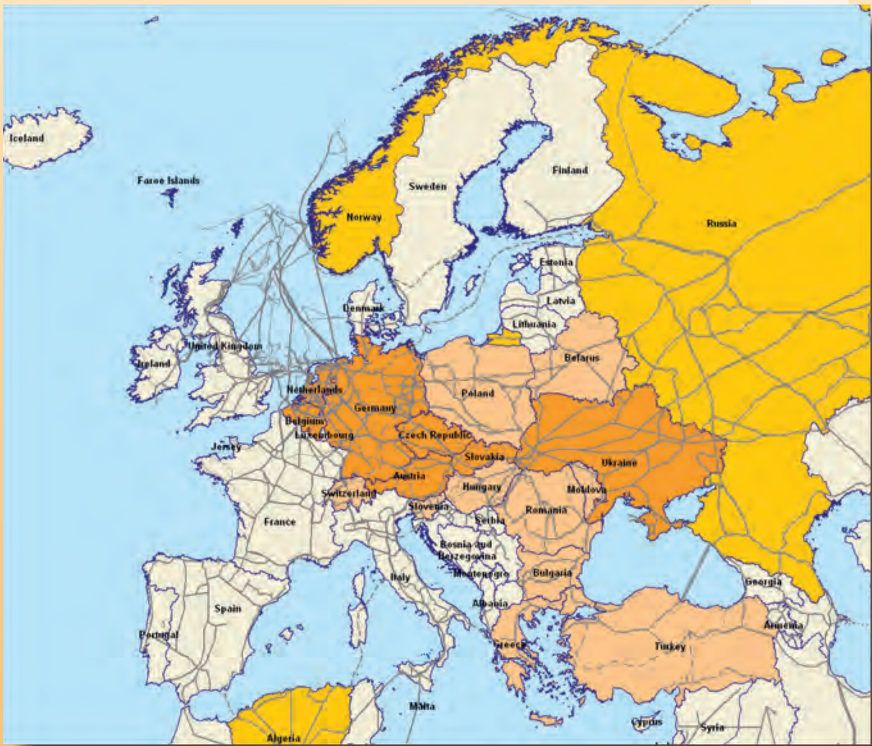
Crossing Borders in European Gas Networks:

The Missing Links

Clingendael International Energy Programme



Nederlands Instituut voor Internationale Betrekkingen
Netherlands Institute of International Relations
Clingendael

Crossing Borders in European Gas Networks:
The Missing Links

Clingendael Energy Paper

September 2009

Clingendael International Energy Programme
CIEP is affiliated to the Netherlands Institute of International Relations 'Clingendael'. CIEP acts as an independent forum for governments, non-governmental organizations, the private sector, media, politicians and all others interested in changes and developments in the energy sector.

CIEP organizes lectures, seminars, conferences and roundtable discussions. In addition, CIEP members of staff lecture in a variety of courses and training programmes. CIEP's research, training and activities focus on three themes:

- regulation of energy markets (oil, gas, electricity) in the European Union;
- the international economic and geopolitical aspects of oil and gas markets, particularly with respect to the European Union security of supply; and
- energy and sustainable development.

CIEP is endorsed by BP, the Dutch Ministry of Economic Affairs, Eneco, Energie Beheer Nederland, Essent, the Dutch Ministry of Foreign Affairs, GasTerra, Nederlandse Gasunie, ING, NAM, NUON, Oranje-Nassau Groep, Port of Rotterdam, RWE, Shell Nederland, Total E&P Nederland, the Dutch Ministry of Housing, Spatial Planning and the Environment, Vopak Oil Europe Middle East, Wintershall, Delta, Electrabel, and Esso Nederland.

CIEP publications and research results are made available primarily through the CIEP website: www.clingendael.nl/ciep.

Title	: Crossing Borders in European Gas Networks: The Missing Links
Editors	: Aad Correljé, Dick de Jong, Jacques de Jong
English Editing	: Deborah Sherwood
Copyright	: 2009 Clingendael International Energy Programme
Photo Cover	: Courtesy of N.V. Nederlandse Gasunie
Number	: 2009/2
Published by	: Clingendael International Energy Programme, September 2009
Printed by	: Jurriaans Lindenbaum Grafimedia B.V.
Address:	: Clingendael 7, 2597 VH The Hague, The Netherlands P.O. Box 93080, 2509 AB The Hague, The Netherlands Telephone: +31 70 374 66 16 Telefax: +31 70 374 66 88
E-mail	: ciep@clingendael.nl

Table of Contents

Executive Summary....iii

Introduction....1

The European Network Develops Continuously....3

2.1 Some history....3
2.2 Independent transmission companies....5
2.3 Conclusion....6

Europe Needs More Transmission Capacity....7

3.1 Recent expansions of the European gas network....7
3.2 Uncertainty in demand for infrastructure....8
3.3 Concerns about cross-border investments....9
3.4 Conclusion....10

Availability of Transmission Capacity....11

4.1 Transmission capacity and commodity pricing....11
A) Ample transmission capacity....11
B) Transmission bottlenecks....12
C) The ‘in between’ situation....13
4.2 Transmission tariffs and spot price formation....14
4.3 Conclusion....15

Capacity Utilisation....17

5.1 Low utilisation does not imply low transmission efficiency....17
5.2 The evolution of the European gas market leads to lower utilisation....18
5.3 US experience supports the conclusion of lower utilisation....18
5.3 Conclusion....19

Costs of Gas Transmission in Perspective....21

6.1 Costs of gas transmission as part of the Energy Bill....21
6.2 Costs of gas transmission are mainly fixed....23
6.3 How much will the consumer benefit from the current focus on lower transmission cost?....24
6.4 Conclusion....24

The Regulatory Framework and Investments in Gas Transmission....25

7.1 EU gas market regulation....25
7.2 TSO investments in gas transmission....26
7.3 Revenue regulation and new investments....29
7.4 Entry and exit systems: scale matters....30

7.5 Lessons from the US? 32

Towards a New EU Regulatory Approach 35

8.1 Setting tariffs on the basis of LRIC 35
8.2. Pancaking in e/e-systems 35
8.3. Distinguishing cross-border and national infrastructures 36
8.4. Long-term transmission (capacity) contracts 37
8.5. Licensing new infrastructures...38
8.6. Is ACER an effective answer for regulating new cross-border infrastructures? 39
8.7. What can be done in the framework of the 3rd Package?..41
8.8 Conclusion..41

Conclusions and Recommendations..43

Executive Summary

Demand for gas is on the rise in Europe, yet its indigenous production is in decline. The need for imports from remote sources will grow. At the same time, a pan-European market for natural gas is expected to develop, leading to new movements of gas in addition to the traditional direct flows from production facilities to consumers. Liberalisation of the gas market has created its own dynamics and requirements for infrastructure. Also, the issue of Security of Supply has moved up on the policy agenda, stimulating diversification and new infrastructure. The accommodation of these developments requires that a significant expansion of the current EU 'interstate' natural gas transmission network should be made in the coming decade.

Investments in transmission capacity, however, are slow to materialise and lack support from – and coordination between – regulators and TSOs. In its 2008 Gas Market Outlook, the IEA concluded that "in marked contrast to North American pipeline investment, investments in internal connections and new supply projects in Europe continue to lag". The result is that it is hardly possible these days to close contracts for the following year's cross-border capacity anywhere in Europe.

There are many arguments in support of ensuring adequate capacity: insufficient transmission infrastructure in the EU hinders potential suppliers in competing for market share. It also frustrates investments in gas production and upstream transmission outside the EU, as well as in gas storages and LNG terminals within the EU. This, in turn, hampers the development of an integrated EU gas market and could negatively affect the ultimate goal of liberalisation, which has been to create an EU gas market with free trade and competition throughout the EU, to the benefit of the EU's citizens. Furthermore, Security of Supply could be jeopardised if such investments continue to be blocked or delayed.

Adequacy of transmission capacity can be addressed from many different perspectives. The supplier, the trader, the student of Security of Supply and the proponent of an integrated European gas market each have their own views of transmission adequacy and system bottlenecks. Many cases for system expansion are made, to be funded either with national or community means. Often their economic rationale is based on contestable claims of wider benefits for the community.

This study does not intend to contribute to the debate around these cases, neither by analysis nor by means of value judgment. It focuses instead on those concrete situations in which market players have not only expressed an interest, but also the willingness to pay for new cross border pipeline capacity. It addresses the main impediments to the development of the EU gas transmission network, notably its cross-border transit dimensions, within and around the EU. It also offers recommendations for regulatory and coordination steps toward overcoming these problems.

Investments in Cross-border Transmission

Investments in pipelines are characterised by significant economies of scale. By organising Open Seasons, in which interested potential users are invited to make long-term capacity reservations, TSOs aim to attract as many customers as possible in order to create an optimal scale. These Open Seasons also help to promote the non-discriminatory treatment of potential users. Open Seasons in Europe attract significant market interest. However, while there are willing investors and shippers prepared to make long-term capacity commitments, cross-

border investments in particular have had difficulty materialising. Stakeholders find the main obstacles to be the way in which gas transmission is regulated and the slow, complicated nature of the decision-making processes.

New transmission infrastructure is capital-intensive. Once a pipeline is built, its costs are sunk. Consequently, the dominant risk of an investment in gas transmission is the so-called market risk, i.e. the risk that insufficient capacity will be contracted and/or the risk that tariffs will be too low to obtain an adequate return on investment. According to elementary economics, this risk should be borne by the investor who decides to build the pipeline, who in turn will seek ways to manage and contain these risks by means of long-term capacity contracts from future users. This concept of shared risks was the cornerstone of the successful and rapid development of the gas industry in Europe in the decades before gas transmission became the domain of regulation. Nowadays tariffs are regulated, with new tariffs being set every 3-5 years. This uncertainty about future regulatory actions (the ‘regulatory risk’) poses a serious additional risk for investors and users alike.

Transmission Companies Apply Market-based Investment Criteria

Unbundling has separated transmission operations from supply activities. In the past, transmission investments were made by integrated companies, the goal being to support commodity transactions along the gas value chain on the basis of integrated business economics. Nowadays, unbundled transmission companies have to act as stand-alone entities. Consequently, investments in transmission are executed only if rewards and risks of the specific investment are balanced. European shareholders (generally private investors) estimate the reward-risk balance and revenues on the basis of the market. Regulated returns set by National Regulatory Authorities (NRAs) may not be sufficient to attract investments if investors judge the risks to be higher than assumed by the NRA.

In addition, transmission companies have less market insight than the integrated companies of the past. Transmission companies know past and current gas flows very well but have little access to reliable information on which to judge future market developments. Transmission companies depend for their future income on the strategies and plans of the commodity players, which are generally highly confidential. This stresses the importance of allowing shippers and TSOs to enter into long-term capacity commitments.

The successes of various Open Seasons demonstrate that shippers and TSOs are prepared to invest significantly in the expansion of the cross border EU gas transmission network, thus offering limiting the need for state intervention and offering outline conditions for market-based investment criteria.

Investments and Regulation

Since NRAs set transmission tariff methodologies and are responsible for tariff adjustments, they have a dominant impact on the economics of a pipeline project. Regulation is a determining factor and becomes prohibitive when:

- NRAs give insufficient endorsement to an investment at the outset;

- Investors consider the risk of future changes in rules and regulations, to be imposed during the economic life of the investment, too large.

Current (regulated) tariffs are often not sufficient to cover the costs of an investment. Consequently, a positive investment decision will not be made unless the NRA makes it economically viable by allowing increases in some or all parts of the current transmission tariffs, particularly those related to transit. This is a complicated decision for a NRA, however, because usually only some shippers/stakeholders will benefit from the investment. However, other shippers and/or stakeholders have to pay at least part of it; even when their market position is negatively affected by the investment. Lengthy regulatory decision processes with the risk of court appeal by affected shippers and other stakeholders are the result.

A second issue is the handling of market risk. In the EU, NRAs usually apply a system of 'revenue regulation' for transmission companies. According to this method, the revenues for a TSO are fixed in relation to its regulatory asset base and operational costs. This revenue capping, however, causes a shift of the market risks from the investor to all users. After all, with fixed revenue, less contracted capacity in certain pipelines will automatically result in higher tariffs in other pipelines (sold capacity x tariff = revenue). Managing the market risk is therefore no longer a matter between the investor and the user(s) of new infrastructure only. The market risk of any investment is passed on to all shippers in the TSO's network. Thus, in the end, it becomes the responsibility of the NRA to make a judgment about a new investment, for which it has neither the "market insight" nor the skills.

These problems are even more complex when the investment concerns cross-border or transit capacity. Different national regulatory regimes, combined with national focuses by the NRAs, make decisions about cross-border arrangements difficult, not least because they may easily lead to conflicts between different national interests. Why, for example, should local shippers and consumers suffer the imposition of higher tariffs and thus pay some of the investment bill to enable international shippers and producers to transport gas to other countries? And why should NRAs, in applying revenue cap regulation, impose the burden of market risk of such transit investments on local shippers/consumers?

Emphasis on Asset Sweating Creates the Wrong Mindset

So far, the liberalisation process has paid little attention to investments in new infrastructures. Asset sweating has been the main paradigm, and NRAs have concentrated on cost efficiency and lowering tariffs and on promoting trade and competition in the market place. Developing capacity allocation mechanisms – but even more so, applying entry/exit systems for transmission tariffs – were the resulting regulatory approaches. To be sure, entry/exit systems, with their virtual hubs, have helped the development of trading and are of primary importance for the market. Yet they also cause "cross subsidies" between short distance and long distance cross-border transports, thereby leading (unintentionally) to cross subsidies between national and cross-border transmission.

Controllable costs of gas transmission are a relatively minor portion of the overall cost for consumers. It is questionable as to whether higher capacity utilisation rates should be seen as a measure of the success of liberalization. Developments associated with an evolving EU gas market, market liberalisation and competition, as well as the provision of choice to consumers, producers and shippers – all of which could improve the performance of the market – will lead to a growing demand for gas transmission capacity for a variety of purposes but to a decline in the average utilization rate. Combined with the reduction in current supplies due to depleting resources within the EU, which is likely to make old supply systems redundant, these developments would actually suggest that lower pipeline utilisation can be seen as the measure of a successful transition of the EU market into a competitive market with short-term transactions. This line of thinking is supported by the experience in the US, where utilisation has decreased and which is seen as the most liquid and competitive gas market in the world.

Lessons from the US?

Investments in interstate infrastructure in the US are abundant. Although the situation in the US differs from that in the EU, it is worthwhile to look at whether there is anything to be learned from the US regime. While in the EU NRAs concentrate on cost efficiency, the federal US Energy Regulatory Commission (FERC) has as its objective the "promotion of the development of a strong and reliable energy infrastructure". In the US, regulated returns and tariffs are such that they make investments attractive for transmission companies. The investors share the market risk with shippers by means of long-term capacity contracts. Shippers and transmission companies may voluntarily enter into un-regulated contracts with the objectives of lowering the costs along the gas chain and sharing the benefits with the transmission investor. Long-term transmission contracts are seen by FERC as sufficient proof that investments are in the interest of the consumers. In this business environment FERC plays a supportive role in the licensing processes and endorses voluntary dedicated long-term contracts between pipeline companies and shippers.

Recommendations on Where To Go From Here

The delays of investments in new gas infrastructures cannot be attributed to the market; they are a consequence of the regulatory design. The successes of the various Open Seasons processes demonstrate clearly the willingness of market participants to enable investments in new transmission capacity. However, the economics of these investments tend to be flawed by an inappropriate regulatory framework, imprisoned by its revenue and tariff setting practices, risk allocation and regulatory decision-making processes.

The issues addressed in this paper are widely recognised by the market players, regulators and policymakers. The new Gas Directive and the new Regulations, as well as the new European Network of Transmission System Operators for gas (ENTSO-G), reflect the same concerns and suggest a variety of remedies, to be further developed in accompanying guidelines. Also, it is encouraging to note that NRAs have taken regional initiatives to jointly seek resolutions for cross-border matters.

