plants are capital intensive, but not in the order of magnitude as in the crude oil and natural gas sectors. Investments in coal mines and power plants can be borne even by smaller market participants. Risk and capital sharing led to several joint ventures in these sectors. This diversity is augmented by several financial players. Investments in crude oil and gas exploration and production are much more capital intensive than in the other two sectors. Additionally the transport infrastructure is capital intensive too and often physically linked to the production facilities (especially for offshore oil and gas fields and LNG). There is a notable difference between the crude oil and natural gas sector. Crude oil sector is the dominating commodity market in the world and the crude oil price is an important price benchmark for other commodity markets (notably the gas sector). This attracts several financial players in form of speculative traders and hedging entities. The gas sector lacks this segment of non-physical players.

The maturity and liquidity in the different commodity markets is different as well. The crude oil market in its current form exists already for 30 years. The liquidity in the derivatives sector exceeds the physical consumption several times. The forward curve is liquid enough to hedge price risks several years ahead by standardized wholesale instruments. The maturity and liquidity in the steam coal and electricity markets is much more limited in comparison. The steam coal price is not an important price marker except for power generation. However, the supra regional market areas (Atlantic and Pacific seaborne steam coal trade) offer a larger market than the still fragmented national electricity markets (even if they are increasingly growing together). Maturity and liquidity of natural gas markets in contrast is much more limited. At least at the import level, market entry barriers are high for newcomers and buyers and sellers are acting rather in a closed shop.

Networks and transport infrastructure

While electricity and natural gas (with the exception of LNG) are network dependent, steam coal and crude oil are not. This situation allows market participants in the crude oil and steam coal sectors to choose among several buyers and sellers in different geographical locations and arbitrage out any regional price differentials. The emergence of LNG enlarges regional markets formerly tied together by point to point pipelines. Electricity networks in contrast are much more meshed than the gas pipelines on the import level.

Transport costs of electricity are comparable low compared to the cost of electricity generation. The same applied to steam coal in case of seaborne transport (and also for domestic barge transports). The transport costs of crude oil differ significantly depending on the area of exploration and production. Shale oil production of crude oil in the US close to refining centres involves only limited transport costs. On the other hand deepwater offshore production of crude oil in remote areas will incur substantial transport costs to deliver the crude oil to the demand centres. Transport costs for natural gas will almost always lead to substantial transport costs. There is a critical transport distance, where transport of LNG is cheaper than by means of pipelines. However, both pipeline and LNG based gas transport involves substantial transport costs.

Capital intensity and investment behavior

The investment behavior in steam coal mining, crude oil exploration and production and electricity generation do not differ too much from each other. All sectors involve capital intensive investments, with investments ranging from several hundred millions to billions of $ / €. Risk mitigation measures in form of long term contracts are an absolute necessity in two cases:

- Project financing by banks is required,
- The applicable market is too small to assume the volume risk,

Financing of investments on a project basis is required for smaller companies with no direct access to capital markets (in particular bond markets). Markets are generally too small to handle the volume risk if there is a lack of transport infrastructure or if transport costs are prohibitive. Most often this is the case of steam coal.

All commodity markets are boom and bust industries, periods with increasing prices triggering large investments are followed by periods of declining and low prices. As can be seen from the figure below, only the crude oil market has recovered from the last bust cycle following the financial crisis.

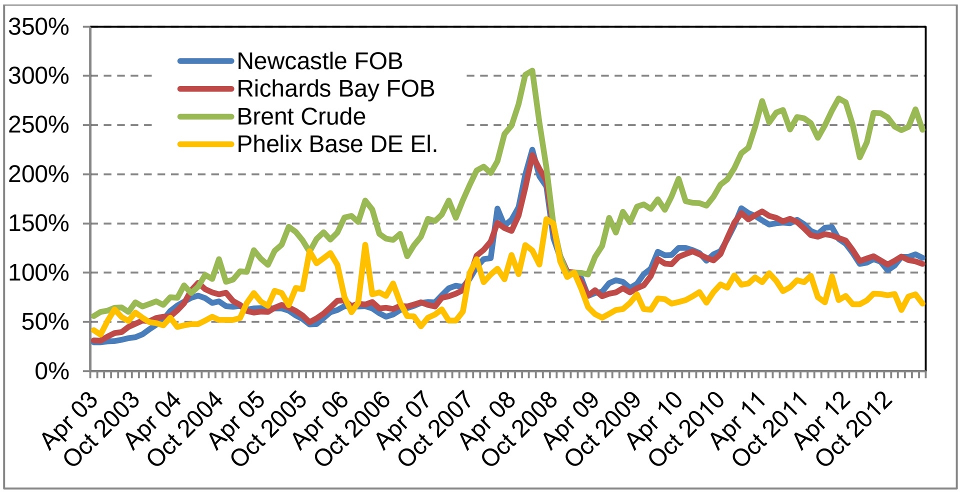

Figure 49: Spot price development for steam coal, crude oil and electricity (index 100 = Jan. 2009)

