PART I
Chapter 2

The gas value chain and its infrastructure: A comprehensive introduction

2.1 Introduction

During the 20th century, natural gas has developed into an important fuel source in many countries’ energy mix. Previously, natural gas was only used on a minor scale. In the US, natural gas was first used in 1821, and at that time its use was purely local. Fifty years later, in Baku (Azerbaijan), natural gas was captured during local oil extraction work. Technological progress during the 1920s made gas transport over long distances possible. In 1925, the US started building a long-distance pipeline system, while in the 1950s the Soviet Union began doing the same on a large scale. The discovery of the Groningen field in the Netherlands, in 1959, launched the development of a European continental gas transport system. A decade later, the British developed their own pipeline network, independent from the continental European system [CE/CIEP 2007]. From the 1970s onward, the European gas network expanded further, with connections to Russia, Norway and Algeria [Cortellje et al. 2009].

The transport and supply of gas is a complex matter, owing to its capital-intensive nature and the investment risks for the stakeholders. This chapter provides a background to gas transport in relation to the value chain (i.e., from gas extraction to gas delivery) and risk management within the value chain. Section 2.2 starts by describing the gas value chain and the various interests of stakeholders in that value chain. The focus is on the position of gas infrastructure. The relevant risks and barriers for new pipeline investments are addressed in Section 2.3. Section 2.4 then focuses on the various forms of risk mitigation. Besides using contracts to mitigate risks, other forms of risk mitigation are also discussed, such as organisational risk mitigation. Section 2.5 discusses traditional and new business models for gas transport. The chapter ends with a conclusion in Section 2.6.

2.2 The gas value chain and its stakeholders

The process from extraction to delivery of gas can be divided into three components (upstream, midstream and downstream), and is defined as the gas value chain. The physical flow of gas starts upstream, including exploration and production as well as the treatment
of the gas to prepare it for transport. After the long-distance gas transport (midstream), the gas physically arrives in the downstream distribution network. The gas is transported by pipeline, or by tanker as LNG. In the latter scenario, gas is made liquid for transport by sea, and regasified at the receiving terminal for connection to the pipeline network. Gas storage serves as a buffer for seasonal and other fluctuations in demand. The downstream component includes the marketing to bring the gas to the customers. In Figure 2.1, the upper chain represents the physical gas flow.

Figure 2.1 Gas value chain: physical flow and payment flow of natural gas

The payment flow and the relevant stakeholders are shown in the lower chain of Figure 2.1. The retailer pays for the gas to the wholesale marketer, which is generally also the shipper. The shipper is required to pay transport charges to the transmission company as well as a fee to the upstream producer. In Europe, the netback pricing mechanism is a common method for pricing gas (see Box 2.1 and Chapter 8).

Each component in the gas value chain fulfills a specific role in that chain, involving various stakeholders, including governmental actors. Developing the chain and putting it into operation is a complex matter involving major investments and risks. Moreover, as soon as a pipeline has been constructed, the costs are sunk [Correljé et al. 2009]. Capital expenditures account for the largest part of the total costs, while operating expenditures are relatively minor (see also Box 2.2 in Section 2.4). Figure 2.3 shows the direct stake-

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14 Gas transport over long distances uses high-pressure pipelines. Gas transport by distribution networks generally uses low-pressure lines.

15 Unlike gas, it is relatively simple to market oil, since more options are available for transport: it is generally transported by pipeline, by train or by boat. Moreover, the oil market is more liquid and has a more global nature.
holders, including governments and financiers, that are involved in the creation and up-keep of the gas value chain.\textsuperscript{16}

\textbf{Box 2.1 Netback pricing mechanism}

In the method of netback pricing, a commodity is chosen that serves as the substitute for natural gas. The most common example is the netback link to the price of fuel oil (for households). Other units of reference are coal or collections of various types of energy, which may include elements of gas-to-gas competition (price determined by supply and demand). The price for the end user, therefore, is calculated using a substitute. The sum remaining for the upstream producer is the price for the end user minus the government’s share and the costs of marketing, distribution, storage, treatment, transport, production and the use of capital, and the residual netback.

\textbf{Figure 2.2 A simplified overview of gas pricing and margin distribution}

* Natural gas price for Dutch domestic consumer in 2006
Note: the relative width of the arrows does not correspond to real-life proportions.
Source: own analysis, based on expert interviews; Energiened [2006].

Figure 2.2 shows a common, though simplistic, breakdown of the price at end-user level. The majority of the revenue is intended for governments (in the form of taxes, participations and royalties in both producer and consumer countries) and the upstream operators. For more details on how prices are determined, see Chapter 8.

\textbf{Upstream operators}

Traditionally, the international energy firms and national energy firms occupy a dominant position in the area of gas exploration and production. The interest of upstream operators

\textsuperscript{16} Owing to the nature of this study, the emphasis is on gas transport, while the other components are only addressed insofar as they are relevant to gas transport.
is to achieve the highest possible returns. They may benefit from directly or indirectly influencing other parts of the value chain in order to mitigate their risks and maximise their profits (see also Risk Mitigation in Section 2.4). Governments issue licences to produce and explore new gas fields. Depending on government policy, the government may participate directly or indirectly in production and exploration, for example as a shareholder in a (national) gas firm (see also Chapter 3). Governments also collect income taxes and other forms of taxation and royalties on upstream activities.