To contribute to the current discussions on regulatory risks and flaws in the regulatory system, we suggest the following four recommendations:

1) Shippers and TSOs that are directly involved in the construction and use of the new capacity via Open Seasons should bear the risks and rewards for new cross-border investments in transmission infrastructures. Tariffs for new cross-border pipelines should be sufficient to make investments in new transit capacity economically attractive and should take into account the duration of the capacity booked. Tariff adjustments should be applied at the time of new investments. They could be based on LRIC, i.e. reflecting actual CAPEX (including economies of scale), and translating these costs into "perpetual" (i.e. fixed, possibly indexed) tariffs.
2) The regulatory framework should endorse long-term, standardised transmission capacity contracts with fixed (indexed) tariffs, as a sound basis for investments in transmission capacity. These often underpin long-term commodity contracts, which should be considered as essential instruments in enhancing long-term supply security for the EU. To allow the necessary flexibilities for market parties throughout the value

chain non-standardised, customised transmission contracts should be offered by TSOs as well, under appropriate regulatory conditions in line with competition law.

3) Tariff differentiation could be an effective instrument to improve the economics of specific transmission investments. There is no question that identical users of a network should be treated the same under comparable circumstances. However, there is less necessity to apply the same tariffs to new and old contracts, to short-term and long-term contracts, and/or to local and cross-border (transit) customers. Applying the non-discrimination principle in entry/exit tariff methodologies in a way that is in the interests of the wider community of EU consumers would allow distinctions to be made in exit tariffs between international and regional users, facilitating effective cross-border flows in the EU gas market and opening up more options for competition in TSO transit.
4) As the new body for the cooperation between NRAs, ACER should receive a straightforward mission to promote the development of a strong and reliable energy infrastructure in the EU energy market. In amending its mandate in that sense, ACER should also be given the necessary power to intervene in cross-border issues in the wider interest of EU consumers.

We believe that the content of these recommendations could most likely be applied in the context of the new 2009 Directive and it's supporting Regulations. The recommendations would imply a 'conversion' of the current regulatory system into a set of rules and processes focusing on the development of a strong and reliable energy infrastructure. This would lead to an environment in which investments in cross-border transmission infrastructure – sought and underwritten by shippers – are facilitated. None of these recommendations are completely without problems, but these should not be insurmountable. Crossing national borders is essential in securing an adequate supply of natural gas to Europe. It is time to construct the missing links.

1

Introduction

Few will disagree that a competitive European gas market cannot function without a well-developed European transmission grid. Indeed, trading gas within Europe is impossible without the ability to transport it. In the shift towards a liberalised market, much attention has been given to fair access to the transmission grid. National regulators have been introduced to ensure that Transmission System Operators (TSOs) open their networks to all parties involved. The focus has been on enhancing economic efficiency in network use ('sweating the assets'). In the short term, this has brought many benefits. Networks have been opened up to newcomers, and the introduction of so-called entry/exit systems has stimulated gas trading.

What was neglected in the shift towards a competitive market was the fact that the European Network is in continuous development. Significant investments are necessary in order to be able to adapt the network to both increasing demand and changing supply patterns within the expanded internal market. In this paper, the "European gas network" stands for those pipelines that interconnect producer regions with consumer markets, plus the interconnections between consumer markets. Most of these pipelines pass through several countries – the so-called transit countries. The involvement of various European States with different objectives complicates the decision-making process on investments in new gas infrastructure. The analogy in the US is usually referred to as the interstate pipeline network.

These days it is not possible anywhere in Europe to contract for next year's cross-border capacity[1]. To quote the International Energy Agency (IEA): "in marked contrast to North American pipeline investment, investments in internal connections and new supply projects in Europe continue to lag". The risk of this stagnation is that the perceived benefits of the liberalisation of the European gas market will quickly vanish if the lack of competition allows producers and suppliers to increase gas prices above a competitive level. We should keep in mind that costs of gas transport are low compared to price deviations in the commodity market.

An inherent component of the European gas system is the transit pipeline. The first transit in Europe took place in the sixties, based on an agreement between the Dutch producer NAM and Distrigaz for the transmission of Dutch gas via Belgium to France. Other transit arrangements followed. For instance, Dutch Gasunie agreed with the Norwegian producers to use the Dutch grid to transport gas to Belgium and France. A significant expansion of the Dutch grid was necessary to allow this transit flow.

Having a transit function is usually attractive for a country. First, by combining its national transmission of gas with the international transit function, advantages of scale can be created for all parties. Second, the transit shipper pays a fee to the pipeline owners in the transit country for the capacity booked. Third, transit gas flows may increase the Security of Supply. In the past, making transit arrangements was perhaps complex, but it never became a decisive

[1] We have not verified this statement in detail and challenge our readers to find exceptions.

obstacle to necessary investments in transit pipelines. Major projects have been executed with many countries involved.

Today cross-border investments in Europe pose complex problems, particularly if these require higher tariffs than those already in place. New transit pipelines into Europe are proposed regularly (such as Nordstream, South Stream and Medgas). Yet once they reach Europe's borders, issues involving investments in inter-European transit pipelines emerge around tarification. Decision-making processes are complex because of the conflicting interests and objectives, both internally for regulators and vis-à-vis other stakeholders.

In this paper we will focus on the European network from the perspectives of investment and regulation. It will be concluded that the current framework hinders necessary cross-border investments. We will analyse the reasons behind this conclusion and present a set of recommendations. In short, the EU should change its paradigm with regard to its gas network. Instead of 'sweating' the current national assets, with a primary focus on cost cutting and the distribution of scarce capacity, the EU should promote the development of a strong and reliable energy infrastructure across Europe.

The structure of this paper is as follows. Chapter 2 highlights historic developments and the current status of the system. Chapter 3 will discuss the future of the European network, the need for additional transmission capacity and the associated uncertainties. Chapter 4 then moves on to analyse the relationship between transmission networks and competition on the commodity market, with an emphasis on the gas market. Chapter 5 discusses the availability of transmission capacity, its utilisation and the need for new capacity. Chapter 6 provides insights regarding the costs of gas transmission. Chapter 7 discusses the process of decision-making about investment in gas networks from an investor's perspective, highlighting the distribution of risks, rents and control. Chapter 8 focuses on the regulatory framework, providing more details on the present set-up and the impact thereof. It continues with ideas for a new regulatory agenda, dealing with the issue of regulatory costs and tariff structures for transmission and licensing. This also includes some lessons from the US and a reflection on the potential role of ACER. Chapter 9 completes the paper with recommendations and conclusions.

2

The European Network Develops Continuously

2.1 Some history

The current pan-European gas network was constructed in a few decades, starting in the early 1960s. After the giant Groningen gas field was discovered, natural gas was sold in the Netherlands and the neighbouring markets of Germany, Belgium and France. Transmission pipelines were built to transport the gas from Groningen to these countries, as is shown in Figure 1[2].

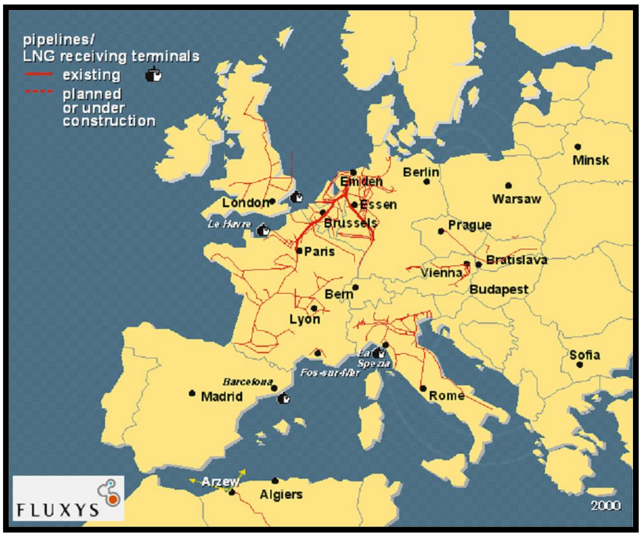


Figure 1: European gas grid in 1970

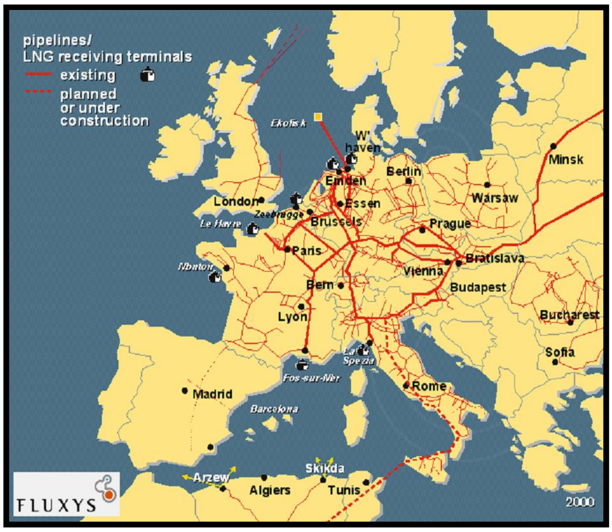


Figure 2: European gas grid in 1980

In the 1970s, European companies purchased gas from Russia, Norway and Algeria, and some main supply arteries were built to move gas from these countries over thousands of kilometres to European consumers. Transmission lines were built to transport gas from the main supply lines to new consumption areas. A truly interstate transit system started to evolve. Norwegian gas had to pass through the Netherlands and Belgium to reach France. Russian supplies for Germany had to pass through the Czech Republic, and Russian supplies to Italy had to pass through Austria. Also in the 1970s, the first liquid natural gas (LNG) receiving terminals were built in France, Italy, Belgium, Spain and the UK. In essence, the international transmission system was designed to connect the several producers with the markets in which they sold their gas.

---

[2] CIEP would like to thank Fluxys for the use of Figures 1-4 in this chapter.

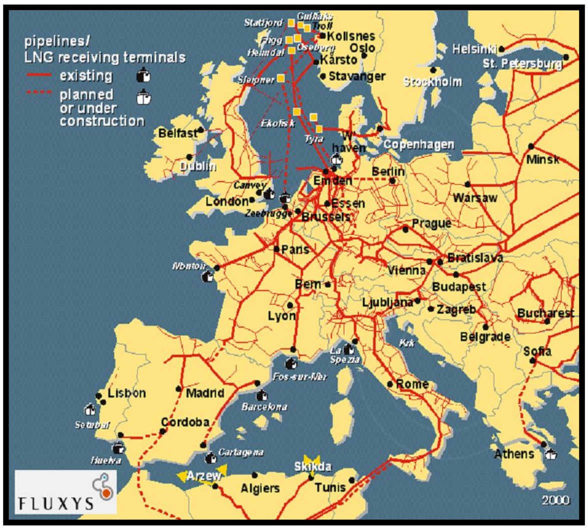


Figure 3: European gas grid in 1990

In the 1980s, the European gas market and the supply capacity developed rapidly and additional import pipelines from Russia and Norway were built. Moreover, several main supply arteries were interconnected by the European midstream gas companies. There were several reasons for this. Interconnection of these main arteries increased the Security of Supply because it reduced the consumers' dependency on a single supplier and route. These connecting pipelines allowed midstream players to engage in arbitrage between the various sources of gas and the existing contracts. Interconnection enhanced the negotiation power of the midstream companies, because it allowed them to more choice between suppliers.

Until the 1990s, producers had little opportunity to bypass the European midstream players. They therefore had to compete to obtain long-term supply contracts from these players, which could thus secure for themselves an attractive 'piece of the cake'. In Germany, the struggle between Gazprom and the German midstream players eventually culminated in the creation of Wingas, a joint venture between Gazprom and BASF/Wintershall. Wingas built its own pipeline network in Germany with the clear objective to compete with Ruhrgas and acquire a larger piece of the rent.

The 1990s were a period of relatively low gas prices and significant growth in the gas market. Norway and Russia increased their sales to Europe, and new major supply lines were built. Examples include the Jamal pipeline through Belarus and Poland to Germany and the Netherlands; the Europipe and Zeepipe from Norway to Germany and Belgium, respectively; and the Algerian pipelines to Spain and Italy. Moreover, production in the North Sea rapidly expanded, particularly in the UK. This motivated the construction of the Interconnector to Zeebrugge for the export of UK-produced gas to the continent.

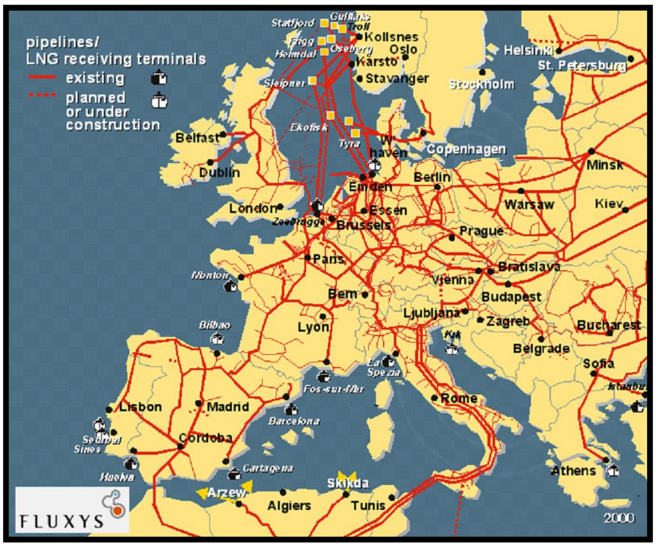


Figure 4: European gas grid in 2000

By the end of the 1990s, the EU Directives began to liberalise the EU's energy markets. The formerly regional midstream players were forced to compete for their market shares. An essential element in the EU strategy was that these midstream monopolies would have to open up their networks to competitors, at fair tariffs and reasonable conditions. From its original role of connecting producers efficiently and directly with their markets, the transmission network became an essential instrument in enabling competition and international gas trade, as will be explained in Chapter 4.

2.2 Independent transmission companies

In the past, transmission systems were built, owned and controlled by monopolistic regional or national midstream companies. After the start of the EU gas market liberalisation, the transmission systems had to be functionally, financially and legally unbundled from their parent companies and converted into Transmission System Operators (TSOs). The TSOs are required to operate fully independently from the commercial interests of the parent companies. In a number of countries this has been implemented more stringently, via partial or even full ownership unbundling of the TSOs. Currently, every region or country has its own TSO, as is shown in Figure 5.

Figure 5: National/Regional TSOs in Europe

There have been extensive debates and negotiations in Europe about full ownership unbundling for TSOs, based on the proposed 3rd Energy Market Package. The final outcome of this package would require further TSO-unbundling, either via ownership or through a more specified and detailed legal, operational and financial separation of the TSO – the TSO then becoming an Independent Transmission Operator. It is yet unclear as to what extent this option will be used. In addition, it should be noted that under pressure from the EU Directorate General for Competition some integrated companies have offered to unbundle the ownership of all or part of their transmission systems. The story of TSOs in the EU is clearly still unfolding.

Ownership of gas transmission companies varies widely, as is shown in Table 1. Most transmission companies are privately owned. They belong to energy holdings with various interests in the European energy sector and/or are listed on the stock exchange. Investments in transmission capacity therefore have to compete for capital with investment opportunities elsewhere in the market. The availability of capital for investments in the transmission sector is dependent on its risk/reward profile, so returns in gas transmission should be market-based.

Company		Ownership		Comments
		Private	State	
E.ON Gas Transmission	Germany	100%	0%	part of listed company
RWE Gas Transmission	Germany	100%	0%	part of listed company
Wingas Transmission	Germany	100%	0%	49.98% Gazprom; 50.02% Wintershall
Gasunie	Netherlands	0%	100%	100% Ministry of Finance
Fluxys	Belgium	48.75%	51.25%	17% listed; 52% GdF/Suez
National Grid UK	UK	100%	0%	100% listed company
Gaz de France/Suez	France	64%	36%	51% listed
ENAGAS	Spain	100%	0%	100% listed
SNAM Rete	Italy	100%	0%	50.03% ENI (20% govern.)
OMV Transmission	Austria	69%	31%	51% listed; 18% IPIC (Abu Dhabi)
DONG Transmission	Denmark	27%	73%	27% listed
GASSCO	Norway	3%	70%	70% State via StatoilHydro & Petoro

Table 1: Ownership of some TSOs

2.3 Conclusion

Within a few decades, a vast European Gas Network was built and funded by merchant companies. This setup has changed. Since the liberalisation of the gas market, independent transmission companies have been created in a number of countries. Nowadays, investments in transmission are judged on their own merits by the transmission companies (mainly private), which require an attractive, market-based risk reward profile.

