LIBERALISATION OF THE ESTONIAN GAS MARKET

A report to Elering AS

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EXECUTIVE SUMMARY

The Estonian gas market

Pöyry has been commissioned by Elering to assess the potential for gas market liberalisation in Estonia. This report presents the work that Pöyry has undertaken over a number of months since May 2011. In the course of this work we have interviewed a large number of industry stakeholders in order that we are able to understand the views of market participants and to develop a practical approach to liberalisation in Estonia.

The Estonian gas market is, by international standards, small in terms of its annual consumption and peak day gas requirements. There is currently very little gas used in power generation in Estonia, although gas does have a reasonable share in CHP and district heating schemes.

The Estonian gas transmission network is connected to Russia at Narva and Värska and to Latvia at Karksi. Even though connection at Narva has had periods out of operation due to its poor condition, and currently has limited availability, there is currently sufficient capacity in the transmission network to meet all annual and peak gas demands.

The major player in the Estonian gas market is Eesti Gaas, which owns the transmission system assets, the majority of the distribution assets and is currently the sole wholesaler of gas. It is owned by Gazprom (37%), E.On (33.66%), Fortum (17.7%), Itera (9.9%) and various smaller shareholders. Eesti Gaas supplies gas to over 90% of the retail market. The sole importer of gas into Estonia is Gazprom. Flexibility is also provided to the Estonian gas market via the Incukalns underground storage facility in Latvia, which is currently contracted solely to Gazprom.

In order to progress towards a liberalised market, Estonian legislation has led to the establishment of a separate system operator, EG Võrguteenus, in January 2006, which is a wholly owned subsidiary of Eesti Gaas. Since July 2007, the Estonian gas market has been open to competition, with all end users, in theory, being able to choose their gas supplier.

Despite these efforts, however, little or no competition has developed in the gas market. We consider that this has been due to a number of reasons:

- The overall size of the gas market is small and therefore not attractive to new entrants that would incur high start-up costs in relation to any possible benefits.
- There is no alternative to Russian gas supplies and therefore no gas-on-gas competition at the wholesale level. There is no surplus of gas available to the wholesale market to provide new entrants with competitive prices.
- End user prices have been relatively low, in comparison to other EU countries, and therefore there has been little incentive for end users to question the status quo.
- Competition in the electricity sector is not yet established at the retail level and this has meant that it is not possible for either the gas or electricity incumbents to offer dual fuel offers. In other markets this has led to at least the gas and electricity incumbents competing with each other.
- Retail customers have little choice of their gas supplier if they are tied into district heating schemes. Furthermore, the limits that are imposed on the use of a single fuel source in district heating schemes may incentivise a move away from gas and into biomass.

- Currently, there is little gas fired power generation in Estonia, and a vibrant gas fired power sector is normally key to attracting new market entrants.

This report addresses the issues detailed above and presents a number of conclusions and recommendations on the future development of the Estonian gas market.

Gas security of supply concerns

Within the Estonian context there are two main areas of concern relating to gas security of supply:

1. Single supplier risk; and
2. Physical infrastructure risk.

As part of our discussion with stakeholders, and with the Estonian government in particular, the single supplier risk has been highlighted as the main reason for there being reluctance to expand the use of gas. This is also quoted as being a similar concern across the region, and as can be seen in Figure 1, for legitimate reasons, as all the Baltic States are between 90-100% dependent on supplies from Russia. Events such as the Russian-Ukraine dispute in January of 2009 provide grounds for these concerns.

Whilst it is not the objective of this report to undertake a security of supply analysis we have noted concerns relating to whether some critical assets, including the storage facility at Incukalns, can meet very high demand as a result of cold weather. Together with potential constraints in the wider Russia supply network, there are concerns that the Incukalns facility may not be able to support high levels of demand in Estonia, Latvia and neighbouring areas in NW Russia.

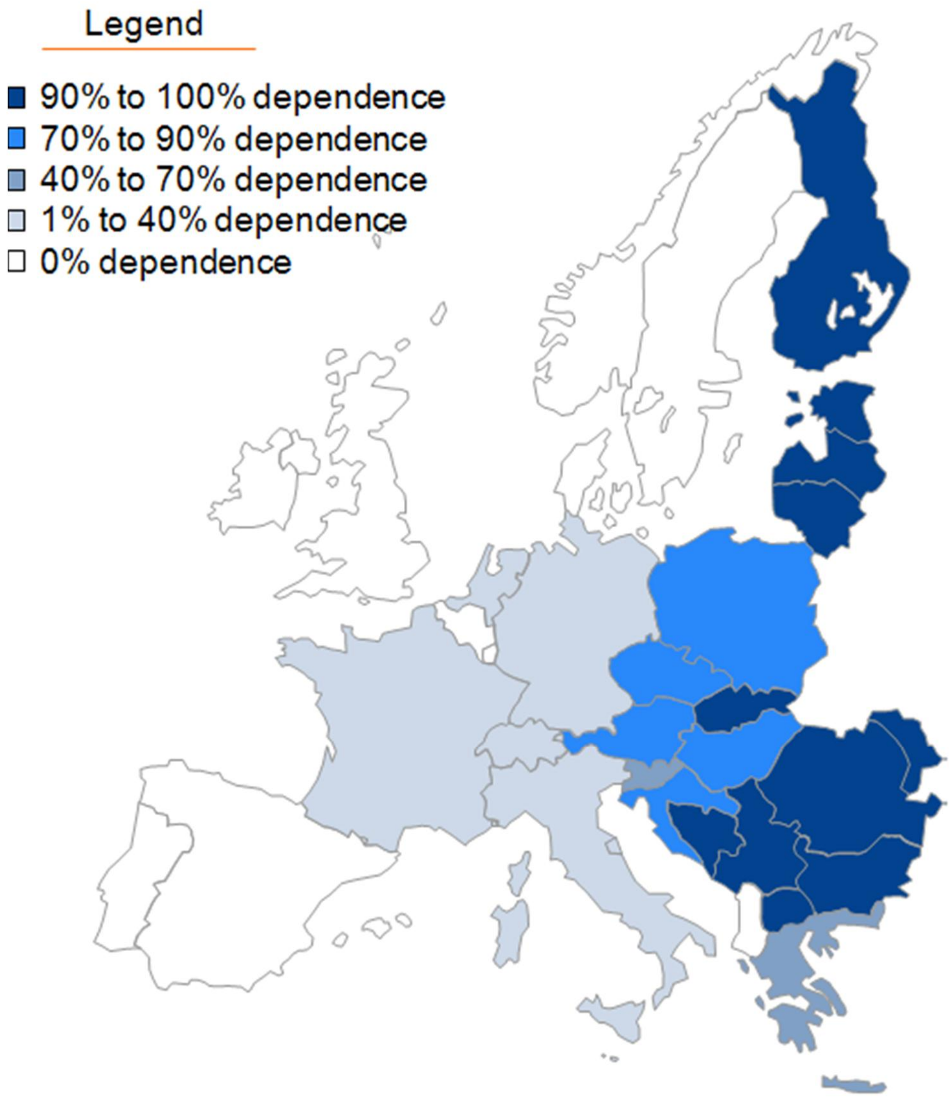
Following the Russian-Ukraine dispute the EU has introduced a new Regulation, EU 994/2010, which was adopted in October 2010. This requires Member States to review security of supply and take any necessary action; including cross-border cooperation if that is seen as the most sensible solution. The Regulation introduces a 'N-1' test for measuring security of supply, which according to the EC's initial impact assessment, Estonia passes. However, Finland and Lithuania did not. Some commentators believe that the whole Baltic region fails against alternative security of supply measures and the EC's final impact assessment may result in a different outcome form the initial results. So the Estonian authorities are right to be concerned about the current position and consider liberalising the gas market as one of the options to improve the situation.

However, improving security of supply can be achieved through different ways, including strategic storage, as used by various other countries in Europe (e.g. Hungary, Belgium). Some other countries put a public supplier obligation in place that requires suppliers to hold a certain amount of storage to cover a stated amount of demand. The option of building a small scale LNG facility is another method that could be employed.

Improving interconnection between the Baltic States may also improve the security of supply position, but only if the single supplier risk is also addressed. So whilst the Estonian regulator has identified the Balticconnector interconnection with Finland as an important solution to this issue, this would only be effective if other developments remove the single supplier risk. We note that the Balticconnector project has not yet received final approval and according to Eesti Gaas estimation, construction of the gas pipeline will not be started before 2013, at the earliest.

Improving security of supply through diversity is one of the key benefits of a liberalised market and we have considered this when constructing the scenarios for the future development of the Estonian gas market. As already noted, measures, such as a small scale LNG terminal, can be taken to improve security of supply outside of delivering a liberalised market, although such steps may not facilitate or result in a liberalised market.

Figure 1 – Countries reliant on Russian supplies (calendar year 2010)



Source: BP World Statistics 2011

Gas market liberalisation

The process of gas market liberalisation is intended to generate benefits for consumers through efficient and competitive market structures and processes. A pre-requisite for a liberalised market is a 'level-playing field' where no one market participant has an inherent competitive advantage over another. In order to achieve this, it is common for the activities of gas transportation, which constitute a natural monopoly, to be separated from production and supply. In a liberalised market, competitive pressures drive both producers and retailers to increase efficiency and reduce costs to be able to compete on price and service.

In addition to this, and in order for competition to develop, there need to be competing gas sources supplying the wholesale market and a number of companies that compete in the end user market. A competitive market will drive desirable behaviour from the market participants.

- Producers will look to develop new sources of supply at minimal cost and use existing sources more efficiently.
- Transporters and their users, Shippers, will aim to reduce supply and transport costs by negotiating new contracts and by using the network more efficiently.
- Suppliers to consumers will develop innovative products and services tailored to customer requirements to incentivise customer switching.
- All will aim to maximise the efficiency of their operations by optimising their business structure.

This should lead to benefits for consumers resulting in:

- efficient gas prices linked to supply/demand fundamentals;
- increased consumer choice;
- higher quality of service;
- improved security of supply;
- better consumer protection; and
- access to innovative products that are tailored to specific consumer needs.

At the EU level, a number of Gas Directives have been published and transposed into Member State's national legislation. The third Gas Directive, which became effective in March 2011, superseded the second Gas Directive and established common rules for the transmission, distribution, supply and storage of gas. The Directive mandates unbundling between network and competitive activities. As a consequence, the owner of a network, which is still active in production or supply, will have to at least legally and functionally unbundle the part of the company which owns the network, which will then be subject to external regulation.

Because of its isolated status and single source of supply, Estonia has been exempt from most of the major impacts of the gas directives. Accordingly, Estonia, along with Latvia and Finland, are granted derogation from Third Party Access to networks until they are directly connected to other states other than Latvia, Lithuania and Finland. Lithuania did not apply for derogation from the third Gas Directive and thus is expected to comply with its requirements.

In May 2011 the Estonian Government issued a draft Natural Gas Law to stakeholders, which includes the aim of ownership unbundling of Eesti Gaas by 2015. We understand that the expectation is for the draft law to be passed in late 2011 or early 2012, subject to satisfactory progress through Parliament. According to a letter that accompanied the draft law it is intended to liberalise the market through greater transparency, increase competition by allowing biogas to enter the market and establish the legal basis for building a terminal for LNG.

Gas prices in liberalised gas markets

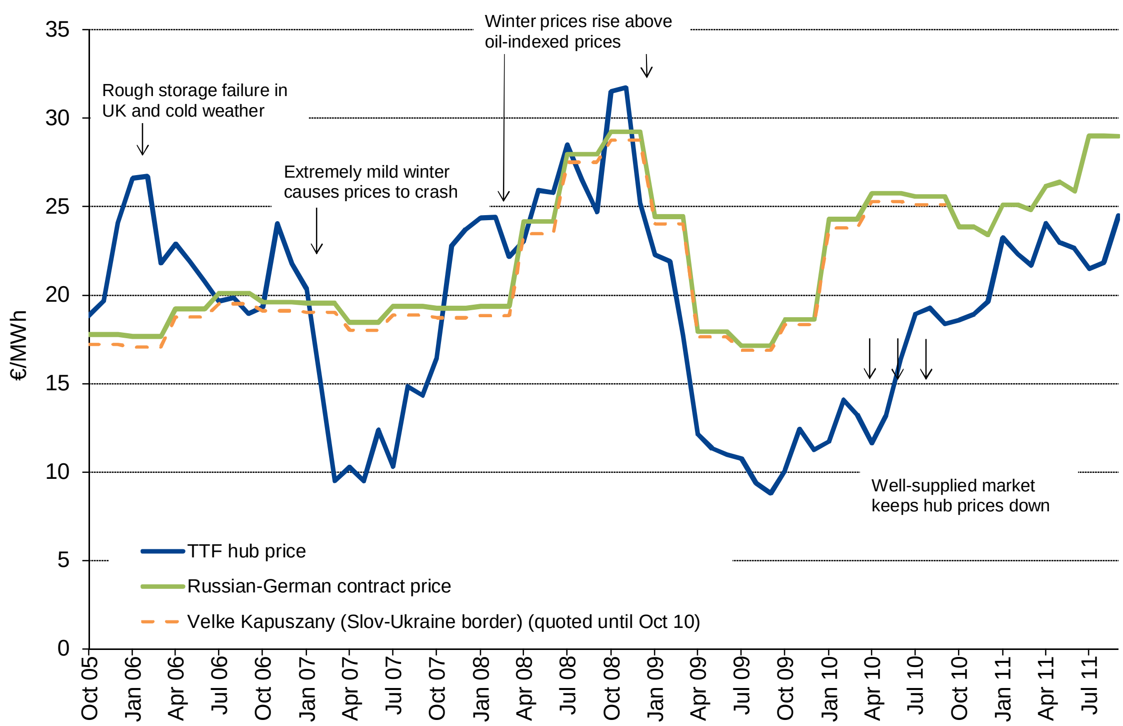
It is widely accepted that in order for gas market liberalisation to deliver benefits to end consumers it will be necessary for competition in gas supply sources to be established. The most likely form of an alternative supply source to the Estonian gas market will be via the delivery of LNG into the market.

However, critical to this is whether access to the global LNG market will bring benefits to the Estonian gas market as compared to the current situation, whereby gas prices are linked to oil products. Whilst there are clear benefits to improving security of supply through introducing a second source of gas to a market, we also need to consider the potential impact on the price of gas.

The development of the global LNG market in recent years has opened up the European gas market, once dependent on indigenous gas and imports through pipelines, to a more international market. Europe now competes with the US and Asia for LNG supplies. The liberalised gas markets of Europe are now supplied by a combination of indigenous supplies and imported gas via both pipelines and LNG.

The process of gas market liberalisation in Europe, particularly in Great Britain and in the Netherlands, has resulted in a number of trading hubs being established that set the spot price for gas. Figure 2 shows historical Dutch TTF hub prices alongside Russian oil-indexed contracts at Waidhaus on the German-Czech border and at Velke Kapuszany on the Slovakian-Ukrainian border. It clearly shows that the liberalised hub price has a greater degree of volatility than the oil-indexed prices, reflecting the supply/demand balance. However, it also shows that it is not always the case that hub price are lower than the oil-indexed price, despite such an assumption by many commentators.

Figure 2 – Historical hub price versus oil-indexed contract price (€/MWh)



Source: Heren

New infrastructure options

There are a number of possible developments that might help to mitigate security of supply concerns, increase gas demand and so encourage competition, although each by itself is not sufficient to result in a liberalised market:

- The potential construction of a LNG terminal located in Estonia, either at Paldiski or at Muuga, or elsewhere in the Baltic region, which would introduce a new gas supply source to the market.
- The potential construction of the Balticconnector pipeline to link the Estonian and Finnish gas markets.
- The development of new CCGTs in Estonia to replace the oil shale plants that will be decommissioned from 2020 to meet environmental regulations.
- The development of a regional gas market to include Estonia, Finland, Latvia and Lithuania under the Baltic Energy Market Interconnection Plan (BEMIP).
- Ownership unbundling of the transmission asset and sales function of Eesti Gaas to create a level playing field that will encourage new entrants into the market.
- A clear commitment to gas in the energy policies of the Estonian and other Baltic state's governments.

We have reviewed the costs associated with the new gas infrastructure options and compared them by both a levelised cost methodology and by a socialised levy on all consumption. Using the latter methodology Table 1 show the results of a local solution for Estonia through the development of a small scale LNG terminal compared to a regional solution of a medium sized LNG terminal and improved interconnection between the Baltic countries, including the Balticconnector. It also shows a more limited case of a medium sized LNG terminal and improved links only between Estonia and Latvia. The analysis shows that the regional approach provides the least cost to consumers and has the benefit of facilitating a more liberalised market than the local or Estonia-Latvia solutions would achieve.

Table 1 – Socialised economic impact of local and regional approach

Approach	Total costs, € mil	Additional cost for 20 years, €/1000m3	Additional cost for 20 years, $/1000m3	% increase over the current price
Local	125	8.9	12.2	2.0%
Regional	972	4.7	6.4	1.1%
Estonia + Latvia	412	8.2	11.2	1.9%

Source: Cedigaz, European Commission, Foster Wheeler, TGE gas, Pöyry analysis
Note: Actual costs to consumers may vary from illustrations above if regulators use a lower rate of return than the assumed 10% and longer depreciation periods.

However, it should be noted that funding this new infrastructure will most likely require either EC grants and/or EU funding, especially via the EIB. Our experience in such projects suggests that private financing will not be forthcoming for any of the potential LNG terminals and interconnectors across the region without such EU funds and support.

Estonia could transform its gas market by making a commitment to switch from oil shale power generation to much cleaner gas fired CCGTs. This would benefit the wider economy and signal higher gas demand potential, supporting the business case for the development of a medium scale LNG terminal.

LNG vs. pipeline

Even if the Estonian government and other Baltic States are prepared to fund the above infrastructure through a levy on consumers, for new gas supplies to be attracted we must see if LNG can compete against potential pipeline prices in the future.

In Table 2 we show various illustrative projections of likely market prices for both pipeline supplies from Russia and LNG supplies that could potentially compete if a LNG terminal was built. It should be noted that these are based on our Pöyry's Central scenario projections using an internally consistent set of assumptions. The actual outturn of prices is likely to be different. In addition, a different set of assumptions would produce a different set of projections but by using a scenario approach it does allow a comparison to be made based on the same set of assumptions and so provide an indicator of what future prices may be.

Table 2 – Illustrative gas source price projections, 2011-2020 (€/MWh)

Gas price in Estonia on current terms (80% oil indexed)	Projected price of new Russian pipeline gas developments	Medium size LNG price (delivered to Estonia)	Small scale LNG price (delivered to Estonia)
21 - 24	27 - 28	26 - 29	29 - 32

LNG prices here are based an average of a basket of illustrative LNG costs in the Atlantic basin, including such supply sources as Algeria, Nigeria, Egypt, Norway, and Trinidad and Tobago and the likely oil indexation associated with such supplies and the additional transportation costs to bring it to the Baltics. For the medium sized LNG project we assume a standard size LNG vessel is used. For small scale LNG we believe it will be delivered to Estonia in two stages: firstly to a large LNG regasification (regas) terminal in a large LNG tanker, and then reloading this LNG onto a smaller tanker and delivering it to the small scale LNG terminal. The Zeebrugge terminal in Belgium has such a facility and the GATE terminal in the Netherlands is considering investing in one.

Pipeline gas prices are derived from new supplies delivered from the Yamal region of Russia taking into account the standard oil indexation used in Gazprom contracts.

In addition, we have benchmarked the oil indexed gas price delivered using an estimate of the current Estonian gas contract price with Gazprom and our standard oil price projections used above.

Table 2 shows that based on the scenario assumptions LNG and new pipeline gas prices to Estonia are very similar over the long-term. Small scale LNG is expected to be more expensive and so to be less competitive with pipeline gas due to additional transportation costs involved. It also shows that the gas price in Estonia based on current terms is lower compared to the projected price of gas from new fields, due to easier availability and existing infrastructure for the production of the gas from established fields.

In considering how competitive the gas price could be it, is worth noting that LNG has higher margins compared to pipeline gas, so the LNG price can be reduced to a larger extent, especially when there is supply competition with sufficient demand to make LNG deliveries attractive. However, the global nature of LNG also means that the very high prices being paid in Asia could result in a significant proportion of spot LNG cargos not being available to the European market at the prices identified above. The extent of this will depend on how Chinese and other Far-Eastern gas demand grows in the next decade.

In summary, a small scale LNG facility would struggle to compete, on price, with Russian pipeline supplies. A medium size facility has the potential to compete, especially if there is sufficient new demand or market size to make the extra delivery costs worthwhile. That said, if the current Estonian Gazprom contract is renewed under the existing terms from 2015, LNG is unlikely to be able to compete.

Scenarios for development of the Estonian gas market

There are a number of potential developments that are being considered for the Estonian gas market. However, at the present time, none of these developments are certain and this introduces some scope for alternative futures. We have considered three possible alternative scenarios for the future development of the Estonian gas market as follows and as summarised in Table 3 below:

- ***Estonian supply security*** – where only a small scale LNG terminal is built in Estonia, there is little growth in the gas market, no Balticconnector is built and there remains a continued reliance on Russian gas. Ownership unbundling of Eesti Gaas is enacted.
- ***Estonian power switch*** – where a medium sized LNG terminal is built, there is a transformation of the gas market through the development of CCGTs as a displacement of oil shale in power generation. In addition there is a gas release programme established and ownership unbundling of Eesti Gaas is enacted.
- ***Regional liberalisation*** – where a regional Baltic market is developed alongside at least one medium sized LNG terminal, gas demand for competing suppliers is larger through access to all regional demand, there is ownership unbundling of Eesti Gaas and Balticconnector and other inter-state interconnectors are built. Under this scenario we also anticipate the liberalisation of all Baltic gas markets and the establishment of gas release programmes by the incumbents. We do not assume any transformation of the Estonian power market.

Table 3 – Summary of market development scenarios

Scenario	Ownership unbundling	LNG terminal	CCGT demand growth	Regional Market	Balticconnector & other inter-state pipes
Estonian supply security	✓	Small scale	×	×	×
Estonian power switch	✓	Medium size	✓	×	×
Regional Liberalisation	✓	Medium size	×	✓	✓

In all of the scenarios we have assumed that the recommended ownership unbundling happens, although it is recognised that this move may not be beneficial if other actions to address access to gas, such as new infrastructure and a larger market to attract new entrants, do not take place.

Under the Estonian supply security scenario the security of supply position is improved through the building of a small scale LNG terminal but the prices are too high to be competitive and so Estonian consumers end up having to pay for this through an additional levy.

Under the Estonian power switch scenario the Estonian market size is transformed making the building of a LNG terminal attractive to developers. LNG international prices could be competitive with pipeline supplies and the significant additional demand may allow contracts to be placed to bring LNG to Estonia. This also ensures prices are not artificially higher than they should be. The cost to the consumer should not be high with the LNG terminal financed privately, such financing being underpinned by sales to the new CCGTs. Security of supply will also be enhanced as the Estonian consumer will have access to LNG and Estonia will have a positive economic outcome from selling its processed oil shale and carbon credits.

The Regional Liberalisation scenario will deliver the widest demand to potential suppliers by providing them access to all consumers in Estonian and other Baltic gas markets. The costs of providing the required additional infrastructure is lower for all the regional consumers than if Estonia builds its own small scale LNG terminal and other benefits from liberalisation will occur, such as a regional gas trading hub. However, we recognise that there will be significant political and logistical barriers to the achievement of such a regional approach and that it may realistically be some way into the future. That said, a commitment from the Estonian government and the other Baltic States is more likely to result in EU funding to support the new infrastructure; so reducing the costs for all consumers.

Conclusions and recommendations

This study has considered potential scenarios for the development of further liberalisation in the Estonian and Baltic gas markets.

There are a number of issues associated with gas market liberalisation but experience has shown that on balance, open, competitive markets can deliver genuine benefits for consumers. The Government of Estonia has recognized these potential benefits and has initiated moves to liberalise the gas market through, for example, the introduction of the draft Natural Gas Law.

In order to achieve an effective liberalised market there are a number of key requirements:

- **First and foremost, access to competing sources of gas**.
- There is sufficient market size to attract new entrants and for them to recover their start-up costs.
- Non-discriminatory access to pipelines and other key infrastructure such as storage – this typically requires the separation of activities between transmission and supply as well as clear access rules.
- Regulation of the incumbent or dominant player to ensure it does not abuse its position through, for example, cross-subsidies or predatory activities in its pricing.
- A set of processes to establish market opening – these could include requiring the incumbent to auction some of the gas it purchases under long term contracts on the wholesale market.

Given the present reliance of the Estonian gas market on Russian gas supplied by Gazprom it is the first key requirement, competing sources of gas, that is most crucial. It should be noted that from a liberalisation and security of supply perspective reliance on

Russian gas per se is not necessarily a problem, although an obvious reason for concern. The difficulty for the Estonian market is that at present there is a single company supplying its gas. If independent Russian gas producers were allowed to export gas in their own right this could create sufficient competition in supply to precipitate a liberalised market in Estonia. Whilst there may be surplus gas available in Russia the prospects of this being exported by parties other than Gazprom are presently very remote.

In any event, concerns over security of supply are such that Estonian government policy to date has been aimed at restricting the role of gas in the national energy mix absent the achievement of a fully liberalised market.

There is, therefore, a strong congruence between the desire for a liberalised market and increased security of supply with establishment of alternative sources of gas the key linking factor. But for this to happen, the size of the market must be made attractive by either transforming the power market by switching from oil shale to gas-fired power generation or by delivering a regional market.

Establishing a small scale LNG terminal and ownership unbundling of Eesti Gaas will not achieve a competitive Estonian gas market and attract new sources of gas, although the small scale LNG would improve the security of supply position, with consumers required to pay levy to cover the investment.

Thus, we have a classic ‘chicken and egg’ dilemma whereby on the one hand the market cannot grow without alternative supplies and on the other hand a liberalised environment and attracting new supplies will be difficult to achieve without market growth.

We consider that the best way around this dilemma, and one that delivers the greatest benefits to the gas markets in Estonia and the wider Baltic region would be through the development of a Baltic gas market with a LNG supply and an interconnection between Estonia and Finland. However, we recognise that this approach will also have the greatest costs and will need to overcome some significant political and logistical challenges.

Regardless of whether a regional solution is achievable the Estonian authorities could deliver the switch in power generation and this should be sufficient to attract a medium sized LNG terminal. This would significantly improve the security of supply position at a cheaper cost than building a small scale local terminal but may not result in wider liberalised benefits, such as establishing a competitive gas trading hub.

Next steps

The Estonian authorities will first need to decide whether it is important to solve their security of supply concerns as a primary objective or to achieve a liberalised market. Whilst the former can be achieved by the latter there are alternative solutions that deliver security of supply but not a liberalised market.

In our view, whilst there will be some resistance from some of the stakeholders, it is clear from discussions with various parties that there is a potential willingness to invest in alternative supply infrastructure , i.e. gas interconnectors and a LNG regasification terminal to bring gas from alternative sources, if the conditions are appropriate. The priority is therefore to ensure that the appropriate signals are provided to the market in order to build momentum towards securing additional sources of supply and expanding the market size. These signals should include:

Increasing demand

- Encourage increased use of gas, especially in power generation, to increase the market attractiveness to new suppliers and new entrants. The most efficient way of achieving this is to commit to converting oil shale generation to new CCGT gas fired plants. This also has the additional benefits of lowering Estonia's carbon footprint.