**Figure 2.3 Players along the gas value chain**

![Diagram](source)

*Source: own analysis, based on expert interviews.*

**Shippers**

The shipper fulfils a possible role between the producer and the buyer of gas, bearing the risk of ownership only during transport. It generally does not buy and sell the gas at its own risk, and as such is not exposed to price and volume risks (see also Section 2.3). The shipper procures transport capacity from the firm managing the pipeline. In exchange, it must offer payment and the guarantee of a certain capacity purchase, preferably for the long term, for example using ship-or-pay contracts.

**Shareholders and governments in the gas infrastructure**

The primary role of pipeline shareholders lies in constructing the transport facilities such as pipelines, compression facilities and possibly storage. During the operational phase, this shareholder is responsible for outsourcing the transport capacity, managing the supplies of

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17 In a bilateral business model, the producer and/or the gas importer are responsible for the gas transport. This excludes any intermediate role from being carried out by a shipper (see also Section 2.5).
gas from the entry to exit points of the transport system and for ensuring that the pipeline facilities are maintained in a good state. The transmission company does not own the gas during transport. The transmission company may sell the available capacity to one or more independent shippers, one or more gas producers or one or more gas importers. The shareholder (whether private, public or a combination of the two) in a pipeline or a series of pipelines (constituting a gas corridor) may be an independent transmission system operator (TSO). Another possibility is that vertically integrated firms act as shareholders in the gas infrastructure, both gas producers and importers. Recent proposals by the European Commission (EC) are based on a further unbundling of activities. This will shift the responsibility for constructing and managing pipelines to TSOs or Independent Transmission Operators (ITOs).\(^{18}\)

Intergovernmental and national authorities define the investment framework. They also issue licences to construct gas infrastructure and are responsible for related new laws and directives regarding such matters as regulation. The construction of international gas corridors may cross multiple jurisdictions, for example within and beyond the EU. Providers of debt capital (such as banks) also play an important role in financing the pipeline.

**Figure 2.4 Relevant stakeholders in the gas infrastructure**

<table>
<thead>
<tr>
<th>Upstream</th>
<th>Midstream</th>
<th>Downstream</th>
<th>Midstream</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas production fields</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field I</td>
<td>Transit country 1</td>
<td>Transit country 2</td>
<td>(Storage)</td>
</tr>
<tr>
<td>Field II</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field III</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Upstream stakeholders**
- National energy firms
- International energy firms
- Government (including politicians and regulations)
- Sponsors

**Gas corridors shippers**
- National energy firms
- International energy firms
- Independent traders
- Utilities (from downstream)
- Government (including politicians and regulation)
- Sponsors

**Gas corridors owners**
- Pipeline companies
- National energy firms
- International energy firms
- Utilities (from downstream)
- Government (including politicians and regulation)
- Sponsors

**Players in other gas pipelines**
- Pipeline owners
- Utilities
- National energy firms
- International energy firms
- Government (including politicians and regulation)
- Sponsors

**Alternative gas supply**
- Gas corridors
- LNG

Source: own analysis, based on expert interviews.

**Downstream stakeholders**

The downstream transmission capacity (i.e., between exit points from the gas corridors and the end users) is less important for purposes of this study. The three principal sectors

\(^{18}\) For a discussion of the liberalisation of the European gas market, see for example Haase [2009] and Chapters 3 and 7.
– representing the end users – are industry, retail and the power sector. Some countries in continental Europe unbundled transmission and trade. In the United Kingdom and the US independent TSOs have been operating in the downstream transport system for some time. Most other operators are the traditional national utilities. The downstream distribution networks are governed by a high degree of regulation. Figure 2.4 sets out a schematic overview of the operators in the gas infrastructure (including multiple-country transportation) as an integral part of the gas value chain.

### 2.3 Risks related to gas infrastructure investments

Naturally, there are risks involved in any gas infrastructure investment. These risks stem from, first, investment barriers and, second, future uncertainty (e.g., about market development). Not all risks are equally probable, nor is their impact equally great.

Investment barriers are caused by, among other things, the entry barriers for investing, and by the level of capital intensity of gas infrastructure projects, where the investments have a long recovery period and are largely sunk. One of the reasons for these entry barriers is that managing pipelines, particularly international ones, is often the domain of firms in which the government holds a majority interest. In some cases, the transmission company is operating as a subsidiary of a vertically integrated gas firm. For example, the Russian gas network has been turned into a monopoly under the unified gas transport system (UGTS), which is a wholly owned subsidiary of Gazprom.