3

Europe Needs More Transmission Capacity

3.1 Recent expansions of the European gas network

Over the past decade, the development of the European gas network has slowed down. With the exception of the BBL transmission pipeline and some minor expansions to the existing network, no new interconnections within Europe have been constructed, see Figure 6. The total length of the additions to the transnational pipeline grid within the EU is probably not much more than 1,000 km. In marked contrast, in the US, about 30,000 km of new pipelines was commissioned in this period (see Figure 16 in Chapter 7). During these 10 years, the yearly gas consumption in both Europe and the US has grown by approximately 100 bcm. Of course, in Europe a large number of LNG terminals have been constructed and commissioned[3]. The growth of LNG capacity reduces to some extent the need for internal pipeline systems.

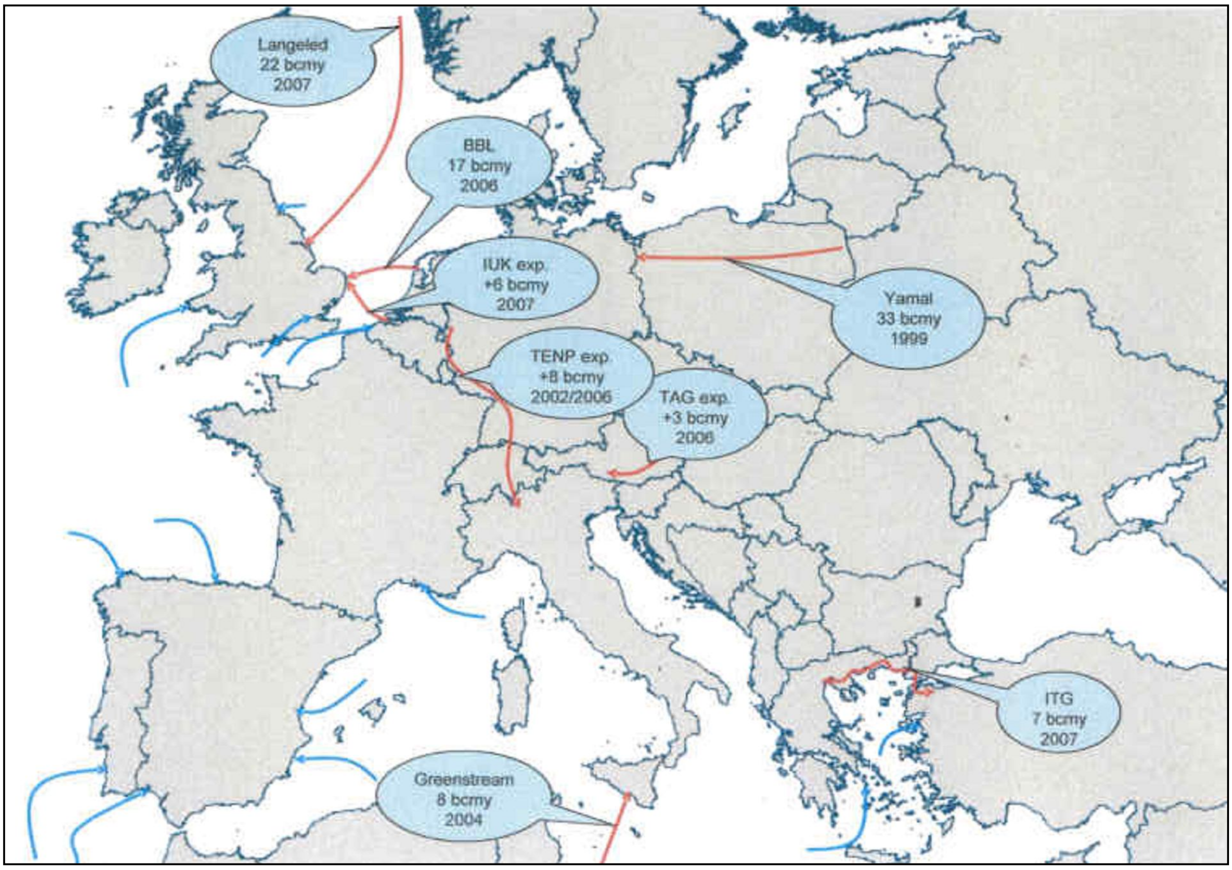


Figure 6: Additions to the European gas transmission network since 1996 in bcm/y

[3] With the exception of those built in Spain, all European LNG terminals are exempted from regulation.

3.2 Uncertainty in demand for infrastructure

The demand outlook of gas in Europe is generally related to the expected economic growth. However, the impact of the current economic crisis and of the European and national environmental policies make this outlook more uncertain than before. In addition, there is uncertainty about how Europe will be supplied in future. Russian gas will inevitably continue to be the backbone of our future supply portfolio, but the level of additional supplies from Russia and other sources, like the Caspian region and LNG supplies, is not clear. There are, however, also several certainties. First, in the decades to come, gas will most likely play a decisive role in Europe's energy mix. Second, to substitute for the declining indigenous supply and to meet possible growth in demand, additional gas supplies from sources outside the EU (Norway, Russia, North Africa, the Middle East and/or the Caspian region) will be necessary (see Figure 7).

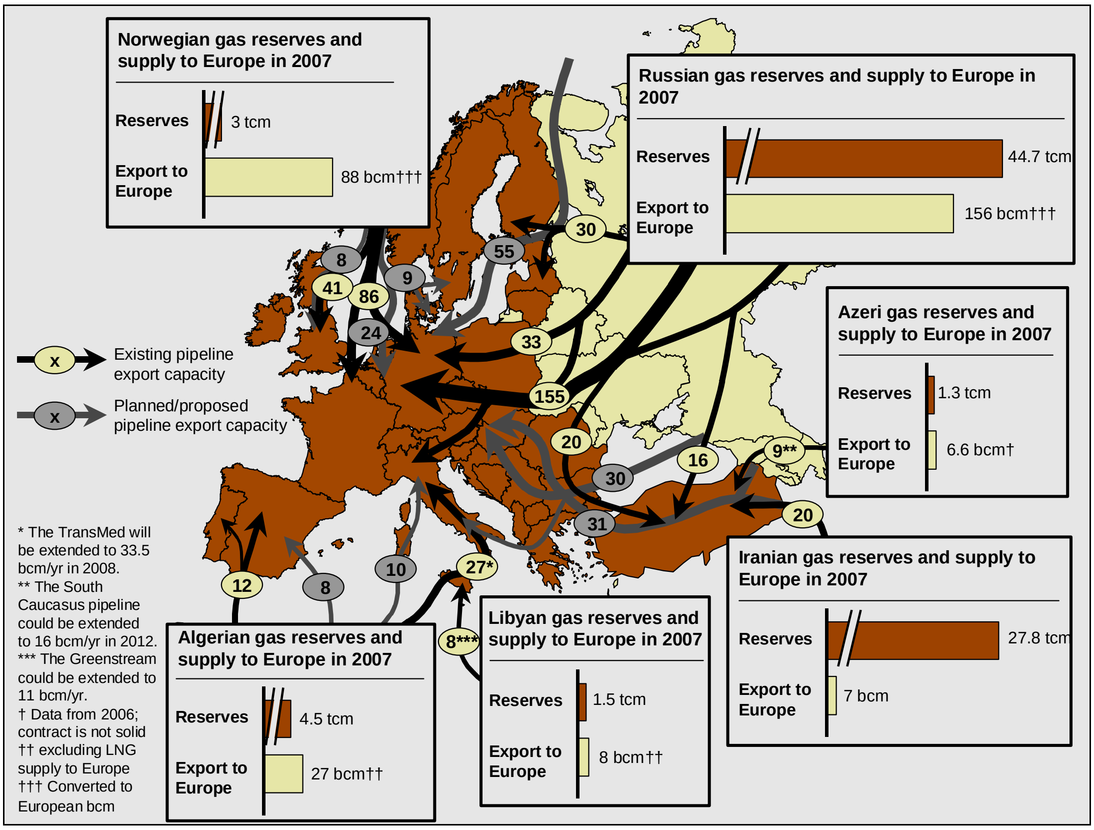


Figure 7: Current and planned import pipelines towards Europe[4]

Major upstream investments will have to be undertaken outside Europe. Potential new import routes are projected, including Nordstream and Southstream from Russia, Nabucco from Azerbaijan/Iran, Europipe III from Norway and Galsi from Algeria. To accommodate new supplies through these import routes, these 'upstream' investments will need to be complemented by investments in the European midstream infrastructure, involving transmission capacity and storage. For instance, major midstream investments in Germany, the Netherlands and Belgium will be necessary in order to transport the Nordstream gas from the northeastern border of Germany to consumers in Germany, the Netherlands, Belgium,

[4] CIEP 2008; the Gas Supply Outlook of the EU.

France and the UK. Potential bottlenecks in midstream infrastructure will jeopardise upstream investment decisions or – at best – delay them.

Market players will furthermore have to make provisions to ensure that their companies are in a position to deal with demand uncertainty and to respond to supply opportunities. They will need – and must be willing to pay for – transmission capacity to manage their portfolios, to secure supplies to their customers, to trade gas (both nationally and internationally), and to balance supply and demand by allowing for flexibility (through access to storage facilities) or by widening their supply options (by contracting purchasing capacity in LNG terminals and/or international pipelines). The utilisation of this capacity is difficult to predict, as it will be dependent on the specific market circumstances, but the availability of this capacity is considered by these market players as essential for their competitive performance in an uncertain market.

The IEA estimated in its 2007 World Energy outlook that OECD Europe will have to invest about US$24 billion over the period 2006-2015 and $24.9 billion over the period 2016-2030 toward the expansion of its transmission capacity.

3.3 Concerns about cross-border investments

One possibly justified concern is that the expansion of the pipeline system – necessary for the support of diversification and competition – is falling behind this expected or envisioned scale. Some attribute this to market failure in the liberalised market[5]. There is also a school of thought which holds that an oversized European pipeline system would benefit the European gas market by means of lower gas prices to such an extent that it would more than fully offset the higher costs of such a system[6]. Both groups hold the view that the development of new infrastructure should become the responsibility of government, emboldened by arguments that the costs of infrastructure are only a fraction of the total cost of gas supply. Nevertheless, the costs of such an approach would be high for society. Not only would government investment interfere with market forces and promote the interests of some players against others (even if unwittingly), it would also risk spending significant amounts of public money on the development of capacity for which the market turns out to have no need.

Interconnection is no 'silver bullet'. More interconnection does not automatically imply more competition. Other conditions will have to be met as well. A liberal development of new interconnectors could be costly and may not result in any more competition. The strategies of producers and market parties play an important role in this respect. Therefore, TSOs and regulators should respond swiftly and positively to indications of producers and other market players who are willing to support new interconnector investments by means of long-term capacity contracts. If Gazprom wishes to compete in the UK market and is prepared to make such capacity commitments, uncertainties around the availability of capacity should not be an obstacle.

There may well be circumstances in which governments have to step in to finance or underwrite investments in infrastructure, for example in the case of market failure. However,

---

[5] APX, EU gas market Integration: Is more capacity all that is needed?, APX Viewpoints, Summer 2007; Ghiosso, Ivan (2007) Regulation and development of natural gas interconnection facilities in Europe, TU Dresden Enerday. Haas, N. and Bressers, H. (2008) In search of an optimal design for European gas markets, Networks Industries Quarterly, Vol. 10, no. 3.

[6] Checchi, Arianna, Gas Interconnectors in Europe: More than a Funding Issue, Centre for European Policy Studies, 2009.

the recent successes of various Open Seasons in Europe organised by TSOs, which have attracted significant market interest by market parties that are willing to pay, suggest that such government intervention is not necessary. This has also been the experience in the US, where investment in interstate pipelines has been abundant in comparison to that in the EU. It would therefore be prudent to first examine why the new investments sought by market parties are not happening. A further look at the decision-making processes and objectives of the relevant stakeholders is required to find out what is frustrating these investments.

3.4 Conclusion

To summarise, a significant expansion of the cross-border gas networks in the EU is needed to reach its objectives of securing supply, promoting competition and unifying its market. However, there is substantial market uncertainty about the magnitude and location of these necessary investments. These days, not many investments are undertaken. This is probably not a case of market failure but a reflection of understandable market caution – an excellent reason for regulators to respond positively in instances where transmission companies are willing to invest and market participants are willing to pay and make commitments to help to realise these investments.

4

Availability of Transmission Capacity

4.1 Transmission capacity and commodity pricing

There is abundant literature on the relationship between contractual structures, price formation and the integration of regional markets[7]. Less attention is given to the impact of transmission capacity on the price formation in regional markets[8]. In this section, some characteristic cases will be empirically examined. It will be concluded that the availability of transmission capacity is of primary importance for the price formation in spot markets, while transmission tariffs play only a very limited role in spot market gas pricing.

With respect to the availability of transmission capacity, three principal cases can be distinguished: A) ample capacity, B) transport bottlenecks and C) the usual ('in between') situation. In the coming paragraphs, some examples will be discussed. Using these examples, some conclusions will be drawn about the relation between spot price formation and transmission tariffs. We would like to encourage our readers to do more research and to come up with a sound economic theory about this subject.

A) Ample transmission capacity

Figure 8 presents the day-ahead gas prices on the National Balancing Point (NBP, British) and the Title Transfer Facility (TTF, Dutch) markets in July/August of 2008. In summer, the BBL transmission line has a relatively low degree of utilisation, usually not more than 50%[9]. The gas flow is from the TTF to the NBP. The figure shows that the movement of spot prices in both markets is more or less identical. The transmission tariff along the BBL line is estimated at about €1/MWh (€0.01/m^3). The price differential between TTF and NBP is not equal to that transmission tariff and seems to hold little relation to this transmission tariff. The situation in Figure 8 was very similar to that in other summers. The conclusion is that ample transmission capacity between two spot markets results in a convergence of commodity prices in these markets.

---

[7] A good overview is provided in the 2009 Special Issue of the Energy Journal: World Natural Gas Markets and Trade: A Multi Modeling Perspective.

[8] But see Paul W. MacAvoy, The Unsustainable Costs of Partial Deregulation, Yale University Press, New Haven & London, 2007 for an analysis of the consequences of transport bottlenecks in the US gas and power markets.

[9] Source: NatGrid

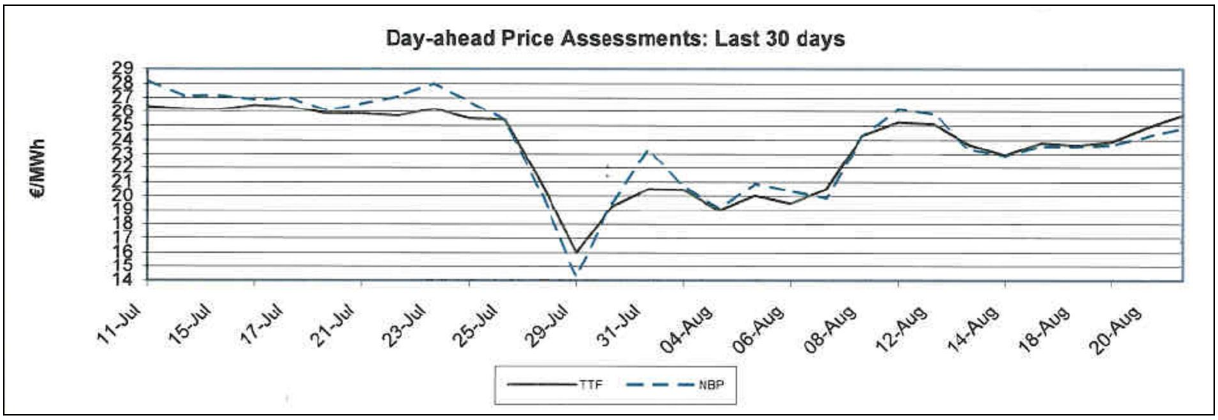


Figure 8: Day-ahead prices on the TTF and the NBP in summer, with ample transmission capacity in the BBL (source: Heren Report, 21 August 2008)

B) Transmission bottlenecks

The situation changes significantly if a transmission bottleneck exists. A transmission bottleneck is defined as a situation where, due to the lack of transmission capacity, there is a serious scarcity of gas (either expected or actual) downstream of the pipeline, while upstream there is sufficient gas available. In a liberalised gas market, a transmission bottleneck may result in a reduced or interrupted supply of gas. Moreover, an expectation among market participants that a shortage of gas may occur will alter their behavior. After all, a *potential* reduction or interruption of the gas supply creates a *potential* scarcity of gas. This expectation will therefore cause a significant price increase for gas in the forward markets.