Developing a regional approach

- Commit to removing barriers and promoting options that allow the successful integration of the Baltic States.
- In particular, assist in facilitating the development of the Balticconnector and resolving the location of a new regional LNG terminal using an agreed set of benefits criteria.

Improving competition between gas suppliers

- Mandate a gas release programme whereby a fixed percentage of gas imported by Eesti Gaas is either auctioned or sold at an agreed tariff or at a level to reflect international prices (say NBP or TTF linkage) on the wholesale market.

Unbundling strategy

- Full ownership unbundling is recommended but only as part of the wider package of liberalisation measures.

National gas policy statement

- Development of an Estonian Gas Sector Development Plan to encompass the above changes as a clear and open statement of the commitment to bring about change.
- The plan should also consider whether, for security of supply benefits, a small scale LNG terminal should be built in Estonia, although without other changes, such as significant increases in demand or size of the market, this will have to paid for by a levy on all consumers. If the wider liberalised market is achieved there is a risk that such a small scale LNG terminal would not be required, unless it forms the start point for the expanded regional facility.

For liberalisation to be successful it will require progress to be made across all of these, as achievement of one, on its own, will not achieve the expected benefits. The Estonian government does not have direct control over all of these factors, but where it does, it will need to engage with stakeholders to bring about a common understanding and acceptance of the changes being made. For example, it should look to avoid the type of legal disputes happening in Lithuania in response to its new unbundling law.

It will also be important, in delivering the above actions, that all parties recognise the window of opportunity that exists with the gas contracts with Gazprom coming to an end in 2015. Establishing and delivering a liberalised agenda and plan, even if the required infrastructure has not all been completed before then, will improve the negotiating position and provide a framework for long-term success for the Estonian gas market.

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1. INTRODUCTION

Pöyry has been commissioned by Elering to assess the potential for gas market liberalisation in Estonia. In the course of this work we have interviewed a large number of industry stakeholders in order to understand the views of market participants and to develop a practical approach to the planned liberalisation of the Estonian gas market.

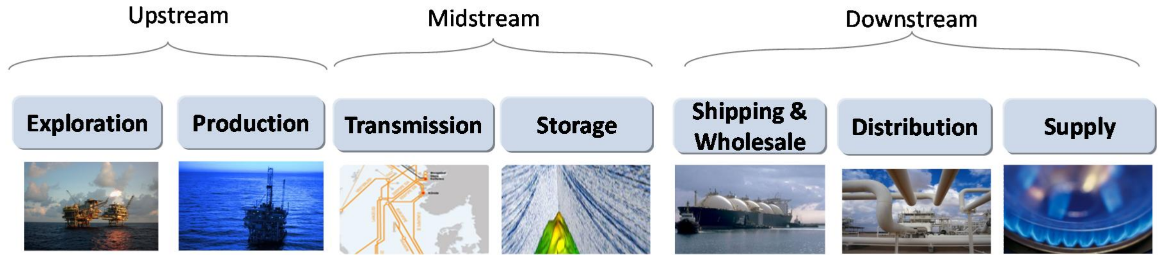
The Estonian gas market is, by international standards, small in terms of its annual consumption and peak day gas requirements. There is currently very little gas used in power generation in Estonia, although gas does have a larger share in CHP and district heating schemes. The Estonian gas transmission network is connected to Russia at Narva and Värska, and to Latvia at Karksi. Even though connection at Narva has had periods out of operation due to its poor condition, and currently has limited availability, there is currently sufficient capacity in the transmission network to meet all annual and peak gas demands.

The major player in the Estonian gas market is Eesti Gaas, which owns the transmission system assets, the majority of the distribution assets and is currently the sole wholesaler of gas. Eesti Gaas is also the dominant supplier of gas and supplies gas to over 90% of the retail market. The sole importer of gas into Estonia is Gazprom. Flexibility is provided to the Estonian gas market via the Incukalns underground storage facility in Latvia, which is currently contracted solely to Gazprom.

1.1 The gas market chain

In order to understand the process of liberalisation it is necessary to understand the structure of the gas market and the roles carried out by its main participants. Figure 3 illustrates the gas market chain, showing how upstream activities such as exploration and production start the chain which then progresses downstream to distribution and supply.

Figure 3 – The gas market chain



The main gas market participants are summarised below:

- **Producers** explore and drill for gas and send their gas production to market via onshore transmission pipelines or via offshore pipelines to entry terminals. Some producers may liquefy their gas and transport it to market via liquefied natural gas (LNG) tankers. Liquefaction is achieved through super cooling of methane gas to minus 162°C.

- **Transmission system operators** ('TSOs') operate the high pressure transmission system, either their own or on behalf of the network owner. The transmission system carries gas at high pressure from the point of production or system entry point (e.g. at a country's border) to the system exit points, including large end users, interconnectors, storage facilities and offtake points to the lower pressure distribution systems.

- **Shippers** buy gas from producers and/or traders at the system entry points or at a traded hub and use the gas transmission system and distribution network to transport the gas to the supply point.
- **Storage operators** take gas into their storage facilities on behalf of shippers, when demand is low and/or prices are low. They and release it, as instructed by the shippers, when demand and/or price is high. There are generally three types of underground storage: depleted gas fields, salt cavities and aquifers. LNG tanks can also work as storage, but are typically smaller in terms of capacity and so are normally used for assisting on peak demand days or for within day flexibility provision.
- **Distribution network operators** offtake the gas from the high pressure transmission system and deliver it to the customers via low pressure pipelines.
- **Suppliers** provide marketing and billing services and form the link between the shippers and the end users. Suppliers to the domestic market usually have more stringent licence conditions than those supplying the industrial and commercial market.
- **End users** are the customers who actually consume the gas. They include everyone from homeowners to power stations. The various consumer segments have different regulations applied to them. Many suppliers will limit the number of market sectors they operate in order to reflect the required expertise and economies of scale needed for the service offerings.

1.2 Structure of this report

This report contains three main elements:

- Background information on the Estonian market and the global context that may influence potential new supplies, split as follows:
  - in Section 2 an overview of the Estonian gas and electricity markets; and
  - in Section 3 an overview of the global and European gas market.
- Consideration of the options for liberalisation, including the regional approach, and scenarios for achieving liberalisation:
  - Section 4 first summarises the background research into the liberalisation process, market design, regulatory structures and ownership unbundling that a liberalised market should employ before then considering potential options available within the Estonian sphere of direct influence;
  - in Section 5 we discuss regional opportunities, including the interconnection of Estonian gas market and a potential LNG terminal in Estonia; and
  - in Section 6 we review whether LNG could compete with pipeline supplies before considering the implementation scenario options, the timelines for various initiatives and some risks and commentary from interviews held with stakeholders before outlining the next steps and way forward to liberalise the Estonian gas market.
- In the Annexes we provide some background analysis and assessment of the liberalisation process, which includes:

- Annex A – a description of the liberalisation process, with an appraisal of factors that may affect the implementation of liberalisation, changes that could increase the chances of a successful liberalisation;
- Annex B – an outline of high-level market design issues, including network access, wholesale markets, and retail competition; and
- Annex C – a discussion of the most appropriate regulatory structures to oversee a liberalised gas market, including regulatory tariff structures.

In Annex D there is a glossary of industry specific terms and a table of the conversion rates used in the report.

Annex E has some background on Pöyry, including its energy market reports and modelling capabilities.

1.3 Conventions

Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

All monetary values quoted in this report are in either GB pounds sterling or euros in real 2010 prices, unless otherwise stated.

Abbreviations are used within this document to aid reading. The full text of the abbreviation is used where it is first encountered and thereafter we revert to using the abbreviation.

The exceptions to this are physical and economic units which take their usual meaning, some of which are described below.

- ‘mcm/d’ or ‘mcmd’ – millions of cubic metres per day;
- ‘bcm’ – billions of cubic metres;
- ‘bcm/a’ – billions of cubic metres per annum
- €/MWh – euros per Mega-Watt hour; and
- p/therm – pence per therm.

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2. THE ESTONIAN ENERGY MARKET

This section of the report provides background information on Estonia and the East Baltic and Estonian energy markets.

2.1 Overview of Estonia

Estonia is a democratic parliamentary republic with a population of 1.34 million. Estonia is a member of the EU and adopted the Euro on 1 January 2011 becoming the 17th member of the Euro area. Of the ex-Soviet Union countries Estonia has the highest GDP per capita, Estonia is listed as a high-income economy by the World Bank and is a high-income OECD member.

2.1.1 Economy

Table 4 below presents a summary of the key indicators of the Estonian economy. The figures highlight that the Estonian economy saw a return to growth of 3.1% in 2010 following the economic downturn experienced in 2008 and 2009. This return to growth led to an increase in GDP compared to 2009, however the 2010 level remains below the 2007 level.

Table 4 – Key indicators for the Estonian economy

	2003	2004	2005	2006	2007	2008	2009	2010
Population as of 1 January (million)	1.36	1.35	1.35	1.36	1.35	1.34	1.34	1.34
GDP at current prices (billion EUR)	8.7	9.7	11.2	13.4	15.8	16.1	13.9	14.5
Real growth of GDP (%)	7.6	7.2	9.4	10.6	6.9	-5.1	-13.9	3.1
GDP per capita at current prices (EUR)	6430	7178	8306	9966	11797	12014	10342	10821
Unemployment rate (%)	10.0	9.7	7.9	5.9	4.7	5.5	13.8	16.9

Source: Eurostat

2.2 Overview of the East Baltic energy markets

The following section presents a summary of the gas and electricity markets in the Baltic region.

2.2.1 East Baltic gas markets

Under the second energy directive[1] which was in place until March 2011, the East Baltic countries (Estonia, Finland, Latvia and Lithuania) were covered by full derogations. However, with the implementation of the third energy directive, the EU set out explicit

[1] 2003/55/EC

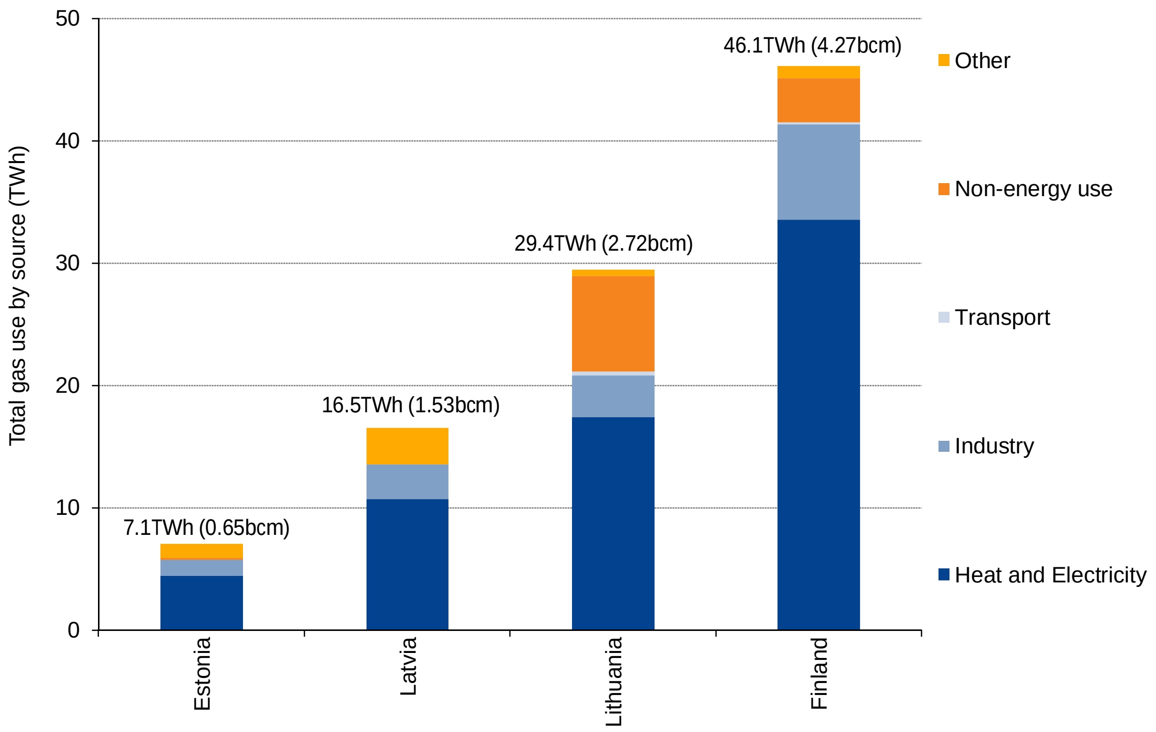
derogations for Finland, Latvia, and Estonia, but not for Lithuania. The derogations for Estonia, Finland, and Latvia will lapse once they are 'directly connected to the interconnected system of any Member State other than Estonia, Latvia, Lithuania and Finland'[2].

If the East Baltic countries continue to develop their markets in line with their own published priorities, they will be required to apply the provisions of the third energy directive during the next three to five years. Further details on the energy directives are provided in Section A.4.2.

2.2.1.1 Role of gas

Total gas consumption by Estonia is the lowest amongst all Baltic States, see Figure 4. Latvian consumption is the second highest with 1.5bcm. Lithuania consumes 2.7bcm of gas; about 40% of this amount is used for electricity generation. Gas consumption in Lithuania has increased significantly since the beginning of 2009, due to decommissioning of the Ignalina nuclear power station. Finland consumes most gas at around 4bcm, mainly for heat and electricity generation and for industrial use.

Figure 4 – Total gas consumption by source in 2009



Source: IEA, Latvian, Lithuanian statistics

2.2.1.2 Supply of gas

All four East Baltic countries are entirely dependent on gas imports from Gazprom. This is a result of the historic development of the gas market within the region such that the current infrastructure does not allow gas purchases from elsewhere to be delivered

2 Article 49(1) of Gas Directive 2009/73/EC

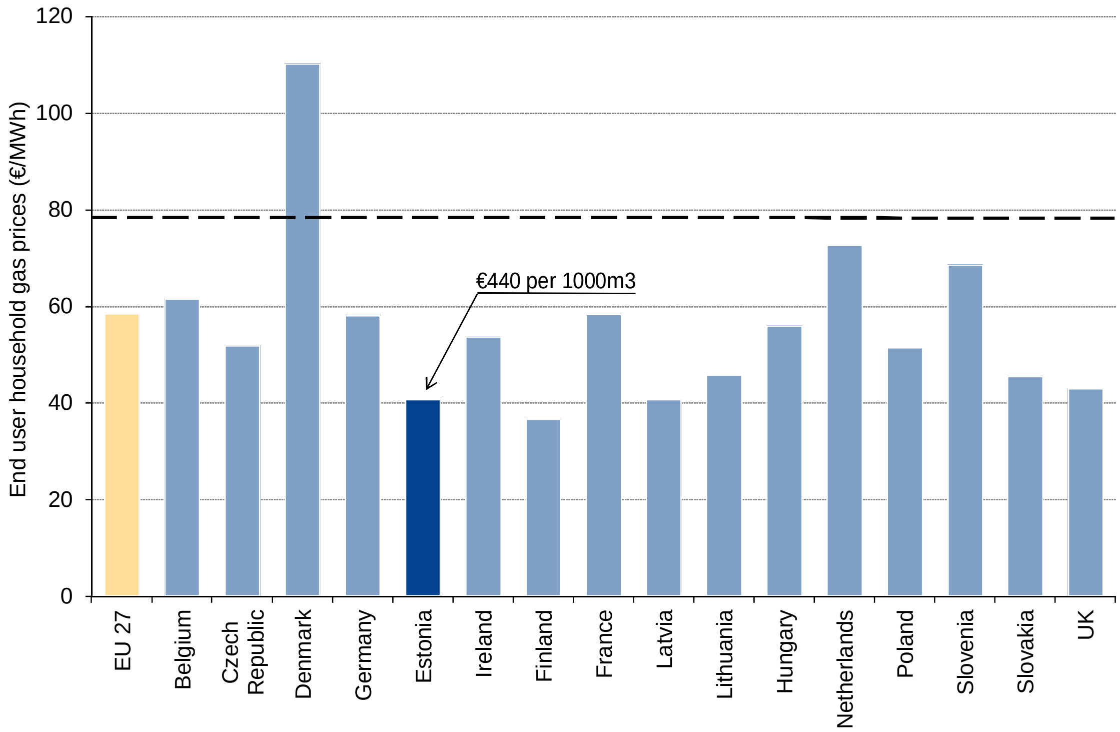
physically into the markets. The result is a continued dependence on physical gas supplies and commercial terms from Russia.

The development of the gas markets has resulted in a single incumbent operator within each of the countries. These are:

- Lietuvos Dujos in Lithuania;
- Latvijas Gaze in Latvia;
- Eesti Gaas in Estonia; and
- Gasum in Finland.

Gazprom supplies the gas to all four countries and is, in addition, the major shareholder (partnered with E.ON) in three of the four national gas companies; the exception being Gasum. Gas is supplied under long-term contracts, which in the case of Estonia are due to expire in 2015. Despite being dependent on one source for their gas the end-user gas prices for Estonia, Latvia and Lithuania are all lower than the EU average, which is shown in Figure 5. Note that the gas prices for households include any taxes charged by the Member States, which in particular explains the very high number for Denmark.

Figure 5 – End-user, household gas prices in various EU countries, April 2011



Note: Prices relate to domestic natural gas consumption under 15MWh/a; prices for Finland relate to consumption under 12.5MWh/a; prices include all applicable taxes
Source: Europe's Energy portal, Statistics Finland

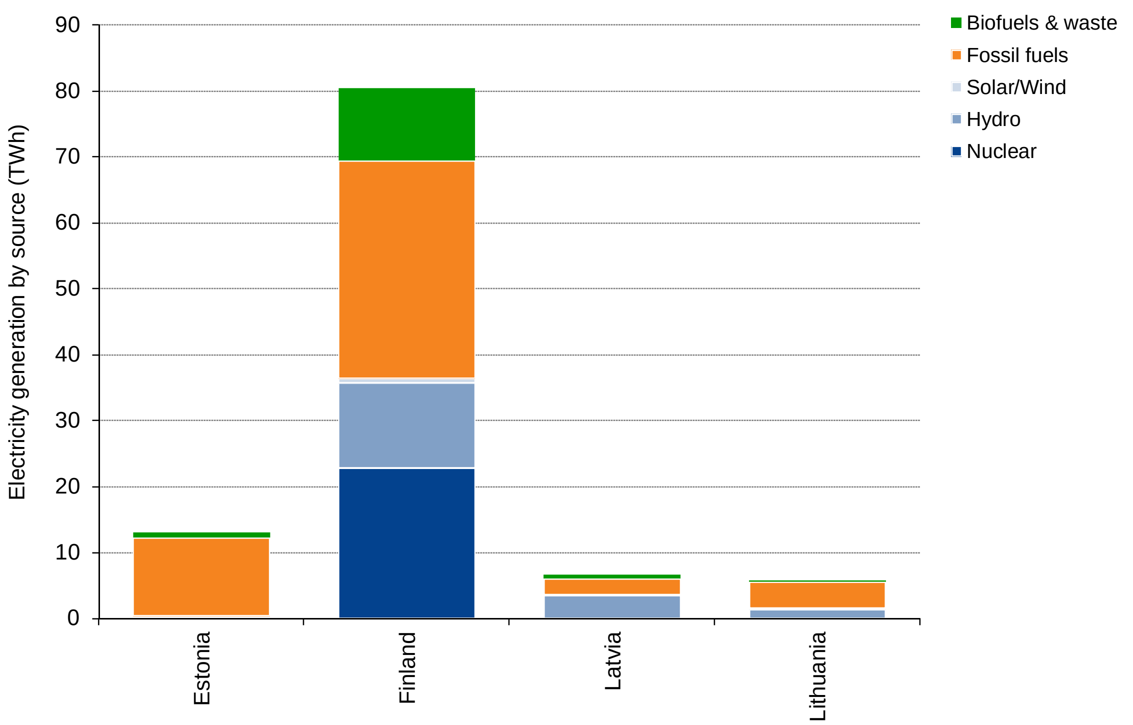
2.2.2 East Baltic electricity markets

The East Baltic electricity market is relatively small with approximately 3 million customers. Consumption in the region is approximately 27TWh/a with a peak demand of around 5GW. Figure 6 shows that Finland generates far more electricity than Estonia, Latvia and Lithuania, around 80TWh/a. In 2010 Latvia and Lithuania generated similar amounts of electricity, 6.6TWh and 5.7TWh respectively, whereas Estonia generated 13TWh.

Transmission capacity between countries within the region is limited; with a single interconnector connecting Estonia to Finland thus giving access to the Nord Pool spot electricity market. However, transmission interconnection with Russia is well developed as a result of the development of the North-West Russian grid during the Soviet Union era. There is concern across the region that it is over-dependent on Russia; and although there have been no serious supply incidents (unlike recent incidents in the gas market) there is a political desire within the region to reduce this dependency.

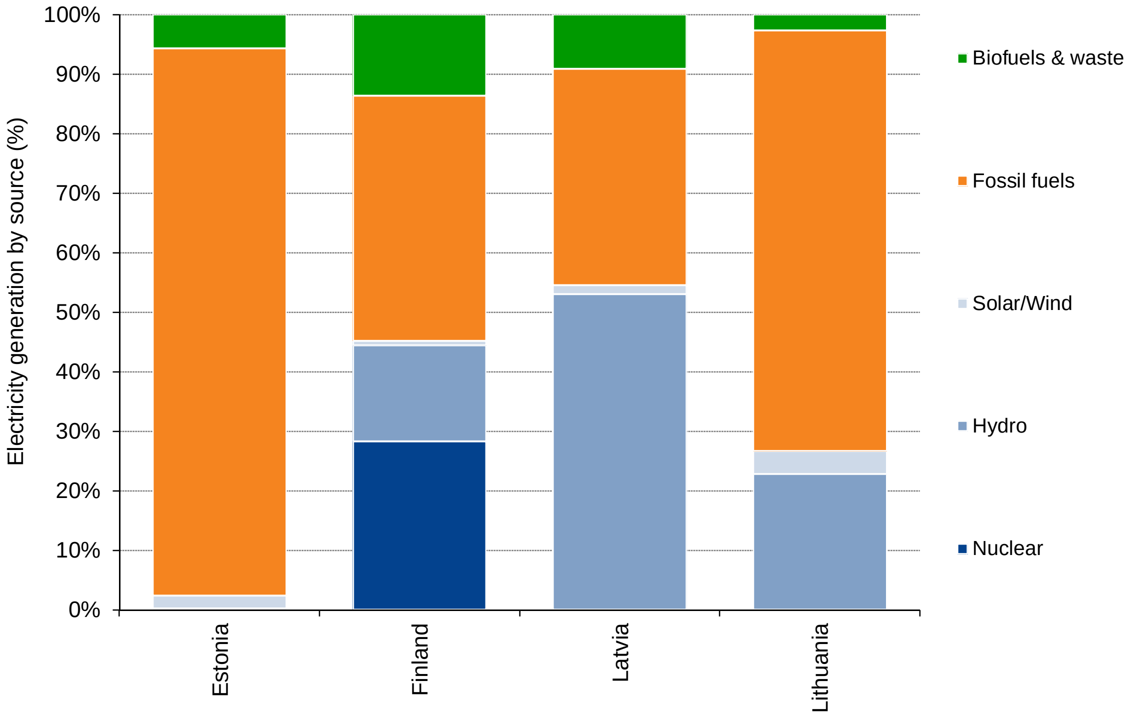
Different sources of electricity generation are represented disproportionately in different states. For example, most of electricity generated in Estonia is from solid fuels, in particular oil shale. Latvia has a more balanced pattern of generating electricity from gas and hydro power. Lithuania generated its electricity mainly from nuclear fuel. In 2009 Ignalina nuclear power station in Lithuania was decommissioned and its capacity was substituted by gas fired power plants, which has changed the percentage ratios in favour of natural gas. Finland generates similar amounts of electricity from gas, nuclear, solid fuels, petroleum derivatives and biomass, see Figure 7.

Figure 6 – Power generation in Baltic States by source in 2010



Source: IEA, LitGrid, Latvian Ministry of Economics

Figure 7 – Power generation in Baltic States by source in % in 2010



Source: IEA, LitGrid, Latvian Ministry of Economics

2.3 Estonian energy markets

The Estonian Competition Authority (CA) is responsible for energy regulation in Estonia. The responsibilities of the CA include the approval of prices for electricity and gas network services, approval of district heat prices, approval of marginal prices of gas sold to household customers by the market, and monitoring both the adequacy of prices for the balance energy sold by the transmission system operator (TSO) and the conditions of balance contract.

As mentioned previously, Estonia has an exemption from the ownership unbundling requirements of the third energy package until the gas system becomes interconnected with another non-Baltic EU member. In addition, Estonia has also negotiated a transition period for full electricity market opening. This will take place in two stages; the first stage was recently completed in 2010 and involved opening the market for all large customers (35% of the market), whilst full market opening is required by 2013.

2.3.1 Future trends in the Estonian market

The Estonian government has set out its views on how Estonian energy use will develop until 2020 as part of the modelling for the National Renewable Energy Action Plan. Targets are set out in the context of meeting the EU target of 25% of energy consumption to be supplied from renewable energy by 2020:

- Final energy consumption will increase by 13.4% compared to the average final energy consumption from 2005 to 2008.
- Electricity consumption will increase by 30% compared to the average of 2005 to 2008 (not including the energy sector).

- Heat consumption will decrease by 8% compared to the average of 2005 to 2008 (not including the energy sector).
- Consumption of fuels will increase by 18% compared to the average of 2005 to 2008 – the consumption of motor fuels will increase by 18% (not including the energy sector).
- In the industrial sector and agriculture, energy consumption will increase by 27%; in transport it will increase by 15%; and in the business and public service sectors and households it will increase by 6% compared to the average from 2005 to 2008.
- Energy consumption in the energy sector will decrease by 3%.

2.4 Estonian gas market

The Estonian gas network has two interconnections with Russia (at Narva and Värska) and one interconnection with Latvia (at Karksi). Of these connections only the Värska and Karksi connections are operational; the Narva connection being typically closed due to congestion in the Russian side network. In total the three pipes represent a technical daily flow capacity of 11.5mcm/d.

Gazprom has significant influence over the gas market; being the sole importer of gas and a major shareholder in both the gas transmission system owner and operator (AS EG Võrguteenus) and the largest supplier of gas in the Estonian market (AS Eesti Gaas). In the distribution market Eesti Gaas has a market share of about 92% which is equivalent to approximately 42,000 customers. The remaining distribution operators share 76mcm/a in total gas sales and have fewer than 1000 customers.

2.4.1 Overview of the Estonian wholesale and retail gas market

From July 2007 the Estonian gas market has been fully opened to competition. However, due to the dominance of Gazprom-owned Eesti Gaas in the Estonian market, and the wider dominance of Gazprom (all the gas sold in Estonia is bought from Gazprom and imported by Eesti Gaas) there is currently no competition in the wholesale market.