#### Figure 2.5 Risks related to gas infrastructure investments

<table>
<thead>
<tr>
<th>Risk</th>
<th>Description</th>
<th>Risk components</th>
<th>Translated to main risks for gas infrastructure investments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commercial (project) risks</td>
<td>• Risks that are inherent to the project itself, or in the market in which it operates</td>
<td>• Commercial viability • Completion risks • Environmental risks • Operating risks • Revenue (market) risks • Input supply risks • Force majeure risks • Contract mismatch • Sponsor support</td>
<td>• Market risks (e.g., volume and price) • Finance risks (project related) • Transport risks (e.g., design, construction, operation, maintenance, and interruption)</td>
</tr>
<tr>
<td>Macro economic risks</td>
<td>• Risks that are related to external economic effects not directly related to the project</td>
<td>• Inflation risks • Interest rate risks • Exchange rate risks</td>
<td>• All risks are applicable</td>
</tr>
<tr>
<td>Political (country) risks</td>
<td>• Risks that are related to the effects of government action/policy or political force majeure events such as civil disturbance and war</td>
<td>• Investment risks (currency convertibility and transfer, expropriation of the project by state, political force majeure); • Change of law risks (new legislation/regulation that affect the viability of the project); • Quasi-political risks (breach of contract and court decisions, sub sovereign risks, creeping expropriation)</td>
<td>• Regulation and policy risks (i.e. those related to the energy mix) • Political force majeure and uncertainties about (geo/political relations, especially when the project involves cross-border financing or investment)</td>
</tr>
</tbody>
</table>

Source: own analysis, adapted from Yescombe [2002]; Razavi [1996]; ECN [2007]; expert interviews.
In terms of uncertainty, Yescombe [2002] distinguishes between (1) commercial, (2) macroeconomic and (3) political risks for project financing. Figure 2.5 shows descriptions of and a breakdown into the various risk components. The most relevant risks for investments in the gas infrastructure under the different components are also mentioned in the rightmost column. These risks together affect the projected cash flows and thus the investment decisions [EC 2007; ECN 2007].

Risks can be organised by probability and impact using a risk profile analysis. Using these distinctions, risks can be organised into four general categories (see Figure 2.6). If the probability is low and the impact also low, the risk is irrelevant. If the probability increases but the impact remains low, the risk becomes more relevant yet still manageable through organisation. If the impact is high but the probability is low, the risk is contingent. The final risk category is critical, since the risk has both a high probability and a high impact.

The category in which above-mentioned risks can be divided depends on the gas infrastructure project and the area operating in. In general, the dominant risk in connection with investment in the gas infrastructure, which can as such be qualified as critical, is the so-called market risk, falling into the category of commercial risks. Specifically in terms of investing in the gas infrastructure, this is the risk that the capacity is not used or contracted sufficiently and/or that the internal tariffs are too low to achieve a certain profitability [Correljé et al. 2009]. In Chapter 4, the relevant risks are integrated into the conceptual toolbox for evaluating gas infrastructure investments.

**Figure 2.6 Risk profile analysis**

<table>
<thead>
<tr>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Organisational</td>
</tr>
<tr>
<td>High</td>
<td>Contingent</td>
</tr>
</tbody>
</table>

Source: expert interviews.
2.4 Common types of risk mitigation in the gas infrastructure business

The market characteristics of the gas market, such as imperfect competition, call for a degree of risk management in order to achieve the long-term investments [ECN 2007]. The risks are divided among the parties in the value chain, in exchange for part of the value in the system. Depending on creditworthiness and on the available options for financing and guarantees, the risk may be absorbed by one specific operator. Any risks that cannot be absorbed are ideally transferred to other parties and/or mitigated. Firms have three options for mitigating risks using a particular organisational structure: vertical integration, horizontal integration and mitigation through organisational risk diversification. A firm can also mitigate its risks using contracts and financial instruments. Contractual and organisational risk mitigation are the methods most commonly used for gas infrastructure investments and are the focus of this section.

2.4.1 Contractual risk mitigation

Contracts divide risks between parties and determine mutual rights, guarantees and obligations. Traditionally, market risks are covered by long-term capacity and volume contracts. A typical long-term contract, a take-or-pay contract using the netback pricing mechanism (generally 15-20 years), places the price risk with the upstream operator, by linking the gas price to the prices of the substitute energy carriers, and places the volume risk with the buyer. Take-or-pay contracts oblige the buyer to purchase a certain minimum volume of gas. Before the liberalisation of the gas market, such contracts also included a destination clause, prohibiting the buyer from reselling the gas to third parties. The destination clause offers gas-exporting countries a greater degree of flexibility, as they can 'unilaterally' determine their sales markets and the accompanying prices. In the EU, inclusion of destination clauses was prohibited since the gas liberalisation, meaning that buyers of gas can sell some or all of the volume purchased on the secondary market [Davis 1984; ECN 2007].

Partly as a result of liberalisation, the transport and commodity markets have become more and more distinct from one another. In such a situation, the shipper concludes a ship-or-pay contract with the transmission company, independently from long-term take-or-pay contracts. If the planned capacity is covered sufficiently by ship-or-pay contracts,

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Credit ratings can be used as a measure of a party's creditworthiness.

To make financial risk mitigation possible, a firm needs access to liquid commodities or financial markets, gas exchanges and forward and futures markets. However, in Europe those markets are not sufficiently developed at present, although more and more financial tools are being introduced into the market, for example for facilitating arbitrage between the various markets (e.g. Henry Hub vis-à-vis National Balancing Point, NBP, and Title Transfer Facility, TTF) [ECN 2007]. In case risk mitigation can not be (sufficiently) achieved, the firm may have to demand a higher rate of return to reflect the higher risk.

See Box 2.2 at the end of this sub-section for the relationship between gas contracts and pipeline capacity. For a comprehensive overview of gas sales and gas transportation agreements, see Roberts [2004], for example.