Some examples suggest that such a price increase can be rather serious. In 1999 there was insufficient transport capacity into California, partly due to a fire in a compressor station on the main transmission line towards California. Consequently, California's gas demand/supply patterns were seriously affected. The result was a gas price increase on the California gas markets from \$8/MMBtu (approximately €0.12/m^3) up to \$50/MMBtu (approximately €0.75/m^3), see Figure 9. From October 2000 until May 2001, the Californian gas price was approximately \$10/MMBtu (€0.15/m^3) above the Henry Hub price. With a Californian gas demand of around 60 BCM in that period, the total costs for the Californian economy due to the shortage of transport capacity between Henry Hub and California was about €9 billion[10].

In 2005 it became apparent that the UK market needed new import infrastructure. However, the new infrastructure being constructed, including Langeled and BBL, would not yet be operational in the winter of 2005/2006. Consequently, winter gas prices in the UK skyrocketed from about 60 pence per therm to more than 100. Ofgem has calculated that these higher prices transferred about £2 billion from British citizens and industries to traders and producers. That amount of money, lost in one winter, would have been sufficient to build four additional BBL pipelines, which could have served the UK gas market for 40-50 years.

In the last couple of years, the gas production in the Rocky Mountain region (US) has increased significantly. However, there was not enough transmission capacity to ship this gas to the consumption areas. Consequently, while downstream gas prices were between \$7 and \$10 /MMBTU, gas production stagnated and upstream gas prices in the Rockies were only

[10] This is excluding the effects of the black-outs due to actual physical shortages of natural gas.

$2-3/MMBTU or even less. This actually undermined the upstream investment climate in that region.

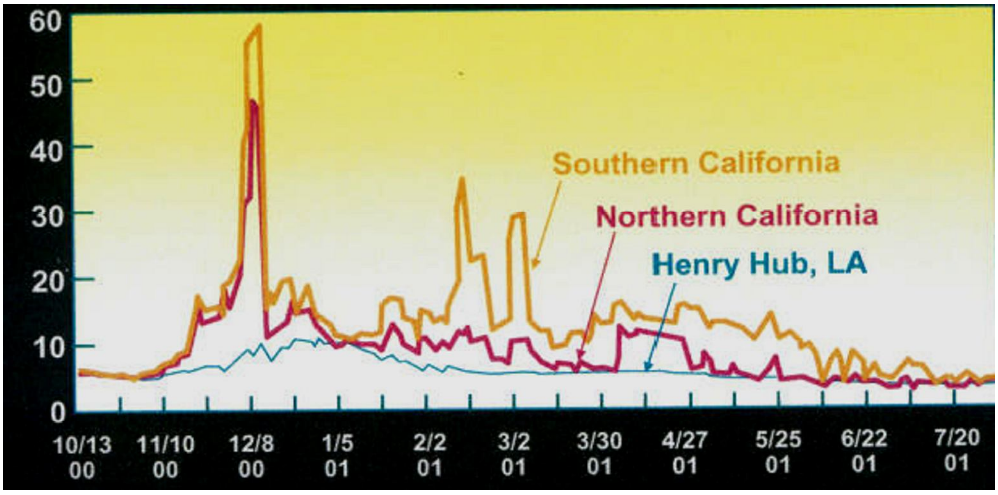


Figure 9: Gas prices in California and Henry Hub winter 2000/2001

In each of these cases, the effect of a transmission bottleneck on the commodity market was a major price increase downstream. In all cases, traders with transmission capacity rights made significant windfall profits. The same is true for the owners of gas, downstream from the bottleneck. The downstream consumers had to bear the costs of the capacity constraints and had to pay for these windfall profits. In each of the examined cases, the level of these windfall profits went far beyond the costs of new transmission infrastructure, by an order of magnitude.

C) The 'in between' situation

We have seen that gas prices converge when there is ample transport capacity, whereas there are major price effects in the case of bottlenecks. Given the major effects of bottlenecks on the commodity market, the societal optimum with respect to the amount of transmission capacity will be to err on the safe side and to have more than sufficient transmission capacity available. This can be seen as the 'normal' situation.

There is almost always ample transport capacity; bottlenecks occur only in stressed situations. An example of such a situation is discussed in this paragraph. We again use the situation of the BBL but now focus on the winter, when the utilisation rate of this transmission line is high (80-100%)[11]. Figure 10 presents the NBP and TTF forward prices during July and August of 2008, for the winter that followed. During the summer of 2008 it was generally assumed that the UK supply, including imports from Norway and via the Interconnector and the BBL, would be sufficient to cope with a normal winter. There was no reason why spot prices in the UK should significantly deviate from the TTF[12]. However, as long as the severity of the coming winter was unknown, there was a chance that the supply to the UK would be insufficient. If that would have been the case, while the BBL was being fully utilised, prices in the UK would have skyrocketed and become substantially higher than those on the TTF.

[11] Source: NatGrid.

[12] Actually, in winter 2008/2009 the spot gas prices of TTF and NBP were very similar.

The NBP forward prices represent the market sentiment about the chance that the UK will have a gas shortage with an associated price differential between the TTF and the NBP. Figure 9 shows that in the summer of 2008, the future gas price on the NBP for the winter of 2008 was about €2/MWh higher than that on the TTF. This difference can be considered to be the insurance premium that covers the risk for UK traders and suppliers that they will be unable to acquire sufficient gas at reasonable prices in the event of a very severe winter[13].

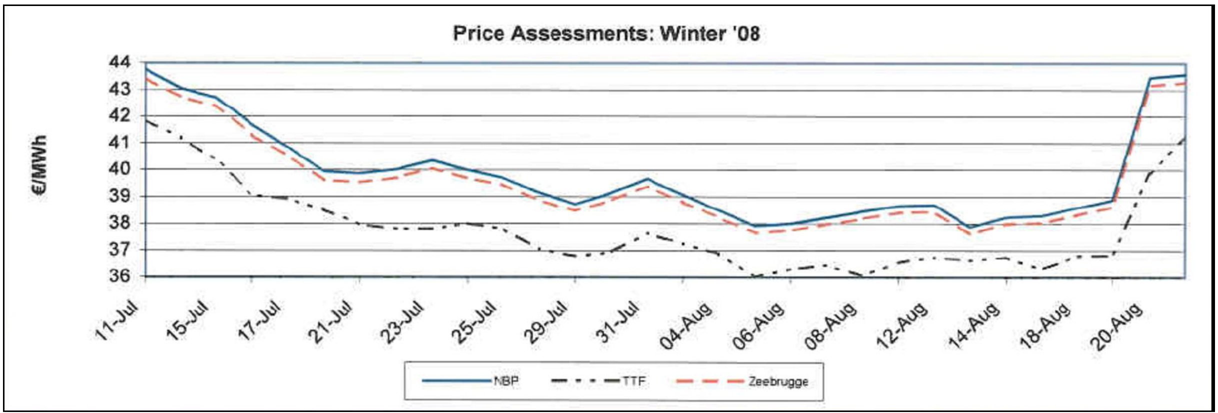


Figure 10: Winter prices at TTF and NBP, with sufficient transmission capacity in the BBL (source: Heren Report, 21 August 2008)

The availability of sufficient transmission capacity is not always a remedy that can remove an 'insurance premium' from a market. Certainty about sufficient tradable gas at the other end of the transmission infrastructure is required. This may explain the difference between the forward prices of Zeebrugge and NBP. November 2005 showed that while spot prices in the UK went up, gas supplies from Zeebrugge to the UK were hardly existent as there was no gas offered for trade in the market.

To conclude, in 'normal' circumstances, the price differential between spot markets is not equal to the transmission tariff between both markets, but instead reflects differences in market expectations of gas price movements in both spot markets under stressed conditions.

4.2 Transmission tariffs and spot price formation

Keeping in mind Figures 9 and 10 and the examples given in the case of transport bottlenecks, assume that a regulator will either decrease or increase the transmission tariffs. Such a decision will not change the amount of transmission capacity and, consequently, it will not affect the supply/demand balance on either market. In case of ample supply, prices converge and remain converged. The decision of the regulator will not change this outcome. Likewise, in the case of a transport bottleneck, the transmission tariff plays no role in the price formation at either hub. Assuming the insurance effect is not altered, the same will be true during 'in between' times. Consequently, the only (and unintended) effect of the regulatory intervention on the transmission tariffs is that the money is transferred from the transmission operator to the shippers/traders[14].

---

13 As the national consumption of the UK in the winter is 60 bcm and the price differential is €2/MWh, the 'insurance premium' that consumers in the UK had to pay in the winter of '08 was about €1.2 billion.

14 The exception to this rule is the exit tariff at the premise of the consumers. A reduction of this tariff can result in a reduction of gas costs for consumers. However, as long as the European gas import contracts are

In a recent study of the US gas market, MacAvoy[15] concludes that the traders have substantially benefitted from the tariff reductions in pipeline systems, while the end-users were the unintentional victims. This was because tariff reductions undermine the investment climate for new transmission capacity. Thus, after a while, the chance of transport bottlenecks under stressful conditions increases, thereby increasing the commodity gas price on the downstream market.

4.3 Conclusion

In this chapter it has been demonstrated that the expected availability of transmission between two spot markets has significant effect on the price formation on both spot markets. On the other hand, the examples suggest that the transmission tariff has little effect. An actual or expected transmission bottleneck causes major price distortions on the market. In the case of ample transmission capacity between two spot markets, prices converge. The examples presented here seem to confirm the findings by MacAvoy, who concludes that transmission tariff reductions by regulators generally benefit traders and not consumers. We recommend more research on this topic.

---

renegotiable and based on the market value of gas for consumers, that tariff reduction, too, will ultimately end up in the pockets of the producers.

[15] Paul W. MacAvoy, The Unsustainable Costs of Partial Deregulation, Yale University Press, New Haven & London, 2007.

5

Capacity Utilisation

5.1 Low utilisation does not imply low transmission efficiency

The liberalisation of the European gas market is aimed at two main objectives. The first involves the creation of competitive, integrated gas markets. This requires the provision of non-discriminatory access to the infrastructure. The second objective is to enhance efficiency and reduce the costs of using this infrastructure, in an attempt to lower final consumer prices. So far, these two objectives have been addressed by one single approach, namely by improving the utilisation rate of the pipeline infrastructure. Third Party Access rules first forced pipeline operators to sell all capacity available. When all firm capacity is sold out, pipeline owners are encouraged to sell as much interruptible capacity as possible. Furthermore, 'use-it-or-lose-it' (UIOLI) mechanisms have been proposed to prevent the hoarding of unused capacity by existing or incumbent suppliers. Based on all these measures, it is expected that due to the higher utilisation rate the pipelines will be used more efficiently while freeing up more capacity to new suppliers.

Within this context, there is a debate about the necessity to expand the European gas network. The EU Directorate General for Competition's Sector Enquiry (2007) showed that the physical utilisation of the network is relatively low because of 'contractual congestion'. Consequently, it concluded that it would be better to increase the utilisation rate of the network rather than expand it. In this respect, it is often argued that current users of the network have significant incentives to hoard capacity, in order to prevent competitors from entering their 'home' markets. Others claim, however, that the current capacity is fully booked by suppliers who have to reserve sufficient capacity to be able to cope with the extreme situation of a very cold winter day[16]. Since very cold days seldom occur, it is logical that the average utilisation of a pipeline is relatively low, even in a situation with scarce transmission capacity.

Upstream		**Downstream**	
Type of infrastructure	***Utilisation***	***Type of infrastructure***	***Utilisation***
Base Load production	90%	Bulk Industry	90%
Swing Production	40%	Heavy industry	80%
Seasonal Storage	25%	Power Stations	50%
Cavern Storage	15%	Medium Industry	35%
Peak LNG storage	1%	Small industry	20%
LNG Terminal	50%[17]	Households	10%

Table 2: Typical utilisation rates of gas infrastructure

[16] Often, suppliers are forced by law to have sufficient supply (and transmission capacity) reserved for their customers, to be able to cope with a severe winter.

[17] Actually, the utilisation of an LNG terminal may be close to zero for a number of years, while in other years, the rate of use could be 80% or more.

The actual utilisation of pipeline infrastructure is fully dependent on the utilisation of the infrastructure upstream and downstream from it. Table 2 presents typical utilisation rates for different parts of the value chain. The average utilisation rate of pipelines lies between 30 and 70%. This large variation is a result of the function a pipeline has in the market. Utilisation of long-distance major supply lines connecting remote production areas to consumption markets may be 70-90%. On the other hand, the utilisation of pipelines close to consumer markets is often only 20-30%. Storage close to markets plays an important role in connecting the highly utilised upstream production facilities and long-distance upstream pipelines with the end-user markets. Yet it is important to realise that these figures are annual average rates of utilisation, which means that during specific periods the shippers may indeed use the full available capacity.

5.2 The evolution of the European gas market leads to lower utilisation

A gas market usually forms on the basis of a gas surplus at a supply source. As the gas market evolves, consumers and their suppliers seek gas supplies from different sources. Similarly, producers look for opportunities to create additional markets for their gas. After all, it is not beneficial for any party to be fully dependent on just one other. The liberalisation of the European gas market has accelerated this evolutionary process; both consumers and producers need choice, and suppliers want to optimise their portfolios to include the use of storage and LNG. Competition and international trading of gas requires transmission capacity to support the transactions. Additional transmission infrastructure is required, not only to accommodate a higher overall volume of gas, but also to enhance ‘optionality’ and manage the supply risks. This reduces the average annual utilisation rate of the pipeline system.

5.3 US experience supports the conclusion of lower utilisation

Information about the evolution of the utilisation rate of the European network as a whole is not available. Only a few transmission operators present detailed numbers about the actual usage of their system. In the US, much more information is available. Moreover, the US market is more mature than the European market and the liberalisation of its gas market took off some time ago, by 1985[18]. Figure 11 shows the development of the utilisation rate of the intrastate pipelines in the United States since 1989. In that period of time, demand for gas has increased by more than 20%. In the same period many pipeline investments have been made, with the effect that the utilisation rate of the pipelines has decreased by 15%. This opposite trend can be explained by the fact that the growth in pipelines during this period outpaced the growth in gas demand.

New pipelines in the US are constructed only if a robust market demand exists. Demand for transport has to be underscored by long-term capacity contracts between pipeline operators and shippers. It can thus be concluded that the market in the US generated the ‘excess’ pipeline capacity. As far as we know, in the US there were no pipelines built on the basis of government intervention. Furthermore, the US also has an effective system of secondary capacity markets and a more general monitoring system by the Federal Energy Regulatory Commission (FERC) to prevent distortions in competition. The US gas market is considered to be the most liquid and competitive gas market in the world.

---

[18] In 1985, FERC Order 436 introduced gas transmission by independent shippers. FERC Order 636 formally concluded the liberalisation process in 1992 with full unbundling of the transmission companies from the wholesalers.