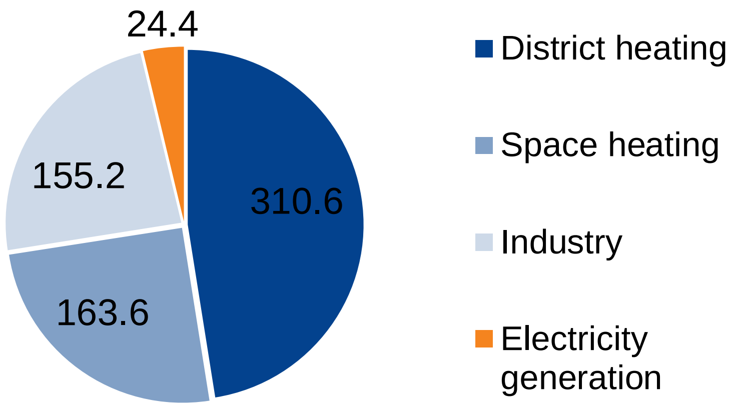
In 2009 natural gas consumption in Estonia totalled 655mcm; of which almost half was used in district heating based applications (310mcm). The remainder was divided between space heating (by domestic and commercial customers (163mcm) and industrial process needs (155mcm). Only 25.4mcm was used for electricity generation, see Figure 8 and Table 5.

Table 5 – Key gas statistics for Estonia

Year	Proportion of market open to competition (%)	Consumption (mcm/year)	Number of retail companies with >=5% market share	Number of customers who switched supplier	Ownership unbundled TSOs	Net load flows (imports – exports, GWh)
2009	100	655	1	1539	0	6.1

Source: Estonian Electricity and Gas Market Report 2009, Estonian Competition Authority

Figure 8 – Natural gas consumption in Estonia in 2009 (mcm/a)



Source: Estonian Electricity and Gas Market Report 2009, Estonian Competition Authority

2.4.2 Pricing

Prices in the wholesale market are negotiated, and are not subject to approval by the regulator. Eesti Gaas controls 92% of the retail market directly and the remaining 8% indirectly through being the sole supplier to the gas resellers. Because of this market dominance, prices in the retail sector are regulated by the Competition Authority. The retail price formula for Eesti Gaas is calculated by using a gas import price (the import price being linked to both heavy and light fuel oil prices for the preceding 6 months) plus a sales margin which is approved by the regulator.

Table 6 overleaf presents a selection of key statistics for the retail gas market in Estonia. The table shows that gas consumption had been fairly constant over the last 5 years until 2009, which saw a 15% reduction. This fall in consumption coincided with an increase in the number of customers switching gas supplier.

2.4.3 Gas network capacity

Figure 9 shows a map of the Estonian gas network. Gas to Estonia is supplied from two sources: via Narva and Värska from Russia and via Karksi from Latvia. Russia meets most of the Estonian gas demand in the summertime, whereas winter demand is met by the gas from Latvian underground storage facility, located in Incukalns.

The gas network in Estonia seems to be in a position to cope with future increases in demand. Currently annual demand and peak day demand are well below system capacity, which means that there are no capacity constraints. According to the annual Estonian electricity and gas market report from 2009, the total transmission capacity is approximately 11mcm/d while peak demand in 2009 was approximately 4.4mcm/d and is projected to grow to about 5.5mcm/d by 2016 according to the transmission operator Võrguteenus.

Figure 9 – Map of Estonian gas network

Source: IEA

Table 6 – Retail market statistics for Estonia

	Consumption (mcm)	Number of companies with market share >5%	Market share of 3 largest gas suppliers (%)				Customers switching suppliers
			Generation	Large industry	Medium industry	Small business and households	
2004	749	1	100	100	100	98	0
2005	774	1	100	100	100	97	0
2006	794	1	100	100	100	97	0
2007	796	1	100	100	100	93	28
2008	748	1	100	100	100	91	1109
2009	635	1	100	100	100	92	1539

Source: Estonian Electricity and Gas Market Report 2009, Estonian Competition Authority

2.5 Gas security of supply

Within the Estonian context there are two main areas of concern relating to gas security of supply:

1. Single supplier risk; and
2. Physical infrastructure risk.

The single supplier risk was highlighted to Pöyry by the Competition Authority and other Estonian government bodies, who believe that the majority of gas coming from a single source (i.e. Russia) represents a significant security of supply risk, as the single supplier is free to impose prices on Estonia and take decisions without the consent of key stakeholders. It also is also felt that the single supplier does not have the appropriate incentive to develop sufficient supplies to ensure that there is no interruption of supplies to Estonia when compared to its other supply obligations to Europe. In discussions with these stakeholders it is clear to Pöyry that this concern is a major factor in driving their considerations for the future role of gas in the energy supply mix and this concern is shared by all of the Baltic countries.

Estonia is not the only country to be dependent on Russian gas, as can be seen in Figure 10. The rest of the Baltic region and much of South-East Europe have a greater than 90% dependency followed by Eastern Europe at over 70% dependency. This dependency was highlight for real in the 2009 dispute between Russia and Ukraine, which is reviewed in more detail in Section 2.5.2 below.

The physical infrastructure risk comes from concerns that various critical assets cannot match peak demand in a very cold winter. Whilst it is not the purpose of this study to analyse security of supply we have noted concerns associated with potential interruptions from the Latvian storage facility at Incukalns in winter time, which could result in no additional gas being available from Russia because of constraints within the wider Russian supply network and/or its own reliance on Incukalns to match demand in the neighbouring parts of Russia. There are also concerns that Incukalns is a bottleneck. According to numbers provided by Elering, the maximum output capacity at Incukalns is 24mcm/d and the three countries directly dependant on it have peak consumptions of 11mcm/d in NW Russia, 11mcm/d in Latvia and 6mcm/d in Estonia. If peak demands coincided in these countries then there would be a 4mcm/d shortfall. However, it should be noted that no such shortfall has occurred to date, although it may have been close on some occasions.

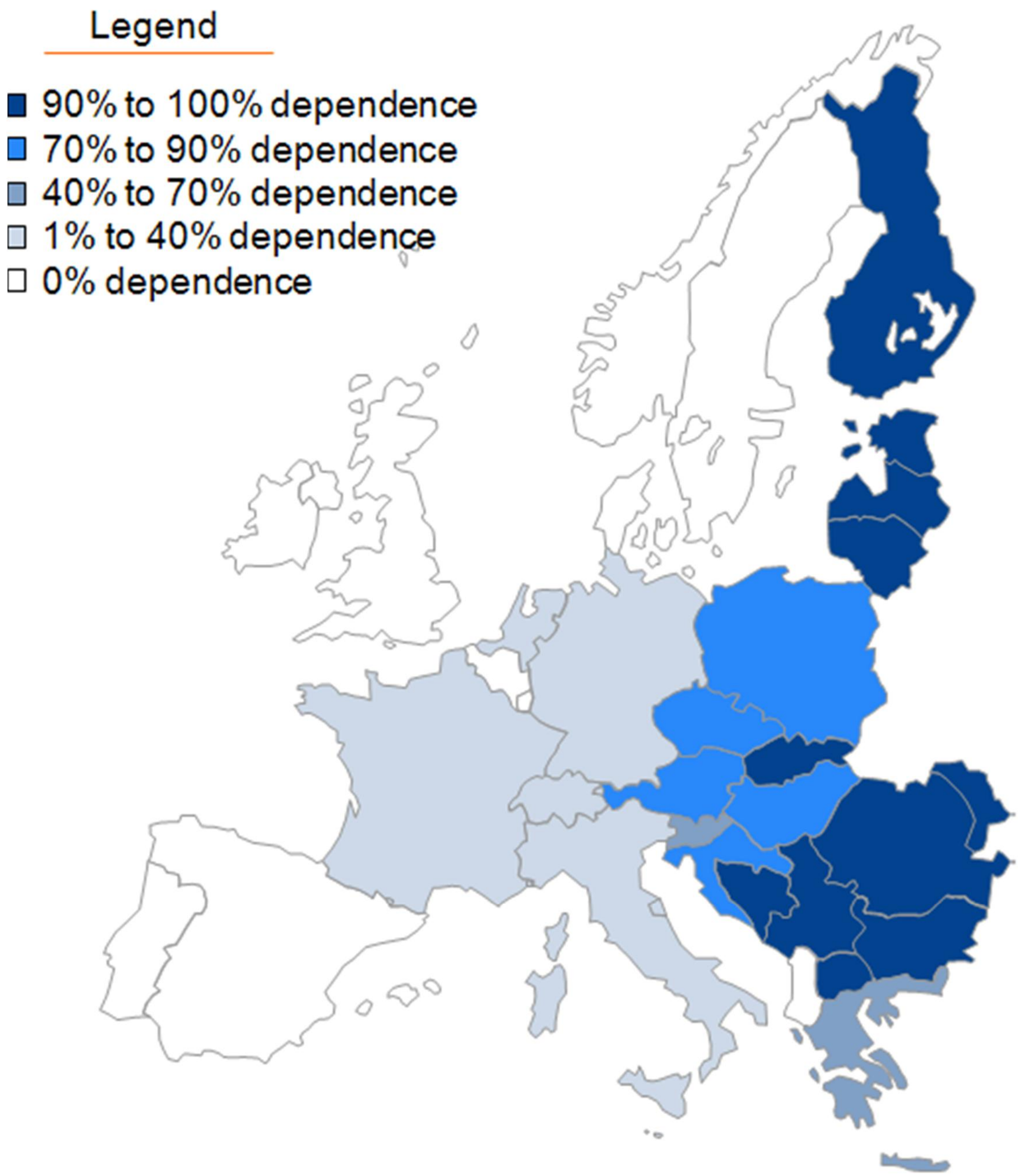
2.5.1 Options to improve security of supply

Improving security of supply can be achieved through different ways, including strategic storage as used by various other countries in Europe (e.g. Hungary, Belgium). Some other countries put a public supplier obligation in place that requires suppliers to hold a certain amount of storage to cover a stated amount of demand. Small scale LNG could be another option to improve security of supply and we discuss this further in Section 4.3.

Improving interconnection between the Baltic States may also improve the security of supply position but only if the single supplier risk is also addressed. So whilst the Estonian regulator has identified the Balticconnector interconnection with Finland as an important part of the solution to this issue, this would only be effective if other developments remove the single supplier risk. We note that the Balticconnector project has not yet received final approval and according to Eesti Gaas estimation, construction of the gas pipeline will not be started before 2013, at the earliest.

As shown in Annex A.2.4, improving security of supply through diversity is one of the benefits of a liberalised market and we will address this again when we develop our scenarios available to Estonia for moving forward in Section 6.3. In the meantime, we understand that Estonia has put in place demand side measures in case of a gas supply deficit that would see electricity generation in Tallinn and Narva switch to alternative fuels.

Figure 10 – Countries reliant on Russian supplies (calendar year 2010)



Source: BP World Statistics 2011

2.5.2 Russian-Ukrainian 2009 dispute

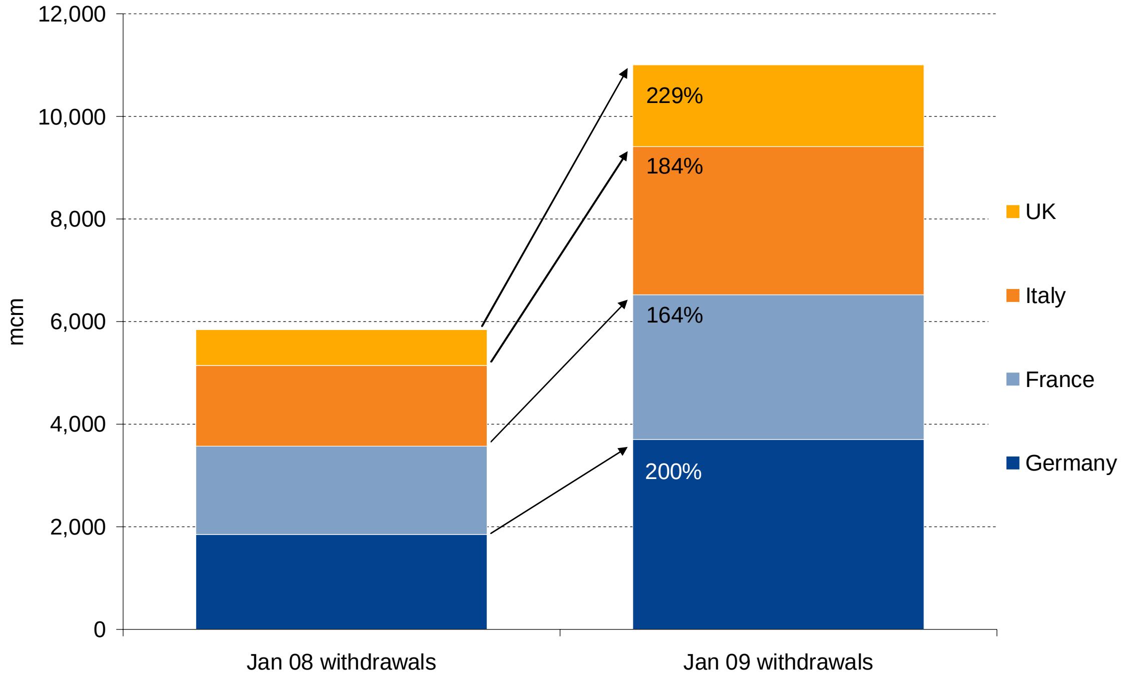
Much of the concern over secure gas supplies stems from the dispute in January 2009 between Russia and the Ukraine. Following an escalation caused by Ukrainian disagreements on the gas prices being charged by Russia and the transit fees relating to exports into Europe, Gazprom first restricted and then completely cut-off all gas supplies into and through Ukraine. The dispute lasted for 20 days and resulted in shortages of gas in many countries in Southern and Eastern Europe, see Figure 11.

As a result, Germany, France and Italy were all called upon to access gas from storage and many pipelines around Europe changed their normal direction of flow from east-to-west, to, west-to-east. Figure 12 shows the increase in withdrawals from German, French, Italian and GB storage facilities in January 2009 as compared to the same period in 2008. The gas demand in each state was similar in both the month of January 2008 and January 2009, so the huge increase in withdrawals from storage was clearly the result from the disruption of Russian gas flows.

Figure 11 – Countries affected by Ukrainian-Russia dispute January 2009

Source: BBC

Figure 12 – Withdrawals from storage during January 2008 and 2009



Source: Eurostats

2.5.3 Economic impact of unserved energy

When a situation such as the Russian-Ukrainian dispute results in gas supplies being disrupted there will be an economic impact felt by the countries and their consumers. It is not within the scope of this study to estimate any potential economic impact of unserved energy in Estonia, however we outline here a description of a standard methodology that Pöyry and others have used when analysing such an impact.

The methodology involves an estimation of the loss of Gross Value Added[3] (GVA), which can be used as a proxy for the effect of unserved energy – i.e. the economic impact of a loss of load. The main features of this approach are that:

- interruptions are assumed to follow a ranking of industries by GVA/mcm (adjusted so that energy intensive industries are interrupted first); and
- indirect or knock-on effects on upstream and downstream industries are also included.

The analysis assumes a simple, proportionate relationship between gas use in a sector and its GVA potential, with similar relationships across the supply chain. In general, these estimates are likely to represent an upper bound on the GVA impact as they do not account for the impact of stocks or flexibility in delivery profile that may mitigate some of these effects. The analysis does not account for the consequential reduction of electricity demand and therefore gas-fired generation. However, the GVA analysis does give an

3 ONS definition: GVA (value of goods and services less the value of the products used to make them) + taxes on products – subsidies on products = Gross Domestic Product. GVA is therefore a measure of the commercial value added to the whole economy.

indication of the orders of magnitude involved when there is an involuntary curtailment of supplies. Finally, the GVA figures are converted into a value of lost load (VOLL) to facilitate comparison with historical gas prices.

2.5.4 EU Regulation on security of gas supply

Another factor to consider is the new EU Regulation on gas security of supply, which all EU Member States have to adopt. The EU Parliament and Council of Ministers passed the Regulation in October 2010[4], in an attempt to correct certain inadequacies in the previous directive[5], in particular the lack of coordination between Member States which was evident in the January 2009 Russian-Ukrainian gas crisis.

The Regulation repeals Directive 2004/67/EC and establishes provisions aimed at safeguarding security of supply, establishing a principle of solidarity at EU level when considering emergency planning and clarifying the roles that Member States, authorities and the Commission will perform.

The EC believes the new Regulation will improve the framework for investment in new cross-border interconnections, new import corridors, reverse flow capacities and storage facilities.

The Regulation requires each Member State to appoint a Competent Authority that will be responsible for:

- establishment of Preventative Action Plans;
- establishment of the Emergency Plan;
- regular monitoring of security of gas supply at national level; and
- updating the plans outlined above at least every two years.

The Regulation requires the Competent Authority to ensure by 3 December 2014 that in the event of a disruption of the largest gas supply infrastructure, the remaining infrastructure (N-1) has the capacity to deliver:

- the volume of gas necessary to meet total demand for a single day of exceptionally high demand (calculated as statistically occurring every twenty years);and
- normal functioning of services to domestic households for a period of 30 days under average winter conditions.

The Competent Authority should also ensure that demand from domestic households can be satisfied during a period of exceptionally high gas demand (calculated as the coldest period statistically occurring every twenty years) when all infrastructure is available.

The Regulation lays down the criteria under which an emergency will be declared and also outlines the procedures that will need to be followed in an emergency situation. In an emergency, the Commission will be responsible for coordinating the actions of the Competent Authorities and market based instruments should be given priority to mitigate the effects of any supply disruption.

The Regulation recommends that joint emergency plans at regional level should be established where possible and necessary. To strengthen the solidarity between Member

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[4] Regulation EU 994/2010

[5] 2004/67/EC

States in the case of a Community Emergency and in particular to support Member States which are exposed to less favourable geographical or geological conditions, Member States should devise specific measures to exercise solidarity, including measures such as commercial agreements between natural gas undertakings, compensation mechanisms, increased gas exports or increased releases from storage. Solidarity measures may be particularly appropriate between Member States for which the Commission recommends the establishment of joint preventative action plans or emergency plans at regional level. The actions of any Competent Authority during an emergency must not endanger the security of supply of any other Member State.

The Gas Coordination Group, which was established by Directive 2004/67/EC, will continue to assist the Commission on issues related to the security of gas supply.

2.5.5 Estonian 'N-1' impact assessment

According to the EC communication COM(2010) 677/4, five countries do not currently meet the 'N-1' criterion (Bulgaria, Slovenia, Lithuania, Ireland and Finland), with the initial impact assessment having taken into account the projects underway under the European Energy Programme for Recovery but excluding demand side measures[6]. However, we have been advised that the final impact assessment is currently being undertaken by the EC and Member States and this may result in a different outcome to the initial assessment.

Some alternative research from the Electricity Policy Research Group of the University of Cambridge[7] suggests that an alternative indicator should be used based on a security range in an N-1 situation as a percentage of peak day demand. When this is assumed to be loss of Russian supplies under this measure all four Baltic States are below the threshold of 100%, with Estonia, Latvia and Lithuania well below. That said it is not clear what assumptions have been made on how much fuel switching has been assumed or how much supply can be provided from the Latvian gas storage facility at Incukalns. The implication is that the whole region needs to develop a solution to improve its supply position in relation to dependence on Russia gas, and this option is discussed in more detail later in Section 5.

So regardless of which security of supply measure is used Estonia authorities are right to be concerned and to consider options to improve the position.

2.6 Estonian electricity market

The Estonian electricity market is also comparatively small within the EU Member States. In 2009 the peak load was 1535MW and in 2010 it was 1587MW, with annual generation in 2009 of 7.9TWh and in 2010 11.3TWh. Domestic consumption was 7.1TWh in 2009 and 8TWh in 2010. The demand in Estonia has increased over time; between 1999 and 2008 there was annual growth of around 4.5% in electricity consumption. However, the economic downturn in 2009 led to a 4.7% decrease in consumption of electricity, falling to 2006 levels. In 2010 new capacity was added to the system and this reversed the recent trend in rising imports (see Table 7 below).

The Estonian electricity market is dominated by indigenous oil shale; Table 8 below shows that in 2008 it accounted for 94% of total generation. This means that Estonia has

6 www.energy.eu/directives/com-2010-0677_en.pdf

7 www.eprg.group.cam.ac.uk/wp-content/uploads/2010/11/PN_Tallinn_BalticGasSecurity_EVI_Secure.pdf

the lowest gas consumption for electricity generation amongst all Baltic States due to a large proportion of other fuels used. Therefore, there is a potential of replacing other fuels with gas, as a cleaner burning fuel, for electricity and heat generation. This is discussed as an option in more detail in Section 4.4.

Table 7 – Overview of the electricity wholesale market

Year	Consumption (GWh)	Import (GWh)	Export (GWh)	Peak load (MW)	Installed capacity (MW)	Average price (€/MWh)
2004	7440	347	2141	1318	2675	-
2005	7510	345	1953	1331	2433	26.2
2006	7978	251	1001	1555	2059	26.2
2007	8534	345	2765	1537	2052	26.2
2008	8557	1369	2310	1637	1960	28.5
2009	7977	3025	2943	1513	1888	31.7
2010	8010	1338	4663	1587	2474	46.3*

Note: *€46.3 /MWh was 9-month-average market price in 2010; however, only 35% of the market is open to competition.
Source: Estonian Electricity and Gas Market Report 2009, Estonian Competition Authority

Table 8 – Fuels used for electricity generation 2008

Generation type	Percentage
Oil shale	94
Natural gas	4
Wind	1.3
Hydro	0.3
Other (including renewable sources and peat)	0.5

Source: Estonian Electricity and Gas Market Report 2009, Estonian Competition Authority

Since this data was released, three new wood and peat CHP units have opened in Tallinn, Tartu and Pärnu with 24-25MW electrical capacity. In addition, a 39MW wind farm in Aulepa (western part of Estonia), the largest wind farm in the Baltic region, has been commissioned.

The continued use of oil shale for electricity generation has a considerable impact on CO_2 emissions and consequently meeting carbon reduction commitments. This is because production of 1MWh of electricity generated from oil shale produces approximately 1tCO_2 emissions compared with 0.36tCO_2 from generation using natural gas. The dependence on oil shale will also affect the price of electricity in Estonia.

The development of oil shale reserves is supported by the Estonian government. The support is in the form of a strategic objective to guarantee the energy independence of Estonia. Conversely, the government is also looking at ways to reduce the annual use of oil shale to 15 million tons a year by 2015; current Estonian oil shale consumption was around 18 million tons in 2010. This involves increasing the efficiency in the use of oil shale to ensure sustainable energy supply and consumption in Estonia.

2.6.1 Overview of the Estonian electricity network

The Estonian electricity system was built as part of the 'North Western Common Power System' of the former Soviet Union; which included Russia, Belarus, Latvia, Lithuania and Finland. The transfer capacity between these countries is generally high, although there is only the single 350MW Estlink 1 line between Estonia and Finland. There is close cooperation between TSOs in the planning and management of the common synchronised parallel operation.

The government-owned company Elering acts as the single TSO, while there are a further 38 distribution networks, the largest of which is owned by Eesti Energia which has annual sales of 6190GWh. This network supplies approximately 600,000 people and has an 81% share of the distribution market. The second largest operator is VKG Elektrivõrgud, which is owned by the Estonian shale oil producer Viru Keemia Grupp. This network is much smaller, having only 35,014 customers and annual sales of 198 GWh.

As mentioned above Estonia also has an interconnection with Finland through a commercial interconnector (Estlink 1). The interconnector is owned by AS Nordic Energy Link; though there are a number of shareholders including Eesti Energia AS (Estonia), Lietuvos Energija AB (Lithuania), VAS Latvenergo (Latvia), and Finestlink (Finland). A second, 650MW interconnector, Estlink 2, is expected to be commissioned in 2014.

2.6.2 Power trading

In April 2010 the 'Nord Pool Spot' (NPS) market power exchange was extended to Estonia as a result of interconnection through the Estlink price area and the development of a day-ahead trading power exchange (Elspot) and intraday trading platform, Elbas. As a part of this process NPS together with five TSOs from Estonia, Lithuania, Latvia, Finland and Sweden started the NPS BEMIP project with the target to open the NPS price areas also in Latvia and Lithuania.

Based on the latest data available there are 17 market participants operating in the market, including companies from Latvia and Lithuania. Trading volume increased steadily during 2010; in April traded volume was 134GWh while in May it had increased to 172GWh and by December it had reached 238GWh. Total trades over the first 9 months (April-December 2010) equalled 2.8TWh. Prices in the region remain slightly lower compared to the rest of the EU Member States; daily prices for 2010 averaging €46.3/MWh with a maximum price of €461.9/MWh and a minimum of €19.2/MWh. Average EU prices, based on Austria, Belgium, France, Germany, Italy, Netherlands, Nordpool, Poland, Portugal, Spain and the UK markets were €47.86/MWh in 2010.

2.6.3 Retail market

Estonia is currently going through a transition period towards the full opening of its electricity market. So far Estonia has opened 35% of its electricity market by allowing large industrial and commercial customers to switch supplier where annual consumption is greater than 2GWh. However there remains much work to do in order to open the remaining 65% (including residential customers) by the EU deadline of 2013.

2.6.4 Security of supply

According to the most recent supply security report produced by Elering, the Estonian power market should have ample capacity to meet demand until 2016 given normal operating conditions and provided the network is developed as planned. Post 2016, any surplus will depend on how much new generation is built, given the expected increase in electricity demand. In addition, Elering has stated that under their optimistic scenario there will be sufficient production capacity to cover domestic consumption even in an event of extremely cold winter.

2.6.5 Renewable energy policy

As discussed previously Estonia's current generation mix is dominated by shale oil with renewable fuels only making up around 2% of the mix. However, there are opportunities to increase the use of renewable fuels in the energy mix; in particular Estonia has indigenous sources of biomass, biogas, hydro, and wind energy.

Estonia has a mandatory target of 25% of final energy consumption to come from renewable energy sources by 2020 as part of the EU renewables directive. There is also a long-term national development plan for the fuel and energy sector out to 2015 (adopted through a decision of the parliament on 15 December 2004) which has set interim targets of 8% of gross national electricity consumption by 2015. This legislation also has a target for biofuel of 5.75% by 2011.

In terms of progress towards these targets, the production of electricity from renewable sources has been increasing over the past 5 years and was 9.7% in 2010.

2.6.6 Renewable policy support

To promote renewable electricity generation Estonia has put in place a feed-in tariff, regulated by the Electricity Market Act which entered into force on July 1st 2003. This Act was later amended – in parallel to a revised feed-in tariff scheme a second scheme, the premium electricity tariff for sold electricity, was introduced. Those schemes came into force on 1 May 2007 (the amendments were in response to unintended consequences in regard to the treatment of wind generation).

As a result of these schemes, subsidies are paid to both CHP and renewable generation. Renewable generation (e.g. wood, wind and biogas) receives €53.7/MWh while CHP generation receives €32/MWh; both of these subsidies being in addition to the market price.

The scheme is funded by a €8.1/MWh in 2010 tax paid by each electricity customer.

2.7 Summary

Estonia is dependent on Russia for gas supplies and this is a major cause of concern of the Estonian government. In addition, opening the gas market to competition has had little impact on the dominant supplier, Eesti Gaas, with few customers changing suppliers. Alternative sources of gas through the Batlicconnector or a LNG terminal would increase security of supply as well as providing the potential for alternative sources to any market new entrant. There is potential for growth in gas demand through the development of CCGTs which would reduce Estonia's reliance on power generation from oil shale. This is discussed as an option in more detail in Section 4.4.