The Transit & Tariff agreements between the shipper and the transmission company specify a number of conditions. An Annual Contract Quantity (ACQ) is determined, with a minimum and a maximum ship-or-pay quantity. Owing
whether or not the tariffs are regulated, the pipeline investor’s cash flows can be guaranteed in order to cover the costs of investment and the return and to attract financiers [Roberts 2004]. Figure 2.7 shows a standard structure for gas contracts, under which the transmission company operates with legal independence. It also shows the role of the authorities, regulation and other parties.

**Figure 2.7 Standard structure (take-or-pay) of a gas contract system**

In addition, the procedures have changed since the liberalisation in the EU and elsewhere. Important changes include:

- More and more often, potential investors in the gas infrastructure are organising ‘open seasons’, during which prospective users can make long-term reservations of capacity [Correljé et al. 2009]. Open seasons are generally not used with gas corridors outside the jurisdiction of liberalised gas markets (to liberalised countries).
- The transport and distribution network is partly regulated, based on the principle of non-discrimination, in order to ensure third party access (TPA).

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* This task could be performed by the transmission company
** If the transmission company is a joint venture
Source: expert interviews.

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23 An example of an exception to that rule, however, is the prospective Nabucco pipeline through Turkey (see Case study 2 in Chapter 11).

24 New tariffs are determined every 3-5 years [Correljé et al. 2009]. In the regulated regime, costs are covered by (1) regulated cost-plus tariffs; (2) regulated transmission tariffs (price cap regulation); and (3) regulated revenue from transmission operations (revenue cap regulation) [ECN 2007].
ures are intended to make it simpler for new operators to enter the market, increasing competition on a non-discriminatory basis and allowing the secondary market to develop [Lecarpentier 2006; De Jong 2007]. In addition, they make it possible for pipeline investors to make the best possible use of economies of scale. Open seasons promote the non-discriminatory treatment of prospective users.

- The price formulas in supply contracts have become more flexible (such as gas hub prices alongside the link to oil prices), and as a rule more periodic renegotiation clauses are specified. Use-it-or-lose-it conditions serve to prevent the contracted capacity from not being used [ECN 2007; Correljé et al. 2009].

Figure 2.9 Standard guarantee structure of gas contracts

Next, Figure 2.9 shows common obligations and guarantees of the respective parties. The upstream producer agrees to supply the contracted gas; this is balanced by the buyer’s take-or-pay obligation. The buyer is also obliged to provide a guarantee to support its creditworthiness. In the ship-or-pay contracts, the shipper agrees to pay for a certain minimum capacity, regardless of whether or not it uses that capacity. The shipper guarantees that minimum capacity by way of a business or government guarantee, a letter of credit or a security deposit.
Box 2.2 Managing the ramp-up period of pipeline capacity and cost realisation

With investments in the gas infrastructure, the realisation of costs is not the same as the use of that investment (i.e. the return). The owner of gas infrastructure and the producer/shipper have various options for strategically managing the difference.

As a rule, the build-up in the increase of the gas sales is phased (during a ramp-up period), owing largely to a layered build-up of the demand (see lower section of Figure 2.8, shown an example in gas through-put per supply region and/or field). This increases the possibility that shippers will be willing to purchase capacity from the transmission company in phases. The capital expenditures (CAPEX), conversely, are realised during the first few years, sometimes followed after some years by additional CAPEX for additional compression. The operating expenditures (OPEX) cover the costs of running the compressor and pipeline facilities for operational use (see upper section of Figure 2.8 and Chapter 4). The uncontracted capacity at the beginning of the pipeline’s operational phase has a downward impact on the expected cash flows, endangering pipeline projects to sometimes being cancelled.

If the ramp-up period is strategically planned and coordinated, the pipeline can be used sooner. Four options are available in this connection. First, the transmission company can build up its capacity in phases, by laying two or more consecutive pipelines alongside one another or putting compressor stations into operation in phases. An example of this scenario is Nord Stream, in which two pipelines are being constructed in separate phases alongside each other.

Figure 2.8 Cost realisation and ramp-up period of pipeline capacity

Source: own analysis, based on expert interviews.
Using this guarantee structure, the only risks to which the transmission company is exposed concern design, construction, operation, maintenance and interruption. If it so desires, the transmission company may engage its subcontractors to construct or deliver parts of the pipeline. The subcontractors provide the transmission company with guarantees for their activities. The operating activities may also be outsourced to third parties. The firm uses equity and debt to finance the gas infrastructure (possibly provided by external investors participating in a joint venture). In some cases, the (debt) capital is provided and/or guaranteed by a government authority. A central or regional government body is also responsible for the licence, regulation and other permits for constructing gas infrastructure. It may also offer the transmission company assistance (political or otherwise). Finally, insurances are offered to the transmission company.

### 2.4.2 Organisational risk mitigation

Besides the long-term contracts, certain choices in terms of the organisation structure are regarded as a strategy of risk mitigation on the gas market. This subsection deals with some common organisation structures, namely vertical and horizontal integration and risk mitigation through organisational risk diversification, and the conditions and market circumstances under which a particular organisational structure is preferable.