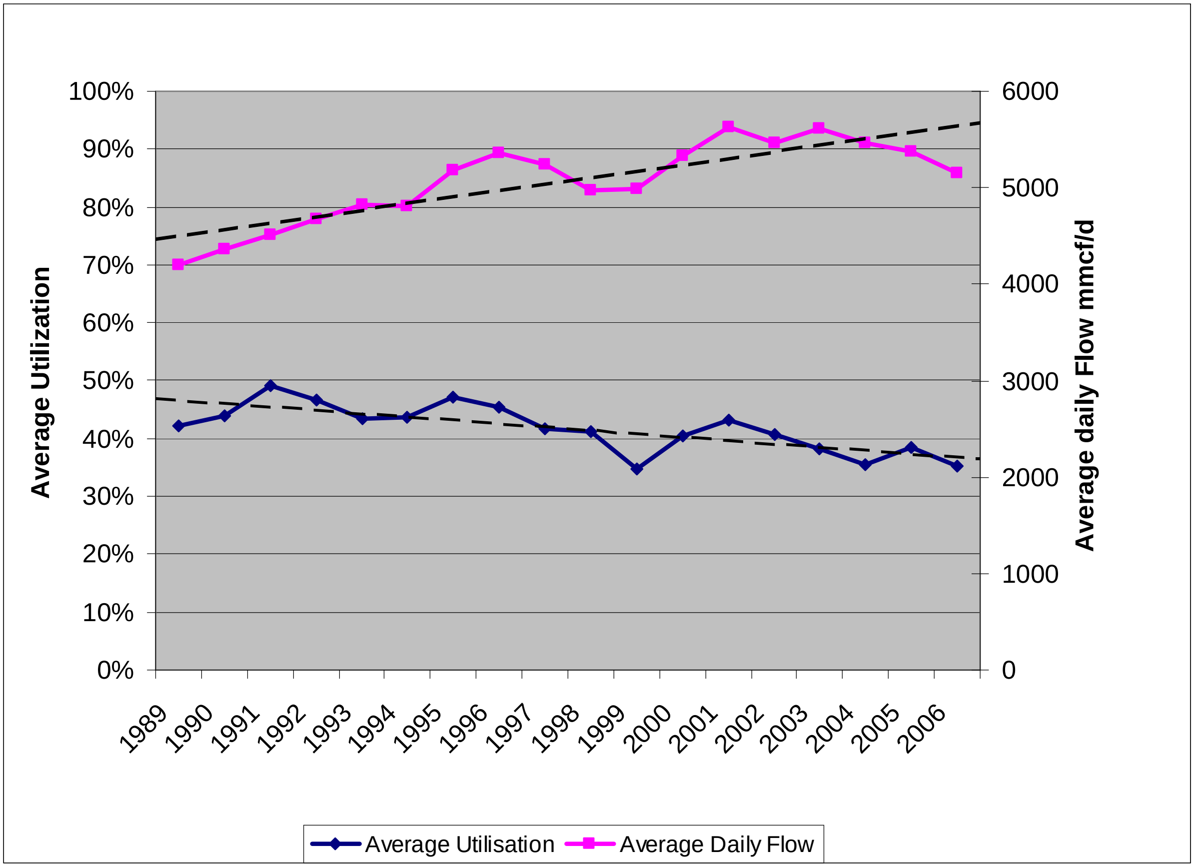


Figure 11: Development of the utilisation of North American intrastate pipelines
(Source: J. Bootsma, master Thesis University of Groningen)

5.3 Conclusion

Although pipeline capacity may be fully contracted, its average utilisation is typically 50% or less. The reason is that part of the gas infrastructure connected to a pipeline is only used under stressed market conditions such as a severe winter. Furthermore, other infrastructure like LNG terminals and storages may also have a low utilisation rate. Although pipeline companies may have incentives to sell as much capacity as they can, it does not imply that utilisation will increase. Market participants who contract transmission capacity will manage their commodity portfolios to achieve lowest costs of supply, and this does not have to imply high utilisation rates. The effect of trading and portfolio optimisation in an integrated EU market may actually be an even lower utilisation rate. This is supported by evidence from the US. We conclude that the utilisation of pipelines in Europe may very well decrease in the decades to come.

6

Costs of Gas Transmission in Perspective

6.1 Costs of gas transmission as part of the Energy Bill

The relative costs of gas transmission is an important factor in evaluating and understanding the relationship between the impact of transport in end-use prices, the use of pipelines, and the investments made in new pipelines. This paper deals with midstream transmission. The transmission of gas from remote production areas, for example from Yamal towards the European boundary, is seen as belonging to the upstream section of gas supply and is therefore not included in this discussion. Similarly, the paper does not deal with LNG shipping but focuses on pipeline transmission in Europe.

The construction and operation of transmission lines and associated compressor stations is capital-intensive. For instance, the construction costs of 100 km of main pipeline (42", including compression) amount to more than €200 million. The actual costs are dependent on the geography, the population density and the amount of supporting constructions like river crossings. On the other hand, the volumes that can be transmitted are very considerable. The capacity of a 42" pipeline is about 1.7 million m^3 per hour (in electricity terms: 17 GW).

The transmission of gas has significant economies of scale. Generally speaking, the cost of a pipeline rises linearly with the diameter of the pipeline, while the capacity of a pipeline increases by more than the square of the diameter. Major transmission routes involve 30" to 48" pipelines (56" for the pipelines out of Russia). For regional transmission (the last 50 km or so), pipelines with diameters between 18"and 30" are used. Distribution grids have pipeline diameters of 18" or less. Figure 13 gives an indication of the costs of gas transmission per 100 km, dependent on pipeline diameter[19]. The figure demonstrates the huge scale advantages that characterise gas transmission.

Current networks consist of pipelines with an average diameter of 30-36". For an expansion of pipelines, generally diameters between 36" and 48" are used. This allows for a comparison of the estimated costs/tariffs per 100 km, based on either the replacement value of a pipeline or the typical costs of expanding a pipeline network. We will come back to this issue in Chapter 8.

[19] Assumptions: 25 years of operation, WACC 7%, tax 25%, Opex 4%, utilisation 80%; own analyses by Clingendael.

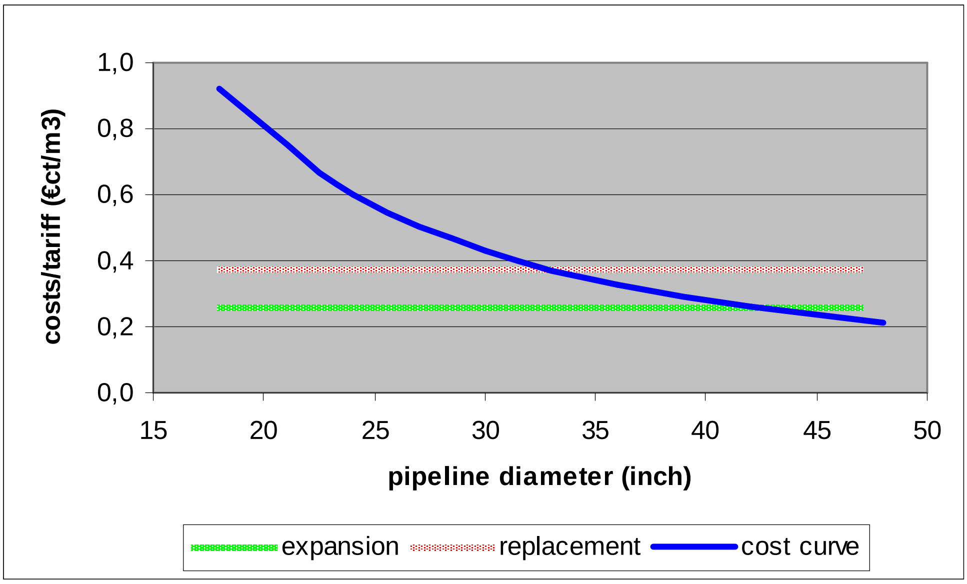
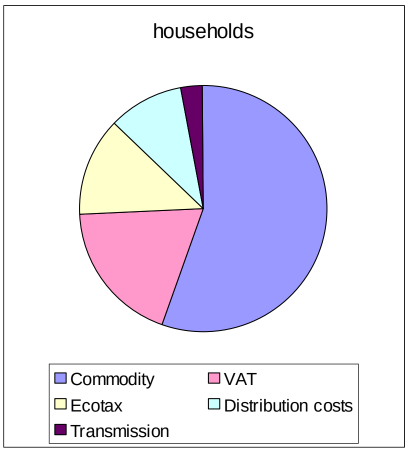


Figure 12: Estimated costs in €ct/m^3 per 100 km pipeline

Note: The blue curve assumes 80% utilisation; the upper red curve represents the replacement costs of networks, assuming 30-36" pipelines. Pipeline expansions usually replace existing lines with new ones of diameters 40-48" and hence, expansion costs (lower green line) are typically lower than the replacement costs. (Source: CIEP)

Regarding the actual costs per m^3 of gas transported, the utilisation rate of the pipeline is of importance. In Figure 12, 80% utilisation has been assumed. However, as mentioned, the utilisation of regional pipelines (those close to the consumers) is significantly lower than 80%. This is particularly the case for distribution grids, which explains their relatively high costs of distribution, despite the fact that distances are shorter.

For a consumer, gas transmission costs are relatively low (typically 0.3 €ct/m^3 per 100 km) compared to the commodity price (20-40 €ct/m^3, excluding tax). With an average transport distance within Europe of about 400 km, the European transmission costs of natural gas are generally less than 5% of the energy bill of an average European citizen, excluding taxes.



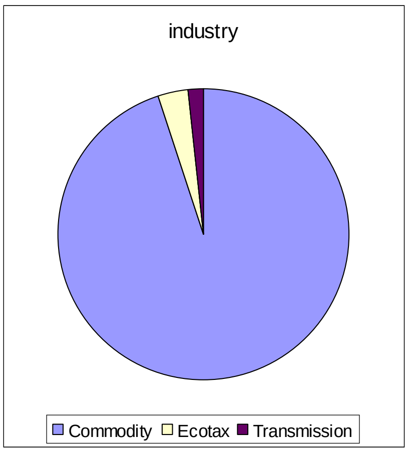


Figure 13: The structure of the gas costs for typical users.

Figure 13 shows the 2008 breakdown of gas supply costs to Dutch households and large industries. Transmission and distribution costs are regulated, whereas commodity costs (including supply profits) are not. The majority of the gas bill for both households and industry reflects the commodity price. In the Netherlands, distribution costs[20] constitute almost four times the costs of transmission. With the exception of taxes, the breakdown of cost for consumers in European countries is not very different.

6.2 Costs of gas transmission are mainly fixed

Table 3 presents the buildup of pipeline costs per unit of gas transported. During the lifetime of an investment, the relative contribution of each cost factor varies. In the first years after the investment, capital costs are high; in later years other costs become more significant. In Table 3 the various cost components are averaged, assuming an economic life span of 25 years. The distribution shown in Table 3 is characteristic for a network comprising pipelines of various ages.

Operational costs comprise mainly fuel (or electricity) for compressors and maintenance of the infrastructure. Fuel costs are dependent on actual usage of the pipeline and on the actual fuel prices. The network operator has little influence over fuel costs. During the lifetime of gas infrastructure, maintenance costs tend to increase over time, until replacement is economically more attractive than intensified maintenance or until safety can no longer be guaranteed. Assuming well-established cathodic protection, underground pipelines have a very long technical life (>50 years); economic life[21] may be shorter. Replacement of the less capital-intensive surface structures will nevertheless be needed at some point[22].

	Percentage	Costs €ct/m^3 per 100 km
Capital costs	50%	0.13
Depreciation	20%	0.05
Fuel costs	15%	0.04
Maintenance + Others	15%	0.04
Total	100%	0.26

Table 3: Buildup of gas transmission costs for a 42” pipeline[23] based on 80% utilisation, averaged over the first 25 years after investment

Table 3 provides important information for running a pipeline business. Since 85% of the costs are fixed, there is not much opportunity for pipeline companies to respond to changes in the transmission market. To compensate for decreasing sales revenues, only maintenance costs can be minimised. However, safety laws and procedures limit the extent to which pipeline companies are allowed to reduce maintenance costs. In sum, practically all costs of running a pipeline are fixed as soon as the pipeline is built.

[20] Distribution costs comprise of network costs, connection costs and metering costs.

[21] We note here that an economic evaluation of a transmission company will generally only be different from an economic evaluation of the whole gas market, as the economic consequences of a pipeline failure for downstream markets may be much larger than those for a pipeline company.

[22] There may also be other reasons for replacement: changes in environmental and/or safety regulation, the unavailability of spare parts or a deteriorating reliability of the equipment can trigger replacement.

[23] Analysis by CIEP.

6.3 How much will the consumer benefit from the current focus on lower transmission cost?

The more efficient a pipeline company is, the lower the transmission tariffs can be. Regulators (and the academic society) therefore make significant efforts to create optimal incentives for pipeline companies to become as efficient as possible. This regulatory strategy is generally called efficiency regulation[24]. However, as Table 3 shows, the controllable costs for a pipeline company are only a fraction of the total pipeline costs. Thus, any improvement in the efficiency of pipeline companies will have only a minor impact on the transmission bill. Actually, with gas transmission costs of less than 3% of the household bill, the fraction of the gas costs that are prone to improved transmission efficiency (and efficiency regulation) are not more than 0.5% of the overall gas bill for households.

There is no question that regulators should continue to monitor efficiency. Nonetheless, later in this paper (see section 7.3) we will show that "efficiency regulation", which often involves tariff setting based on revenue capping and a system with X-factors, frustrates the investment climate for new pipelines and therefore indirectly hinders the development of competition in the commodity market. Since so little effect can be expected from efficiency regulation for the household bill, it seems questionable as to whether regulation has the correct focus.

6.4 Conclusion

Investments in gas transmission imply fixed costs. The proportion of controllable costs is relatively low over the economic lifetime of a pipeline. The return for a transmission investment is almost fully dependent on the demand for transmission by market participants. Transmission of gas has significant scale advantages. Although pipelines are expensive, the costs for transmission are only a small part of the energy bill. The current focus of regulators on controllable costs will hardly change the overall costs in the gas chain.

[24] See Crew, M. and Parker, D. (2008) Developments in the Economics of Privatization and Regulation, Edward Elgar, Cheltenham; Introduction, pp. xviii-xxiii.

7

The Regulatory Framework and Investments in Gas Transmission

A discussion and assessment of the future of the European gas infrastructure and its prospects for enhancing a competitive internal gas market requires an examination of the impact of the regulatory framework on TSO investments in cross-border transmission capacity.

7.1 EU gas market regulation

Energy market regulation in the EU is a relatively new phenomenon. It started with the Electricity Directive of 1996, followed by the Gas Directive of 1998. The political environment and market parties themselves pressed for further changes and regulatory strengthening, resulting in two new directives for gas and electricity in 2003, followed by more specific regulations. By the end of 2007, the dynamics of the market and changing paradigms caused the European Commission to present a 3rd Energy Market Package, including two new almost identical directives for gas and electricity, repealing those of 2003. In addition, two regulations were introduced, regarding access to gas transmission networks and to cross-border electricity grids, both repealing the earlier regulations. Also a new institution, the Agency for the Cooperation of Energy Regulators (ACER), was introduced as an agency for the cooperation between national regulatory authorities (NRAs). This 3rd package was finally settled in June 2009 and shall enter into force by September 2009. National implementation of the directives in national legislation must be completed by May 2011.

This 3rd package will in all likelihood not be the end of the story. Regulation will have to adjust to the changing needs of a dynamic gas market[25]. Placing this regulatory process in a more global context, we should note that developments in the EU gas market, its overall energy policy basis and the ongoing (re)structuring of the EU gas industry are part of a dynamic process. Markets are dynamic by definition and are in a process of continuous change. Policy development is a political process and is dynamic due to the constitutional organisations controlling it. Ideally, regulatory approaches should therefore follow and respond to these changes. Yet market dynamics and regulation are difficult to align. By nature, regulation is a more or less bureaucratic phenomenon with strict rules, market consultations and a very thorough process of decision-making. Indeed, regulatory decisions often have a significant effect on the business of specific companies. Changes in policy and the regulatory framework cause uncertainty in the industry and hamper the investment climate. This *Regulatory Risk* particularly emerges when new regulation affects tariffs – and with them the economics of new and existing infrastructure. The regulatory approach thus has to find a balance between: on the one hand, the need for constant adjustments based on interaction with the highly dynamic market and energy policy environment; and on the other

[25] See: Unbundling in the EU Energy Package: Are we singing the right song? Jacques de Jong, Clingendael International Energy Program, December 2007.

hand, the ability to provide consistency and predictability. Figure 14 provides an illustration of this dynamic interaction[26].

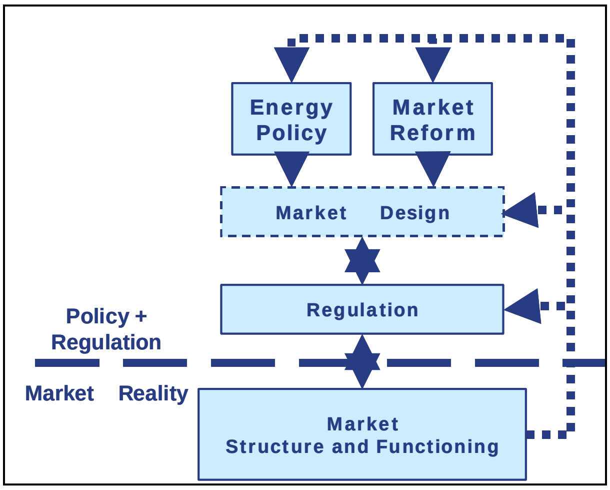


Figure 14: The regulatory framework and the market

Traditionally, national regulatory approaches have assumed that economic regulation can and should steer clear of other policies and concentrate on establishing a level playing field for the national market. In actual practice, EU energy markets have gone through a process of re-regulation and industrial and ownership restructuring as part of a wider strategic process. Current processes largely take place at the national level. It is important to recognise that this could stand in the way of achieving an integrated EU gas market. NRAs may therefore need to take on a more active role with regard to cross-border issues.