Source: Platts, IHS McCloskey, EPEX Spot

The forward curves for the three commodities are shown in the figure below. It is expected that electricity prices will slightly recover. However, the recovery of wholesale prices will be not sufficient finance investment in new power stations. Crude oil prices are expected to be a little bearish in the future, however the reduction is small compared to the current actual Brent crude price level, which provides currently large incentives to invest into exploration and production of new fields. The increases of steam coal prices will be limited. However the increase in combination with current wholesale price levels will allow investing in new steam coal mines provided they have a favorable production cost structure.

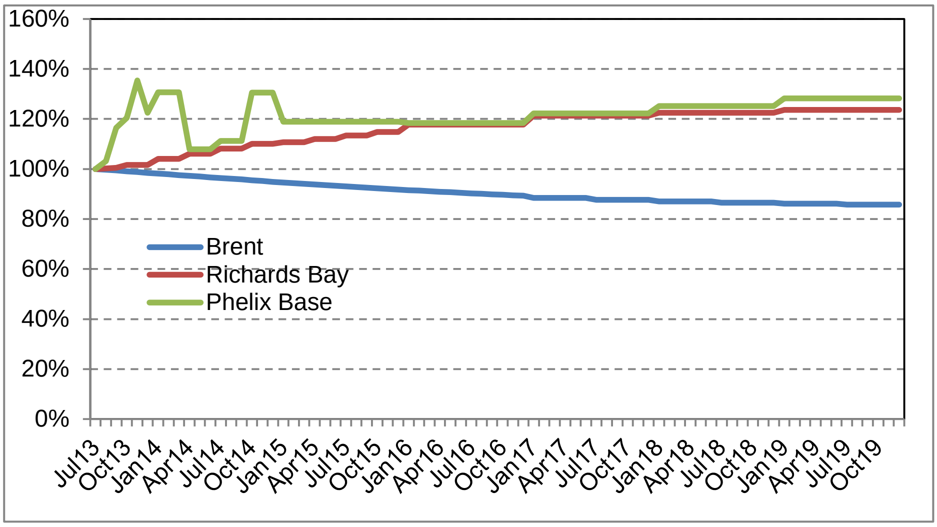

Figure 50: Forward prices for steam coal, crude oil and electricity markets (index 100 = July 2013)

Source: Platts, IHS McCloskey, EPEX

5.4 Conclusions

As has been seen in 5.3, there are substantial differences between the four commodities steam coal, crude oil, electricity and natural gas. Lessons to be learned for the temporal contract structures in the EU gas sector from the three other commodity sectors are not too obvious on first sight. However, some observations can be drawn from the other commodities.

The occurrence of new steam coal producers led to increasing transport distances. Former national coal markets have grown together to only two regional wholesale markets (Atlantic and Pacific steam coal trade) tightly linked to each other by active arbitrage. A similar situation exists in the crude oil sector, where spot market prices of two market regions (WTI and Brent) are used to price spot transactions in other regions of the world. Price differentials of these markets to the major price benchmarks WTI and Brent reflect either transport costs or quality differences. Electricity spot markets in Europe have been or will be linked by regulatory measures (market coupling). As a result, prices in different regional crude oil, steam coal and electricity markets are arbitrage free (i.e. no trader can yield profits by moving a commodity from one market to another, since specific transport cost would exactly equal the price differential of the two markets). This is not yet the case in the natural gas sector were price differentials between the European and American hub prices and Asian import prices are not arbitrage free given the specific LNG costs.