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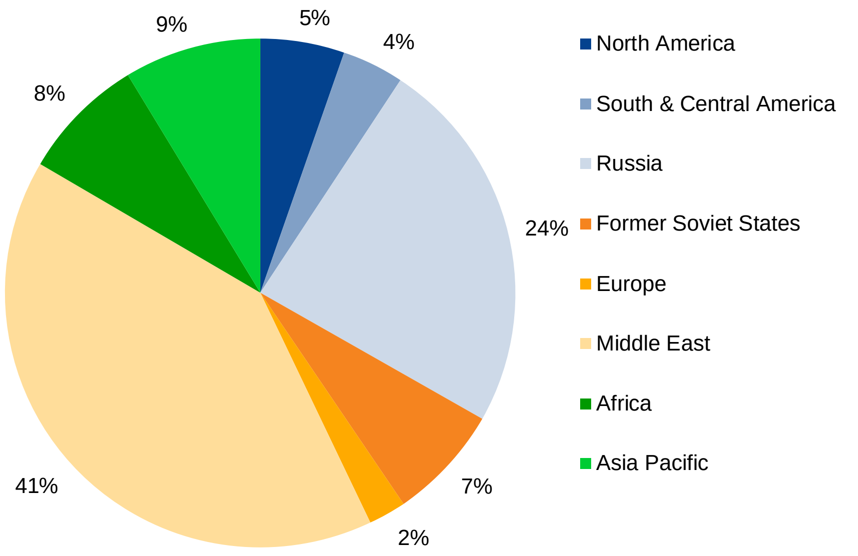
3. GLOBAL AND EUROPEAN GAS MARKETS

3.1 Overview

Gas is a major energy source and is used worldwide for power generation, industrial processes and heating. Global gas consumption was estimated to be about 3,200bcm in 2010. Major importers of gas are Germany, Japan and the US; and major exporters of gas are Russia, Canada, Norway, Algeria and the Middle East. Russia has the largest proven reserves of any single country, which account for around 24% of world proven gas reserves[8]; whereas the combined reserves of the Middle Eastern countries accounts for 41%, as shown in Figure 13.

Figure 13 – World gas reserves (end of 2010)



Source: BP Statistical Energy Review 2011

Norway, Russia, and Algeria are the main suppliers of gas to Europe and are likely to remain so in the future, although LNG is playing an increasingly important role and re-gasification capacity is likely to increase. The rapid expansion of LNG supplies, the development of a LNG spot market and the growth of gas trading hubs in Europe has led gas markets to become increasingly global.

Europe and the US have both experienced a decline in conventional gas production over the past decade. This decline has been compensated by LNG supplies and new import pipelines to Europe, and was largely expected to be by LNG in the US. However, the rapid growth of shale gas production over the last five years in the US has displaced the planned LNG imports and turned around the fortunes of US indigenous gas production.

Shale gas production in the US has significantly changed the US supply/demand balance and this has been termed a ‘shale gas revolution’ by some commentators. By 2030, shale gas is forecast to make up almost 50% of total US gas supply. This has already

8 Proven gas reserves are the reserves, which, by analysis of geological and engineering data, can be estimated with a high degree of confidence to be commercially recoverable from a given date forward, from known reservoirs and under current economic conditions.

reduced the requirement for the US to import LNG, and has meant that more LNG is available for other regions of the world.

The developments in shale gas and other forms of unconventional gas are timely because gas demand in some regions of the world is still growing. According to the IEA, global gas demand is projected to increase at a 1.4% cumulative growth rate between 2008 and 2035. It is not expected to increase significantly in the EU, Japan, and the US, but the majority of demand growth is projected to occur in Brazil, China, and India. In the IEA's recent 'Golden Age of Gas Scenario' – which is a high scenario for gas demand; gas demand from China increases to be the same as the entire EU market demand by 2035, and demand in India quadruples from current levels[9].

3.2 Liquefied natural gas

The development of liquefaction technology in the 1960s allowed the storing and transportation of gas in a liquid form. Natural gas is treated in a liquefaction facility to remove water and other components that would freeze to solids, and is then cooled to -162°C. Liquefaction reduces the volume of the gas by around 600 times.

LNG is then loaded onto ships with special storage tanks, which allow storage of LNG in liquid form over a period of time, and delivered to regasification terminals, turned into a gaseous form and distributed to end customers, see Figure 14.

Figure 14 – LNG value chain

It should be noted that LNG is not the same as gas supplied through bottles or tanks for use in cooking and heating systems. Such gas is referred to as "liquefied petroleum gas" ('LPG') which is typically a mixture of propane (C_3H_8) and butane (C_4H_{10}), whereas natural gas is mostly methane (CH_4).

LNG is a convenient way of transporting geographically remote reserves to the main consuming markets, and is more economically viable as a transportation method over long distances than pipelines. The break-even point is quoted at between 3,000km and 4,000km, depending on the type of geography to be traversed.

LNG volume is typically reported in cubic metres on regasified basis and in tonnes on a liquid gas basis, see Annex D. 1bcm of regasified LNG equals around 1,300,000 tonnes of liquid gas.

3.2.1 LNG supply

Figure 15 shows the growth of LNG supply by country since its inception in 1964. Qatar, which started producing LNG at the end of 1996, is now the world's largest producer with expected production of regasified output of 102bcm/a by 2012-2013. Through its link with

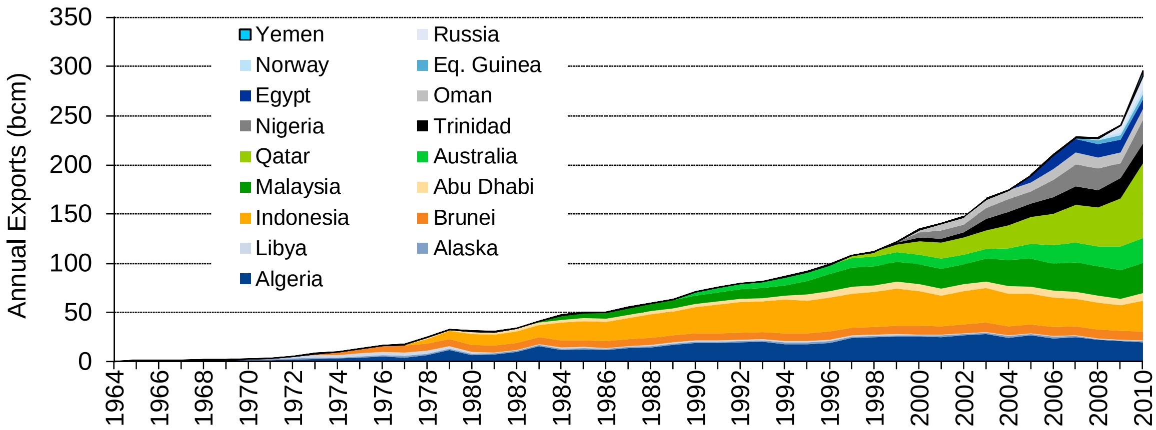
9 'Are we entering a golden age of gas?', IEA, 2011

the South Hook regasification terminal in South Wales, Qatar has become a significant supplier of LNG into the UK and onward into Europe via the Interconnector between the UK and Belgium.

Malaysia is currently the world's second largest producer with regasified output of 29bcm/a in 2009. Other significant exporters include Algeria, Australia, Indonesia, Nigeria, and Trinidad and Tobago.

A feature of the last decade has been the increasing role played by producers in the Middle East and in the Atlantic Basin (including the Mediterranean) in global LNG supply. The increasing role of the Middle East has added new flexibility to global LNG supply as the region is approximately equidistant from markets in Europe and North-East Asia allowing cargoes to be switched between destinations without a major disruption to shipping programs.

Figure 15 – LNG by exporter



Source: BP, Pöyry analysis

3.2.2 LNG contracts

To cover the costs of expensive liquefaction facilities, LNG suppliers favour entering into long-term contracts for financial security.

In the Pacific Basin, contracts generally have rigid destination clauses, and Cost-Insurance-Freight (CIF)[10] and Delivered-Ex-Ship (DES)[11] contracts predominated until about 10 to 15 years ago when buyers began to look for Free-on-Board (FOB)[12] deals which gave them more flexibility to trade cargoes. The buyers in the established markets

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10 CIF – the buyer takes title and risk of the LNG somewhere between loading and before the arrival of the ship in the territorial waters of the buyer's country. Any request by the buyer to divert a cargo will require the agreement of the seller, since the seller is responsible for transporting and delivering the LNG.

11 DES – the buyer takes title and risk of the LNG as it leaves the ship at the specified destination port. The position with regard to diversions to alternative destinations is the same as for a CIF contract.

12 FOB – the buyer takes title and risk of the LNG as it is loaded on the ship, although some FOB contracts have destination clauses, particularly in the Pacific Basin, which require the buyer to transport the LNG to a terminal in its own market.

in the Pacific Basin (Japan, Korea, and Taiwan) were prepared to accept the more restrictive conditions since they had no alternative sources of gas supply. As a result of the lack of contractual flexibility, the Pacific Basin market was much less liquid than the Atlantic Basin market. However, as the supply/demand balance has become more uncertain, buyers are now looking for more flexible contracts that allow them to vary quantities at short notice. They have also increasingly purchased Atlantic Basin cargoes on a short or medium term basis when demand has increased more rapidly than expected or there has been a short-fall in production from regional producers (for example the failure of Indonesia to meet its contractual commitments over the last few years).

In the Atlantic Basin, LNG contracts are more flexible in terms of the rights of buyers to divert cargoes, mainly when they are purchased under an FOB contact but diversions of CIF and DES cargoes have also become more common. There are a number of FOB contracts that allow diversion at the sole discretion of the buyer, whilst others (FOB, CIF, and DES) give the buyer the right to divert, but only having obtained the seller's permission. In addition, some contracts allow destinations to be altered by agreement between buyer/seller with a sharing of the 'upside profit'.

In addition, some regasification terminals, e.g. Zeebrugge currently and GATE in the future, have reloading facilities allowing the buyer to divert LNG (following initial unloading) without reference to the seller. There is even the example of Qatari LNG being delivered to Zeebrugge and then the LNG being re-loaded onto a different ship and taken to Kuwait or Korea.

3.2.2.1 LNG spot trading

The contracting position for LNG delivered to Europe is relatively flexible. The trend in the increased flexibility of contracts can be seen in the growth in short-term LNG trading (defined as two-year or shorter contract duration), from around 2-3% of total trade in 2000 to around 17% in 2008. This trend has continued.

3.2.2.2 Liquefaction & regasification

The worldwide LNG liquefaction capacity currently amounts to 363bcm/a of regasified volume. Liquefaction facilities tend to run at very high load factors, close to their capacity, whilst worldwide regasification capacity is about twice that of liquefaction, at about 715bcm/a.

The balance of liquefaction to regasification capacity demonstrates that there is considerable physical flexibility in terms of where LNG cargoes can be sent, though various contractual arrangements constrain this flexibility.

3.2.2.3 LNG size classification

There is no officially accepted LNG size classification. A suggested guide presented at the Global Forum for flaring reduction and gas utilisation states that a small scale LNG terminal has a capacity of up to 100mcm/a, a medium size terminal has a capacity of up to 3bcm and a large scale terminal has a capacity above 3bcm.

According to an Australian consultancy, CNGI, a small LNG carrier has a capacity of less than 1,100m^3 of regasified output, a medium size carrier has a capacity up to 140,000m^3 and a large scale carrier has a capacity higher than 140,000m^3 of regasified output.

3.2.2.4 Future of LNG

With declining indigenous production in Europe there is a need to import more gas, and this will increasingly need to be supplied by LNG. This also allows European buyers to diversify their supplies. In addition, the rapid increase in energy demand in the Far-East will also require more LNG to be developed.

The total global supplied volume of LNG is projected to reach 400bcm/a (4.3TWh/a) of regasified output by 2020 and LNG is expected to become even more competitive compared to gas delivered by pipeline. However, it may experience competition from new sources of pipeline gas and unconventional gas.

3.3 Unconventional gas

Unconventional gas (coal bed methane, shale gas, tight gas[13] and methane hydrates[14]) is expected to play an increasing role in the global gas market in the future. As mentioned in section 3.1 the US has already seen a large-scale development of this resource and there is potential for developing unconventional gas in a number of European countries, including Poland, Germany, the Netherlands and Romania.

Whilst the potential for unconventional gas developments is being pursued actively in a number of locations, there are a number of reasons why unconventional gas production may not expand as rapidly on a worldwide basis and in Europe in particular:

- Impact on local communities – large scale unconventional gas extraction will have a range of impacts on local communities, including the need to secure access rights to land, disruption to infrastructure e.g. transport, and issues such as noise pollution. Whilst such issues have been directly addressed as part of developments in the US, there is no guarantee that local communities elsewhere will accept such developments, particularly if the direct benefits are not communicated effectively.
- Environmental impact – unconventional gas extraction, and in particular that for shale gas, will typically result in disruption to a large area of landscape as a result of the high number of wells required to maximise gas production. In this respect, the environmental impact would typically be greater than for other energy infrastructure projects such as a gas storage facility or a power station. In addition, the extraction technique of hydraulic fracturing will require very large volumes of water, the treatment and disposal of which are likely to provide significant environmental challenges. In addition, where chemicals are used in conjunction with the water, there is the potential risk of contaminating the supply of drinking water. Given these environmental implications, projects may be subject to delay or additional cost as a result of the licensing and permitting processes, particularly in ecologically sensitive areas.
- Geological uncertainty – in many cases, the potential for significant unconventional gas reserves is yet to be conclusively proven. In addition, some resource areas are likely to provide only limited reserves which prove to be either technically or commercially un-exploitable.

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13 Tight gas is specifically defined in US taxation rules according to the permeability of the rocks in which it is found. Outside the US the term ‘tight gas’ is more loosely defined and reserves are not reported separately from conventional sources.

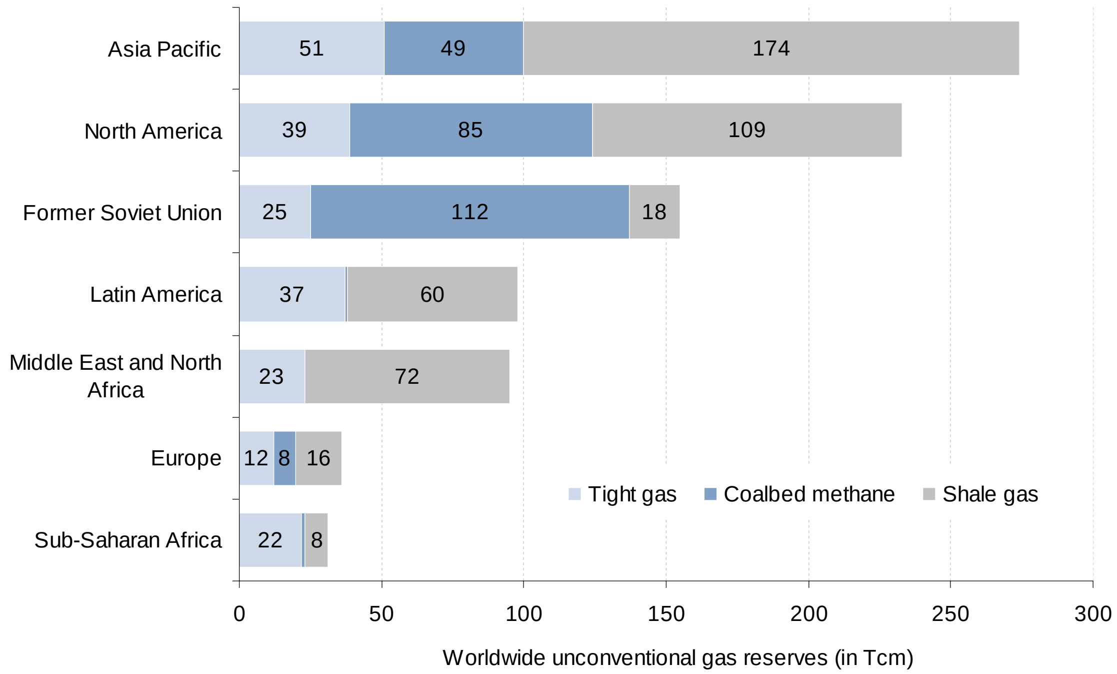
14 Methane hydrates are not yet technically recoverable.

- Proximity to existing pipeline infrastructure – this has proved to be an important factor in the rapid development of unconventional gas in the US. Where potential new reserves are remote from existing pipeline infrastructure, this may deter the necessary level of investment to exploit the unconventional gas sources.

Figure 16 shows the worldwide resources of unconventional gas, and illustrates the huge potential of the Asia Pacific region. By comparison, Europe has relatively small unconventional gas reserves but they could still be significant if they are developed at a reasonable cost. However, at this stage there is a high degree of uncertainty about the future of European unconventional gas.

Figure 16 shows Pöyry's projections for unconventional gas production in Europe for our three standard scenarios.

Figure 16 – Worldwide unconventional gas reserves



Source: IEA 2009

3.4 EU conventional gas production

The main sources of indigenous gas production to the European Union are those in the North Sea belonging to the Netherlands and the UK. Both are in decline, which any unconventional gas proportion would do little to offset, unless significant progress is made in Poland, the most promising area being investigated.

3.4.1 UK continental shelf

In 2010, the UK produced 57bcm of gas and exported nearly 16bcm to the Continent and Ireland. UK demand was 94bcm in 2010 and the additional gas was imported from Norway and via LNG terminals. The output from the UK Continental Shelf (UKCS) is in decline, having nearly halved its production since 2000, in which it was 108bcm, and is expected to continue to fall.

3.4.2 The Netherlands

In 2010, the Netherlands produced 70bcm of gas; this is an increase on the previous five years in which net production ranged between 62 and 67bcm. Much of Dutch gas production is from the giant Groningen field. To maintain the swing capability of this field for as long as possible, the Netherlands implemented the 'Small Fields' policy, which provides a set of incentives and obligations aimed at using more expensive smaller fields first and capping production from Groningen.

3.4.3 The rest of the EU

Although the UK and the Netherlands account for most of the indigenous supplies in Europe, Germany, Denmark, Italy, Romania, and Ireland also produce gas. In the future, aggregate indigenous production capacity in the rest of Europe is projected to decrease.

3.5 Gas imports to EU

Traditionally, gas has been imported into the European Union from Norway, Russia and North Africa via pipelines. More recently, as mentioned above, LNG, in particular from Qatar, has also become a significant source of European gas.

3.5.1 Norway

Norway has been and will remain a significant supplier of gas to Europe. Norwegian production is expected to remain above 90bcm/a until 2024[15] and as Norwegian production has risen steadily over the last 20 years a network of offshore pipelines has been developed to enable exports to reach Germany, the Netherlands, Belgium, France, and the UK.

3.5.2 Russia

As shown earlier in Figure 13, Russia has the largest gas reserves in the world and has supplied European markets since 1969. It currently supplies 160bcm/a to the EU and to most of the markets in Central and Eastern Europe, including those in the eastern Baltic region, which are almost entirely dependent on supplies from Russia. The state-owned gas company Gazprom has a monopoly on gas exports from Russia.

To increase security and avoid transit states, Gazprom has just completed building the first of two lines (each of 27.5bcm/a capacity) of the Nord Stream pipeline, which will deliver gas directly into Germany under the Baltic Sea. The second line should be completed in 2012.

Gazprom has also proposed a 63bcm/a pipeline (South Stream) to bring Russian and Caspian gas under the Black Sea to Bulgaria and onwards with a north-western route going across Serbia, Hungary, and Austria, and a south-western route running through Greece and Italy. Construction is proposed to start in 2013 with a target commissioning date for the first line set for 2015.

3.5.3 North Africa

Algeria has three main pipelines that connect it to Europe. The first is the 31.5bcm/a Transmed line to Italy. The second is the 11.5bcm/a Maghreb pipeline that supplies

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[15] 'Ten Year Statement 2010', National Grid

Spain. A third pipeline, Medgaz, with an annual capacity of 8bcm, has been built to Spain and commissioned in May 2011.

Libya has a 9.4bcm/a pipeline to Italy – Greenstream – developed by Saipem (an Eni company) as part of the Western Libya Gas Project. Due to the current political situation in Libya, flows have been interrupted since February 2011. Before this, there were proposals to increase this pipeline by 2-3bcm/a in the next few years. Such an expansion will depend on the restoration of political certainty.

3.5.4 Caspian Region

The proposed 31bcm/a Nabucco pipeline would supply gas from the Caspian region and provide competition to Russian gas. Its gas supplies are expected to come from Azerbaijan and possibly Iraq. The gas will be delivered to a number of Central and Eastern European states, with Baumgarten as the final destination.

Its construction is expected to start in 2013, one year later than initially proposed, to synchronise the project with the timeline of gas suppliers. The Nabucco consortium now expects first gas to flow through the pipeline in 2017.

3.5.5 LNG re-gasification

Europe has a number of LNG regasification terminals, a few under construction and many more terminals planned, as shown in Figure 17. Some projects which have been recently cancelled or postponed do not appear on the map.

Belgium, France, Greece, Italy, Portugal, Spain, Sweden and the UK all have one or more regasification terminals, which supply gas into national gas networks on a regular basis.

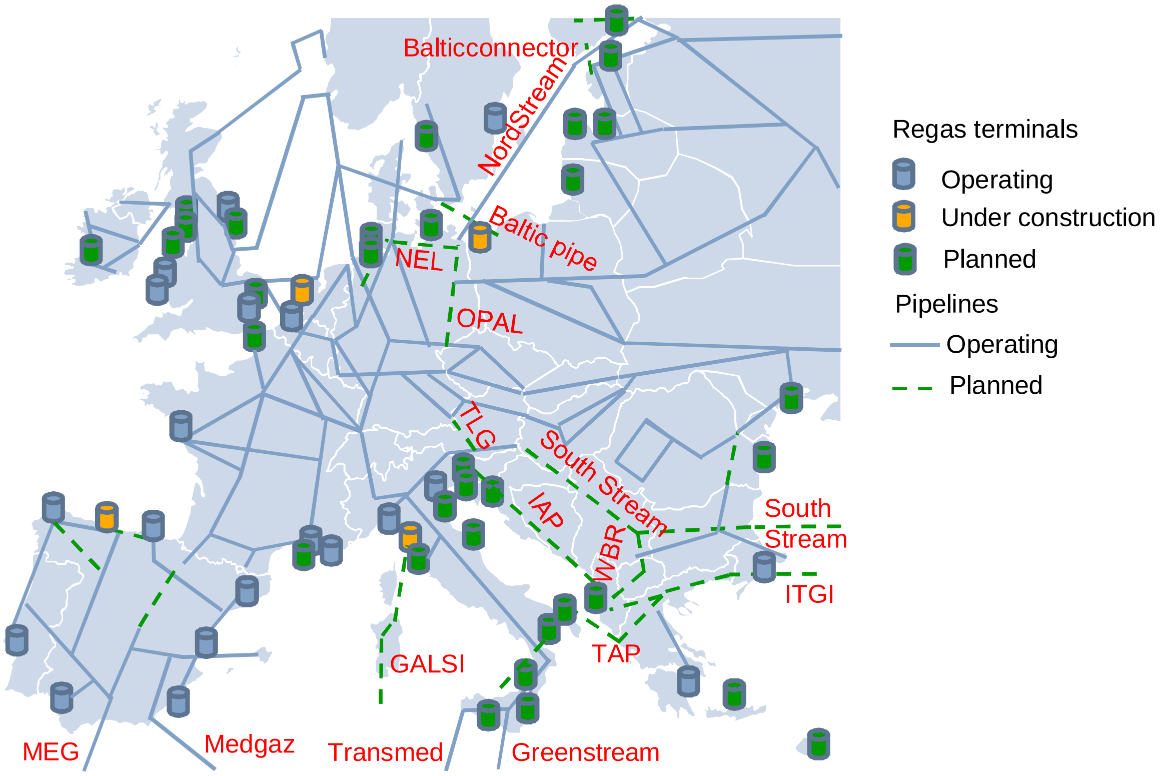
The newly built Gate terminal in the Netherlands has recently completed its commissioning stage and is in operation. Terminals in Italy and Spain are under construction and expected to start operating in 2012. The Polish terminal, Swinoujscie, is expected to start operation in 2014. In addition, quite a few regasification terminals have been proposed in Southern Europe and in the Baltic region, however, it is not certain how many of these terminals will be built.

Table 9 shows the capacities of all the existing LNG regasification terminals in Europe.

European regasification capacity accounts for about 20% of worldwide regasification capacity. Total European regasification capacity stands around 170bcm/a of gas and is expected to grow by another 30bcm/a by 2015. Spain has the largest regasification capacity of 60bcm/a, which is expected to grow to 67bcm/a in 2012. UK regasification capacity is around 50bcm/a.

Most LNG owners and operators are public companies that work on a commercial basis and do not restrict third party access to the facilities. This means that the European LNG market is non-discriminatory and contributes to the liquidity of the market.

Figure 17 – Schematic map of European gas infrastructure



Source: GIE, Entsog

Table 9 – Capacities of existing European LNG regasification terminals

Country	Site	Storage capacity ('000 m3 liq.)	Production Nominal capacity (bcm/year, gas)	Operator	TPA	Start
Belgium	Zeebrugge	380	9.0	Fluxys LNG	Yes	1987
France	Fos-sur-Mer	150	5.5	Elengy	Yes	1972
	Montoir-de-Bretagne	360	10.0	Elengy	Yes	1980
	Fos-Cavaou	330	8.3	Elengy	Yes	2009
Greece	Revithoussa	130	5.0	DEPA	No	2000
Italy	Panigaglia	100	3.3	GNL Italia S.p.A.(Snam Rete Gas)	Yes	1969
	Rovigo	250	8.0	Adriatic LNG	Yes (20%)	2009
Netherlands	Maasvlakte	540	12.0	Gasunie, Vopak		2011
Portugal	Sines	240	5.2	Ren Atlantico	Yes	2004
Spain	Barcelona	540	17.1	Enagas	Yes	1969
	Huelva	460	11.8	Enagas	Yes	1988
	Cartagena	437	11.8	Enagas	Yes	1989
	Bilbao	300	7.0	Bahia de Bizkaia Gas	Yes	2003
	Mugardos	300	3.6	Reganosa	Regulated	2007
	Sagunto	450	8.8	Saggas	Regulated	2006
Sweden	Nynashamn	22	0.3	AGA (Linde)	Yes	2011
UK	Isle of Grain	1000	19.5	Grain LNG	Yes (no RTPA)	2005
	Teesside	138	4.6	Excelerate Energy		2007
	Dragon	320	6.0	Dragon LNG	No	2009
	South Hook	775	21.0	South Hook LNG Terminal Company Ltd	Yes	2009

Source: GIIGNL

3.6 Interconnection within Europe

Much of Europe is well connected through gas transmission pipelines. Through the presence of interconnectors, market traders are increasingly able to move gas between countries in order to balance their system needs: for example, some flexible long-term Dutch and Belgian contracts are able to supply GB in winter. Interconnection plays an important role in increasing pan-European competition and in creating a single European gas market.