This being said, we will discuss in this chapter some of the interactions between new investments in gas infrastructures and regulatory processes, looking at both content and decision-making procedures. The new ACER will be discussed as well, including lessons we might learn from the US, where FERC plays an explicit and important role in the promotion of cross-border (intra-state) transports, trade and transmission.

7.2 TSO investments in gas transmission

In the coming decades, significant investments in the expansion of the European gas network will be required. It is uncertain, however, where these investments will have to be made, how much capacity is needed and when. Although, in the foreseeable future, the new European Network Transmission Operator for gas (ENTSO-G) will present a non-binding network development plan for the EU as a whole, which will include forecasts of the demand for gas, this does not guarantee that concrete investments will be made. The dominant risk for gas transmission companies is that a pipeline will be underutilised. The reason is that as soon as a pipeline is built the costs are sunk and can only be recovered if used sufficiently by shippers at an acceptable tariff. Underutilisation or lower tariffs than initially anticipated mean that the investment will not be recovered. It has been shown that investments in gas transmission require hundreds of millions of euros and have a high front-end risk. As the economic lifetime

---

[26] Linde, van der, Coby, Aad Correljé, Jacques de Jong, Christoph Tönjes, (2006) The paradigm change in international natural gas markets and the impact on regulation, International Gas Union / Clingendael International Energy Programme, CIEP 02/2006.

of pipelines – and hence the tariff basis for cost recovery – extends over several decades, risks of lower than anticipated use of the pipeline or changes in the tariffs remain significant. Consequently, investment decisions are not made easily, and any investment in a pipeline requires a very thorough investigation of the future market.

Figure 15 represents a simplified investor view of an investment in a new pipeline. It is assumed that the investment decision is made in 2009 and that the pipeline will be in operation between 2014 and 2038. After 25 years, the internal rate of return (IRR) for the project, based on a utilisation rate of 100%, is 7%. The figure shows three lines. The blue dotted line shows the pure cash flow and illustrates that it will be 2025 before an investor "gets his invested money back", without return. The red solid line depicts the 7% IRR line, which ends (by definition) at zero in 2038. This assumes full capacity tariff recovery over the entire economic life of the project.

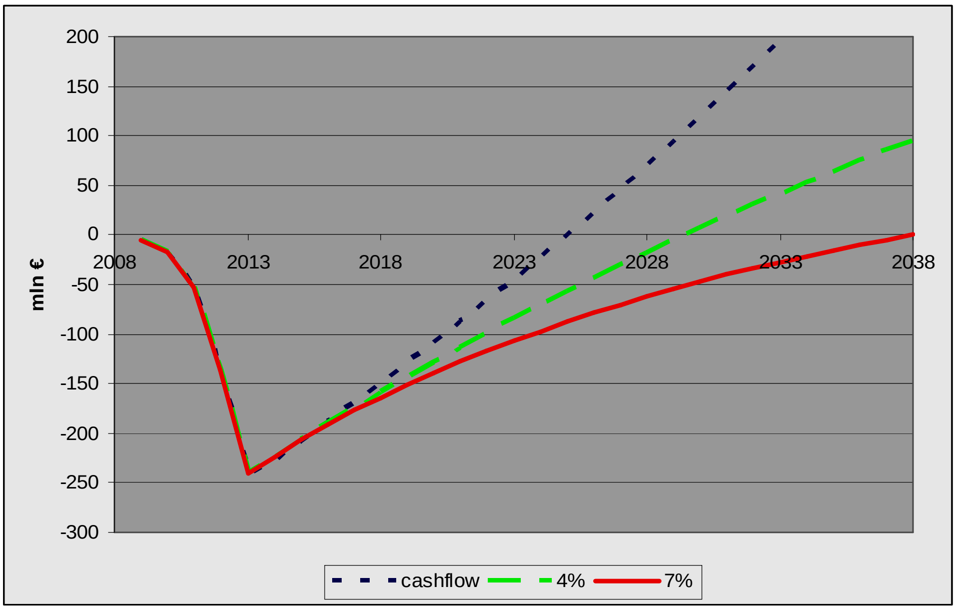


Figure 15: Financial evaluation of an investment in transmission capacity

Note: Assumption: 7% IRR after tax & 100% utilisation and fixed (real) tariffs).
Source: CIEP

The green dashed line is of importance for an investor because it compares the return of a pipeline project with a risk-free cash flow that has an interest rate of 4%. It can be concluded that as opposed to a risk-free investment in State bonds[27], an investment in a pipeline pays off only after 2029.

In a market economy, the risks and rewards of major gas infrastructure projects are borne by the main stakeholders: the pipeline companies, the suppliers and/or the buyers of the gas. In the past, moderate returns and long payback times were acceptable to integrated gas companies and their shareholders, as investments in pipelines were backed by their commodity transactions. Usually, long-term commodity contracts (10-20 years) formed the basis for pipeline investments. The commodity contracts carried the pipeline investments,

[27] If an investment is financed either fully or partially with debt, this time frame will be even longer for an investor, because banks generally require a shorter period to pay back their debts.

ensuring long-term utilisation. In return, lower tariffs for the shippers reflected the relatively low market risk for the pipeline entity. Typically, given the risks involved, the allowed weighted cost of capital (WACC) for a new pipeline with long-term contracts was between 8 and 10%[28].

After unbundling, transmission companies no longer had the guarantee of commodity transactions, and so had to look for alternative solutions for the long payback times or the failure to recoup their investment. Experiences in the US (transmission and LNG terminals) and Europe (LNG terminals) have shown that long-term (10-20 yr) capacity contracts, in conjunction with the holding of Open Seasons to attract as many shippers as possible, are a good remedy for adequately reducing the market risks for pipeline companies. Currently, a crucial question is that of what triggers the building of additional pipelines. There are two possible approaches to developing investment plans and making investments.

The first approach is that the pipeline company invests fully at its own risk. This happens in cases where capacity utilisation risks are low and tariffs are predictable. The pipeline company carries out market research (usually in consultation with market players), creates its own supply and demand plan and checks this plan with the available pipeline capacity. This exercise may result in the identification of possible future shortages in pipeline capacity, which can be developed into investment proposals. The market risk and the risks of over- or under-investment are borne by the pipeline company, since it is not allowed to require shippers to contract capacity under long-term arrangements. This approach is typically followed when the market is predictable, for instance to cover a steady growth of a local distribution market. This market will not suddenly disappear, alternative future supplies will still need the same infrastructure, and consequently the use of the infrastructure is reasonably assured. Although consumption by individual customers in the local market may vary, the variation in total market demand will be limited. Thus, in this case, pipeline companies can safely take on the investment risk.

The second approach is usually followed when the utilisation of the capacity is uncertain, for example because the pipeline is built for trading purposes. Cross-border flows and connections to LNG terminals also tend to fall into this high-risk category. In such a situation, the pipeline company will seek assurances from those who can influence or predict the risk of the utilisation of the pipeline[29]. Consequently, shippers/traders will have to bear significant parts of this risk by signing long-term capacity contracts. In this situation, the pipeline company responds to signals from shippers. One or more shippers indicate interest in new or additional capacity along a specific route. Subsequently, Open Seasons are organised to confirm the expectations of the future demand for transport capacity, serving the interests of one or more individual shippers. Based on these bookings, the principal demand for capacity can be estimated and the pipeline company can determine whether any additional pipeline capacity is needed. If this is the case, an investment proposal is developed and the shippers "put their money where their mouth is" and contract capacity. If they do not use this capacity in the contractual period of 10 to 20 years, the costs will still fall to the contracting shippers. After this contractual period, the utilisation risk belongs to the investor. The attractiveness of the Open Seasons model is that where possible, the choice of whether or not to expand the

---

[28] In this paper, WACC is quoted in nominal terms, after tax. See for example the (regulated) rates for the interstate pipelines in the US.

[29] Berg, S.V. (2001) 'Infrastructure regulation: Risk, Return and Performance', Global Utilities 1 (May), pp 3-10. Joskow, P (2005). 'Vertical Integration', Handbook of New Institutional Economics, Springer/Kluwer

pipelines is left to the market, economies of scale can be realised, and the risks of investment decisions are shared between the pipeline company and the interested shippers.

Recent successes of Open Seasons in various countries, in terms of the capacity demanded, demonstrate that the market is sending strong signals to invest in specific new transmission infrastructure. The interested shippers have demonstrated a willingness to pay for the investment through tariffs and to take on a substantial part of the market risk by entering into long-term transmission (capacity) contracts. However, the ultimate decision of whether to invest lies with the TSOs. New investments will have to meet the criteria of their shareholders, which are to a large extent private companies. This means that the risk profile and the revenues from the infrastructure investments will be compared with other opportunities these shareholders may have.

7.3 Revenue regulation and new investments

The EU regulatory regime requires *ex ante* regulated third party access and mandates that NRAs at least accept the methodologies for setting transmission tariffs. Generally, NRAs use methodologies that are based on determining efficient economic costs, in which the Regulated Asset Base (RAB) is a major component, and formulate efficiency targets by setting allowed revenue turnover with its consequences for tariff setting. This methodology works well in the context of existing infrastructures and assets and is usually referred to as a process of 'asset sweating' but does not sufficiently take into account the new investments for major new infrastructures.

As stated, the dominant risk for any investor in a pipeline is the risk that a pipeline (after some time) will not be fully utilised. Yet often, the TSO's WACC is regulated and fixed, in order to mitigate the expected natural monopoly's excess rents. This WACC is established *ex ante* in relation to the RAB, so the TSO no longer faces the utilisation risk. The corollary is that it has to accept a lower – but more secure – rate of return, typically in the order of 6-8%. As a consequence, the utilisation risk is shifted from the TSO to the users of the system. This process will hereafter be referred to as "revenue regulation"[30].

Of course, this does not mean that the utilisation risk has vanished. A pipeline company which faces underutilisation in a particular region, due to the decline of indigenous production or to changing transit patterns, will be allowed by the NRA to raise tariffs in all of its regions in order to achieve its regulated revenue turnover. In theory, this implies that the last user of the network could be faced with paying the total network bill. In other words, revenue regulation does not eliminate the market risk; it transfers it to those shippers and end-users that will use the network in future, and most certainly to the captive users: the household customers.

Shifting the market risk from the TSO to all shippers in a network has two major economic drawbacks, particularly in relation to transit arrangements. First, as stated above, international transit pipelines generally face a significantly higher utilisation risk than pipelines close to the regional consumers[31]. Thus, implicitly, under revenue regulation this risk is partly transferred

---

[30] We are aware that a number of hybrid systems are in use in the EU. Without going into the details (which are nonetheless not unimportant) we will refer to these systems as "revenue regulation".

[31] For instance, Russian supplies from Nordstream to the UK may use the German and Dutch networks for some time, while Statoil uses the German network to sell gas in Poland and Eastern Germany. However, Gazprom and Statoil may decide at some point to make a gas swap (as they have done in the past) that would diminish the need for transport through Germany and the Netherlands.

from transit shippers to regional shippers and consumers. Long-term capacity contracts for transit shippers can reduce this risk. These contracts, though, are typically for only 10-15 years, and because not all pipeline capacity may be contracted from the beginning, a significant part of the market risk (typically 50%) remains. Regional shippers and consumers cannot influence or predict the utilisation of the pipeline grid by international gas transporters. Therefore, this shift of transit risk to local/regional users by the application of revenue regulation is economically and socially flawed. Revenue regulation burdens a national society with the risks of transport for consumers external to that society by 'socialising' these risks in its national tariff system.

Secondly, the shift in market risk from the investor to the shippers removes the incentive for the network company to secure the future utilisation of its new assets. Instead, revenue regulation imposes upon the national regulator the responsibility to approve investment decisions in the RAB. It is highly questionable whether the NRA can obtain better market knowledge than a network company or the shippers, as was argued above. Moreover, since national regulators are primarily responsible for national consumers, regulatory decisions regarding transit pipelines may become skewed towards purely national interests and the development of international transit pipelines are hindered. This, of course, particularly harms the consumers in downstream countries for which transit is sought.

7.4 Entry and exit systems: scale matters

Setting the allowed cost basis for tariffs is one thing; choosing the method to translate costs into tariffs is the next step. Based on the UK experience, the new EU Gas Regulation requires a tariff transmission structure with separate entry and exit tariffs to and from the transmission system. This so called entry/exit (e/e) system must be implemented in all EU member states by September 2011[32]. In an e/e system, all entry-paid gas may be moved throughout the transmission system. This creates a 'virtual' trading hub, such as the UK National Balancing Point (NBP)[33]. The larger the e/e system, the more gas can be traded and the more traders, suppliers and customers will join. Like the NBP, the Dutch TTF system has gained a strong foothold in the market, followed by other – usually smaller – virtual hubs such as the EGT and VPP in Germany, the PSV in Italy and the PEGs in France. Each of these hubs is associated with an e/e tariff system, often with a national State as its territory.

Entry/exit systems are effective in facilitating trade. However, their drawback is that they cause cross subsidies between long and short haul transport. Tariffs at a specific entry point are equal for all shippers, whether they transport the gas only over a few kilometers or a few hundred. Long-distance transmission ('transit') is therefore relatively cheap, while short-distance ('local') transport, in contrast, is relatively expensive[34]. Thus, in an e/e system, local consumers cross-subsidise transit flows. The larger the e/e area, the more pronounced this effect is. This raises the problem of the optimal scale of the entry/exit area. Indeed, the larger an e/e area becomes, the less rewarding it is to construct transit capacity.

[32] Article 13.1 Regulation EC/715/2009 (OJ 14.8.2009.)

[33] Traditionally, gas trading develops at locations where different pipelines meet, thus creating physical hubs. A well-known trading hub in the USA is Henry Hub in Texas. In Europe, similar hubs are at Zeebrugge, Emden and Baumgarten.

[34] However, due to scale disadvantages, it will be less expensive than building newly dedicated local pipelines.

Box 1: Optimal size of an entry/exit system

No studies have been done on the optimal regional scale of e/e-systems, but a rough calculation provides some insights. Suppose a transmission tariff of 0.25 €ct/cm per 100 km and a system with 50% local usage and 50% transit. If the e/e-system were to cover some 250 km, the average distance factor for local use would be 125 km; for transits this would be 250 km. The average distance to be covered for all flows would be 187.5 km. Assuming non-discriminatory tariffs, the local shipper would have to pay 0.15 €ct/cm more. If the e/e-system were to cover 500 km, this price effect would double. But there is more. Entry-exit systems are prone to uncertainty because of their complicated technical planning, as the TSO in such a system does not know flow directions. Larger e/e-areas therefore imply larger risk of interruptions and extra costs related to strengthening the "backbone" of the system. Cross-subsidies in the order of 0.2 to 0.3 €ct/cm may be acceptable, relative to the commodity price effect caused by the increased liquidity of a larger gas hub. We suggest that the optimal size is probably in the order of 250 km, but more research on this topic would be recommendable. Regulatory designs should take this aspect of cross subsidisation into consideration.

EU regulation focuses on the returns that TSOs generate over the whole of their networks. Under such an approach, individual entry and exit tariffs on particular locations often have little or no relation to the actual investments required. The tariffs are designed to serve national or even local needs. In e/e systems, tariffs usually have little to do with transmission distance. The result is that tariffs tend to be substantially below the investment costs, in particular if transport distances become large, as is often the case for supra-regional (transit) transport. In such situations, investments in the expansion of the network are economically not attractive for TSOs because such investments would result in a loss. As a consequence, investments – even when these contribute to enhancing regional competition on the commodity market – are hampered. The latter is true in particular for cross-border investments, required for transits, as transit flows generally cover long distances in an e/e system.

In a situation in which tariffs lie below expansion costs, investments have to be made attractive by regulatory intervention. Usually this is done by increasing all tariffs in an e/e system or in a region. For investments within a certain region, this could be based on the argument that the expansion promotes competition and benefits all consumers in that region. However, difficult and lengthy procedures (often of a legal nature) are required in order to make all stakeholders accept that the transmission tariffs should increase, when the investments may only benefit certain users. This becomes even more complicated if the expansion mainly concerns 'transit gas' that is not meant for the 'local' market and thus does not benefit local consumers, while the investment may require higher (national) entry and exit tariffs. The transiting country and its TSO will certainly want to receive adequate compensation for their transit services. This creates an almost impossible dilemma for the NRA, which is oriented toward its national consumers.