Long term contracts are rather an exception in the steam coal, crude oil and electricity markets. Downstream or upstream vertical integration are preferred to mitigate price and volume risks. These risk mitigation strategies are mainly applied in case of capital intense long term investments with high up-front investments. Vertical integration has an additional advantage compared to long term contracts. The profit margins in the different layers of the value chain are not fixed. Depending on the state of the market, the larger part of the profits is maybe achievable in the upstream or downstream levels. Vertical integration allows reaping the total profit. Long term contracts are applied in cases where corporate vertical integration is not possible[162] or where it is not well suited due to the ownership structure (e.g. minor interests in assets with a long lifetime). Long term contracts as a proxy (in particular in the electricity sector) mimic the characteristics of a corporate integration. In the steam coal sector long term contracts are used to balance the interests of producers and consumers of steam coal, which are intrinsically linked to each other. The link can be prohibitive transport costs to other potential customers or the complete lack of transport infrastructure at all. Long term contracts in the steam coal sector are normally based on a form of a cost-plus formula or fixed prices. In the electricity sector these long term contracts are structured as tolling agreements. A tolling agreement leaves the primary fuel price risks to the tolling customer. The tolling agent receives a fixed fee to cover the investment costs. The duration of these long term contracts resembles the financing structures of the investments (usually between 15-20 years). Vertical integration in the gas sector has been historically

[162] For legal or regulatory reasons

the exception. However, vertical upstream and downstream integration seems to become more popular as has been seen in discussed in 3.2 and in more detail in 3.2.2.

All of the commodity sectors can be characterized by high capital intensity. However, capital intensity of exploration and production is particularly high in the crude oil and natural gas sectors. The prevailing risk mitigation strategy of long term contracts in the natural gas sector is not observable to the same degree in the crude oil sector. Some E&P companies from emerging and developing countries are integrating downstream. A potential explanation for this structural difference is potentially the price expectation of market participants. The other major reason for the far reaching lack of long-term contracts in the crude oil sector is the lack of a long term price exposure of final crude oil product consumers. Refined products for usage in the traffic, heating and chemical feedstock sector are generally bought on a spot basis (with some minor exceptions). These consumers have no medium- to long term price exposure and are therefore reluctant to enter into long term contracts.

6 FINAL CONCLUSIONS

The following sections present the overall conclusions of this project, drawing together the insights gained from the analysis of the EU gas sector, as presented in chapter 2, as well as the results of our research into other gas markets and other commodity markets, as presented in chapters 3 and 4.

The EU gas market experienced fundamental changes in the durations and structures of contracts the last couple of years. This applies not only to new contracts, but affected almost all existing contracts as well due to the renegotiation of existing contracts. New gas long-term contracts are becoming shorter down along the value chain. At the upstream side contracts tend to be long-term with durations for new contracts often in the range of 10 to 15 years, while at the downstream side contracts are typically more short-term oriented with durations typically below 5 years. These new contracts exhibit not only shorter contract durations, but also other contract specifications and here in particular new pricing formulas. The classical long-term contract with prices linked to a basket of underlying other commodities (mainly crude oil and / or refined products) with a take-or-pay obligation is and will be replaced by long-term contracts with shorter contract durations; the prices will be linked to the spot gas prices of the trading hub, where physical delivery is foreseen (except for special circumstances, where long-term prices are linked to other commodities or are linked). The changes in the contract structure referred to above applies partially not only to new contracts, but also to existing renegotiated contracts (except for the contract duration). The above developments are taking place in parallel to the development of a highly liquid spot market with short-term contracts. These short-term contracts with duration of up to one year are highly standardized and offer no flexibility. Gas under short-term contracts is traded on OTC markets and gas exchanges with market participants numbering up to 3-digit figures (as for example in the UK NBP trade). These short-term markets have been fuelled by an excessive gas supply following the financial crisis and a subsequent sharp decline in gas consumption. These developments are similar to earlier developments in other mature gas markets (e.g. US gas market), but also in other commodity markets such Brent crude, steam coal and electricity markets. On the hand, the development of short-term contracts will be no means led to a complete abolition of long-term contracts. Long-term contracts will be also needed in the future as a risk mitigation tool for highly capital-intensive exploration and production investments (characterized by a long asset lifetime and lack of scalability of investments).

6.1 Impact on competition

6.1.1 Insights from other gas and other commodity sectors

In the US wholesale gas markets were initially liberalized in 1985 when FERC ordered Third Party Access (TPA) in interstate commerce. Further regulatory measures strengthened the competitive opening of the US wholesale gas market and facilitated the development of liquid spot markets (in particular linked to the Henry hub). The reliance on spot trading and paper forward trading replaced gradually classical long-term contracts. The diversity of market participants and the increasing usage of domestically produced shale gas increased the competitiveness in US wholesale gas markets.