Vertical integration includes forward and backward integration, both of which are used in practice. Complete (or incomplete) vertical integration generally occurs in the gas market as a result of the highly capital-intensive nature in parts of the value chain, the need for economies of scale, the need to secure economic rents and the possibility of influencing market conditions through control over the chain [Davis 1984]. Gas-exporting countries are increasingly taking stakes in downstream markets, while midstream operators from Europe try to gain access to the upstream market, both for the purpose of realising greater competitive power.
However, in a liberalised gas market, stakeholders have a limited number of options for mitigating their commercial risks through vertical integration, following the implementation of the EU directives, the aims of which include unbundling. In non-liberalised markets, which include many gas-exporting countries, vertical integration is still a common strategy, owing to economies of scale, among other factors [ECN 2007]. Such a strategy is only favourable if vertical integration is necessary in order to protect or create value, requiring the firm’s competitive position to improve significantly [Stuckey and White 1993; Thompson and Strickland 2001]. Stuckey and White [1993] identify four situations in which vertical integration might be a good strategy:

1) in the case of a high-risk and unreliable market;
2) if firms in some parts of the value chain possess more market power compared with firms in other parts of the chain;
3) if vertical integration results in market power by creating entry barriers or price discrimination;
4) if the market is still relatively underdeveloped, forcing a firm to integrate vertically in order to develop the market, or if the market is deteriorating.

The current characteristics of the gas market correspond largely to these points. Producing countries are facing increased uncertainty about the use of gas in the energy mix, owing to developments in technology, economy and/or policy in connection with sustainable energy sources, or the ‘security of demand dilemma’. For consuming countries, the uncertainty concerns the question of whether sufficient gas will be available, based on economic and/or political and geopolitical considerations, known as the ‘security of supply dilemma’. Vertical integration may also result in the creation of barriers to entry, although regulating policies try to break some of those barriers [CIEP 2010]. From the perspective of vertically-integrated firms and traders, investments in transport capacity might have an optional value owing to the ability to sell more gas in the future, if the firm so wishes (in part because on the commodity market costs are relatively ‘minor’ compared with possible opportunity losses on the commodity market). In financial-economic theory, this type of infrastructure investment is regarded as a platform of strategic growth options (see chapters 3, 4 and 11).

Moreover, the degree of vertical integration and concentration differs across the various phases of development. The phases of development on and between regional and sub-regional gas markets also differ greatly. According to De Jong [1989], vertical integration occurs primarily during the embryonic and mature market phases. Vertical differentiation appears to be more frequent in bull markets and less common in bear markets. In embry-
onic markets, vertical integration may yield benefits that stimulate development. Similarly, vertical integration may be an attractive strategy in mature markets, because of the ability to cut any higher transaction costs within the value chain [De Jong 1989; CIEP 2010]. For the purposes of this study, economies of scale resulting from vertical integration are primarily interesting because of the possibility they offer to control chains and manipulate markets (see also chapters 3 and 4).

Yet, Stuckey and White [1993] also argue that vertical integration causes high internal organisational costs and represents a high-risk strategy because it limits the flexibility of the business strategy. As a result, the exit barriers are relatively high. Moreover, innovative capacities may disappear as a result of insufficient investment. The impact of vertical integration on competition may also be unfavourable, because it reduces the liquidity of the wholesale market. The resulting volatility makes vertical integration relatively appealing, which in turn creates barriers for market access for non-integrated firms [Moselle et al. 2006; CIEP 2010]. If the impact of these factors exceeds the benefits, outsourcing or unbundling (vertical differentiation) may serve as an appropriate solution [Thompson and Strickland 2001].

Horizontal integration occurs if market parties in the same parts of the chain work together in consortiums or realise mergers and acquisitions (M&As). In the case of cooperative consortiums, the risks are not reduced, but shared between the parties. Horizontal concentration in the gas market takes the form of both M&As and consortiums. Horizontal concentration occurs chiefly in the mature market phase, though tendencies are also visible in the introductory and declining phases. As a rule, horizontal deconcentration is more common during expansion phases. The limited possibilities for product differentiation on the gas market mean that there is less tendency toward deconcentration [De Jong 1989]. Horizontal concentration occurs upstream as well as midstream and downstream, and can lead to a lack of symmetry in market power, even if liberalisation policies, in the EU for example, attempt to break that market power.

Market parties can diversify their project-specific (commercial) market and some political risks by offering multiple options for gas transport [ECN 2007]. Moreover, the possibility to adopt this strategy depends on the firm’s internal characteristics. In practice, it is easier for major incumbents to realise such a strategy than for small, new firms. The three tradi-

26 Conversely, vertical integration may have a relatively positive effect on competition by excluding, to an extent, ‘double marginalisation’. This is a situation in which upstream and downstream operators with market power operate separately from one another and can both demand a price that exceeds the marginal costs of production. In such a situation, competition is better ensured by an integrated company [Tirole 2003]. In liberalised markets, in which components of chains are unbundled, this gives rise to the risk that competition will come under pressure from double marginalisation [CIEP 2010].

27 Görg argues that acquisitions are more likely to taken place in Cournot-type markets, except for situations involving relatively high adaptation costs. Under such conditions, a greenfield strategy seems more desirable [Müller 2001].
tional gas suppliers outside the EU use this strategy for their pipeline (and LNG) investments, among other purposes. Russia has been using this strategy with Europe since the 1990s (see also Part II).