This complicated process of decision making, which frustrates necessary investments in transit, could be avoided by setting cross-border entry and exit tariffs at the level of Long Run Incremental Costs (LRIC). A similar conclusion has been derived by Hunt (2008), who also finds that the present approach towards e/e pricing hinders the development of a pan-European gas market.

7.5 Lessons from the US?

What can the EU learn from the US model? Although the US is one country, with a federal government, a federal regulator (FERC) that regulates intra-state trade and transmission in gas and in electricity, there is no federal law that requires full-scale energy market liberalisation as there is in the EU. Therefore, many and sometimes significant differences exist between individual states. Some, such as Texas, have adopted full liberalisation, but many others still regulate retail trade. In California and other states, liberalisation was introduced and subsequently abolished or partly abolished. Nevertheless, wholesale gas markets have been liberalised. Several trading hubs exist, of which Henry Hub (Louisiana) is the most important. A number of large infrastructure companies, with nationwide intrastate networks and storages, provide transport and other services.

The Federal Energy Regulatory Commission (FERC) regulates and monitors interstate transmission companies and the wholesale markets for gas and electricity. The mission of FERC is: “to regulate and oversee energy industries in the economic, environmental, and safety interests of the American public”. The vision of FERC is: “abundant, reliable energy in a fair competitive market”. FERC operates independently from state regulators and can impose decisions on them if interstate transmission is at stake. FERC’s priorities are (1) the promotion of the development of a strong and reliable energy infrastructure, (2) to support competitive markets by developing rules that encourage their fairness and efficiency and prevent the accumulation and exercise of market power, and (3) the prevention of market manipulation through vigilant oversight and firm but fair enforcement[35]. FERC’s record in facilitating the expansion of the interstate gas-grid system is quite impressive. In the period from 1998-2008, the interstate grid was expanded by some 30,000 km.

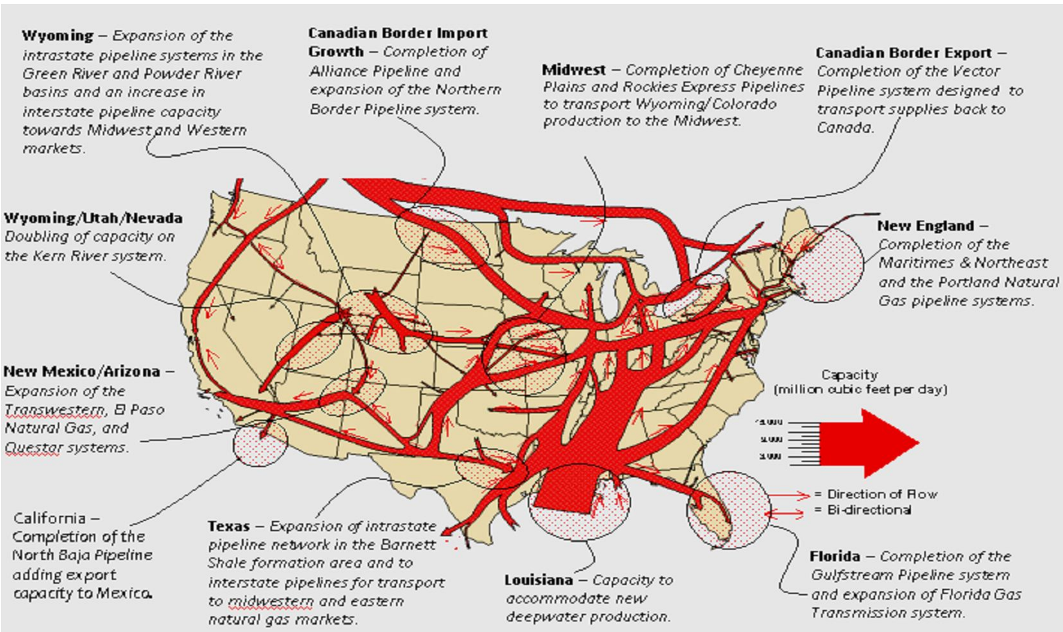


Figure 16: Major Additions to the US Natural Gas Transmission Grid 1998-2008 (US EIA)

Although the gas market in the US is different from that in the EU, in terms of market structure and design the drivers are the same. Both markets seek to attract additional (external) supplies to meet demand. In both markets, the main driver for the increase in the demand is the power sector. Furthermore, while in Europe there are many conflicts of interest

[35] FERC Annual Report 2006.

at an international level, the same conflicts of interest arise in the US at an interstate level. Yet although the EU has an EU-wide regulatory regime, it has no federal structure and therefore no institutional setup such as FERC. The question then arises as to whether the new ACER could be considered the answer we need for providing fair and effective regulation for the EU's new gas infrastructures.

In the US there is competition in the interstate transmission sector, in particular for new pipelines. If a pipeline company expects sufficient demand for capacity to create a business case, it organises an Open Season, usually in competition with other pipeline businesses. Market participants have the opportunity to choose which Open Season to join. This gives these participants negotiation power with respect to tariffs and other contractual provisions. The pipeline company that succeeds in getting sufficient binding commitments from market participants can create its business case and submits it to FERC. FERC generally approves the negotiated (long-term) contracts, including the negotiated tariffs, as long as they are based on a (regulated) Return on Equity (RoE) of maximally 12%. The presence of long-term transmission contracts is sufficient for FERC to decide on the social benefits of the investment and, consequently, FERC makes an order to force individual states to cooperate in the permitting process. After this procedure, the pipeline company decides whether or not to invest.

A notable difference between the US and the EU on regulating new interstate pipelines is the approach with respect to the allowed returns on investments. While FERC allows a WACC of about 9% (equal to a 12% Return on Equity), EU NRAs apply a WACC of just 6-7%. This makes investments in gas transmission in the EU significantly less attractive and reduces the number of potential investors to virtually zero. The US success of new investments in gas infrastructures provides food for thought and reflection, allowing higher returns in the EU. This could attract potential investors for cross-border transmission in the EU, leading to more competition and enhancing supply security.

8

Towards a New EU Regulatory Approach

The previous chapters maintain that a new approach towards network investments is needed, with a focus not only on the local market and existing assets, but also on new investments, cost principles, tariff structures for cross-border transit and the role of long-term contracts. NRAs should set or allow tariffs that give TSOs incentives and assurances to carry out necessary investments in infrastructure. This would require tariffs to reflect the incremental costs of expansion. A workable basis to regulate the tariffs for new capacity in cross-border gas infrastructures may be in an approach that draws upon the Long Run Incremental Costs (LRIC). The LRIC principle is embodied in the EU regulations[36]. Yet it is not applied in the EU, most likely because it is not easy to apply in practice.

8.1 Setting tariffs on the basis of LRIC

A brief indication of the concept of LRIC is given in Box 2. We do not, however, advocate a full "wall-to-wall" conversion to the LRIC system. Rather, we propose that LRIC concepts be applied to e/e tariffs every time that new investments have to be made which will affect these tariffs. This step-by-step approach avoids the need to make arbitrary and speculative estimates of future expansions as well as the regulatory, political and economic issues arising from a full transition. The valuable elements of the LRIC concept – i.e., the use of incremental capital expenditure as a basis for tariff setting, the pursuit of fixed (indexed) tariffs and leaving the market risks with the market players – are preserved and applied every time a new cross-border investment is required.

8.2. Pancaking in e/e-systems

There is a relation between the size of the hub and the need for hub-to-hub interconnections along the transport route. Many market participants favor large e/e areas because it increases the possibilities to trade. Some, including the EU trading community (EFET), are making a case for a multi-system integration, as a stepping stone towards a single EU gas market[37], obviously with a single e/e tariff system. We have, however, addressed the negative impacts of non-discriminatory e/e tariffs for local use and transits. Indeed, we suggested that the optimal size of an e/e-system could be approximately 250 km.

Obviously, transporting gas over large distances in Europe would involve a number of e/e-areas, requiring hub-to-hub transmission and a 'pancaking' of tariffs. It is argued that this creates barriers to trade in the gas market and should be avoided. To this end, in the electricity market, the 'copper plate' paradigm has been accepted as a basis for electricity transmission pricing in the EU. Yet whereas electricity is rarely transported over large distances, gas flows follow contract paths of 1,000 km or more, as is shown in Figure 7 in Chapter 3. Long-distance gas flows pass through several e/e systems, and shippers have to pay entry and exit tariffs for each zone. According to the LRIC paradigm, long-distance tariffs should be in line

---

[36] Regulation (EC) No. 714/2009, article 13.6.

[37] EFET-position at the November 2008 Madrid Forum; http://ec.europa.eu/energy/gas_electricity/forum_gas_madrid_en.htm

with the incremental costs to expand the pipelines. As the costs of pipeline increase as a function of distance, the aggregation of the e/e tariffs should reflect the cost to expand the total long-distance pipeline. This would imply, for gas transport, that pancaking would be an efficient approach.

Box 2: The LRIC concept

The long-term nature of the LRIC concept implies that the (annualised) cost of the required future capital investment should be included in the tariffs. In such an approach, the capacity utilisation risk belongs to the transmission company. While under revenue regulation tariffs would increase if utilisation decreases, under the LRIC, the tariffs stay the same. The question is further how to assess expansion costs. Determining the current efficient cost of operating a network is already difficult. The uncertainty and complexity of estimating future incremental costs are even more challenging. Theoretically, each incremental investment has its own costs and should be considered individually. However, in many situations “standardised costs” are used as a practical and acceptable shorthand, as calculating the real cost would be too demanding, too costly and inherently uncertain.

In the case of pipelines, it can be expected that expansion investments will often involve significant scale advantages, as capacity expansions may take place with pipelines with diameters of 42”or 48”, while traditionally pipelines have diameters between 30 and 36 inches. As suggested by Figure 12 in Chapter 6, tariffs based on the LRIC principle could be as much as 30-40% lower than tariffs based on replacement costs, as a consequence of economies of scale and capacity utilisation factors. It could also be an argument to differentiate in tariffs between long-term and shorter-term capacity bookings.

The establishment of an LRIC-based tariff system would require a thorough discussion between the NRA, the TSO and market participants. The knowledge gained by all parties about efficient network cost could be a valuable starting point for such negotiations. The establishment of tariffs based on such a system could be seen as a one-of-a-kind exercise, introducing concepts of ‘better regulation’ and giving the necessary guarantees and stability for investors and market parties, together with limiting regulatory and administrative burdens for all concerned. It would free NRAs from their recurrent periodical burdens of making sure that TSOs do not diminish their efficiency-levels in the cost-base that is included in their tariffs. This task is currently a crucial component of the revenue cap system, under which TSOs are allowed to earn back all their efficient costs. Benchmarking efficient cost is usually very complicated, as all peers are different.

Once established, regulated tariffs based on LRIC will require no future amendments for specific pipelines and contracts. In principle, this should allow for fixed tariffs for a contracted period of time, including differentiation over contractual periods. Tariffs then should be fixed in real terms, allowing cost recovery for inflation, eventually with a correction factor for sector-specific efficiency gains. Under such a system of ‘perpetual tariffs’, TSOs are not able to adapt their tariffs if they have higher operational costs and thus will have a strong internal incentive to become or remain as efficient as possible. Furthermore, TSOs are not allowed to raise their tariffs if the utilisation of their pipelines decreases and have to accept a reduction in their profits, which is an incentive to offer different cost-based tariffs for different capacity-booking periods. So the TSOs will have the full responsibility for both their costs and the utilisation of their network.

8.3. Distinguishing cross-border and national infrastructures

The next issue is striking the balance between ‘national network users’ and those that are using a network for ‘pass-through’[38]. An option in the EU could be to split transmission infrastructure into a regional/national part and an international part. The idea behind this is that international (cross-border) transmission should be regulated in a different manner than national transmission. By splitting the network, cross subsidies between national and international shippers can be reduced or eliminated. Furthermore, differences in risk profiles

[38] Using this terminology in order to prevent the legally inconsistent term of ‘transits’.

of both transmission 'markets' can be taken into account by allowing investors in international pipelines a higher return. It would also be possible to exempt investments in international (cross-border) capacity. This split may be attractive in countries like Austria and Belgium, where a clear distinction between international transmission pipelines and local networks can be established. However, it may be more difficult to apply it in countries like Germany and the Netherlands, where transit flows and local flows use the same pipelines.

By splitting the network, cross subsidies between national and international shippers can be eliminated. Furthermore, differences in risk profiles of both transmission 'markets' can be taken into account by allowing investors in international pipelines a higher return. It would also be possible to exempt investments in international (cross-border) capacity. Recently, the German NRA (BnetzA) decidedthat the OPAL pipeline, connecting the Nordstream landing point at Greifswald with the Czech border, would be exempted from the TPA rules only for transit flows[39]. The exemption is for a period of 22 years and has the 'use-it-or-lose-it' type of capacity-conditions. As is the case with this type of exemptions, complex arrangements will have to be made in meeting the conditions. A decision to invest has not yet been made, but the special treatment of transit flows in a national infrastructure could give rise to some interesting lessons and precedents.

However, there are also some disadvantages. First of all, in such a system, transit flows will have to be separable from national flows; actually, these volumes would bypass the national market. This hinders the potential access of transit gas to the national market and reduces the liquidity of the market. This may not be a major problem, particularly if the 'national' hub is located at the upstream border, as is the case in Austria (Baumgarten) and Belgium (Zeebrugge). However, this requires the hubs to be physical instead of virtual. Traders clearly prefer virtual hubs. A second drawback of this approach is that the split in two regimes may easily lead to two (physical) systems of pipelines, making it more difficult to achieve scale advantages from the combination of transit and national/regional transmission into one pipeline/network. Furthermore, in cases of integrated national/international networks, like in the Netherlands and Germany, it seems questionable as to whether EU law would allow for different entry and exit tariffs for transit shippers and regional shippers. EU regulations require that "tariffs, or the methodologies to calculate them, should be applied in a non-discriminatory manner". This seems to leave little room for different tariffs for different types of users. Nevertheless, now and then, proposals *are* made to have different tariffs for international and regional users[40]. Given the different risk profiles, this may not be a bad solution, after all.

8.4. Long-term transmission (capacity) contracts

Long-term commitments throughout the gas value chain are an effective way of coordinating risks and rents with the stakeholders concerned. Yet buying and selling gas molecules is pointless without transmitting them. Different needs for flexibility, balancing, load factors and seasonality will also lead to differences in the need for access to and use of capacity in gas infrastructures. Long-term transmission contracts also demonstrate the robustness of market demand and are a justification for investments in new infrastructure. If such investments need to be supported by capacity contracts, the use of fixed (indexed) tariffs would create significant security, both for investors in and users of the transmission infrastructure and those

---

[39] http://www.bundesnetzagentur.de/media/archive/15735.pdf

[40] See for instance Paul Hunt's paper from February 2008: "Entry-exit transmission pricing within notional hubs", Oxford Institute for Energy Studies.

upstream or downstream in the supply chain. This would benefit the investment climate significantly. Transmission tariffs are one thing; contracting transmission-capacity is another.

Today, transmission contracts are separated from commodity contracts. As a consequence, there is no direct linkage anymore between transmission and commodity transactions. Nonetheless, major long-term supply contracts for the EU market would not be possible without similar long-term transmission contracts. Furthermore, investors in LNG terminals and gas storages have good commercial reasons to contract transmission capacity on long-term conditions and to create optionality in these contracts, consistent with the options they have from their investments in terminal or storage capacity (e.g. increasing send-out capacity in an LNG terminal).

Dedicated, customised contracts are therefore necessary and should be allowed under the regulatory framework. Of course, competition law will be applicable and non-discrimination principles will have to be applied as well. Therefore, NRAs have developed approaches such as use-it-or-lose-it (UIOLI) or use-it-or-sell-it (UIOSI) rules, stimulating the efficient use of capacity and preventing potential abuse by dominant shippers. On the other hand, investors in upstream production, LNG terminals and gas storages will need certainty about their access to transport capacity. In essence, such contracts should be considered as transmission options, open to shippers intending to fulfil specific transactions that are as yet unknown. Note that in entry/exit systems it is possible to feed the gas into the system without having secured a final customer. Particular shippers will put a value on these transmission options, which surpasses the cost of contracting the capacity, whether used or not. Measures that would undermine that certainty of access to the transmission system would have damaging effects on these investments in terminals and storages; precisely because it is unknown when their capacity will be employed in a transaction. Indeed, lack of secured access to transport at the right time may turn these facilities into stranded investments. The application of UIOLI or UIOSI, therefore, should require careful consideration of the interests of the various stakeholders.