The Australian, Japanese and Chinese gas sectors in contrast rely currently to a much larger extent on long-term contracts, but for different reasons. Australia is a rather new gas exporting country. Australia has and will increase its production considerably the last 10 years in order to export to fast developing economies in the Far East. These new fields and associated transport infrastructure (in particular gasification facilities) are capital intensive, show a long lifetime and the investments are not easily scalable. Therefore Australian exploration and production companies are seeking to back-up these investments by long-term contracts. In contrast to the longer temporal contract structures in dedicated export facilities, contract durations in the domestic gas sector have been reduced as a result of competitive opening of Australian wholesale and retail gas markets. The Japanese and Chinese gas sectors in contrast are highly import dependent. Both sectors enjoy regional monopolies.

The crude oil trade using short term contracts developed following the breakdown of administered prices at the end of the 80ies. The administered contracts were a surrogate to the former vertical integration of major oil exploration and production companies, which were broken off in the process of the nationalization of upstream assets. Long-term contracts were never of an importance comparable to the gas or other sectors due to the lack of final customers with a long-term exposure to crude and refined oil product prices. Except for the exploration and production level is today highly competitive and market prices in different regions of the world are almost arbitrage-free.

The steam coal market is characterized by a strong inter-fuel competition to other primary fuels since in developed countries steam coal is only used to generate electricity. Long-term contracts are thus rather unusual as they would leave buyers with a price risk, which are not easy to hedge. Even in case of linkage of steam coal prices to electricity prices, their competitive position in the merit order will be affected by the prices of other competing primary fuels. The departure of long-term contracts is a combined result of a declining domestic coal production and a competitive opening of the electricity markets. Steam coal markets are highly competitive and market entry and exit is only limited by the accessibility of concessions and required capital to develop a coal mine. Steam coal prices in different world regions differ only for the respective transport costs between the world regions.

Electricity markets are comparable to natural gas markets in their network dependence. Transport of electricity (as for natural gas) is thus a natural monopoly. The unbundling of these natural monopolies from generation, trading and supply activities has opened up the market to competition. The emergence of spot-markets and standardized forward trading after the competitive opening of wholesale electricity markets has led to a market entry of a variety of new market participants on the generation and wholesale level. Today most EU electricity markets are characterized by a decent level of competiveness. Markets with less developed competition will be improved by regulatory measures such as market coupling.

6.1.2 **Expected impact on competition in EU gas markets**

The emergence of short-term contracts in the EU gas sector allows market entry of market participants on the import-/wholesale-level, markets to which most of these players had no access to before. Both contract volume and duration of this type of contract lower the inherent risk and require less risk capital to be active on these markets.

Market exit is also facilitated by short-term contracts. The large degree of standardization in these short-term contracts improves the fungibility and allows closing positions with only marginal transaction costs.

Short term contracts will allow to arbitrage actively between existing wholesale hubs. Prices will converge up to the costs of short-term transport capacity between markets, thus providing efficient price signals.

Where markets are sufficiently liquid, transport and storage capacity will rather have the role of a hedge against regional or intertemporal price spreads. The expectation with regard to these spreads will determine the willingness to pay for such capacities. Thus, risks for market parties will mainly be reduced to financial risks, i.e. the residual price risk if, for instance, the lack of transport capacities forces a market party to source gas from a comparably more expensive hub.

With regard to gas supplies to the EU markets, while the EU will compete with other regions for gas, at the same time suppliers will compete against each other to supply gas to the most attractive markets. Some existing suppliers only have limited options to sell the gas elsewhere. Thus, the interdependency between suppliers and buyers is mutual. Together with rather oversupplied markets, it is therefore expected that competition will also increase on world gas markets thus providing efficient price signals on a global scale (as further elaborated below). With more gas available under short-term contracts on a global scale, e.g. spot LNG cargos, prices as well as the economic cost of not having the gas will direct the gas to where it is most valued, as has been the case, for instance, during the last years with increasing numbers of spot LNG cargos diverted from their original destinations to Japan, China and other Asian markets. Where or when the necessary infrastructure is in place, supply risks will be reduced rather to price risks.

More competitive and liquid trade based on adequate price signals are likely to attract more market parties and larger gas volumes to the market. This will increase the diversity and positively affect security of supply. Liquid forward markets in particular, which are likely to be strengthened by increased transaction volumes on short-term markets, will provide effective signals to market parties, producers and infrastructure investors. Such a situation can be observed on the US gas markets where price signals, not only from the “famous” Henry Hub but also from a multitude of other market centers, provide transparent price signals and, where necessary, trigger infrastructure investments.