Integrated firms have other options for risk mitigation. In addition, from the perspective of integrated firms, investments in infrastructure are a tool to reinforce their core activities (on the commodity market). For non-integrated firms, conversely, those investments are the core activity, and need to yield commercial returns. Depending on the ownership structure, the required rate of return of a transmission company may be greater than those of integrated firms.

2.5 Gas infrastructure: old and new business models

One result of liberalisation, also given the increased distances between production and consumption, technology, other forms of risk mitigation and intra- and interregional arbitrage possibilities, is that the business models for pipeline and LNG infrastructures have changed since the 1990s. Traditionally, the buyer and producer have been the primary parties involved in realising the gas infrastructure. As a result of liberalisation and other factors, third parties, such as independent shippers, are involved more and more often in gas infrastructure. At the same time, the increased distances between production and consumption often imply that transit countries are involved. Before this section addresses the traditional and new models of gas infrastructure at greater length, a brief description is given of the time horizons for gas infrastructures, with particular focus on the process of development and construction.

2.5.1 Time horizon of gas infrastructure

Investments in the gas infrastructure can be made for existing gas infrastructure (brownfields) or for new infrastructure (greenfields). Before governments and firms conduct official negotiations, a feasibility study is carried out, based on economic and technical issues. The governments of the parties involved then draw up a letter of intent. Next, the representatives of the gas firms conduct the contract negotiations in order to compile a memorandum of understanding (MoU). Eventually, the MoU may lead to a final investment decision (FID). In the heads of agreements, as they are called, the gas firms involved agree on certain matters, and also agree to negotiate about the elements on which they have not yet reached consensus. Finally, the contract is drawn up. In this final phase of the negotiations, the tariffs and other (mostly minor) points of negotiation are specified (see also Figure 2.10).

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28 Investments in existing pipelines may pertain to either of two purposes: the upkeep of the infrastructure or the expansion of the existing infrastructure.

29 This is a letter of approximately fifteen lines, in which the heads of state of the countries involved express their intention to conclude a contract in the future for the construction of new gas infrastructure.

30 A MoU is sometimes called a framework agreement or an agreement in principle.
In terms of pipeline infrastructure specifically, ‘transit’ across the territory of third parties occurs if the two countries (or jurisdictions) involved are not directly connected. The interests of the transit countries in between must be guaranteed in terms of such factors as (regulated) transit fees and royalties. Transit agreements are concluded at the level of the governments, and are generally supported by business agreements. A solution, to a degree, for limiting the transit negotiations lies in offshore gas pipelines. Underwater pipelines make it possible to save on transport costs (e.g. royalties and transport and transit tariffs) and reduce the direct influence of local gas firms and governments. However, the countries adjacent to the water through which the pipeline is conducted influence the issuance of environmental permits and other licences.

As Figure 2.10 shows, the development phase of a pipeline generally takes 10-15 years. Once a decision has been made to build the pipeline, it takes approximately 3-5 years before the pipeline infrastructure is operational. Depending on quality and maintenance, the technical life of the pipeline will be around 50 years.

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If the pipeline crosses a country’s Exclusive Economic Zone (EEZ), that country will have to issue a licence. The EEZ is a zone that extends to 200 nautical miles beyond a state’s coast. Within that zone, the country in question has several rights, such as the right to exploration of any natural resources present, the fishing rights and the right to conduct scientific research. A country that imposes an EEZ is responsible for managing that area’s nature and environment. Arrangements on this issue were laid down in the UN Treaty of 1982 (UNCLOS). Similarly, countries that might be adversely affected by cross-border environmental problems resulting from the construction of the pipeline can also influence the process by way of environmental requirements, using the Environmental Impact Assessment (EIA) procedure. This consultation procedure applies not only to transit countries whose EEZ the pipeline crosses.
Depending on the business model, the negotiations for the realisation of LNG projects are generally governed by the same procedures, though the advantage is that direct transit through third-party countries is generally not relevant. However, maritime straights such as the Suez Canal and the Strait of Malacca mean that transit risks remain for some routes, such as the route from Qatar to Europe by way of the Suez Canal and other waters.

2.5.2 Old and new business models for gas pipeline investments

As described above, new models for gas infrastructure have been developed during the course of the development of the regional gas markets. In terms of the development of the business models for pipeline infrastructures, a distinction can be made between bilateral and multilateral: without transit through third-party countries and including transit countries, respectively. In addition to this, the appearance of independent shippers alongside producers and ‘end consumers’ has also changed the business models.

Bilateral business model

The scenario in which a relatively small number of stakeholders is involved can be approximated using a bilateral model. In that model there is one gas producer (or one gas importer), that also manages the network, contracts the gas out to retail firms or sells it directly to the end user. The financing for the infrastructure is based on the gas contract. The risk of debt repayment is generally determined using the creditworthiness of the importing firms and the accredited reserves and/or creditworthiness of the supplier of the gas [Barrett 2007]. Most older gas corridors to Europe were created along the lines of this model [ECN 2007]. A recent example of the bilateral model is the Greenstream, which connects Libya directly with its buyers in Italy.