However, the European gas network is not uniformly developed. In particular, Eastern Europe, Spain and Portugal rely on gas imported to the EU and have very little interconnection capacity with the rest of the EU. It is the aim of the European Commission to support the single market through an increase in interconnection. To this end, both the new EU Regulation on security of supply and the financial crisis support package to the EU, both aim to bolster interconnection between the member countries, especially interconnectors allowing west-to-east flows.

The development of trans-European energy networks (TEN-E) plays a crucial role in ensuring security and diversification of supply. Interoperability with the energy networks of third countries (accession and candidate countries and other countries in Europe, in the Mediterranean, Black Sea and Caspian Sea basins, and in the Middle East and Gulf regions) is also essential.

The European Commission assists a variety of TEN-E projects, and ranks them under three categories, as follows:

- **Projects of common interest** must display potential economic viability. The economic viability of a project is assessed by means of a cost-benefit analysis in terms of the environment, the security of supply and territorial cohesion.
- **Priority projects** are selected from among the projects of common interest. To be eligible, they must have a significant impact on the proper functioning of the internal market, on the security of supply and/or the use of renewable energy sources. Priority projects have priority for the granting of Community financial assistance.
- **Projects of European interest** are certain priority projects of a cross-border nature or which have a significant impact on cross-border transmission capacity.

In a separate development, following the economic crisis, some projects have also been recognised under the European Energy Programme for Recovery (EEPR) and are eligible for funding based on their importance in helping Member States' economic recovery. This is discussed in more detail in Section 5.2.4. Some examples of proposed interconnector projects include:

- The proposed TLG pipeline crossing Austria from Germany to Italy (shown in Figure 17), where it joins the TAG pipeline is a project of common interest.
- The Lanzot reverse flow project allowing gas to flow from the Czech Republic to Slovakia is an EEPR project.
- Projects to improve linkage between the Baltic States and Finland to end their isolation from the rest of the EU.
- Expansion of interconnector between Spain and France is a project of European interest and an EEPR project.
- Two projects extending from the landing point of the Nord Stream pipeline in Germany – the NEL pipeline extending the WINGAS network towards the

Netherlands, and the OPAL project connecting Nord Stream to the Czech Republic (shown in Figure 17) – both have status of projects of common interest, priority projects and projects of European interest.

3.7 Gas trading in the EU

So far in this section we have discussed the increased global nature of gas markets and the development of the European gas network. These drivers have both been factors in the development of gas trading across the EU, and a change in some of the traditional methods for purchasing gas in Europe.

Gas purchasing typically occurs via either long-term contracts or sourcing from the short-term market. Long-term contracts (more than 5-years) delivered to a border point or to the entry point of a transmission system still account for the majority of gas sold across Europe. Long-term contracts often helped to underwrite the development of new production facilities and/or transportation infrastructure. The price of gas was typically indexed to an alternative commodity, usually oil, or a basket of oil products, as it was originally seen as a close substitute for gas, is traded worldwide, and is commonly used by the companies involved in gas exploration and production. However, this pricing mechanism does not reflect the true cost of gas extraction and increasingly gives way to short-term contracts; according to our estimates around 30% of European gas was traded on short-term contracts in 2010.

Short-term contracts at trading hubs usually have a fixed price and can be for periods of less than one day or up to one year. The use of short-term contracts has increased significantly over the last 15 years with the gradual liberalisation of the gas markets, expiry of long-term contracts, more buyers and sellers, and increased transparency of prices.

The development of short-term trading at the different trading hubs and the regular and reliable reporting of prices have resulted in indices that are now used in medium and occasionally long-term contracts delivered to hubs rather than the border/entry points.

Whilst the UK increasingly relies on short-term and medium-term gas with prices linked to gas indices, the rest of Europe is still largely dependent on long-term oil-indexed contracts.

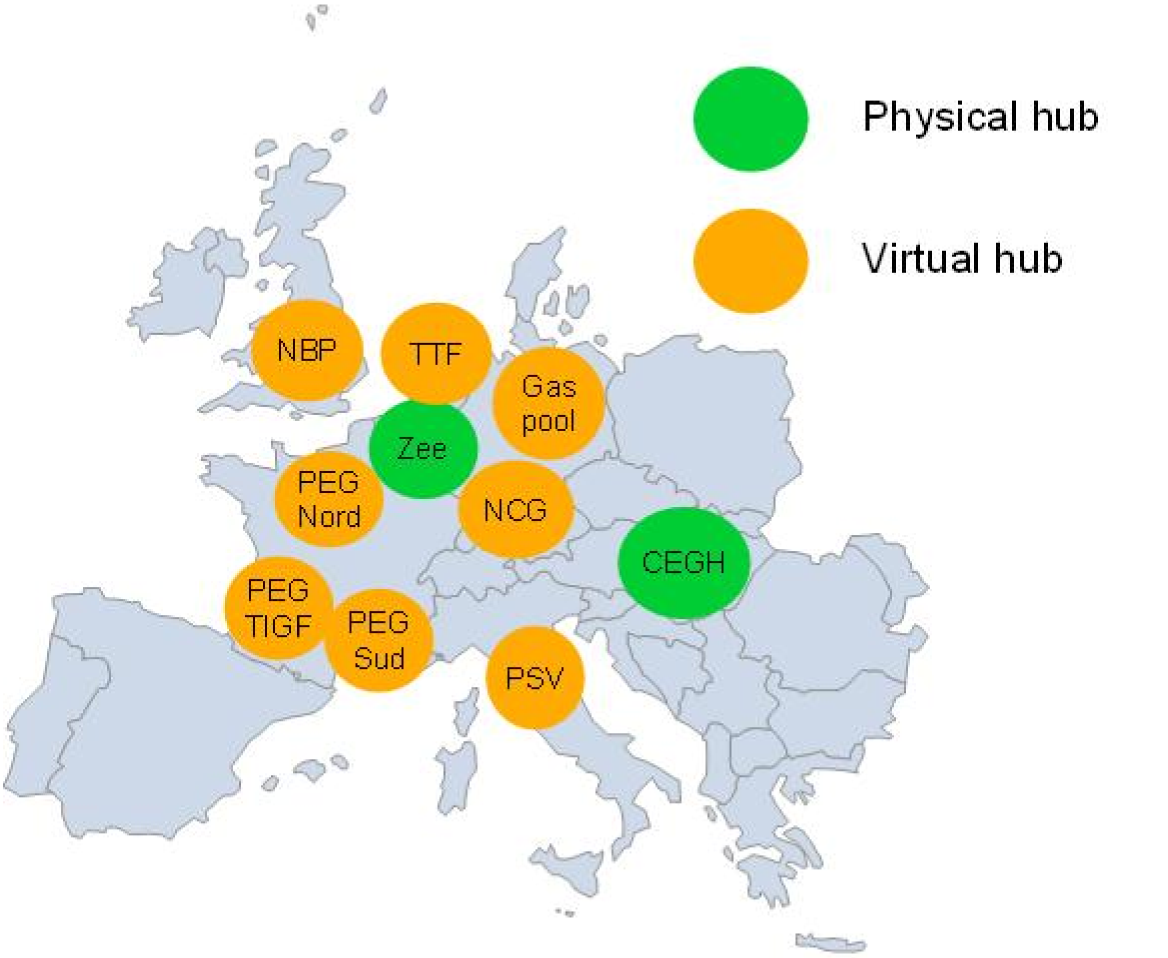
3.7.1 Europe's gas hubs

The main hubs in terms of gas trading in Europe are shown in Figure 18. These are: the NBP (National Balancing Point in GB), Zeebrugge (Belgium), TTF (Title Transfer Facility in the Netherlands) and the NCG (NetConnect Germany). There is a second hub in Germany, Gaspool, three hub points in France, known as PEG Nord. PEG Sud, and PEG Sud-oest, and two others further south and east, the CEGH (Central European Gas Hub at Baumgarten on the Slovakian/Austrian border) and the PSV (Punto Scambio Virtuale) in Italy; however, these hubs are still in their infancy with regards to liquidity levels.

Most of Europe's gas hubs are 'virtual' hubs as the TSO facilitates a transfer of title to the gas in its transmission system regardless of where the gas has entered the system or is to exit the system. This is a feature of the entry/exit gas balancing system that was introduced in GB in 1996 and then became the required model for all systems in Europe in 2005 following the implementation of the second gas directive. Further detail can be found in Annex B.2.2.1 on page 110.

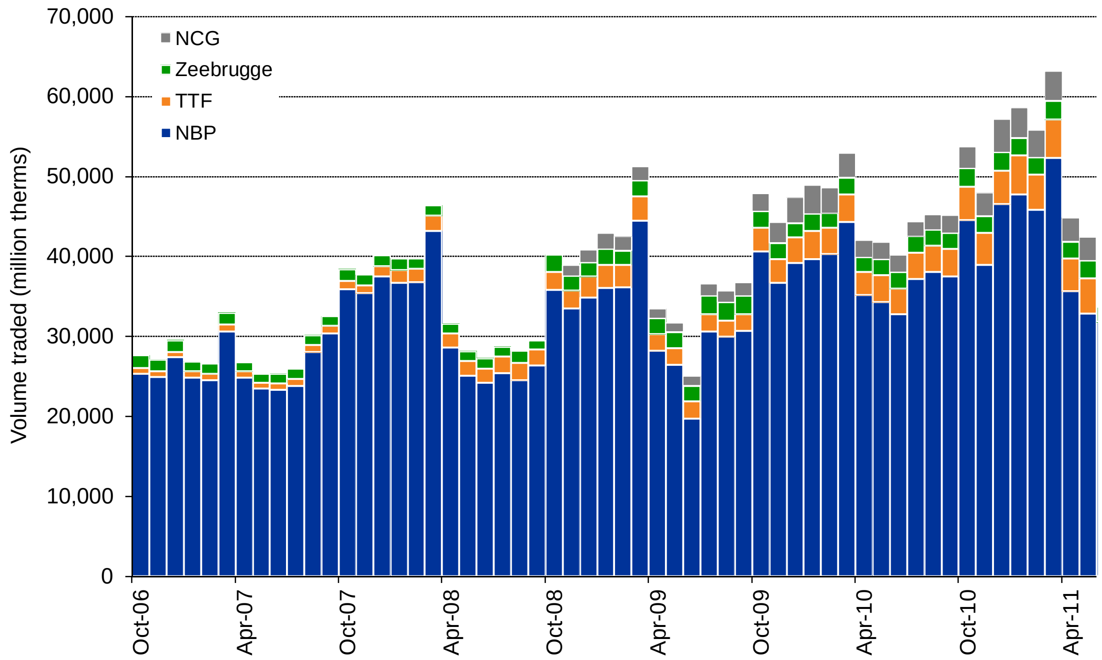
A physical hub is based around a relatively small part of a transmission system, usually around an entry point where a number of pipelines/sources meet and may include storage facilities, and is usually described by its geographical location, e.g. Zeebrugge or Baumgarten. The world's first and perhaps most famous physical hub is Henry Hub in Texas, USA, which played a significant role in the development of the liberalised US interstate wholesale gas market. Virtual hubs are usually easier than physical hubs for traders to operate in, due to the guarantee of delivery and the lack of requirement for traders to obtain capacity, but this has not prevented the success of Henry Hub being used to price spot contracts in the US.

Figure 18 – Europe's gas trading hubs



Of the hubs shown in Figure 18, the NBP is the most liquid. Owing to the UK's geographical location between Norway and the European continent, a variety of gas sources can be brought to market, particularly given recently commissioned LNG terminals. Other hubs, including the TTF and NCG, are also growing in liquidity, but they are still some way off in approaching the scale of the NBP. This is illustrated in Figure 19, which shows the quantities traded at the four most transparent and liquid hubs in Europe.

Figure 19 – Hub flows for the most liquid hubs



Source: Huberator, APX, National Grid, NetConnect Germany

3.7.2 Hub prices versus oil-indexed prices

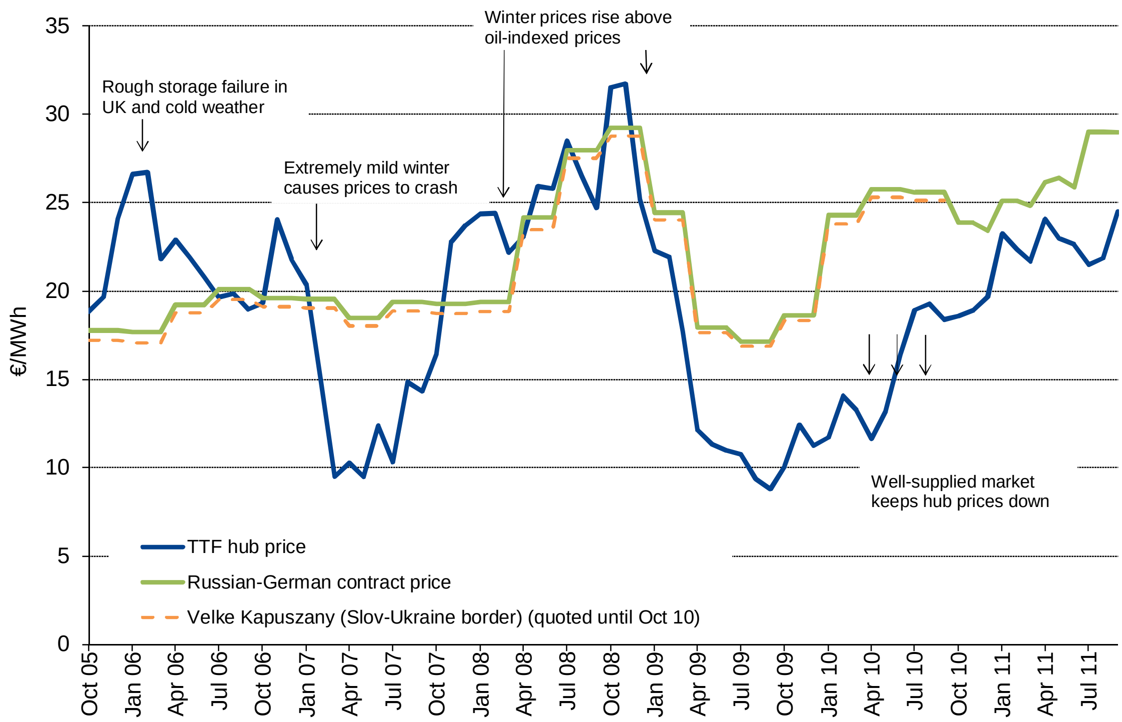
The shorter-term nature of trading at hubs means that hub prices are more volatile than long-term, oil-indexed prices. They are sometimes lower and sometimes higher than an oil-indexed price, as illustrated in Figure 20, which shows historical TTF prices alongside Russian-German, oil-indexed contract prices. The oil-indexed gas price shown was quoted at Waidhaus on the German-Czech border until October 2010, after which time a general Russian-German contract price has been quoted.[16]

Hub prices are influenced by events which change the gas market's supply/demand balance. . Whether it is more or less economical over time to procure gas from hubs rather than on long term contracts thus depends on timing and exposure to risk. Weather is a key factor affecting gas demand in northern Europe and hub prices often move above oil-indexed prices during the winter months. However, LNG re-gasification capacity has increased considerably in Europe since the high prices seen in 2008 and this has helped keep hub prices low despite high oil prices and cold winters.

Figure 20 also shows the border price quoted at Velke Kapuszany on the Slovakian-Ukrainian border, which is further east than Waidhaus. Russian gas delivered to this border has been transported a shorter distance, which is illustrated by the consistent small discount to the Waidhaus border price. The transportation distance from the main Russian gas fields to Estonia is shorter than to Velke Kapuszany; so it would be reasonable to expect the discount to the Waidhaus price to be greater.

16 Quoted monthly in 'European Gas Markets', published by Heren.

Figure 20 – Historical hub price versus oil-indexed contract price (€/MWh)



Source: Heren

3.7.3 The future of oil-indexation

The future of long-term, oil-indexed gas supply contracts is a highly pertinent issue and much discussed in today's gas market. There are many contract re-negotiations underway and much has been made of the changing dynamics of Europe's gas markets.

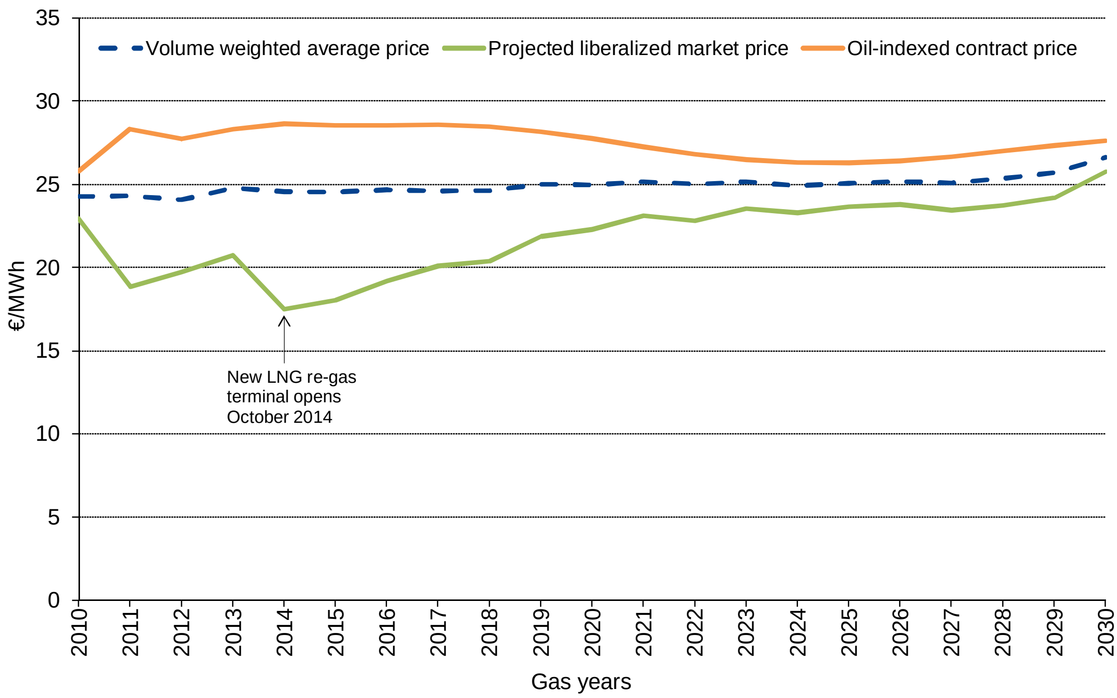
Pöyry projects gas prices for most of Europe's gas markets, including Poland, which is the market closest to Estonia. It has some interesting features which help us examine the future role of oil-indexed contracts. Figure 21 shows the projected cost of oil-indexed contract gas from Russia supplied to Poland alongside the projected annual average market price of gas if a hub were to emerge in Poland. The projected hub price varies from year to year and is considerably lower than an oil-indexed contract price (assuming an oil price around the 100$/bbl level).

Currently, approximately two thirds of gas consumed in Poland is supplied by Russia. Polish consumption in 2010 was 14.3bcm and Russian imports amounted to 9.08bcm.

In Figure 21 the volume weighted average price (of the projected hub and contract prices) is closer to the oil-indexed price, but as contracts expire and demand increases more volumes are supplied at a market price, and the weighted average moves closer to the market price. If a hub in Poland does not emerge immediately, these volumes could be bought at the German gas hub or on the LNG market (after 2014, if the new terminal is constructed). The influence of introducing a LNG terminal on the Estonian gas market is not clear at this point, as the gas price will depend on the contracts concluded; this does not mean that the gas price in Estonia will be lower than the current gas price.

The price differential between the potential marginal source of gas setting the hub price and the projected oil-indexed contract price is very large under the scenario shown, and if this were to be the case it is possible that this could lead to contract re-openers bringing down the contract price earlier than expected.

Figure 21 – Projected contract price versus annual average hub price in Poland



Note: Oil prices are assumed to fluctuate around $100/bbl in our central scenario

3.8 The potential of gas in a low-carbon Europe

In Section 3.1 we mentioned the IEA projection of global growth in gas demand. In Europe the debate over the use of fossil fuels and the desire to reduce emissions of CO_2 has led some to forecast a much greater reduction in European gas demand. However, gas is relatively clean and efficient compared to other fossil fuels and it has already played a part in reducing Europe's CO_2 emissions and has the potential to continue to play a significant role.

There is an on-going discussion within the EU over the desirability of a move from a 20%, to a 30% reduction target in CO_2 emissions by 2020. If Europe is to establish a secure, affordable, sustainable and low-carbon future it will require a fundamental change in the electricity supply sector.

Achieving such demanding targets implies electrification of heat and transport with rapid decarbonisation of the power sector (driven by major growth in renewable generation) and significant improvements in energy efficiency. Such a vision relies heavily on extraordinary rates of renewable generation deployment, highly successful technical innovation, and dramatic changes in consumer behaviour. There are significant risks along the current consensus of an 'electricity focused' pathway, which include, supply chain, funding, technology, security of supply, and affordability risks.

Gas has been the foundation for a large part of European success in meeting Kyoto carbon reduction targets; enabling the economy to both increase energy consumption (and hence maintain economic growth) whilst delivering carbon reductions. It has also contributed to improved competitiveness, greater security of supply, and better air quality. Gas will likely be needed to compensate for reduced nuclear output in Germany following their decision to return to an early closure programme.

Continued use of gas allows technologies to develop; it can make much better use of heat recovery from electricity generation and could result in a lower cost solution in achieving the future low-carbon world, as much of the required infrastructure is already in place.

3.8.1 The relative cost of gas

Levelised cost is often cited as a measure of the overall competiveness of different electricity generating technologies. It represents the full life cycle costs associated with the constructing, operating and decommissioning of an asset. Thus, it includes capital expenditure, fuel cost, fixed and variable operating and maintenance cost, financing and amortization costs – all costs incurred in producing energy.

Levelised cost represents the present value of the total cost of building and operating a power generating plant, converted to equal annual payments and expressed in real money to remove the impact of inflation. Levelised costs are usually presented on per unit of energy basis to compare projects of different sizes on like for like basis.

Figure 22 shows that average levelised costs of electricity generated in Europe related to the levelised costs of one of the lowest generation sources, CCGT; CCGT generation levelised costs are assumed to be 100%. Levelised costs of electricity generation using fossil fuels are much lower compared to levelised costs of electricity generated from renewables. One should note that the major part of the levelised costs of fossil fuel generated electricity is fuel and CO_2 costs. Hence, fuel and CO_2 prices determine the levelised costs of fossil fuel generated electricity.

Renewables offer a broad range of technologies, with some technologies (biomass, geothermal electricity and hydro power) that may be competitive with fossil fuels in terms of cost. In the future the levelised costs of most renewable energy technologies are expected to decrease due to technological development and lower investment costs per unit. However, this will still not be to the level of CCGT’s levelised costs.

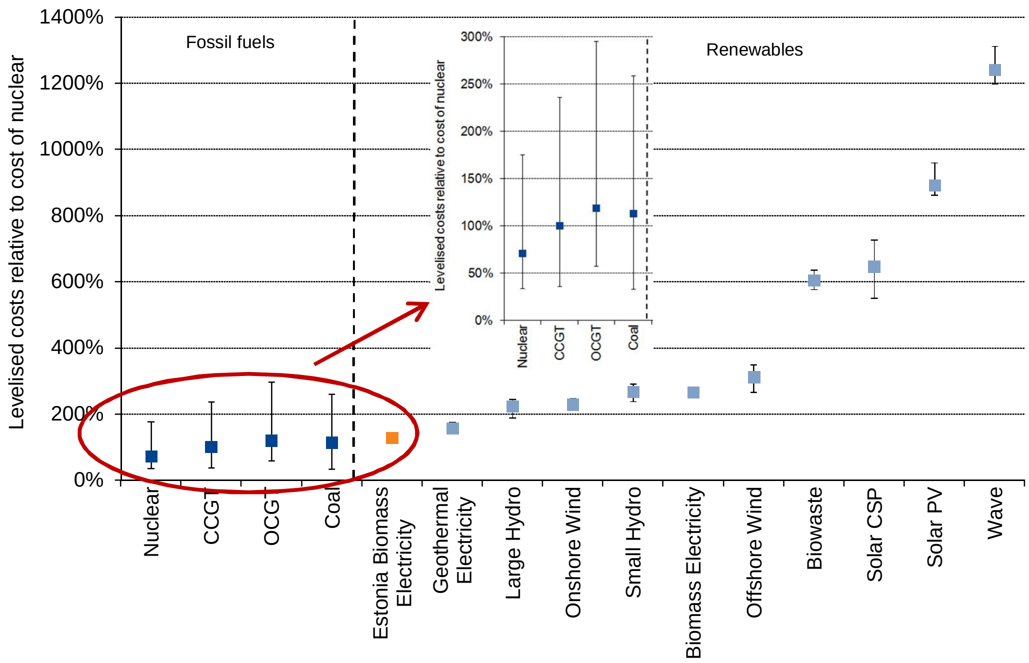
3.8.2 Gas in power generation

Demand for gas in power generation varies considerably around Europe, as illustrated in Figure 23. Its use is expected to increase in countries like Germany and France, although the drivers behind demand for gas-fired power plants are fairly complex. These include country specific power generation mix, the expected renewable deployment and relative fuel costs.

Gas demand for power generation is more price elastic than for other sectors. Assuming an economic dispatch of electricity power plants, small variations in relative fuel prices, such as gas/coal, can have great impacts on gas consumption. Such high price elasticity causes gas demand for power generation to vary significantly year-on-year.

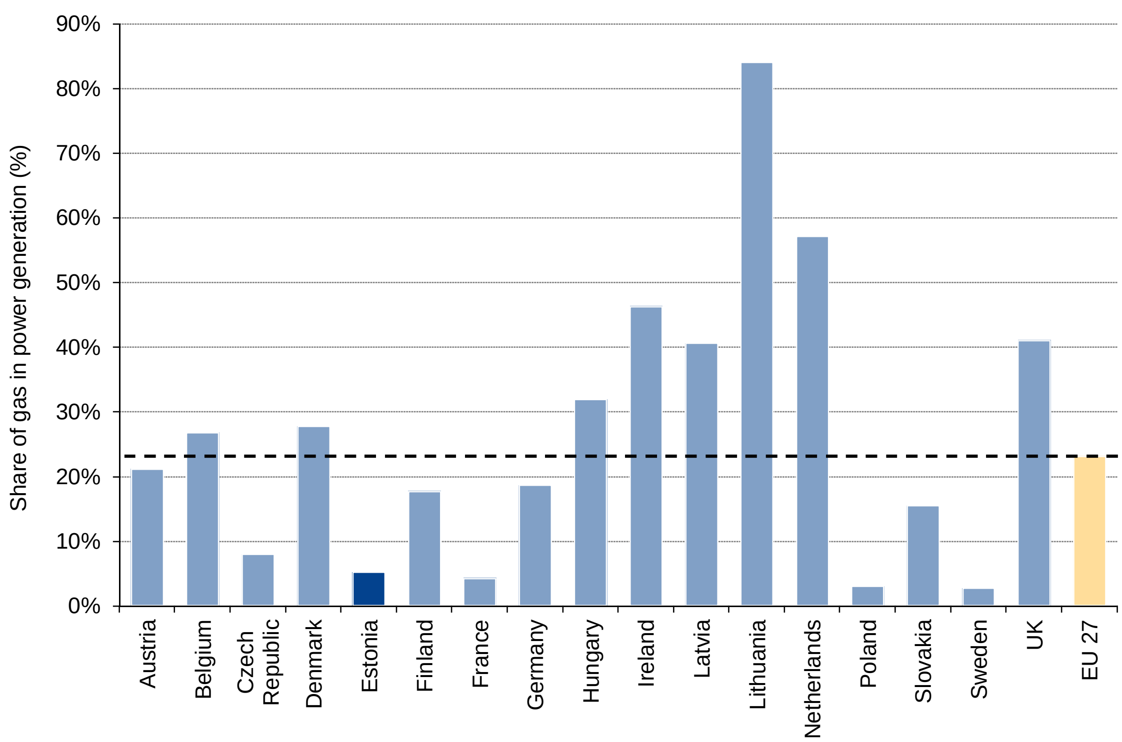
Gas-fired generation can also provide base-load or flexible power and is not intermittent in nature - unlike renewables – which makes it one of the most robust and cost effective generation technologies

Figure 22 – Europe relative average levelised costs of electricity in 2011



Source: Pöyry, DECC, Mott Macdonald

Figure 23 – Share of gas in power generation in Europe in 2010



Source: European Commission, Energy trends to 2030, 2009

3.8.3 Future of gas in a low carbon world

As with other sectors there is much uncertainty over the role gas will play in the transition to a low carbon world and its interface with power generation. Future developments in the electricity sector could have contradicting impacts on gas demand. Although the share of renewables in the electricity generation mix is set to increase, demand for gas from the power sector could either decrease or increase as a result.