However, short-term markets will not develop by themselves nor can regulators or policymakers order the wide-spread usage of these markets. The emergence of short-term markets is hampered by an inefficient size of the overall market (the market needs to be large enough to accommodate several market participants and to mitigate the market power of market dominating parties) and the diversity of supplies (the market size is alone is not sufficient. Supply needs to be diversified to avoid monopolistic or oligopolistic behavior) and market participants (the market participants should have different trading objectives; this will improve liquidity and will soften volatility of prices). These prerequisites are particularly not met in the CEE countries. However, political measures (such as super-regional market integration and strengthening of interconnectivity by new transport infrastructure) have been taken in order to allow for a similar development in CEE countries, which could be observed in Western Europe.

If there is a general increase in short-term contracts, maybe even to a level which would prevent those market parties, that would like to have a long-term contract, from being able to become part of such a contract. The result could then be an increase in vertical integration.

In many of the assessed markets, vertical integration seems to serve as a hedge to mitigate any risks involved in short-term markets, for both sides.

- Companies at the demanding end may want to ensure access to resources and favorable pricing conditions and/or hedge against price fluctuations
- Companies at the supplying end may want to ensure offtake of volumes and mitigate risk of renegotiations

Thus, vertical integration could have a positive effect for both sides. An ownership stake of a major buyer of the gas in an offshore development will, on the one side, serve well to ensure the investor and financing institutions that the risk to strand the investment and there will be no buyer for the gas is rather limited, as the buying side shows a commitment.

On the other side, the buyer’s stake gives him the security that access to the resources will not be barred in the future. In addition, any risk which may be involved in the pricing arrangement is mitigated for both sides. Compared to the rather marginal investments elaborated on above, vertical integration could thus be a surrogate for long-term contracts in development of new gas field meant to supply gas to the EU or for the development of the necessary transport infrastructure related to such a new development.

In light of the limits for vertical integration of transport networks, as imposed by the EU unbundling requirements, vertical integration may rather occur outside of transport networks, or where transport networks are involved, i.e. those outside of EU jurisdiction. In addition, it should be pointed out that vertical integration within the EU will, in any case, be limited by cartel offices and competition authorities enforcing competition legislation.

In addition, where gas prices are traded under market prices (regardless of the contract duration) gas producers and importers/wholesalers may attempt to spread downstream along the value-chain in order to secure their demand with gas-hubs providing the necessary instrument to effectively balance and optimize portfolios.

6.2 Impact on security of supply

6.2.1 Insights from other gas and other commodity sectors

The strive for spot markets and short-term contracts in the US gas sector has not led to a deteriorating security of supply. Being historically an almost self-sufficient gas producer, increasing prices signaled a need for additional supplies. Subsequently, new LNG import terminals at the Gulf coast were built to substitute a declining domestic production. The shale gas revolution reversed this trend and rendered these investments worthless. The investors reacted by reversing the flow in these LNG facilities in order to export from them.

Crude oil markets have been volatile in the past. Political developments have led to temporary supply interruptions. However, except for the OPEC boycott following the Yom-Kippur war (1st oil crisis) and the supply interruptions following the Iranian revolution and the 1st Gulf war (2nd oil crisis) were the only physical supply interruptions. During all other periods crude oil prices were reacting on the strained supply and demand balance and provided good signals to expand and decrease exploration and production activities. Due to the lead times of E&P activities, it may time before supply is adapted to demand (which is particularly true for rising oil prices). Low crude oil prices after the Asian crisis led to lower investments. A soaring demand for crude oil during the second half of the new millennium motivated new investments in crude oil production. Several of these projects are still under development and will become productive the next couple of years. The backwardation[163] of crude oil prices shows the adaption of E&P activities to the anticipated future supply and demand balance.

Steam coal can be easily stored either in situ (by reducing production output) or in physical bunkers. Short-term supply interruptions do not play a comparable role compared to gas or electricity markets. If steam coal supplies are short, steam coal prices will soar and make steam coal uncompetitive in electricity generation. Vice versa, low prices will improve the competitive position of steam coal and will increase demand for steam coal. The price level will thus balance the demand for steam coal. Supply of steam coal will be also steered by the wholesale price level of steam coal. Higher prices will render new investments more economic, lower prices will led to mothballing of existing mines and postponement of planned investments. The resulting boom-and-bust cycle inherent to the steam coal industry will thus lead to long-term balancing of demand and supply.

Electricity has the highest sensitivity to severe distortions in the supply and demand balance. Electricity cannot be stored in large scale and generation needs to equal demand continuously. Security of supply is therefore a large concern in the electricity supply. Fluctuating wholesale prices in EU electricity markets have in the past provided correct signals to adapt generation investments. After the liberalization, electricity prices collapsed immediately. Low electricity prices led to a decommissioning of older and inefficient power plants. High prices during the middle of the decade triggered investments in new power plants. Current distortions in EU wholesale electricity prices and

[163] In a backwardation situation spot prices are higher than forward prices.

potentially following distortions in the supply and demand balance are not a result of short term contracts and spot markets, but are attributable to flaws in the current market design of wholesale electricity markets (in particular the RES support schemes).