Multilateral business model

If transit is involved, it becomes more complex to realise a pipeline. Transit countries can influence the operation of the pipeline, sometimes as single or joint shareholders. The political risks attached to transit through third-party countries can be mitigated using bilateral governmental agreements, combined with business contracts for transit fees and royalties. The first Algerian pipelines to Italy and Spain, and the Soyuz-Transgas and Yamal-Europe pipelines are examples of this model. Following the collapse of the Soviet Union and its loss of control over the Soviet republics and Council for Mutual Economic Assistance (CMEA), the transit agreements were revised, and transit became more complex [Barrett 2007].

Bilateral shipper business model

Two submodels can be used to show the involvement of a shipper. First, there is the model in which a single shipper contracts all the capacity using ship-or-pay contracts and as such

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32 This sub-section is based largely on Barrett [2007].
33 Chapter 6 and Chapter 12 discuss the increased Russian transit risks at greater length.
links one or more gas suppliers to one or more buyers. In this model, financing the pipeline requires that the majority of the capacity be sold to the shipper. As a result, it is no longer a real concern for the pipeline owner whether the pipeline is actually filled. Use-it-or-lose-it rules can be used to prevent shippers from abusing their market power. In the past, the pipeline system from Norway to northwestern Europe was an example of the bilateral shipper model. Lately, it seems as if Nord Stream pipeline will also adopt this model [Barrett 2007; Correljé et al. 2009].

In the second submodel, the multi-shippers model, the various producers and marketers can procure transport services from multiple shippers, creating greater competition and flexibility among the producers for the various markets. The United Kingdom (UK) Interconnector and the Balgzand-Bacton Line (BBL), among others, follow this model. The involvement of independent shippers and infrastructure companies leads to higher business risks, which contracts may serve to reduce [Barrett 2007].

**Multiplicity business model**

The most complex business model, the multiplicity business model, is characterised by open access and competition at all points of the gas infrastructure. Multiple shippers can purchase capacity in some or all parts of the gas pipeline. Various gas suppliers, aggregators and end users have access to the shippers’ services. To date, this model has not been put into practice, though the proposal for the Nabucco pipeline matches it most closely [Barrett 2007]. In the multiplicity model, the gas infrastructure is financed primarily using multiple long-term ship-or-pay contracts, combined with government or intergovernmental agreements for transit. This model is more competitive and is often initiated by newcomers on the market or by shippers. These projects, which are generally midstream-driven, are more difficult to realise. Political involvement may help with the troublesome financial and other aspects of realisation [ECN 2007; Barrett 2007].

### 2.5.3 Old and new business models for LNG terminal investments

As far as LNG infrastructure is concerned, the different LNG business models correspond to the pipeline business models described above. The rationale of vertical integration and economies of scale, interregional price differences (i.e., arbitrage opportunities), the opening of the US market, high energy prices and the seller’s market in this decade until the autumn of 2008 have combined to create a second generation of business models for LNG. This type diverges significantly from the traditional LNG business model of long-term contracts. These new LNG business models could have a spill-over effect on the business models of pipeline projects (and vice versa).

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33 Norwegian gas exports were organised through the state-run monopoly on gas sales, the Gas Negotiating Committee (GFU). Since that system was abolished, Norwegian gas export has followed the multishipper model.
The first traditional type of LNG regasification terminals corresponded to the bilateral model, in which the producer and the buyer conclude long-term contracts. The transmission project is integrated, and no project financing is needed. The buyer bears the costs of regasification. Gaz de France and Disttrigaz of Belgium built their first generation of terminals in this fashion, with Société Nationale pour le Transport et la Commercialisation des Hydrocarbures (Sonatrach) of Algeria as their supplier. Under pressure of regulation, third-party access and official tariffs are being demanded more and more often.

For the most recent type of LNG regasification terminals, the project is initiated by independent operators, while producers and/or buyers contract capacity for the long- and the short term. The Gas Access To Europe (GATE) terminal in the Port of Rotterdam, a partnership between Nederlandse Gasunie and Vopak, is an example of the latter type of LNG terminal [Barrett 2007; De Jong et al. 2010].

Specifically, the second-generation type is driven by gas producers to gain access to the market. Self-contracting also occurs on the European pipeline gas markets, and is therefore an interesting topic to address in this subsection. This new business model includes [De Jong et al. 2010; CIEP 2008; IEA 2008]:

1) Producers reserving part of their liquefaction capacity for short-term deals.

2) Producers and mid-streamers contracting their own production (i.e., self-contracting): Upstream stakeholders purchase planned liquefaction output, and in turn market it themselves, either through capacity and/or equity acquisition at regasification terminals downstream in consuming countries or through direct sales to interested buyers. Various pockets of liquefaction output are thus allocated to different markets either by a consortium or by a single player, achieving supply diversity and optimal revenues through the attainment of regasification assets downstream.35

3) The emergence of LNG aggregators buying LNG on a long-term basis and selling it in a mixed portfolio (though few firms have actually ventured on with this business model). Aggregators, as they are known, make sales commitments to LNG receiving terminals in LNG consuming countries. Often, long-term supplies are bought by an aggregator and then sold on a short-term basis on different markets, as described above.