Firstly, the greater share of renewables will increase the need for flexible sources of supply to offset the associated intermittency. Owing to technical constraints, such flexibility is usually provided by thermal and hydroelectric power plants. Therefore, in the case where gas-fired power generation provides the swing, gas demand from the electricity sector may increase as the transition to a low carbon world takes place, especially if CCGTs were not running at base load until then. Thus, the role gas will play in the transition varies across countries, depending on the degree of flexibility that is both required and available in European electricity markets.

Secondly, changes in relative fuel prices can have different impacts on gas demand across European countries and will depend on their respective electricity generation mix; on a country level, it may rise or fall depending on fuel, CO_2 prices and economic environment.

3.9 Summary

The global gas market is set for a period of change as many countries face limited indigenous supplies and increasing demand. LNG has become a significant competitor to gas delivered through pipelines, and this is resulting in an increasingly global market for gas. In Europe, LNG will compete with imports from Russia, Norway, and North Africa.

Unconventional gas has transformed the supply position in the US, and LNG will struggle to compete against the shale gas revolution if development costs remain low. Asia is likely to see a significant increase in demand, which will attract further LNG imports and encourage the development of unconventional gas resources. However, significant LNG developments are already in development near to Asia and especially in Australia. Some of this LNG will be linked to coal-bed methane unconventional gas production.

The EU continues to encourage the increased interconnection of Europe and the development of gas trading. Gradually this is beginning to impact upon long-term oil-indexed gas contracts. Eventually gas could become a freely traded commodity, perhaps reducing price but possibly increasing volatility.

All these changes in Europe’s gas markets are happening against a background of plans to reduce carbon emissions, which could have a mixed effect on the future utilisation of gas. However, gas is highly likely to remain a significant energy source to Europe for the foreseeable future.

4. ESTONIAN LIBERALISATION OPTIONS

In this section, we summarise the issues to be considered in market liberalisation outlining the process to be followed, market design issues and regulatory considerations. However, these have to be considered by what is achievable and what options are available to Estonia and other regional countries. In this context we will explore a range of options that may help in the realisation of gas market liberalisation.by considering to what extent Estonia should unbundle the gas transmission network, how access to competing gas supplies could be achieved with small scale LNG and how can demand for gas be transformed by switching away from oil shale power generation.

4.1 Liberalisation analysis

4.1.1 Liberalisation process summary

The EU has been strongly in favour of the liberalisation of energy markets because of the consumer benefits that are expected to arise. However, European experience demonstrates that the expected benefits will only materialise if market conditions are suitable. Market liberalisation has been most successful where both ownership unbundling and competing sources of supply have facilitated genuine competition at the wholesale and retail levels. However, in the absence of sufficient market size and competing and diverse sources of supply, competition is likely to be between the incumbent gas and electricity companies or between large European players, who have made strategic investments as part of their response to competition in their home markets. An in-depth analysis of the liberalisation process can be found in Annex A.

4.1.2 Market design

Our analysis has involved an examination of the market roles, network access and pricing, including third party access rules, and the allocation of capacity. We have reviewed the advantages and disadvantages of entry/exit and postalisation methods of capacity allocation and associated tariffs and concluded that the entry/exit model is the most appropriate form of capacity allocation and tariffs setting mechanism for Estonia.

In addition to capacity and tariff regimes, any TSO or ISO will require mechanisms to physically manage the balance of the transmission network. Our recommendation is that a residual balancing role is adopted which is based on shippers taking primary responsibility for their own balances with the TSO taking action where required.

A successfully liberalised market will allow potential new entrants access to competitively priced gas supplies in order that they are able to compete with market incumbents. This may require: the development of a gas trading hub for efficient price discovery; and/or a mechanism by which the incumbent could release gas to the market and support for new entrants to access gas, ideally through divestment by the incumbent of either part of their existing portfolio, agreed market share reduction targets or restrictions on tariffs.

For competition to be deemed effective it is important that consumers have an easy mechanism to switch suppliers and are able to differentiate between cost reflective retail tariffs.

An in-depth analysis of market design factors can be found in Annex B.

4.1.3 Regulatory considerations

The role of an energy regulator is to ensure that energy wholesale and supply markets are competitive and that any natural monopoly, such as transportation and distribution networks, operated and cost-compensated for on a fair and non-discriminatory basis. The latter is typically done through rules that set the tariffs for a price control period based upon an agreed expenditure as well as incentives to be efficient and to innovate technically. An in-depth analysis of regulatory considerations, including principles for tariff setting, valuing transmission assets, and a more detailed action checklist for promoting a liberalised market can be found in Annex C. Getting the correct model for gas transmission access will be vital and this is discussed next.

4.2 Estonian model for gas transmission unbundling

4.2.1 Estonian transmission tariff setting

Estonia's current TSO, EG Võrguteenus, currently applies a regulated postalised tariff system for gas transmission rather than the recommended entry/exit tariff system (see Annex B.2.2 for more detail). The amount of tariff paid is calculated based either on contracted capacity at exit points or on actual offtakes. The capacity is allocated on first-come-first-served principle.

Standard transmission tariffs are set ex-ante by the Competition Authority (CA). For transit tariffs there is only ex-post supervision. The minimum contract duration for transmission capacity is one calendar year. Multi-annual contracts do not obtain a discount to the annual tariff. Approved gas network tariffs for different gas network operators with tariff classes can be found on the CA's website.

4.2.2 Relative importance of unbundling

The Estonian gas market is served by a single gas supply company, Eesti Gaas, and the transmission system and the vast majority of the distribution system is operated by its subsidiary EG Võrguteenus.

Eesti Gaas obtains all of its gas through long-term take-or-pay contracts with Gazprom, which also has a 37% stake in Eesti Gaas. This reliance on a single supplier is the main source of security of supply concerns. This is compounded by the perceived risk of transmission constraints within the Russian transmission system or an interruption in supply from the Latvian gas storage facilities.

A secondary, but crucial, concern is the question of how to secure investment in infrastructure. The current gas transmission network is based on Soviet era infrastructure, which results in delivery from Russia being the only physical option. Improving physical security of supply therefore depends on new investments, such as the proposed regional LNG terminal, which would introduce new supply source and provide the opportunity for alternative gas suppliers to enter the market.

The liberalisation steps taken so far, by the Estonian authorities, have had little impact in creating a competitive gas market. In other markets, such as GB, where competition has developed, the incumbent monopoly gas supplier sourcing its gas through take-or-pay contracts came under pressure from the availability of lower priced gas on the developing wholesale market. This has not yet taken place in Estonia but demonstrates that market conditions are equally as important as legislation in achieving competitive markets.

The fundamental issue facing the Estonian gas market is its small market size which is isolated from the rest of the EU. This issue has outweighed the fact that the market is fully open to competition and that transportation has been legally separated from supply. Given this, it is likely that the unbundling requirements of the 3rd Gas Directive will by themselves also make relatively little difference to the development of competition in Estonia.

4.2.3 Recommend option under the 3rd EU Gas Directive

The Third Gas Directive came into force in July 2009. The unbundling requirements do not need to be implemented until March 2012 (with derogations available to 2013). The rationale for the Third Directive is that the previous requirements have not led to effective ownership unbundling. Under the Third Directive, Member States have the right to make unbundling optional for integrated natural gas undertakings serving less than 100,000 connected customers. The three options are:

- **Ownership unbundling:** transmission system operation and ownership can be carried out by the same entity but must have no common control ownership with production or supply activities
- **Independent System Operator (ISO):** a vertically integrated company is able to retain ownership of transmission system assets, but the transmission system operator must be an independent company. Although the Directive is primarily focused on transmission, ISOs can undertake transmission system operation or combined transmission system and distribution system operation.
- **Independent Transmission Operator (ITO):** a legally separate and highly ring-fenced subsidiary of the vertically integrated company owns and operates the gas transmission system (or gas transmission and distribution systems).

At present the gas TSO in Estonia (EG Võrguteenus) is 100% owned subsidiary of the dominant supply company, Eesti Gaas AG. Where the TSO is controlled by the dominant supplier in this way, there is little incentive for the TSO to invest in new infrastructure which would facilitate the entry of competitors to the market. For this reason, and as part of a wider initiative to liberalise the gas market, full ownership unbundling should be the preferred outcome, particularly as it appears to be a component of the most successful liberalisation regimes[17].

4.2.4 Implementation of transmission system unbundling in Estonia

As the accounts of gas market liberalisation in Section Annex A have shown, it has often been a controversial and highly politically charged process. The form of unbundling that results is often an output of larger and separate considerations being resolved, rather than a conscious choice based on the merits of the various unbundling options. The increasingly narrow requirements of EU legislation mean that the range of possible outcomes for unbundling as a result of the liberalisation process is now much more constrained. However, within the range of options legally available it is likely that the final result will continue to be driven, or at least influenced, by wider political considerations. A key part of developing an implementation plan for unbundling should therefore be a consideration of the likely influences that may make one outcome more practically feasible than another.

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17 'The arguments for and against ownership unbundling of energy transmission networks', Michael Pollitt, Judge Business School and ESRC Electricity Policy Research Group, University of Cambridge, 2007.

The derogation from the unbundling requirements of the Third Directive means that there is no EU requirement for Estonia to pursue unbundling at the current time. The derogation applies until Estonia is 'directly connected to the interconnected system' of a Member State other than Latvia, Lithuania or Finland. Although the meaning of 'directly connected' is unclear in this context, a natural interpretation of the words would suggest that none of the LNG terminal, Balticconnector, or Poland-Lithuania interconnector would directly end Estonia's derogation from the unbundling requirements, although this would need to be clarified in discussions with the EC. Consequently, it is likely Estonia will need to pursue ownership unbundling without a requirement to do so under EU law, whether now or in the medium term to 2015.

An added difficulty in achieving ownership unbundling is that the incumbent is a private company, not a state-owned monopoly. Gazprom and the other owners of Eesti Gaas are strongly opposed to ownership unbundling and were highly critical of the announcement in June 2010 of the Government's intention to proceed with a completion date of 2013. In October 2010 the Government announced that the option of nationalising the transmission network would not be pursued, and subsequently, the draft Natural Gas Act published in June 2011 extended the deadline for implementation of unbundling to January 2015 (also the year that the take-or-pay contracts with Gazprom are due for renewal). The draft Natural Gas Act proposes the unbundling of only transmission networks.

A serious deterioration in the relationship between the Estonian government and Gazprom would be damaging to Estonia's interests in the event that progress on gas market liberalisation continues to be slow and there are still no alternative suppliers to Gazprom at the time the take-or-pay contracts are renewed in October 2015. As the monopoly supplier there is a risk, which may or may not materialise, that Gazprom increases prices higher than otherwise might be the case.

Pöyry recommends that as part of a wider liberalisation plan the ultimate goal of full ownership unbundling of Eesti Gaas should be pursued. It may be desirable, as an intermediate step, to move to an ITO model, which would enable the current ownership structure of Eesti Gaas and EG Võrguteenus to continue although with stricter ring-fencing requirements. The need for heavy regulatory involvement in the ITO structure could also present a learning opportunity for Estonian regulators.

4.2.5 Unbundling implementation risks

Whilst unbundling has been successfully introduced across the majority of countries in Europe, Estonia will need to take into account the experience of Lithuania. . Lithuania announced, in May 2010, that it proposed to adopt full ownership unbundling as its preferred option for both the gas and electricity markets in order to be compliant with the 3rd Directive. During the next year there were differing views from the government on why it was making the change and from the incumbent company shareholders, Gazprom and E.ON, on why such a move was hasty and to the detriment of Lithuanian gas market.

Then on 13 July 2011, the President signed into law a bill that delivered unbundling of Lithuania's natural gas production, supply and transmission assets. According to the statement released at the time the President stated that she "is convinced that the law is an important step toward reducing the country's energy dependence. The separation of ownership will cut Lithuania's dependence on a sole gas supplier and will open up the market to competition. This will allow the country to accelerate the implementation of its energy projects and ensure fairer gas prices". The law gives the government the powers to reorganise the gas import and transportation company Lietuvos Dujos (Lithuanian Gas) and transfer the ownership of its gas transmission pipelines to the state within two years.

However, Platts[18] has subsequently reported that the ‘shareholder Gazprom has publicly attacked the government over unbundling, arguing not only that the EU rules allow for other approaches than the full break-up but also that the government failed to consult the other shareholders over its decision. Gazprom says the move would violate the company’s privatization agreement, as well as a Russian-Lithuanian treaty to protect investments’. In addition, Germany’s E.ON Ruhrgas told Platts ‘that it regards the Lithuanian choice, ownership unbundling without compensation, as a violation of the rights of E.ON Ruhrgas International. We are in talks with the Lithuanian government in order to find a solution.’ Both sides are publically talking about legal redress and this should inform Estonian decision makers.

4.3 Potential of small scale LNG

Section 3.2 outlined the development of large-scale LNG in Europe. More recently, small scale LNG solutions have been developed for markets isolated from gas pipeline networks. Examples of this can be found in Norway and Sweden, but also in South East Asia. This has been possible because of high oil prices, making LNG cost-competitive with many petroleum products, including marine fuels.

The characteristics of the small and large scale LNG businesses, value chains and economics are different, and the markets can co-exist only because of the isolation of small scale markets from the global gas business. This section aims to illustrate some of the differences, beginning with scale, to provide some perspective on the issue.

4.3.1 Reception terminals on the Norwegian coast

Norway is one of the largest producers of gas and has large scale LNG liquefaction capacity (5.6bcm/a) at Melköya Island. Despite this, it has a very small domestic gas demand with the vast majority of gas produced, including LNG being exported to other markets. However, a local, coastal gas market has emerged, based on isolated industrial demand and marine fuel demand.

Apart from a local gas network in Stavanger, owned by Lyse Gass, there is no onshore pipe-based distribution infrastructure in Norway. So a number of very small scale liquefaction facilities have grown up to supply the coastal industrial and marine fuel market, transporting LNG on small tankers and barges. LNG is also exported to similar coastal markets in Sweden from these small liquefaction facilities.

The difference between small scale and large scale LNG is huge. The existing small scale liquefaction facilities in Norway are shown in Table 10. These small scale facilities are a factor of 10 to 100 times smaller than a traditional liquefaction export terminal.

Table 10 – Small scale liquefaction facilities in Norway

Facility	Capacity t/year	Capacity mcm/year	Owner
Tjeldbergodden	12,000	17	Statoil
Kollsnes	140,000	200	Gasnor
Karmöy	20,000	29	Gasnor
Risavika/Skangass	300,000	430	Nordic LNG

[18] Platts – European Gas Daily, 14 July 2011

There are approximately 50 receiving terminals in Norway (Figure 24 shows those operated by Gasnor), mainly along the coast. Delivery is either by ship, with further distribution by truck or pipeline, or by truck directly from the production facilities in the southwest. The largest terminal in operation is located at Mosjøen in Northern Norway, with a current throughput of 30mcm/a.

Some of the other, smaller terminals include:

- Høyanger on the West Coast, throughput approximately 10mcm/a;
- Lista in the South, throughput approximately 7mcm/a;
- several ferry terminals on the West coast, throughput 5-20mcm/a; and
- the Naturgass Grenlands distribution network in Eastern Norway (3 terminals, each taking around 5mcm/a).

From 2011 one more LNG terminal in Fredrikstad, close to the Swedish border with a total tank capacity of 6.5mcm/a is expected to become operational.

As far as Pöyry has been able to establish, all Norwegian receiving terminals are based upon standard, modular pressure tanks. These have the advantage of facilitating a step-by-step expansion, as well as being removable.

Figure 24 – LNG receiving terminals operated by Gasnor

Source: Gasnor

4.3.2 New LNG reception terminal in Sweden

Until recently, part of Stockholm used town gas, obtained from naphtha/light petroleum. By 2010, Grontmij, a Dutch company, has completed conversion of 90,000 properties connected to Stockholm's town gas network to be able to use natural gas and bio-gas.

In 2011, AGA/Linde commissioned a new LNG reception terminal in Nynäshamn, south of Stockholm. The terminal will supply industrial demand and the growing market for gas as a transport fuel. LNG will also be used to replace naphtha in the Stockholm town gas grid.

The terminal consists of a jetty and storage tank, with a capacity of 20,000 tons of LNG. Permits have been granted for reception of up to 300mcm/a. The expected terminal cost is around €30 million (275 million Swedish Krona)[19].

4.3.3 Small scale LNG value chain

A buyer of small scale LNG in an isolated market will have a different negotiating position and buying power than an established European incumbent with access to grids, hubs and spot LNG markets. Effectively, in the European small LNG market, there is no gas-on-gas competition whatsoever. There are only two suppliers of small scale LNG in Northern Europe, and both reside in Norway and take gas from fields producing on the Norwegian continental shelf. This means that a Norwegian producer of gas always has a choice between selling gas in large quantities to Europe or the UK, or to a local LNG production facility. In order to attract sellers to the small LNG market, therefore, the price payable for gas is likely to be the European or UK price at landfall minus transportation cost. This is likely to be significantly higher than the cost of production. In this way, the producer captures part of the monopoly rent.

Conditions at the beginning of the small scale LNG value chain are different than for an integrated large scale LNG supplier, which has more flexibility in pricing depending on market conditions. A supplier of small scale LNG will have to recover the costs of liquefaction, shipping and potentially regasification to be cost competitive with alternative fuels in the market. This can work if local fuel prices are high, for example due to taxation, but imported small scale LNG is unlikely to be able to compete on price terms with Russian pipeline gas.

Small scale LNG is typically consumed by stranded customers, located in areas with no gas networks; and although the Baltic States are isolated from alternative supply sources and could technically import small scale LNG, Russian pipeline gas is always likely to be priced more competitively than small scale LNG.

4.3.4 Small scale LNG economics to Estonia

We believe that small scale LNG could potentially be delivered to Estonia via two stages: first to a large LNG regasification terminal in a large LNG tanker and, second, reloading this LNG onto a smaller tanker and delivering it to the small scale LNG terminal. Terminals such as Zeebrugge in Belgium have such a facility. A limiting factor may be availability of small LNG ships to support this and any other small scale LNG terminals in the Baltic region, but such a review is beyond the scope of this study.

19 www.cisionwire.com/ncc/r/ncc-to-construct-lng-terminal-in-nynashamn,c421010

Estimating the costs for a small scale LNG terminal with a capacity of between 0.3-0.5bcm has proved difficult as estimates have varied considerably. The differences in the defined technical capability means we have seen a range from €30-150m of capex to build a small scale LNG terminal. Using figures provided by Pöyry's own experienced engineering consultants we have adopted a capital cost of €100m for a 0.5bcm facility, with on-going operating costs of €4 million, making a total levelised cost of €125m.

Then, using the same methodology described in Section 3.8.1 and assuming a lifetime of 20 years and 10% cost of capital this gives a levelised cost of €2.72/MWh. This is a much higher cost when compared to other potential investment projects (see Table 11 on page 74), mainly due to lower capacity and relatively high capital costs.

An alternative method of considering the economic impact is to assume that the cost of the terminal is socialised through a security of supply levy across all Estonian gas customers. Based on the current consumption of 0.65bcm of gas, the above investment cost would equate to €9.5($13)/1000m^3, which equates to a 3.7% increase in consumer bills over the assumed 20 year lifetime period. This is a higher cost to Estonian consumers than the regional approach discussed later in Section 5.6.

4.4 Replacement of oil shale generation capacity

Finally in this section, we have considered options that provide a significant practical boost to expanding the market the size of the gas market within Estonia. Whilst concerns over the single source have, in the past, limited the political desire to expand gas demand this must be considered a vital part of the potential options available to achieve a liberalised market, if a successful plan is to be developed. A larger gas market will increase the attractiveness to investors and new entrants.

Today, Estonia generates the vast majority of its electricity from oil shale. Oil shale has the highest CO_2 emissions per unit of energy produced compared to other conventional fuels (0.106t CO_2/GJ for oil shale compared to 0.055t CO_2/GJ for gas). In addition, oil shale burning power stations are not as efficient as newer gas fired power stations (c.35% efficiency for oil shale vs. c.50% efficiency for CCGTs).

In this option we have considered replacing oil shale generation by gas generation in the form of CCGTs. Such a replacement will result in savings from the amount of fuel required and the CO_2 emissions.

Estonia's electricity consumption is 8010GWh and it exports 4663GWh and imports 1338GWh. Of this total power production of 11,335GWh 94% comes from oil shale. Using various sources[20],. we estimate the total amount of oil shale used for power generation to be 15mt at 35% efficiency. This amount of oil shale can be converted with 12.5% yield into 1.9mt of shale oil, which has a similar equivalence to heating oil, and can be sold on an international market at prices similar to LSFO. Applying Pöyry's proprietary annual projections of oil product prices and assuming that the amount of oil shale produced is constant and that Estonia can start selling its shale oil starting from 2012 to continue to 2040, we estimate that Estonia can obtain €22billion (2010 real) in shale oil

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[20] Unconventional Oil: Tar Sands and Shale Oil – EROI on the Web, The oil drum, 2008
A study on the EU oil shale industry – viewed in the light of the Estonian experience, European academies science advisory council, 2007
Unconventional Oil & Gas Production, The Energy Technology Systems Analysis Program, 010
New Tech to Tap North America's Vast Oil Reserves, Popular mechanics, 2009

sales. Assuming €17/t mining costs and €7.3/bbl ($10/bbl) refining costs, the costs of producing and processing oil shale from 2012 to 2040 equate to €11billion (2010 real).

To generate the same amount of annual electricity using CCGTs requires 2.3bcm of natural gas. For this exercise we have assumed that the new gas would be supplied by LNG through a new 2.5bcm regasification terminal. We have used our proprietary gas price projections for spot LNG plus the additional shipping costs to bring the LNG to Estonia. Assuming constant gas demand from power generation into the future, we estimate the total costs of this gas from 2012 to 2040 to be €16billion.

In addition, use of gas instead of oil shale will save 7.7million tCO_2/a, which, and again using our proprietary annual projections of EU ETS CO_2 prices, results in an additional reduction of costs of €9 billion (2010 real) between 2012 and 2040, (assuming the constant emissions of CO_2 generated and saved) (the annual savings value will vary from year to year with the varying CO_2 prices). This amount of CO_2 will contribute 78% of saving towards Estonia 2020 target of 6.9million t greenhouse gas emissions in 2020; 2005 level of greenhouse emissions is 6.2 million t.

We estimate the capacity of required CCGTs to be 1.5GW at a capital cost of around €1.4billion. The expected costs of replacing the planned 600MW of the existing oil shale based power generation are €1 billion[21]. This means that the additional capital costs required will be about €400million more than already planned for.

So putting all of the above together and assuming 10% cost of capital, the NPV of replacing oil shale power generation with CCGTs is €65million. Of course, the cost of capital for the Estonian economy may be lower than this, but for consistency with the other infrastructure options we have used the same value.

One should interpret this number with great care, as in addition to the above mentioned costs, Estonia will face costs of expanding its gas and/or electricity networks. The key to understanding the amount of these costs will be the location of CCGTs. For example, if new CCGTs will be located near to the existing oil shale power plants, gas network expansion costs will be high, with little electricity network expansion costs, as existing power plants are already connected to the electricity network of the required capacity. If new CCGTs will be located near to the new gas source of the LNG terminal, gas network expansion costs will be low due to proximity, whereas the electricity network expansion costs may be high. . Such additional gas and electricity expansion costs will need to be investigated further should this option be progressed. However, it is unlikely that they would be more than the positive value identified from switching from oil shale to gas fired power generation.

4.5 Summary

In considering the options available to Estonia to directly influence some of the key activities required to deliver a liberalised market we have identified that Estonia has the option to unbundle its gas transmission ownership, to develop a small scale LNG facility and the potential to significantly expand its gas demand by switching its current oil shale generation to gas fired CCGTs, with the latter having a better economic analysis than the current situation. We will consider these again as part of our liberalization scenarios in Section 6.2. Another way of expanding demand and achieving diverse and new gas supplies is to consider a regional approach, our analysis of which follows in the next section.

[21] ec.europa.eu/energy/infrastructure/events/doc/2009/2009_11_25_hlg_report_170609.pdf

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5. REGIONAL APPROACH

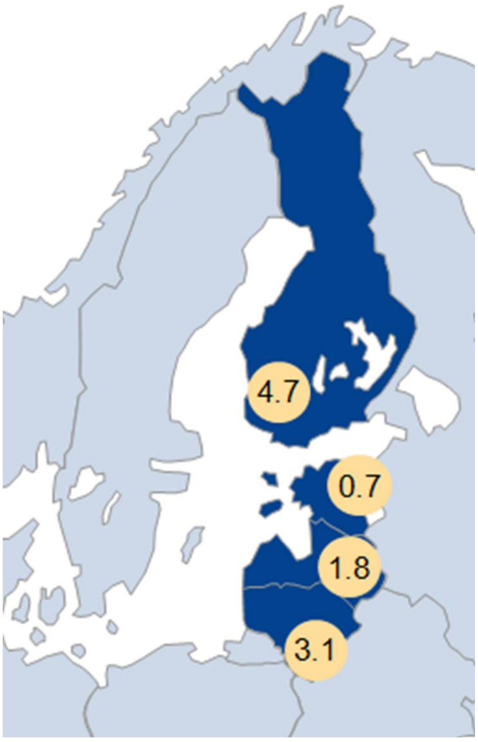
In Annex A we discuss the importance of well-connected energy markets to the development of the single EU gas market. For this reason the EC is keen to end the energy isolation of the East Baltic region. This section will consider whether there is merit to considering the Baltic region as a whole in order to further gas market liberalisation. There is a president for this as the Baltic energy market interconnection plan (BEMIP) supports construction of new gas infrastructure in the Baltic region and seeks solutions to the economic and political challenges this presents[22].