6.2.2 **Expected impact on security of supply in EU gas markets**

Today, spot market prices are already behaving quite volatile. News with regard to unusually low storage levels at the end of winter, outages of a North Sea pipeline or only unusually low temperatures in spring, for instance, have an immediate impact on prices, driving pricing levels upwards. The consequences from an increase of short-term and spot trade will be twofold:

- Firstly, spot market prices will increasingly be influenced by the short-term supply and demand, which would lead to a higher volatility of prices.
- Secondly, the larger volumes traded under these prices will improve price signals to consumers.

To this extent, consumption will respond effectively to price signals, the improved price signals and the larger traded volumes exposed to spot-market prices will lead to more efficient consumption.

Whilst the new market equilibrium is sought for, price signals may serve well to discourage consumption in case of scarcity situations and thus enable the supply systems to maintain overall system stability and to deliver the gas where it is valued most. Furthermore, any reduction of demand as reaction to price signals (and also vice versa, any increase of consumption in case of low prices) will stabilize prices. In addition, where longer term supply contracts also prevail but pricing is developed towards more short-term elements, i.e. where hub-indexed pricing is included, gas prices will be subject to the short-term variations of spot-prices, improving the efficiency of economic signals generated by prices.

It should be considered that some consumers may not be able to react in short-term to price signals due to their low price elasticity of demand, e.g. households relying on gas for space-heating during a cold-spell. However, in the longer run, the price signals could also serve well to allow for informed decisions on alternatives, e.g. better insulation in households or alternative fuels. This will clearly not work in environments where price signals are not visible, i.e. where the regulatory regime sets prices independently from the actual supply-demand situation and procurement costs (regulated price below costs) as is the case in China for instance. Therefore, it is important to design regulatory approaches in a way that price signals are not obstructed.

In addition, the stronger exposure to market price signals will enable market parties to regularly compare their contracts against the market. Market parties will use price review and market realignment provision (included in long-term contracts) in cases where the contractual arrangements move away from the market conditions. In this respect, the evidence for this would be the recent renegotiations of supply contracts with Statoil, Qatargas or Gazprom.

Based on the assessment of the current situation in the EU gas sector and the insights gained from the study of other gas commodity markets as well as from the interviews, we believe that an increase in short-term contracts may lead to a changing behavior of investors.

These changes may express a growing hesitation to invest in gas field exploration and development and transport infrastructures or as requirements of higher rates-of-returns commensurate with the perceived investment risks. In the US for instance, the prevailing pressure on gas prices over the last years seems to have led to a reduction in drilling activities, with the rig count shifting in favor of oil rigs (nevertheless, the comparably low lumpiness of shale gas development will allow for swift reactions on future prices changes).

Investors, i.e. typically the well-known large oil and gas production companies, either internationally active companies or national industry leaders, need additional financing to fund the large-scale projects in exploring and developing large new gas fields[164] or transport infrastructures. In order to manage such investments, often in a two-digit billion Euro range, investors as well as external financing partners will need to rely on contractual arrangements which mitigate the risk of asset stranding and provide for stable revenue streams to repay their debt. In essence, long-term agreements safeguarding such investments can be observed almost everywhere where such investments are already under way today. Where long-term contracts have been not concluded, other tools have been used to in order to mitigate the risk of asset stranding.

In the more mature EU markets, additional investments play a rather marginal role, more so in the direction of increasing diversity of supply and transport routes. With demand for gas being rather stable and (within limits) predictable, the question arises as to whether long-term agreements used to back up any investments are rather used because this is the traditional way.

In particular, in combination with market-based pricing, there is little value added by a long-term supply agreement as once infrastructure is in place, the gas can be marketed with high certainty. This may look different for pure infrastructure investors as the risk to strand a pipeline for instance if simply no gas is flowing, may be considerable (as the case of Nabucco demonstrates).[165]

In addition, if prices become more volatile due to an increase in short-term contracts, price signals will be harder to read for investors, mainly because prices will be harder to predict for the future. As typical exploration and production investments have lead times of several years, plus a pay-pack period of at least 15 to 20 years, cash flows will be difficult to predict. The expected result will be that investors would rather commit to investments when the outlook is positive, i.e. when prices are

[164] These will increasingly be located in a technically challenging environment, i.e. deepwater offshore or arctic regions.