8.5. Licensing new infrastructures

A discussion of regulatory issues in energy infrastructures cannot neglect the serious concerns about licensing procedures. It can be observed that these procedures usually take a long time, especially in a cross-border context. Numerous bureaucratic hurdles are harming investments in new infrastructures, even if there is a clear market need. There is a clear need to improve the current process of decision-making. Licensing is a national responsibility, but the consequences of national decisions can have significant effect on neighbouring countries. Here there could be a role for the EU. One approach already taken is to flag a certain project with the indication of “European interest”, involving the appointment of a high-level EU coordinator that should facilitate a faster completion of the national licensing procedures. But again, this is a burdensome process and results to date are still lagging behind expectations.

Additionally, these projects could be made subject to regulatory streamlining under EU law, for instance by defining – in a bi/trilateral cross-border context – the concrete procedural steps and their timing. One step further could be that the Commission itself takes a coordinating role for such projects, offering political and legal assistance[41]. From a practical standpoint, the Commission could offer to support coordinating committees for all major new pipeline projects. The Commission could also set standards for intergovernmental agreements that underpin pipeline development, dealing with issues such as the host government agreement,

[41] Some of these ideas are mentioned in the February 2009 Activity Report of the European Coordinator on the SE-European Energy Corridor.

mechanisms for the implementation of strategic and project environmental assessment, etc. This would reduce the influence of individual member states in upholding or obstructing pipeline projects for political reasons. This could even evolve into a one-stop shop for all regulatory approvals, either by the Commission itself or, following the model used by FERC in the US, licensing and regulating such projects of "extraordinary EU interest" by a European authority and giving this mandate to the new ACER. All this, however, would require some kind of EU legislation, either in the form of a Regulation or an EU Decision.

8.6. Is ACER an effective answer for regulating new cross-border infrastructures?

In the coming decades, the EU gas market will face significant challenges that are comparable with the 1998-2008 infrastructure process mentioned for the US. National regulation should facilitate such a process, on the basis of EU rules. The new Agency for the Cooperation of Energy Regulators (ACER), as formally established in June 2009, should therefore actively promote the development of a strong and reliable energy infrastructure. However, ACER has no such clearly defined mission. Its main focus is to give opinions and advice to the European Commission and to the new ENTSO-G body, the European Network of Transmission System Operators for Gas. Mandatory powers for ACER are limited to specific cross-border issues, notably with regard to conflicts between neighbouring regulatory authorities and – perhaps more importantly – on exemptions for new cross-border infrastructures. We will discuss the challenges for the new ACER, its abilities and inabilities in some more detail.

Box 3: Some cross-border issues for national regulators

The BBL pipeline was exempted under art. 22, on the condition that it would offer virtual reverse flow capacity. After a long debate with its stakeholders, BBL introduced this service and the Dutch regulator approved it. BBL planned to introduce the service by September 1st, 2008. Yet the UK regulator Ofgem refused to accept the agreement between the Dutch regulator and BBL because it has a different opinion about the market based tariff setting. Therefore, the reverse-flow service is not available to date, although BBL has put all contracts and other provisions on its website. BBL is just waiting for Ofgem's approval.

In 2007, the Dutch TSO and the neighbouring TSOs in Belgium and Germany organised Open Seasons. These Open Seasons attracted significant attention, including a substantial expansion of the cross-border capacity. In July 2008, shippers and TSOs were able to sign long-term cross-border transmission contracts, allowing substantially more transmission capacity from the Netherlands to Germany and Belgium. Consequently, an investment decision was able to be made. Dutch authorities approved these investments, but the regulatory authorities in Belgium and Germany did not allow their TSOs to make their part of the investment decision.

The German and Dutch gas markets are strongly connected. To improve liquidity, regulators in the Netherlands and Germany forced the TSOs to introduce new balancing regimes. Instead of working together, German and Dutch regulators have introduced new but different balancing regimes, which may significantly hinder the development of cross-border trade in NW Europe. Similarly, to improve liquidity at the TTF, quality services to convert H-gas to L-gas, were socialised in the Netherlands and the costs were incorporated in the transmission tariffs, while this was not the case in Belgium and Germany.

It is useful to note that cooperation between EU NRAs already does exist. They have their own cooperative framework (CEER) and are jointly developing advice and opinions for the EU Commission and other stakeholders in the framework of ERGEG. In addition, more specific cooperation on regional levels exists in the framework of the Gas Regional Initiatives, where barriers and bottlenecks to cross-border trade are identified and regulatory action to abolish these barriers are developed. This is, however, all done on a voluntary basis, and as NRAs are (by nature) nationally focused. Cross-border cooperative approaches and meeting cross-border or even wider European interests are not of primary importance, as is illustrated by the examples in Box 3.

Regarding the need for effective decision-making by NRAs, we would therefore argue that the principal task of ACER should be, similarly to that of FERC in the US, to "promote the development of a strong and reliable energy infrastructure" in Europe, in order to enhance supply security and a competitive internal EU gas market. In this respect, ACER should be enabled to intervene, mediate and perhaps even overrule the decisions of NRAs if the wider interest of the EU gas market is at stake. A number of important elements could be addressed in this context.

First, since TSOs cannot be forced to invest in loss-making projects, ACER should have a role in convincing NRAs to allow TSOs to recover their investments at reasonable return rates. An option could be to provide ACER with the mandate to establish an EU-wide methodology and structure for cross-border transmission tariffs, especially focusing on trade between e/e zones.

Second, ACER should promote a competitive EU gas market, with a mandate to take action in removing barriers in the intra-EU trade. Promoting a harmonisation of relevant regulatory and contractual arrangements could do this, as there are many differences in market rules and designs, operating and scheduling protocols, and other control-area practices that complicate transactions throughout the EU. ACER could also develop and promote best practices in market rules and transparency.

Third, ACER could play a more pronounced role in licensing and permitting new transmission infrastructure, by underlining and arguing the European significance of a (possibly cross-border) project. This could be especially relevant in cases where NRAs have to cooperate on licensing. Here, the example of FERC could be followed in licensing projects of "extraordinary EU interest".

Fourth, as ACER will have to give advice on the ENTSO-G 10-year network development plan, it could no doubt have an important role in its establishment, depending on the force and quality of its arguments. The plan is not binding but indicative. It has to include, for example, integrated network modelling, scenario development and a supply adequacy outlook. More specifically, it also has to focus on potential investment gaps, notably with respect to cross-border capacities. In enhancing its role in potential conflicts between NRAs on specific investments, ACER could build upon its inputs and on the comments it makes in the context of the development plan, especially as this must be drafted every two years. ACER could, in principle, play a vital role with respect to the development of the intra-EU gas network, but it will take a significant amount of time to bestow ACER with sufficient additional mandatory powers to be truly effective. Proposals to expand regulatory mandates and to create authoritative institutions at the EU level are usually considered to be "death-on-arrival" in political terms[42]. Certainly, a step-by-step approach to strengthen internal EU regulatory systems could provide further arguments for developing ACER, as part of an effective energy regulatory approach within the EU, eventually becoming a European "FERC". However, the urgency to invest in gas transmission does not allow Member States and national regulators to simply "wait and see" how ACER will develop.

---

[42] It is to be noted however that ongoing discussions on strengthening EU regulatory oversight in financial markets could create interesting precedents for other sectors including energy.

8.7. What can be done in the framework of the 3rd Package?

As we indicated already in section 7.1, a dynamic market needs dynamic regulation. If we look at the new regulatory approach we discussed in this chapter and take into account the need for timely regulatory action, the question arises as to what can be done in the framework of the 3rd Package. In answering this question, we will make a distinction between the content and the process.

As to the content, our approach is basically to introduce a different regulatory format for cross-border infrastructure investments. Due to their nature and to their market based Open Season approach for identifying market interests, one could expect that all those investments require exemptions for TPA under article 36 of the new Gas Directive. Although the conditions to apply this rule are quite challenging, it would seem to us that interesting possibilities would exist to apply or to allow the LRIC approach in this context. The same could be argued for applying a somewhat different ruling for setting tariffs in the e/e system, along the lines discussed in section 8. 4. When cross-border projects are at stake, applying the exemption rule would also require that the respective NRAs would have to coordinate their views and positions in order to reach consistency in their decisions. It might help if ACER could draft an opinion on these issues, as a guideline both for NRAs and for the European Commission. All this could be done under the existing legal framework.

The question of procedures is more difficult, especially regarding the role of ACER. Accepting political realities, it is an often-heard view in the EU's "gas market community", that ACER is welcomed, but that it is only considered to be a small first step. Although the quality of its staff and director will be very relevant factors – and the interplay between the director and the chairman of the Regulatory Board even more so – when it comes to decision making in ACER, severe doubts are expressed as to its process given a 27-member board. This could give rise to intransparent processes, with the risk that decisions will not always be rational and objective. On the other hand, one could argue that in cases where neighbouring NRAs have different views, they would have the incentive to develop a workable solution rather than refer to ACER about a conflict. Therefore, after more experience in operating in its current form, amending the ACER regulation may well receive consideration.

8.8 Conclusion

This section has highlighted the main problems and solutions with respect to cross-border transmission infrastructure, essentially referring to the tariff setting, contracting and licensing practices in e/e systems. It suggests that by adjusting the tariffs for new pipelines, while allowing a wider variety in contracting practices and facilitating the provision of local licenses, the investment climate can be improved considerably. A stimulating and facilitating role in coordinating international controversies over these issues could and should be played by ACER, the ENTSO-G and the regional cooperation between TSOs. The 2009 Gas Directive and its supporting Regulations are considered a useful and effective contribution to these developments.

9

Conclusions and Recommendations

Contrary to previous assumptions, we have concluded that any expectation of a higher utilisation rate of the transmission grid is unrealistic and should be considered a misleading yardstick for the success of market liberalisation. On the contrary, it can be expected that the utilisation rates of pipelines will decrease as market liberalisation progresses.

Nonetheless, it is obvious that further expansion of the European gas network will be needed in the coming decade. Market growth and the shift in supply pattern will need to be accommodated. Expansion may also be necessary to enable further competition on the commodity market, to enhance Security of Supply and to allow market players to strengthen their competitive positions.

The need for new transmission infrastructure is confirmed by the significant interest shown by market parties in Open Seasons, which make investments economically viable through the closing of long-term utilisation contracts. However, we draw the same conclusion as the IEA that investments in transmission infrastructure are lacking or at least suffering delays, especially those relating to cross-border capacity. Currently, it is nearly impossible to contract for next year’s cross-border capacity anywhere in the EU. With this in mind, it should not come as a surprise that the EU gas market still consists of a series of national markets. The lack of investments in cross-border capacity in the EU is in marked contrast with the situation in the US.

We subsequently studied the trends in transmission infrastructure investments and have come to the conclusion that the EU’s current regulatory framework is counterproductive with respect to the promotion of investments in cross-border capacity, as the primary focus is on existing capacities. In part, this is due to the focus of NRAs on national (and often short-term) consumer interests. The current tariff-setting system is often based on revenue regulation, which withholds and/or gives the wrong incentives for shippers and investors. Tariffs are often too low to justify new investments, and transit is ‘subsidised’ in some situations by national consumers.

We also concluded that the lack of investment in transmission infrastructure should not be seen as a ‘market failure’. The significant success of Open Seasons clearly demonstrates the willingness of market participants to enable investments in the expansion of the transmission grid. We believe that the establishment of an independent EU regulator could significantly contribute toward the encouragement of investment if, like the FERC in the US, the regulator were to have as its main mission “the promotion of the development of a strong and reliable energy infrastructure”. The abilities of the new ACER fall short of this, as the agency has no effective mandate to intervene when cross-border interests are at stake. Its mandate should also include the licensing process for constructing the infrastructure. Adjusting ACER, however, will take time.

The urgency for new investments leads us to a number of recommendations regarding the realignment of the economics of investments and the lessening of the regulatory burden. The recommendations below are particularly pertinent to investments in cross-border capacity and could, in our opinion, be implemented under art. 36 of the 2009 Gas Directive.

1) The risks and rewards for new cross-border investments in transmission infrastructures should be carried by the market participants, notably those directly involved in the construction and use of the new capacity. Tariffs for new cross-border pipelines should be high enough to make investments in new transit capacity economically attractive and should take into account the duration of the capacity booked. Tariff adjustments should be made at the time of new investments, and could be based on LRIC – i.e., reflecting actual CAPEX and including economies of scale – and translating these costs into ‘perpetual’ (meaning fixed, possibly indexed) tariffs in entry/exit systems.

Applying LRIC as methodology for new cross-border infrastructures could be a very interesting option and would give sufficient reason for confidence to investors and market parties, especially if this approach could be translated in long-term fixed tariffs that would be corrected for inflation when necessary (including the sector-specific efficiency gains). It would also place the capacity utilisation risks on the right shoulders.

2) Long-term (standardised) transmission capacity contracts with fixed (indexed) tariffs should be accepted as a sound basis for investments in transmission capacity. Often these will underpin long-term commodity contracts, which should be considered as essential instruments in enhancing long-term supply security for the EU. In order to allow the necessary flexibility for market parties throughout the value chain, non-standardised (customised) transmission contracts should be offered by TSOs as well, under appropriate regulatory conditions in line with competition law.

Long-term commodity and transmission contracts are essential elements of effective and efficient gas value chains, especially for facilitating and promoting the EU’s external gas supply security. Accepting this notion would in itself already significantly improve the investment climate in the gas industry. In addition, allowing flexibilities and options in using infrastructure capacities would call for allowing customised contract approaches. This could be done in line with EU competition law if UIOLI or UIOSI principles are added and applied in accordance with market parties’ interests.

3) Tariff differentiation could be an effective instrument for improving the economics of specific transmission investments. There is no question that identical users of a network should be treated identically under the same circumstances. However, there is less necessity to apply the same tariffs to new and old contracts, to short-term and long-term contracts, and/or to local and cross-border (transit) customers. Applying the non-discrimination principle in entry/exit tariff methodologies in a way that would serve the interests of the wider community of EU consumers would allow distinctions to be made in exit tariffs between international and regional users, facilitating effective cross-border flows in the EU gas market, including options for TSO transit-competition.

E/e-systems for transmission tariffs are the prevailing rule in the EU, as they promote competitive markets and market liquidity. Long haul transmission of the gas commodity therefore requires effective cross-border flows and transmission conditions for shippers. Accepting that major gas flows based on long-term commodity contracts will have to cross several borders, and in order to minimise barriers that arise due to the consequences of pancaking, innovative methodologies and interpretation should be explored wherever necessary, by NRAs, ACER and the EU Commission.

5) As the new body for the cooperation between NRAs, ACER should be given a straightforward mission to promote the development of a strong and reliable energy infrastructure in the EU energy market. Amending its mandate in that sense, ACER should also be given the necessary powers to intervene in cross-border issues in the wider interest of EU consumers.

By definition, NRAs have national mandates, views and focuses, serving the interests of national consumers and market parties. Cross-border issues, however, have an intra-national character, calling for effective mechanisms and institutions at the EU level. The new ACER falls short of this requirement and should already explore ways and means to amend its role, its mandate and its governance. Useful lessons can be gained from US experiences. Also the prevailing political climate seems to call for wider regulatory oversight in EU markets, including energy. This may facilitate a more stimulating and coordinative role for national energy regulators. In this context, the Gas Regional Initiatives could provide support for enhanced cooperation and harmonisation.

These four recommendations imply a ‘conversion’ of the current regulatory system to a set of rules and processes focusing on “the development of a strong and reliable energy infrastructure”[43]. This would lead to an environment in which investments in cross-border transmission infrastructure – sought and underwritten by shippers – are facilitated. None of these recommendations are completely without problems, but they are not insurmountable and are small relative to the benefits envisaged by the shippers seeking this expansion. It would enhance the trading of gas in the EU and promote competition. Consumers would be the winners.

Most likely, the content of these recommendations can be applied in the context of the new Gas Directive and the new regulations, especially in cases of cross-border projects where a coordinated, mutually consistent approach by the NRAs involved is required. Crossing national borders is essential in securing an adequate supply of natural gas to Europe. It is time to construct the missing links.

[43] This is one of the main stated objectives of the US regulator FERC.

Clingendael International Energy Programme