However, new infrastructure alone is unlikely to encourage a large number of new competitors, unless it is accompanied by a harmonisation of market structure across the Baltic nations. The benefits from liberalisation are most likely to occur (and then be shared among consumers) if the Baltic nations can encourage market participants to become active in the region as a whole rather than in one or two of the nations where infrastructure is developed.

5.1 Baltic energy markets interconnection plan

The gas markets of Finland, Estonia, Latvia and Lithuania are each supplied entirely by Gazprom. As outlined in Section 2.2, all nations except for Lithuania are exempt from the EU third energy directive.

Figure 25 – Regional gas consumption (bcm/a, 2010)



Source: IEA

22 ec.europa.eu/energy/infrastructure/bemip_en.htm

Figure 25 shows annual gas consumption in each of the four gas markets, each of which is small by EU standards. By comparison, in the same year Denmark consumed 4.9bcm, Poland consumed 17.1bcm and Germany consumed 97.3bcm.

The Baltic energy market interconnection plan (BEMIP) is an action plan for integration and market improvement in the Baltic Sea region. The plan was initiated in 2009 and covers:

- energy market integration;
- electricity interconnections and power generation; and
- diversification of gas routes and sources.

The plan includes Finland, Estonia, Latvia, Lithuania, Poland, Germany, Denmark and Sweden, all of which are members of a high level group chaired by the Commission. Norway has an observer status.

The BEMIP aims to end the isolation of the Finnish and Baltic gas markets, and to increase diversification and security of supply. Implicitly, it thus assumes the implementation of the third energy package, and hence gas market liberalisation.

For electricity market integration, the future market design for the three Baltic States has been agreed. They will be integrated in the Nordic market model, already covering Finland, Sweden and Denmark. Implementation is under way and will be completed in 2013 with full market opening.

For gas, required actions to improve market functioning have been identified. There is an indicative list of projects that needs to be put in place to achieve integration. In the case of Finland and the three Baltic States, this new infrastructure is crucial to market liberalisation to offer an alternative source of supply. The infrastructure required to integrate the markets, diversify sources of gas supply, and connect to the wider European gas grid have been identified as:

- the Balticconnector, a pipeline between Finland and Estonia;
- the Amber PolLit link, a pipeline linking Lithuania and Poland; and
- a LNG terminal with a capacity sufficient to meet security of supply requirements for the entire region (assessed to be 2.5 bcm/a), located in one of the three Baltic States or Finland.

5.2 Interconnectors

5.2.1 Balticconnector

In February 2011, Gasum published an executive summary of a study on an offshore pipeline between Finland and Estonia. The study covers technical concepts, routing and environmental impacts. Two routes were studied: one between Inkoo and Paldiski (80 km), and one between Vuosaari and Paldiski (140km). The cost for the shorter route was estimated to be €96 million, (€1.2 million per km)[23]. The offshore pipeline would have compression at both landfalls making it capable of physical reverse flow.

[23] Balticconnector Executive Summary, 2011

The study concluded that it is indeed possible to lay an offshore pipeline between Finland and Estonia as part of an integrated solution to provide diversified supplies of gas to the region via connection to a LNG terminal in Finland or Estonia.

Gasum has recently shown reluctance to develop the project, which has caused Estonia (Eesti Gaas) to request it takes over project leadership. Initially the parties were due to report in May 2011 but the current status of these negotiations is not known.

5.2.2 Amber PolLit link

In April 2011, an agreement was signed between Gaz-System, the Polish TSO, and Lietuvos Dujos to conduct a pre-feasibility study to construct a pipeline linking the Polish and Lithuanian gas grids. A European Commission grant covered 50% of the cost of the study. The results of the first stage of the feasibility study, assessing the venture in terms of its economic viability were originally expected to be ready in July 2011.

The second stage of the feasibility study, analysing three performance scenarios, providing the specification of project costs and expenses, technical description of the prospective variants of gas pipeline routes, an evaluation of the environmental impact and the schedule of performance, was planned for July 2012.

There are potential developments that would mean that interconnection with Poland would be desirable. These include the LNG terminal being developed at Swinoujscie (see below) and indications that Poland could in future be the leading European producer of shale gas (see Section 3.3). Poland has also renewed its 10bcm/a contract with Gazprom until 2037. With Poland so well supplied, it is possible that in future capacity at the LNG terminal could be used for gas destined for Lithuania, and potentially to the Baltic region.

The first study of a gas pipeline between Poland and Lithuania was called ‘project Amber’. Since then the term ‘Amber Pipeline’ has been used for different pipeline projects connecting the Lithuanian and Polish gas systems.

The interconnector is expected to connect Poland with Lithuania with a capacity of 3bcm/a at an estimated capital cost of €292 million or a total cost of €340 million[24]. A proposed commissioning date is 2014. However, the project work is in its infancy with no project managing/coordinating company appointed as yet.

5.2.3 Infrastructure planned in Poland

Poland is currently building a LNG terminal in Swinoujscie, on the Baltic coast close to the German border. Commissioning is planned for 2014 and the investment cost is €950 million. The purpose of the terminal, which has received EU-financing of €200 million from the EBRD, is to diversify supplies and reduce dependence on Russian gas.

The terminal will have an initial capacity of 2.5bcm/a, expandable to 7.5bcm/a. It will be fully equipped with unloading jetty for large LNG tankers, two storage tanks and a regasification train. A 20-year supply contract has already been signed with Qatargas which will supply its first shipment in July 2014.

The Polish gas market is amply supplied by domestic production and imports from Russia and in addition there is significant potential for shale gas. From a supply/demand

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24 A. Jahn, Implementation of an Entry/Exit Model for the East-Baltic Gas Market, 2011

perspective, a LNG terminal is not required. However, an additional motive may be to supply neighbouring Central European markets, with gas contributing to diversification and security of supply.

Poland also plans to expand its cross-border gas links to Czech Republic and to Germany in 2011. The Czech link will be new and have a capacity of 1bcm/a, expandable to 2.5bcm/a.

Other links that are being considered include the interconnector with Lithuania (described above), and an additional link to Slovakia in the south. Gaz-System, the Polish TSO, is building these links in order to ensure that the capacity of the LNG terminal in Swinoujscie is utilised. They wish to create a North-South gas corridor, which will interlink the regions gas pipelines to increase security of supply.

The potential benefit of these projects for the Estonian gas market will be access to further diversification and security of supply via Lithuania, but possibly with additional interconnection costs.

5.2.4 Economic feasibility of interconnectors

European interconnectors are currently underdeveloped as a result of insufficient funding. TSOs have normally have no incentive to develop interconnections with other networks as part of their regulated assets and rates of returns.

In 2006, the European Commission introduced new guidelines for trans-European energy networks (TEN-E) which are outlined in Section 3.6. However, the implementation of the planned projects has been progressing at a slower pace than was initially expected.

One of the obstacles for building new gas interconnections is related to expectations of low profitability. The aim of interconnection is to increase the competition in the gas market, which may change the use of existing assets and so result in less profit for the TSOs. In addition, an uncertain regulatory framework, higher risks associated with capital intensive projects, an uncertain economic situation and lengthy permitting procedures impact construction of interconnectors.

5.2.4.1 Financing gap

In January 2009, the consequences of interruption of Russian gas supplies to Europe could not be mitigated due to a lack of reverse flow options and inadequate interconnection and storage infrastructures.

As a result of gas supply disruptions, high oil prices in 2008, increased reliance on imported energy resources and the economic crisis, the European Parliament introduced a European energy programme for recovery (EEPR, as mentioned in Section 3.6) to increase Community spending in defined strategic sectors, addressing the lack of confidence among investors and strengthening the overall economy. The European Council asked the Commission to present a list of specific projects to be included in EEPR, taking into account an adequate geographical balance and to reinforce investment in the development of infrastructure projects.

In 2010/11, the EEPR supported the construction of 31 gas infrastructure projects with €1.39 billion of funds. This support included €80million for reverse flow projects in 9 Member States and c.€1.3bn for gas interconnectors and new import pipelines.

'Energy infrastructure – a blueprint for an integrated European energy network'[25], estimates that the investment needed into European energy infrastructure is around €200billion for the coming decade. Regulated tariffs and congestion charges will have to pay for the bulk of these investments. It states that under the current regulatory framework, the necessary investments will not take place or not take place as quickly as needed.

It is estimated that only about 50% of the required investments for transmission networks will be taken up by the market by 2020. This leaves a gap of about €100billion. This gap is caused partly by delays in obtaining permits, difficult access to finance and lack of adequate risk management instruments, especially for projects on pan-European level.

The report highlights that the European Parliament should facilitate regional cooperation, provide transparent and straightforward permitting procedures, involve participation of public into permit decision making process, arrange better ways of informing stakeholders and general public and create a stable financing framework through an improved cost allocation and mitigated investors' risks.

5.2.4.2 Justification of EC grant

A feasibility study for a pipeline may come at a significant cost and typically these studies are financed in part by the European Commission or similar organisations.

The potential interconnector between Finland and Estonia meets requirements of the TEN-E program it is a high-pressure gas pipeline making it possible to supply regions of the Community from internal or external sources. It may, therefore, be eligible for an EC grant.

An interconnector between Estonia and Finland is one of the TEN-E priorities[26] for action to support delivery of these two objectives:

- Adapting and developing the energy networks in support of the operation of the internal energy market and, in particular, solving the problems of bottlenecks, especially trans-frontier bottlenecks, congestion and missing links, and taking account of the needs arising from the functioning of the internal market for electricity and natural gas and the enlargement of the EU.
- Establishing energy networks in island, isolated and peripheral regions, together with the connection of those networks, where necessary.

The following gas projects are mentioned as priority projects by the TEN-E program:

- Gas networks in Estonia; and
- Gas pipeline between Finland-Estonia.

The European Community provides financial aid for projects in one or more of the following forms:

- Grants for studies or works.

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[25] European Commission, Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network, 2010

[26] European Commission, Commission Decision on establishing the 2011 annual work programme for grants in the field of trans-European networks (TEN) - area of energy infrastructures (TEN-E), 2010

- Interest rate rebates on loans given by the EIB or other public or private financial institutions.
- Financial contribution to the provisioning and capital allocation for guarantees to be issued by the EIB on its own resources under the loan guarantee instrument.
- Risk capital participation for investment funds or comparable financial undertakings with a priority focus on providing risk capital for trans-European network projects and involving substantial private sector investment.
- Financial contribution to the project-related activities of joint undertakings.

The financial aid provided for the above mentioned forms (apart from the risk capital participation) can cover up to 50% of eligible cost of the feasibility study.

A decision to grant Community financial aid will take into account:

- the maturity of the project;
- the stimulating effect of Community intervention on public and private funding;
- the soundness of the financial package;
- socio-economic effects;
- environmental consequences;
- the need to overcome financial obstacles; and
- the complexity of the project.

The Commission will decide the amount of financial aid granted to the study and will specify the conditions and methods for the implementation. Payments will be made in a form of pre-financing and, where appropriate, divided into payment instalments.

In conducting any study, Estonia, in cooperation with the commission, will need to undertake technical monitoring and financial control of the projects and certify the reality and conformity of the expenditure incurred. Estonia will also have to provide a description of the control, management and monitoring systems set up for the project.

5.2.4.3 Project financing

Another critical consideration in economic feasibility will be whether the proposed interconnectors, and any potential LNG terminal, are able to attract financing of the capital investment costs. Historically, many infrastructure developments across Europe were funded by utilities and often through joint-ventures. Typically these projects also raised project financing by raising debt from Banks and other financial institutions. These loans were typically over a 16-20 years period.

However, since the recession in 2008 projects of this nature have found raising debt to more difficult. Pöyry supports many utilities and financial lenders on the economics of potential projects and we have found nearly all major infrastructure developments that have proceeded to financial closure, and so allow construction to start, have required some form of EU funding, normally through involvement of the EIB. Private lenders deem the risk to high without the commitment of the EIB and are unwilling to be part of any financing consortium. So any new developments in the region will have to take into account the need to potential financial backers to see EU funding support, which is itself will have to be seen to be supporting the EU’s energy infrastructure objectives.

5.3 Baltic LNG terminal

BEMIP foresees the construction of a regional LNG terminal in one of the four countries. The purpose of this terminal is to provide a means of diversification and security of supply for the entire region. This means it will require a capacity of at least 2.5bcm/a, approximately 25% of regional demand. As an investment, it is thus quite different from regular import terminals, which are typically built to meet incremental demand, not security of supply requirements.

Given the fact that there is already ample capacity in existing import lines, and that gas provided by Gazprom is likely to remain price competitive with imported LNG, it is unlikely that imported LNG would replace all Russian imports. The flows through the terminal may remain small and irregular, consisting of stranded spot cargoes acquired at low price to be put in storage, for example during the summer. This means that the terminal cannot be financed based on throughput alone. A different model will be needed.

An additional purpose that the terminal could meet is to provide a means to build up a market for LNG as a shipping fuel as an alternative fuel source to meet the new sulphur regulations as designated by the International Maritime Organization (IMO)[27]. Imported LNG can be reloaded onto smaller vessels and ferried to ports around the Baltic Sea. This is an important additional purpose for two reasons:

- It helps to put infrastructure in place which is currently missing, but necessary for a market to develop (as required by new emission restrictions implemented by the EU and IMO, and effective from 2015).
- It provides an additional source of income for the potentially under-utilised terminal.

The East Baltic LNG Task Force, which is part of the BEMIP program, is evaluating where the regional terminal should be located. The factors being assessed include security of supply, market development, commercial factors, financial plans, and timing/maturity. Whilst the report prepared for the EC on the future development of the energy gas market in the Baltic sea recommended that the regional LNG terminal should be placed in Finland or alternatively Estonia, this has not yet been agreed to by all the parties involved. Thus the location is still a critical point to be resolved.

Several LNG terminal projects are under consideration in the countries across the region and these are shown in Figure 26. That said, it is Pöyry's view that the size of the market means only one is likely to be required as small scale LNG is not able to complete with Russian pipeline gas and without significant demand increases in each of the markets there is risk that the utilisation factors will not support a positive business case.

5.3.1 Estonia

Estonia has two locations for a possible LNG terminal close to the port of Tallinn; either Muuga Harbour or Paldiski South Harbour.

The Muuga port authority Port of Tallinn has ordered a study with an initial risk assessment which also includes another six alternative locations. As a part of the assessment, suggestions are given for the overall selection of technology for the terminal with regard to the existing facilities in the harbours and other site specific conditions. Balti Gaas is one of the interested developers of the Paldiski LNG terminal.

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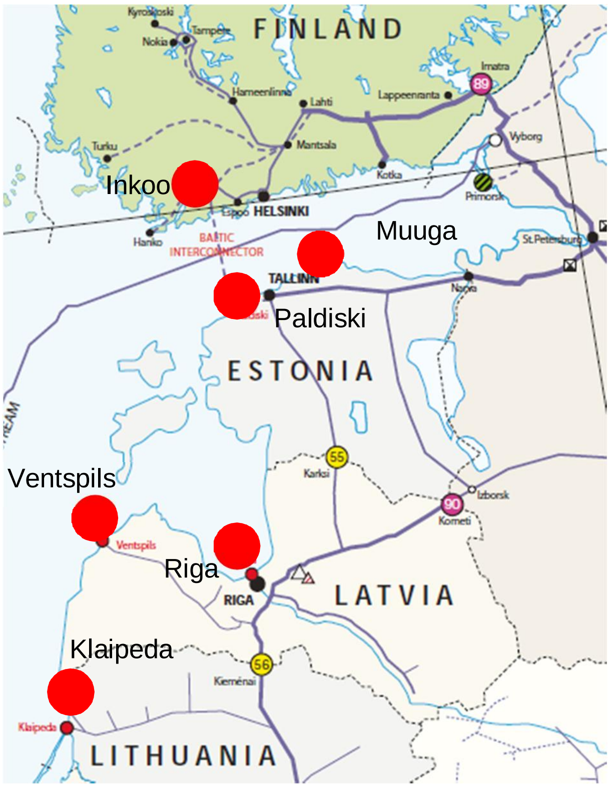
[27] DNV report on Greener Shipping in the Baltic Sea, 2010

Figure 26 – Proposed LNG regasification terminals in the Baltic region



Source: Entsog, Pöyry

During its interview with Balti Gaas, Pöyry obtained its views on progress with the Paldiski LNG terminal. Balti Gaas said that the terminal is at planning stage and will be operational in 2013. Initially, the project is planned to comprise a single 160,000m^3 container small scale terminal, with expectations that it will subsequently be upgraded to double the size in order to become a regional terminal. It believes no external funding will be required for the small scale terminal and it is anticipated that the largest customer will be a new 400MW CCGT, located in close proximity.

In time, the LNG terminal should, ideally, be connected to the Balticconnector. The liberalisation of the Estonian gas market is not crucial for the small LNG terminal, but it will be a prerequisite for a larger one.

As an alternative to Paldiski, another potential location that is being considered for a LNG terminal is Muuga, about 20km east of Tallinn, which will also be very close to Balticconnector. This is being supported by Vopak, who have an interest in the GATE terminal in the Netherlands, and which would be the project developer. In our interview with them they identified what they believed where a number of advantages this project has over the other LNG projects in the region, such as location of existing infrastructure, vicinity to large users and the ability to develop demand growth in the Muuga district.

It also suggested that such a LNG terminal could act as a satellite, downstream of its Gate terminal in the Netherlands, to improve efficiency.

However, Vopak itself would not be a new supplier in the region. It also acknowledged that the Estonian market on its own is too small and a LNG terminal would need to serve a bigger market than just Estonia.

5.3.2 Lithuania

Lithuania is planning the construction of a LNG regasification terminal in Klaipeda. In June 2011, Klaipėdos Nafta, a national oil company and owner of Klaipeda oil import terminal, selected an international company Fluor as a managing adviser for preparation and implementation of the LNG terminal project. The expected capacity of the terminal is 2bcm/a and it is planned to be operational in 2015.

Fluor will be advising Klaipedos Nafta for 4 years, until the end of 2014, and will have to prepare a technical plan for the LNG terminal, assist in selection of technologies, carry out the works necessary for obtaining of mandatory permits, and solve the project security, navigation and other issues related to technical implementation of the project.

Lithuania has a larger gas market than Estonia, although not sufficient on its own to support a LNG terminal at a national level. In addition, EU funding support is not likely to materialise unless it is linked to future interconnection of a regional market.

5.3.3 Latvia

Latvenergo, the national energy company has proposed four locations for a LNG terminal in Latvia: Riga, Ventspils, Liepaja and Vidzeme. Nominal capacity and a project developer have not been decided upon yet[28]. A Latvian member of the European Parliament has announced that the EC will only support construction of the terminal in Riga[29]. However, this is not our understanding of the EC position, as it has made it clear that any financial support must meet its requirements to link the Baltic States into the EU gas market.

5.3.4 Finland

Gasum has performed a feasibility study investigating the possibilities of constructing a LNG regasification terminal in Finland (Inkoo). At present, the future of a terminal in Finland is not clear due to the political debate about what role, if any, natural gas should have in Finland and if it is to have an expanded role if it should be as part of a regional solution.

5.3.5 Terminal location

The East Baltic LNG Task Force is expected to make a decision regarding the location of a Baltic LNG terminal shortly. Without a decision, there will be no EU funding, and implementation of the third energy package for gas will be severely hampered.

It is clear to Pöyry that new infrastructure is neither commercially viable nor financeable using a national approach, and will not attract the support of the EC or EU funds. Market integration and a regional perspective on liberalisation is the best solution. Without the backing of the EC and availability of EU funds, including from the EIB, it is our view that the proposed LNG terminals will struggle to get the private financing needed to proceed.

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28 www.baltic-course.com/eng/energy/?doc=40829

29 www.baltic-course.com/eng/energy/?doc=42975

The location of the terminal will be determined only when agreement is reached between the four countries involved on the preferred location from a regional point of view. It is clear from negotiations so far that objective structural, environmental, temporal and economic benefits and drawbacks alone will not be sufficient to make a decision – some sort of political compromise will be required.

Of the proposed locations for the regasification terminals shown in Figure 26, Paldiski would appear to be a good solution as it sits next to the proposed interconnector with Finland, the largest of the four gas markets and it is critical that Finnish consumers can easily access this new supply source to facilitate LNG deliveries. The proposed capacity of 2.5bcm/a would be suitable for the market size, although the throughput could be low without additional gas demand being developed.

However, planning for the similar sized LNG terminal at Klaipeda in Lithuania is well underway and its national market has a higher current demand for gas than Estonia. Just like Estonia such a facility is seen as critical in improving its security of supply. So there are likely to be difficulties on settling on one location.

5.4 Entry–Exit regulation

Traditionally, gas transport fees have been set based on capacity required, volume of throughput and distance travelled. The regulatory systems in place in the Baltic countries reflect this traditional approach. As a result, there has been concern that due to locational factors, there would be differences in where and how costs are recovered. This situation would arise if a national approach was adopted for tariff setting, where each country recovers costs for infrastructure in its own territory, and charges are added on along the way. For example, Finland was concerned that it might have to pay transit fees to four different countries to get access to gas in Germany. To avoid this, it is clear that a regional approach to regulation and tariff setting would be required.

Our detailed analysis in Annex B.2 identifies that an entry-exit based model is the preferred way forward and this has been suggested for any new regional approach, which would:

- avoid booking capacity in several systems;
- promote gas trading; and
- accord with EU recommendations for other liberalising gas markets.

A regional entry-exit regulatory model effectively means that in order to get access to the joint infrastructure, a shipper has to pay an entry fee at the transmission system inlet, and an exit fee when leaving the system (for example at the interface with local distribution). With this regional model, costs can be shared regionally and location becomes unimportant. The regional model can, if desired, be implemented on top of national regulation, which can then be gradually adapted according to local needs.

5.5 Financing/ownership model

As indicated above, entry/exit regulation is assumed for the infrastructure required under the BEMIP program. This means that the capacity and throughput-based fees will be charged for entry into and exit from the transmission system, rather than be based on the distance travelled. The LNG terminal would constitute an entry point to the regional system.

However, it is likely that only a small part of terminal costs will initially be recovered via entry fees, because of low utilisation. We expect that the remainder will have to be socialised to the entire customer collective, as a transmission surcharge. Thus cash-flows will be secure enough to allow debt financing, regardless of actual throughput.

For this reason, TSOs need to be the primary bookers of capacity, able to resell it to shippers, potentially in an auction based process. TSOs will hold primary capacity on a use-it-or-lose-it basis, i.e. they will not be able to unduly monopolise capacity to prevent shippers from trading. There would need to be mechanisms in place to release all capacity to the market for varying durations on a firm and interruptible basis in response to market requirements. The same principle applies to shippers holding capacity.

The LNG terminal operator will be restricted to operating the terminal, running capacity auctions and to promoting utilisation. He should not be allowed to trade in gas, or to hold capacity. The LNG terminal operator is compensated by a management fee, coupled with incentives to increase terminal utilisation and treat all shippers fairly and equitably.

5.5.1 Private vs. public ownership

Gas infrastructure is characterised by economy of scale, large irreversible investments and external effects, which may lead to market failure. Therefore, the market may not be the best instrument to attract optimal investments.

Traditionally, most LNG facilities are privately owned. However, political concerns about fossil fuel energy security, a desire to encourage construction of new facilities, a move towards privatisation in energy sector and reduced funding availability as a consequence of the financial crisis, have led to alternative ownership structures being considered.

The alternatives to private ownership are public ownership or regulation of private ownership. Transferring public ownership of production and/or transmission and distribution systems to private ownership may be a part of a liberalisation process.

There are pros and cons to both public and private types of ownership. Under private ownership, the major challenge is the design of a regulation that gives incentives both for efficient utilisation of the existing LNG infrastructure, and for optimal investments. Under public ownership, the major challenge is the design of incentives for efficient use of resources, avoiding inefficiencies due to high-cost operations and investments. There are examples of successful public LNG ownership in several South American countries, as a part of a LNG programme designed to reduce uncertainty in gas supply. However, the EU has guidelines on provision of state funds and any support from public funds may require approval from the EC.

5.5.2 Cost allocation between all countries in the region

The majority of costs (i.e. those not covered by entry fees) will be carried by the entire consumer collective. Thus, costs are distributed between countries in relation to market size. Over time, the surcharge will have to be adjusted to reflect market growth, and terminal utilisation.

5.6 Economic analysis of Baltic infrastructure projects

Having identified various projects that could facilitate a regional approach we need to consider their viability. To compare the projects on a like for like basis we calculated levelised costs of the projects on a per MWh of capacity usage basis (see Section 3.8.1. for this methodology), with the results shown in Table 11. Please note, that the table contains total costs of projects; these are calculated as present value of capital costs and operating costs of these projects, discounted at an assumed cost of capital of 10%.

For comparison purposes we have assumed a lifetime for each asset 20 years and 10% cost of capital for each of the considered projects. Capital investment costs and operating costs assumptions are taken from public sources; in cases where the data was not available we have used values from similar projects.

The analysis shows a regional LNG terminal has similar levelised costs to the PolLit link, due to similar sizes of the projects and investment costs.

A regional LNG terminal in the Baltic region will also require expansion of the capacity of the existing pipelines between Estonia and Latvia and between Latvia and Lithuania. We estimate the total costs for the both of the pipelines to be around €115 million.

Balticconnector has the lowest costs of the two new pipelines, due to the lowest investment costs involved, although as this will be a sub-sea link its cost estimate may have a high degree of uncertainty. The Estonia-Latvia interconnector upgrade is also cheaper than the Latvia-Lithuania interconnector upgrade, due to shorter length of the former.

Table 11 – Levelised costs of proposed projects

Project	Total cost (€ mil)	Capacity (bcm/y)	Levelised cost (€/MWh)	Levelised cost (€/1000m3)
LNG terminals				
Medium size LNG terminal	375	2.6	1.57	16.9
Interconnectors				
Pollit link	340	3	1.23	13.3
Balticconnector	134	2.6	0.56	6.0
Pipeline expansion				
Estonia - Latvia	37	1.7	0.24	2.6
Latvia - Lithuania	87	1.7	0.56	6.1

Source: Cedigaz, European Commission, Foster Wheeler, TGE gas, Pöyry analysis

An alternative measure is to look at the economic impact if the costs are socialised across all the regional consumers, akin to a security of supply levy.

We can also compare the results of the regional levy method against the local levy described in Section 4.3.4. The regional approach has a higher number of projects with higher investment costs, as opposed to the local approach, with only one project. However, regional gas consumption is much larger, compared to local gas consumption of Estonia alone. As a result, the regional approach results in a lower additional cost of €4.7($6.4)/1000m^3 over 20 years, or a 1.1% increase over the existing gas price of €440/1000m^3, see Figure 5 for gas prices. A relatively more expensive local LNG terminal will result in a 2% gas price increase over the current price.

Pöyry has also been asked to consider the case of a medium sized LNG terminal being utilised only by Estonia and Latvia, reflecting the case of Finland remaining non-committal to expanding gas usage and Lithuania continuing to develop its own LNG terminal. In this case only two infrastructure projects would be required: the medium size LNG terminal and the Estonia–Latvia pipeline expansion. The total costs of these projects will be €560 million less compared to the regional approach, which will result in a gas price increase of 1.9%, similar to the local small scale LNG case.