[165] It should be noted though, that also long-term contracts for transport (or storage) capacities may not provide ultimate security of demand or future cash-flows, as also here renegotiations or premature contract cancelling may occur.

attractive and the general market exception is rather the continuation of stable or increasing prices, and will be more hesitant to invest during phases of depressed prices. This outcome will be a development of gas markets more into the direction of a boom-and-bust-cycle-type economy where such moves as those described will further strengthen the overall dynamics. Such a development can be observed for the US gas market over the last decades. The Australian gas sector also shows a similar development, with many production and liquefaction projects starting in times of a very positive outlook and where, at present, with rising costs and pressure on prices, several projects were put on hold.

In general, investors reacting on such price signals independent of each other are likely to provide a higher level of diversification, thus fostering competition and security of supply. Although, the long-term security of supply should thus be supported, such a cyclical pattern may have some negative side-effects though, mainly because of the time lag between an investment decision and the investment to take effect. The oil market shows a pretty similar pattern and allegedly still suffers from investment cutting during the low oil-price phase at the end of the 1990ies. However, assuming an increased efficiency of scarcity signals, as elaborated above, the market should show the necessary resilience to absorb a strengthening of cyclical patterns. In addition, as already mentioned above, forward markets will have an increasing role in providing future-oriented price signals for investors.

6.3 Future Role of Long-term Contracts in the EU gas sector

Whilst the above sections focus on the impact that an increase in short-term contracts will have on the EU gas market, the question remains open as to which role long-term contracts will still play in the future.

From the research undertaken so far and also from the interviews conducted in the course of the project, the conclusion is that, for the time being, long-term contracts will continue to be used for parts of the sector despite the certain increase in short-term contracts and transactions all along the value chain as well as spot trading. Nevertheless, large portions of these trades will be on a secondary level, i.e. revolving around buying and reselling commodity (and limitedly also capacity). This means that long-term contracts are expected to be used to a certain extent, at least where significant infrastructure investments are required and/or where both parties have a strong interest in establishing a long-term relationship because of strategic or security of supply considerations for instance.

Therefore, long-term contracts (or vertical integration as a surrogate) are thus likely to be also in future be used, for instance in (and not necessarily exclusively):

- Large-scale development of gas fields, e.g. offshore or in otherwise challenging environments, e.g. Arctic regions or where a completely new infrastructure is required
- New build of long-distance gas transmission pipelines
- New build of liquefaction and regasification infrastructures
- It seems as if new build of gas-fired power plants could also be a case for long-term contracts

Where used, the interest in long-term contracts will be driven by the demand/need of investors (i.e. equity and debt providers) to ensure a stable and predictable cash flow and to mitigate volume-risks as well as – within limits – price risks.

However, long-term contracts are already subject to changes and will change further in the years to come. First of all, the duration of what has to be considered as a long-term contract will change. Where in the past contract durations of up to 30 years could be observed, essentially covering the whole payback period of for instance a gas field development, in the future long-term contracts may have a typical duration of around 8 to 15 years (for commodity supply) or maybe 20 years (for large infrastructures). The contract duration will have to be seen in close relation with prices or pricing formulas chosen in this contracts, as well take into account opening clauses.

For commodity, it seems safe to assume that the traditional long-term, oil-indexed contract will not prevail in the long-run. Thus, also where long-term contractual relations will continue to exist, the changing market situation with a strong development towards short-term contracts is, in general, expected lead to changes of pricing in long-term contracts and will, in fact, lead to pricing based rather on short-term market developments. Currently, the existence of and change to long-term contracts based on hub price development can already be observed, e.g. for deliveries to Europe which are then based on development of NBP or other European trading hubs, or LNG supplies from the US, which are based on Henry Hub prices (plus a fixed component to cover infrastructure costs). Price baskets are also likely to increase in importance. This expectation with regard to the design of long-term contracts (where they continue to exist) was further corroborated during the expert interviews held during the project. Typical pricing elements to be taken into account in future, which were also mentioned during the expert interviews, were:

- Coal price development
- CO2 price development
- Power price development
- Gas price development
- Inflation (e.g. consumer price index or retail price index)

Of course, for a certain time at least, oil-indexation could still be a component in such price baskets, but it will surely lose importance. In addition, contracts will be very much shaped by fixed components, starting values, floors, caps, take-or-pay clauses, etc. It is expected that the gas industry will show some creativity in determining new pricing mechanisms. Furthermore, opening clauses will be quite an important characteristic of these long-term contracts. A long-term contract leaving plenty of room to adapt pricing, as well as volumes over time, is certainly less strictly binding as a contract only allowing for renegotiation under very limited conditions. And a long-term contract, closely linked to overall market development and taking the market situation of the involved parties into account, is certainly less prone to renegotiation moves by one the of the involved parties. If prices of long-term contracts are linked to hub prices, long-term contracts will include no risk anymore for the buyer as excess volumes can easily (and without a loss) be sold at hubs.