35 Firms with regasification capacities or sales commitments in multiple consuming regions also make free-on-board off-take commitments to fill those capacities or to sell (or ‘divert’) to higher-paying markets in a more flexible fashion than previously seen. This strategy may be pursued by LNG producers already established on the market with assured cash flows from earlier investments, or by new LNG players, to the extent that they have a sufficient cash flow from supplies committed under long-term contracts. An example of self-contracting by producers is the Qatar/ExxonMobil development of two 7.8 mtpa trains. Pipeline suppliers to the European market, notably those from Russia, Norway and Algeria, also appear to add “flexible supplies”, not committed to their markets by means of long-term contracts, in their supply portfolio for Europe, for purposes of direct marketing and sales on the wholesale spot market [De Jong et al. 2010; CIEP 2008]. An example is Nord Stream, where Gazprom Marketing and Trading has already contracted pipeline capacity (see also Chapter 12).
The new business models have enabled LNG (and pipeline gas) to become more flexible, fostering the impression that interregional gas-to-gas competition may decouple this flexible LNG from long-term, take-or-pay, oil-indexed contracts, see also Chapter 8 [Jensen 2004]. At the value chain level, some consequences of self-contracting (and other forms of flexibly marketing LNG) are [De Jong et al. 2010]:

- the need for producers to secure regasification capacity on different markets (or overcapacity in the case of pipeline systems) in order to realise the potential of arbitrage. This is also done in order to maintain shipping capacity to ensure that the supplier remains capable of reaching the markets included in its arbitrage portfolio;
- the need for producers to develop the tools and capabilities to sell gas directly on the markets of their choice, without long-term supply contracts for flexible gas.

This business model may lead to chronic surpluses in shipping and regasification, which would result in higher risks and costs for producers (and aggregators). The downside risks of the new business models are both revenue- and volume-related. In case of a buyer’s market, short-term and spot gas prices may well be less desirable than the prices realised under long-term contracts and it may even prove difficult to place LNG on markets which are already well supplied. For these reasons, according to De Jong et al. [2009], self-contracting producers and aggregators often exploit at least one ‘haven’ of last resort for their LNG via the firm’s regasification capacity. In many cases this is situated in the US, which offers the most liquid market, with the greatest capacity to absorb surplus LNG even if the global or US market is oversupplied. Naturally, this assured outlet for LNG comes at a cost, because of its low prices (see also Chapter 8).

Whether this business model will evolve and develop further depends on (1) the risk appetite of LNG suppliers to continue to exploit their resources on the basis of the new business models in conditions of lower and/or volatile energy prices; (2) the ability and compliance of the markets, particularly the European market operators and to a lesser extent those on Asian markets, to accept and manage the supply risks associated with these business models; and (3) the willingness of producing and consuming governments to step back from LNG sale and purchases transactions. The economic crisis of 2008/2009 is encouraging gas-exporting firms to go for long-term contracts rather than choosing a business model of flexible supplies [De Jong et al. 2010].

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The share of flexible LNG on the Asian market may be considerably lower than the Atlantic Basin (i.e., the European and US LNG markets), because those markets are based primarily on long-term oil-linked contracts. In the Atlantic Basin, approximately 40 percent of the total trade consisted of ‘flexible’ LNG before the economic downturn in 2008 [De Jong et al. 2010].

34
2.6 Conclusion

This chapter offers an outline of the complexity of gas transport as an element in the gas value chain. The gas value chain has three components: upstream, midstream and downstream. The producer, the infrastructure company, the shipper and the downstream buyer are the principal actors in the chain. In addition, financiers and governments are other parties that are indispensable for successfully constructing new gas infrastructures. Investments in gas infrastructure are largely characterised by market, financing, transport, macroeconomic, policy (including regulation-related), and political and geopolitical risks. Contracts between the various parties, such as pipeline companies and shippers, can serve to better guarantee investments in infrastructure. With traditional long-term take-or-pay contracts, the risks are divided between the various parties in the value chain. Parties can also adjust their organisational structures in order to manage and mitigate their risks. Vertical and horizontal integration are commonly used strategies for this. Similarly, project risks can be mitigated by diversification (of gas transport, for example). The liberalisation in the EU has restricted a number of these possibilities in order to promote the operation of market forces.

Gas transport becomes more complex as the number of parties that can influence the decisions increases. If the transport crosses transit countries, the negotiation process may become more difficult. In that process, the industry actors seek the assistance of governments to help the negotiations and to issue investment guarantees. Factors such as liberalisation, arbitrage possibilities on and between regional gas markets, the need to secure economic rents, the necessity of economies of scale and high prices until the autumn of 2008 have forced pipeline gas and LNG providers to develop new business models for gas transport and sales. Besides the business models that include shippers, the self-contracting model, as it is known, offers suppliers flexibility in their methods of selling gas. It is unclear whether that business model will develop further, considering the downside risks (i.e., price erosion).

If an infrastructure firm operates independently or if the infrastructure is handled as a project, the investment should be profitable in and of itself. The choice of a particular organisation structure will affect the perception of profitability (or capacity utilisation), the creation of possibilities for uncontracted capacity and the way of dealing with risks. Exercising control over the gas value chain may increase the options available. This aspect is discussed at greater length in the following chapters in this part.