However, in such a market environment, there seems to be little rationale left for the selling side not to sell the gas directly at the hub itself.

APPENDIX: INTERVIEW GUIDELINE

LT-ST market in gas - Expert interviews

The interviews were run along the following research questions, roughly laying out the scope of the discussion (in accordance with the individual expertise of the interviewee, not all topics were covered in all interviews):

EU gas sector

- Current contractual terms
    - To what extent can short-term contracts replace long-term supply contracts?
    - Why will there always be a role for LT contracts? What will be common contract terms (duration)?
    - Which pricing principles are attached to LT contracts between producers and wholesalers?

- Security of supply
    - Which SoS risks are attached to ST contracts? How can these risks (if any) be mitigated or maybe even compensated?
    - Do the long term and short term contractual relationships provide appropriate investment signals and financial stability/viability for the exploitation of gas fields and new infrastructure?
    - What are the opportunities and risks of the move towards spot and futures trading with respect to security of supply?

- Competition
    - Are there any risks related to ST contracts with respect to competition? How can these risks (if any) be mitigated or maybe even compensated?
    - What is the impact of ST contracts on liquidity and competition?
    - What is the impact of ST contracts on the role of gas producers and exporters in downstream markets? How ‘real’ is the possibility of large parties being able to

influence hub prices via supply 'management' (withholding or increasing supply volumes)?

- What is the role of both LT and ST contracts in the competition between coal and gas in power generation?

Other large gas markets

- Australia
  - How will LNG supplies from Australia change the (Asian) gas markets?
  - Will oil-price indexation remain the dominant pricing model for exported LNG?
  - Which role will vertical stakes of companies like KOGAS; Sinopec, Petronas, Tokyo Gas, Osaka Gas, Petro China play in future for the market development?

- China
  - Which importance will have imported LNG have for China in future? How this be affected by domestic shale gas production and potential supplies from Russia and Caspian region?
  - Which role will oil-indexation have in future supply contracts? How does this influence the domestic price structure?
  - Will Chinese importers be prepared to contract gas supplies for 20 and more years ahead also in future? What will be the future role of supplies from LNG spot markets?

- Japan
  - Which role will oil-indexation have in future supply contracts with first contracts for US LNG based on Henry Hub prices instead?
  - How will LNG imports develop in future?
  - Will Japanese importers be prepared to contract gas supplies for 20 and more years ahead also in future? What will be the future role of supplies from LNG spot markets?

- USA
    - Why/How can investments in gas production and transportation be sustained without long-term contracts?
    - What drives export investments, i.e. LNG terminal investments? And who are the parties pushing for the long-term contracts we see, the US exporters or rather the importers?

Brent crude oil, steam coal and power markets

- Brent crude oil trade
    - Are vertically integrated downstream activities (refined products) an important tool to hedge prices risk in upstream activities (exploration and production) in vertical integrated companies?
    - Will the Brent crude price index maintain the leading price index role? Will a declining level of liquidity negatively affect the role of Brent crude as the most important price index? How can the high confidence in the Brent price index been explained given the lack of transparency and the limited number of market participants?
    - How are decisions for capital intensive investments in exploration/production of e.g. offshore fields being determined (especially of production companies with no or only little own downstream activities – e.g. Sonagol Angola)?

- Atlantic seaborne steam coal trade
    - What is the basis of investment decisions of coal producing companies in the almost complete absence of long term contracts?
    - It there a correlation in the competitiveness of (i.e. dark spark spread) and investments in power stations and investments in steam coal mines?
    - Why is the level of vertical integration (either by means of long term contracts or corporate vertical integration) rather low given the lack of other risk mitigation means?

- German / UK / Italian wholesale electricity market
    - Why did long-term contracts disappear after the liberalisation of the electricity markets to a large extent?
    - Is there a correlation between contract structures in electricity and primary fuel markets (in particular gas and coal)? Is a correlation needed to hedge risks?

  How does a correlation of contract structures or lack thereof influence the competitiveness of this primary fuel in the generation market?