Table 12 – Socialised economic impact of local and regional approach

Approach	Total costs, € mil	Additional cost for 20 years, €/1000m3	Additional cost for 20 years, $/1000m3	% increase over the current price
Local	125	8.9	12.2	2.0%
Regional	972	4.7	6.4	1.1%
Estonia + Latvia	412	8.2	11.2	1.9%

Source: Cedigaz, European Commission, Foster Wheeler, TGE gas, Pöyry analysis

5.7 Advantages of regional approach

5.7.1 Market size

In order to attract market participants, the cost of operating in the Baltic region must be exceeded by the expected benefit from operations there. A single gas market across the region would allow new entrants to target all four Baltic nations and minimise set-up costs. Each market alone is unlikely to be large enough to attract significant numbers of competitors required to deliver the benefits of liberalisation, but the combined market might attract both new sources of gas and market entrants. Table 13 shows not only the benefits of combining the market size but the consistent level of demand, which will give some confidence to potential new entrants.

Table 13 – Baltic region gas consumption

bcm/year	2006	2007	2008	2009	2010
Estonia	1.01	1.00	0.96	0.65	0.70
Finland	4.76	4.57	4.74	4.27	4.71
Latvia	1.76	1.70	1.67	1.53	1.82
Lithuania	3.07	3.62	3.25	2.73	3.12
Total	**10.60**	**10.89**	**10.61**	**9.18**	**10.35**

Source: IEA

5.7.2 Increased competition

As noted, allowing parties to access a single medium sized regional market rather than four small markets may attract new entrants to compete for business. New entrants competing for business should reduce costs for the end user alongside stimulating innovative product offerings as retailers attempt to differentiate their products.

The market could be designed such that the incumbent company in each market (listed in Section 2.2) has the obligation to release gas from their portfolios to allow new entrants access to existing supplies. This has been practiced elsewhere when competition has been slow to develop (UK, Germany and Denmark). The incumbents should also be allowed to compete for market share in the neighbouring markets, instantly creating three credible alternatives to each incumbent (assuming consumers are prepared to switch away from their own national provider). However, as the ownership of three of the incumbents is very similar (Finland being the exception), the question remains whether they would actively compete for market share.

5.7.3 Security of supply

A single regional market with increased interconnection will increase security of supply for the region. Security of supply would be further enhanced through the introduction of a LNG terminal which would reduce dependence on Russian gas.

A regional market could benefit from infrastructure being better optimised on a regional basis than on a national basis. The existing infrastructure (pipelines from Russia, the storage facility at Incukalns, current interconnection between Estonia, Latvia, and Lithuania) and the proposed new infrastructure (such as Balticconnector) suits a regional market and would deliver security of supply for each of the Baltic countries. This would be a more efficient outcome than each country attempting to address security of supply concerns in isolation from each other.

5.7.4 Signal for EU support

The only gas market that is not currently run along national borders is that in the North and Republic of Ireland, with further integration rules planned. However, the development of a regional gas market in the Baltics would thus send a strong signal that the Baltic nations are committed to the EC vision of a single European gas market and wish to demonstrate that the Baltic region is an open market for all participants.

5.8 Barriers to regional approach

A single gas market across four separate nations will cause some barriers which would need to be overcome before the benefits of liberalisation can be delivered. We have identified the following issues.

5.8.1 Political issues

The development of a Baltic regional market will require the governments of all countries involved to believe that such a plan will benefit the region and will not be to the significant detriment of any single nation within the region. The countries will become increasingly interdependent and thus the gas network and development of infrastructure will be for the benefit of the region rather than to secure the interests of any single nation. Currently, three of the Baltic States have plans for a LNG terminal, but only one will be necessary – so two of the countries will need to ensure that they are able to secure the benefit of the terminal being located in a neighbouring state. The progress of the East Baltic LNG Task Force will illustrate the political will of the parties to work together.

5.8.2 Time to put in place

A single gas market will require four governments, regulators, and gas companies to agree on a range of complex issues. Assuming that the political will is present, there remain a number of detailed agreements that would need support from the major market participants. This will take time to develop and agree.

There would be a considerable advantage if the regional market could be agreed by 2015, which is the latest date that the derogation from EU Third Party Access (TPA) rules could expire. Putting in place a single regional market at this time rather than four national markets and then having to combine the rules thereafter would prevent significant inefficiencies.

2015 also coincides with the expiry of the long-term contracts supplying Estonia and Lithuania. If new entrants are persuaded that there will be a regional market by this time, there may be an opportunity to replace the contract supplying the incumbents with more than one contract supplying competing market participants.

The physical infrastructure required will take considerable time to plan, build, and commission.

5.8.3 Single source of gas

Developing a regional market may not be a sufficient condition in isolation to ensure the success of competition. If all parties are supplied by Gazprom, then it will be difficult for any new market participants to enter the market without a separate gas release programme by the incumbents. The role of a LNG terminal to introduce competition to Russian gas is therefore vital.

The incumbent companies having a similar cost base (currently based on Russian imports) may not in itself be a bar to competition developing; for example in the case of Great Britain competition developed from a position where many parties were supplied via similarly priced oil-indexed contracts. Parties could compete through reducing non-energy costs or through developing attractive or innovative terms and conditions.

The BEMIP high level group has observed that cost differences do exist between the nations as Estonia and Latvia have negotiated a 15% discount on the price of gas from Gazprom that Lithuania has not secured. It has also noted that Baltic prices are above the German border prices despite the lower transit costs of supplying the Baltic region. These facts could be taken to demonstrate that Gazprom is able to extract a significant rent from its position as a monopoly supplier.

5.8.4 Cost allocation

New infrastructure is unlikely to be commercially viable in isolation. The benefits to the region will be delivered through enhanced security of supply and through reduced costs to end users as competition is stimulated. It may be necessary to allow the socialisation of the initial capital costs in order to encourage investment. If costs are to be socialised, the rules by which costs can be passed to the gas users of the four Baltic States will need to be agreed.

5.8.5 Financing and ownership

Assuming that rules can be agreed that determine how the costs of any investment will be recovered, investors will need to be found to raise the capital required. It is important that the investors are independent of the current incumbent supplier in order to allow genuine competition to develop. Ideally investors would also be independent of the incumbent suppliers as well (even if the Gazprom did not hold a significant stake in three of the four incumbents).

However, based on Pöyry's experience of advising utilities and banks on major infrastructure projects such as these being considered here, it is clear that without EU grants and/or loans private funding from Banks and other institutions will not be forthcoming. So projects will either have to receive funding via consumer levies or direct from Government funds, with both potentially requiring EU approval under state aid guidelines.

5.8.6 TSO cooperation

There is currently a national TSO in each country in the region. In order to operate the combined transmission system on a regional basis a significant level of cooperation will be required between them. It may be more efficient for a single regional system operator to be established that will be able to optimise the operation of the combined system. This may be achievable via some form of contractual joint venture between the existing TSOs. Whatever the solution, significant political will and effort is likely to be necessary to ensure this step.

5.8.7 Is a Baltic regional market big enough to attract new entrants?

A combined market would be slightly larger than the markets in either Ireland or Denmark. Both countries have liberalised markets and have witnessed development of competition between suppliers to end consumers. For example, in Ireland, though Bord Gais Energy (BGE) has a 93% share of the residential supply it has only a 40% share of the total gas market, with less than 50% market share in industrial and commercial sectors[30]. There are approximately six independent new entrants to the industrial and commercial sector, and it is expected that over time competition within domestic users will also develop. Competition has also developed through BGE entering the electricity market and offering dual fuel products to customers.

5.9 Summary

A regional rather than a national approach would deliver the greatest benefits to the end consumers of the Estonian and other Baltic gas markets. However, there will be significant political and logistical barriers which will take time and will to resolve. The costs of new infrastructure will be high, but investment is necessary to introduce a competing source of supply to Russian gas. Security of supply to the region, as a whole, would be significantly enhanced by a LNG terminal and improved interconnections, e.g., the Balticconnector, and so some of these costs should be shared amongst the consumers of the region. The infrastructure required to build a new LNG terminal and provide the interconnections across the region will require EU funds, either through EC grants or EU loans through the EIB. These will not be forthcoming unless the projects are agreed as delivering the objectives that the EC has laid down for linking the Baltic gas markets into the rest of the EU.

The regional market would ideally be operated by a single market operator that is able to optimise gas flows across the region. An entry-exit system would be introduced and entry-paid gas traded freely at a new single hub, which may be termed the Baltic Balancing Point (BPP).

It would be expected that the size of the regional gas market would be sufficient for new entrants to be encouraged to enter the market and to begin to compete against the incumbent suppliers.

Finally, a region wide gas release programme would require all the incumbents to auction a fixed percentage of their contracted gas supplies to new entrants thereby encouraging greater competition and reducing barriers to entry. The market incumbents would be able to compete across the region.

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30 Gas Market Update Q4 2010, Commission for Energy Regulation

6. IMPLEMENTATION OPTIONS

There are a number of potential developments being considered for the Estonian gas market, see Section 4. In Section 5, the Baltic region gas demand and planned infrastructure was described in detail and the advantages of and barriers to a regional approach to liberalisation were discussed. In this section we first consider whether LNG, both small and regional scale, could be competitive with Russian gas pipeline deliveries. We will then consider the feedback from consultations we have undertaken with various stakeholders across the region and use this to develop a set of scenarios that bring about improvements to security of gas supply and/or achieve a liberalised market. Finally, we will identify what needs to be done in order to achieve the best outcome for liberalisation and set out the next steps.

6.1 Pipeline and LNG price projections

Pöyry projects oil-indexed contract prices, based on our oil price model and assumptions, and a LNG spot market price which is derived from detailed proprietary modelling of European, Far Eastern and US gas market developments using our Pegasus model (see Annex E.3.1. for more details).

In Table 14 we show various illustrative projections of likely market prices for both pipeline supplies from Russia and LNG supplies that could potentially compete if a LNG terminal was built. It should be noted that these are based on our Pöyry Central scenario projections using an internally consistent set of assumptions. The actual outturn of prices is likely to be different. In addition, a different set of assumptions would produce a different set of projections but by using a scenario approach it does allow a comparison to be made based on the same set of assumptions and so provide an indicator of what future prices may be.

Table 14 – Illustrative gas source price projections, 2011-2020 (€/MWh)

Gas price in Estonia on current terms (80% oil indexed)	Projected price of new Russian pipeline gas developments	Medium size LNG price (delivered to Estonia)	Small scale LNG price (delivered to Estonia)
21 - 24	27 - 28	26 - 29	29 - 32

LNG costs are based on an average of a basket of illustrative LNG costs in the Atlantic basin, including such supply sources as Algeria, Nigeria, Egypt, Norway, and Trinidad and Tobago. LNG prices include the likely oil indexation component pertinent to LNG contracts and the additional transportation costs to Estonia. For the medium sized LNG terminal we assume a standard size LNG vessel is used.

For small scale LNG we believe it will be delivered to Estonia via two stages: first to a large LNG regasification terminal in a large LNG tanker and, second, reloading this LNG onto a smaller tanker and delivering it to the small scale LNG terminal. Terminals such as Zeebrugge in Belgium have such a facility and the GATE terminal in the Netherlands is considering investing in such capability.

Pipeline gas costs are derived from new supplies delivered from the Yamal region of Russia. These fields are expected to provide much of the Russian gas exports in the future, as the traditional fields deplete. In a similar way to LNG, pipeline gas prices have a large oil indexation component, which is already present in existing Gazprom contracts.

It is also worth noting that LNG has lower costs compared to Russian gas from new developments, due to relative difficulty of gas development in remote areas of Yamal and due to the requirement of building significant new infrastructure to bring it to the European markets. That said, LNG is also used heavily in the Far-East and this region has historically shown that it is prepared to pay higher oil-indexed prices than spot cargoes currently entering the European market.

In addition, in Table 14 we have benchmarked both LNG and pipeline gas prices against oil indexed gas prices delivered under an estimate of the current Estonian gas contract price with Gazprom. The latter has been projected into the future by assuming that the gas price has fixed and an oil indexed components, as is the case with other known Gazprom contracts, and using the same Pöyry oil price projections used above. It has the advantage of showing any potential benefit of retaining the current contract terms and prices.

Table 14 shows that based on the scenario assumptions, LNG and new pipeline gas prices to Estonia are very similar over the long-term. Small scale LNG is expected to be more expensive and so be less competitive with pipeline gas due to additional transportation costs involved. It also shows that the gas price in Estonia based on current terms is lower compared to the projected price of gas from new fields, due to easier availability and pre-existing infrastructure.

In considering how competitive the gas price could be it, it is worth noting that LNG has higher margins compared to pipeline gas, so the LNG price can be reduced to a larger extent, especially when there is supply competition with sufficient demand to make LNG deliveries attractive. However, the global nature of LNG also means that the very high prices being paid in Asia could result in a significant proportion of spot LNG cargos not being available to the European market at the prices identified above. The extent of this will depend on how Chinese and other Far-Eastern gas demands grow in the next decades.

In summary, a small scale LNG would struggle to compete on price with Russian pipeline supplies. A medium sized facility has the potential to compete, especially if there is sufficient new demand to make the extra delivery costs worthwhile. That said, if the current Estonian Gazprom contract is renewed under the existing terms from 2015, LNG is unlikely to be able to compete.

6.2 Key issues and stakeholders' views

Before identifying a set of scenarios for potential liberalisation it is important to consider the views of various stakeholders across the region. As part of this study Pöyry has undertaken a series of stakeholder interviews. The parties interviewed were: Balti Gaas; Eesti Gaas; Elering; Estonian Ministry of Finance (MoF); Estonian Prime Minister's Office; Estonian Competition Authority (CA); EG Võrguteenus; Estonian Ministry of Economic Affairs (MOEA); Eesti Energia; Estonian Parliament representatives; Latvijas Gaze; Gazprom (shareholder in Eesti Gaas); Klaipedos Nafta (developer of a Lithuanian LNG terminal); Latvian Department of Energy, Ministry of Economics; and Vopak (potential developer of a LNG terminal in Estonia and partner in the GATE LNG terminal in the Netherlands).

From these we have identified the following key issues that the stakeholders believe are vital before a successful liberalised market can be achieved. It should be noted, however, that not all parties believe such a change is necessary.

6.2.1 Single source of gas

Gazprom does not believe that having a single gas supplier has disadvantaged the Baltic gas consumers, and this was illustrated by end-user gas prices being lower than the EU average, see Figure 5 on page 19. A number of stakeholders cited the single source of gas as a barrier to competition and consequently to liberalisation. Others have cited it as a security of supply risk, which Eesti Gaas discounted.

However, in the next few years the Baltic gas markets could have moved on – the current Estonian supply contract with Gazprom expires; the exclusive Latvijas Gaze AS contract for storage use will expire in 2017[31]. If oil prices are much higher by this time, contract renewal negotiations could start from a higher base price, and whereas other markets in Europe have the traded hubs to offer an alternative, the Baltic region may find negotiations with a single supplier more difficult.

The timeline in Table 15 shows the expiry of the contracts coincides with plans to unbundle Eesti Gaas and develop LNG supplies. Even if a regional market was not yet complete, progress towards better interconnection across the region and with the rest of Europe would certainly offer some leverage in negotiations with Gazprom.

Pöyry would recommend measures to encourage new gas supplies into the region on the grounds of avoiding the single supplier risk in the future; potential new suppliers will encourage new entrants and contribute to gas market growth.

6.2.2 Regional approach

The regional approach to liberalisation is a good idea for all the reasons outlined in Section 5.6, but stakeholders have identified many of the barriers also outlined in this report.

LNG developers see the regional market as an opportunity to sell more gas, but individual countries need to be persuaded that there will be benefits for all, wherever a terminal is situated. Eesti Energia is not concerned in which country the LNG terminal is located but considers access to the gas networks essential. This will require TSOs working together and a single system operator to establish rules for a robust entry-exit model and TPA.

The size of the Estonian gas market makes some stakeholders downplay the importance of gas, 'it plays a minimum role', and a regional market may encourage more of an interest. Various stakeholders also identified that improved interconnection would be the next most important step after having more than one supply. It would provide market size to attract new entrants and provide more efficient pricing signals.

Pöyry recommend pursuing a liberalised, regional gas market because it delivers the lowest cost to consumers and meets the criteria set by the EC for future funding. Without such funding it is not clear that any of the identified infrastructure projects will get the financing needed to meet both the security of supply concerns and achieving the integration of the Baltic gas markets with the rest of Europe. Whilst there are barriers to be overcome and even if plans for a regional market take longer than expected to deliver results, the threat of competition can go a long way to encouraging a better outcome from the current incumbents.

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31 www.bloomberg.com/news/2011-07-29/latvia-seeks-to-allay-estonian-fears-over-lng-terminal-plan.html

6.2.3 The future of gas demand in the region

In Section 3.8 we describe the potential of gas as a fuel for electricity generation in a low carbon Europe. In terms of cost, gas is cheaper than renewable generation technologies and in terms of emissions it is relatively clean and efficient compared with other fossil fuels.

As members of the EU, the Baltic States will have to meet increasingly demanding targets for CO_2 emission reductions. Historically, gas has proved to be a good value choice to achieve emission targets in other EU countries, such as the UK, and Eesti Energia suggest 1000MW of oil shale power generation in Estonia must be replaced by 2023, and a potentially a large proportion of the new generation could be gas-fired. This potential was analysed in detail in Section 4.4, which showed a positive benefit from such a switch. However, not all stakeholders believe this will be the outcome, with many expecting a mix of generation, including nuclear and new renewables.

So the future for gas in power generation has the potential to transform the position of gas in Estonia. However, Eesti Gaas have concerns that subsidies to renewable energy will be a problem for gas, and so believes the potential future market will be the industrial sector.

6.2.4 National policy framework on gas

The national policy framework for natural gas is one factor influencing the liberalisation agenda which is controlled to a large extent by the Estonian Government. To help give stakeholders confidence that liberalisation will progress and ultimately be achieved, this should provide strong and clear long-term policy signals on the future role of gas which are consistent with the Government's liberalisation strategy.

The Office of the Prime Minister and Parliament have both stated that the political will to undertake further gas market liberalisation exists. However, a number of stakeholders have commented that the Estonian authorities have in recent years seen growth in natural gas usage as undesirable given the current import dependency on Russia, and that this has not been a positive message to potential new suppliers or investors in infrastructure. There is a strong theme through the current national energy policy of maintaining oil shale as a major fuel for electricity generation (with plans to even use this in gas turbines assuming this becomes technologically proven), whereas in a properly liberalised market natural gas could compete successfully, on both economic and environmental grounds, without compromising security of supply (see Section 4.4).

The current target for natural gas to form less than 20% of the energy mix in 2020 is also relatively stringent in the context of an expansion of gas-fired power generation, the addition of a single 400MW CCGT running at a 70% load factor potentially breaching this.

Pöyry recommend that the national policy framework relating to natural gas is clarified in the light of the liberalisation process. This might well provide a clearer and more positive long-term signal on the future role of gas to market participants.

6.3 Implementation scenarios

There are various liberalisation options available to Estonia, as outlined in Section 4. Our view is that a regional approach, as outlined in Section 5, has the potential to resolve many of the issues facing both the Estonian and the wider Baltic gas markets. However, at the present time, outcomes are uncertain for various initiatives and infrastructure projects, including new LNG terminals and interconnectors. The current timeline for these developments in Estonia and the Baltic region are shown in Figure 27.

In order to put some structure to the potential options associated with these timelines we have considered some alternative scenarios. Having established that ownership unbundling is the most robust form of implementing the 3rd Gas Directive, we have assumed this goes ahead in each scenario, but the other developments differ under our scenarios as follows and summarised in Table 15:

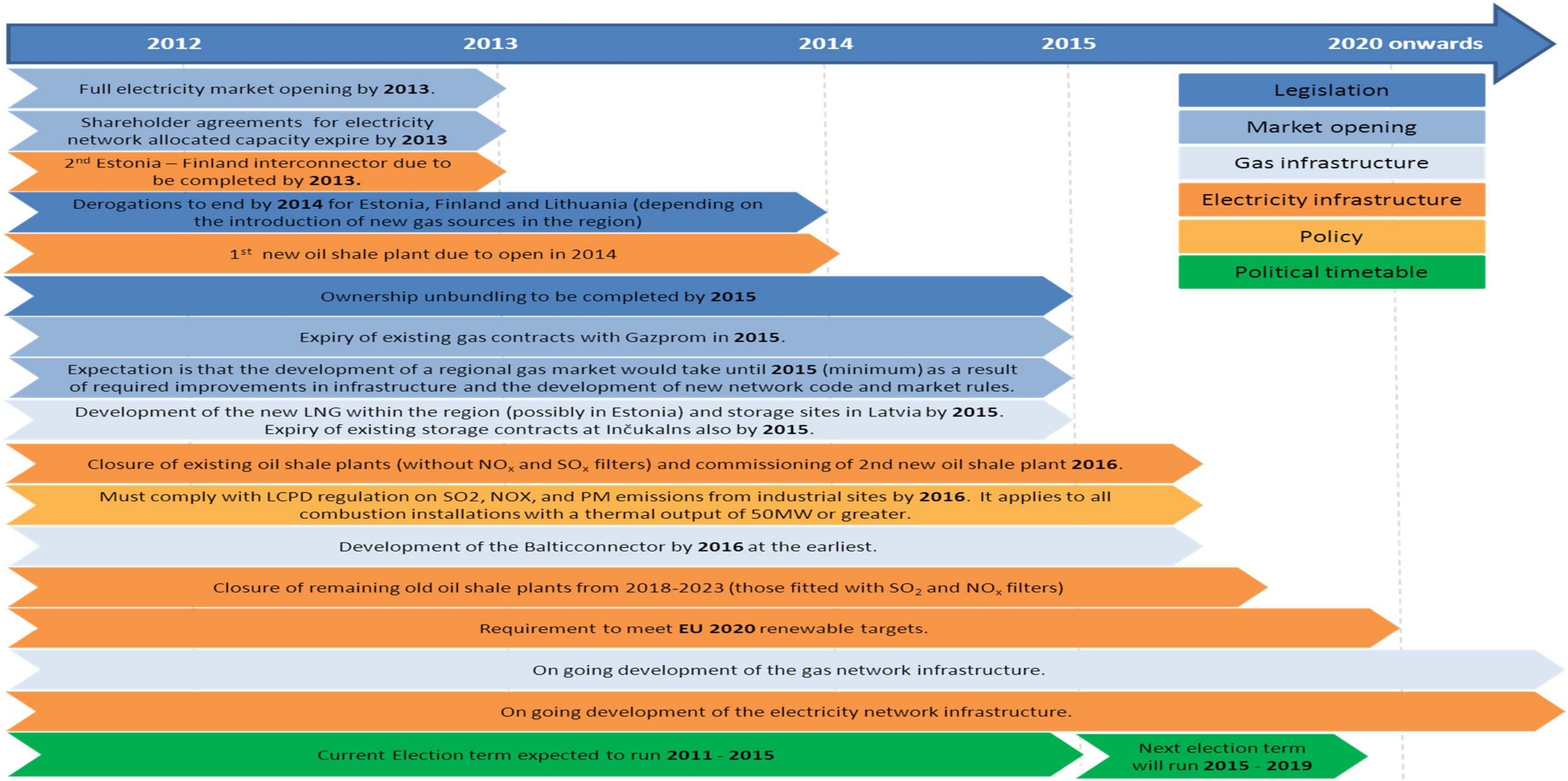
- ***Estonian supply security*** – where only a small scale LNG terminal built in Estonia, there is little growth in the gas market, no Balticconnector is built and there remains a continued reliance on Russian gas.
- ***Estonian power switch*** – where a medium sized LNG terminal is built and there is a transformation in the gas market through the development of CCGTs as a displacement of oil shale in power generation. In addition, a gas release programme is established.
- ***Regional liberalisation*** – where a regional Baltic market is developed alongside at least one medium sized LNG terminal, gas demand for competing suppliers is larger through access to c10bcm of regional demand and the Balticconnector and other inter-state interconnectors are built. Under this scenario we also anticipate the liberalisation of all Baltic gas markets and gas release programmes from the incumbents being established. We do not assume any transformation of the Estonian power market.

Table 15 – Summary of market development scenarios

Scenario	Ownership unbundling	LNG terminal	CCGT demand growth	Regional Market	Balticconnector & other inter-state pipes
Estonian supply security	✓	Small scale	✗	✗	✗
Estonian power switch	✓	Medium size	✓	✗	✗
Regional Liberalisation	✓	Medium size	✗	✓	✓

These scenarios are now discussed in more detail.

Figure 27 –– Timeline of various activities & proposals In Estonia and the region



6.3.1 Estonian supply security scenario

Under the Estonian supply security scenario Eesti Gaas ownership unbundling is enacted. The System Operator develops a Network Code that provides transparent transportation rules based on an entry-exit system.

According to our assumptions from Section 4.3.4, a small scale LNG terminal will have an investment cost of €100 million. Assuming that the cost of the terminal is socialised through a security of supply levy across Estonian gas customers, consuming 0.7bcm of gas, the investment cost would equate to a €8.9/1000m^3 levy, which equates to a 2% increase in consumer bills over the assumed 20 year lifetime period.

However, as shown in Section 6.1, the price of small scale LNG is not attractive when compared to Russian pipeline supplies and so little or no gas is delivered to challenge the Russian dominant supply position. Thus, there is no development of a gas trading hub or competition at the wholesale level. The small scale LNG is not large enough to encourage any switching to gas in power generation.

Efforts towards a regional market are not progressed and the region as a whole remains an isolated energy market. No new entrants enter the market, which remains small and unattractive to outside investment. Supply competition does not develop and Eesti Gaas retains its current level of market share.

The goal of effective gas market liberalisation is not achieved, although the security of supply improvements achieved through the above mentioned levy may be deemed worthwhile to some stakeholders.

6.3.2 Estonian power switch scenario

A medium sized (c.2.5bcm) LNG terminal is developed (in either Paldiski or Muuga) which is competitive, on price, with Russian gas supplies. In parallel, the decision is made to switch the current oil shale generation to new gas-fired CCGTs, realising the benefits identified in Section 4.4. This provides sufficient demand security to underpin the LNG terminal investment and to attract competitive spot LNG cargos or for longer term contracts with LNG producers. As a result of this, there is no need to socialise the costs across consumers.

The Eesti Gaas Networks business ensures connection of the LNG terminal to the transmission system and any necessary reinforcement is put in place so that LNG can, if required, flow to the Incukalns storage facility in Latvia. Additional flexibility is available to the Estonian gas market through LNG storage tanks that are developed as part of the LNG terminal. Thus, Estonian security of supply concerns are alleviated.

Significant utilisation of the LNG terminal provides the incentive for the development of a wholesale gas market, encouraging large end users to seek alternative suppliers to Eesti Gaas. LNG is also used for injection into the Latvian storage facility to improve seasonal supplies and security of supply. Such a LNG facility would be funded through a combination of EU funding and private investment.

In addition, a gas release programme is mandated, whereby Eesti Gaas is required to auction a fixed percentage of its contracted gas supply to new entrants, thereby encouraging greater competition at the wholesale level. Ownership unbundling of Eesti Gaas takes place and the unbundled transmission operator establishes an entry/exit capacity, tariff and balancing regime.

In this scenario, the growth in the market and the competing supply source encourages the development of more competition at the wholesale gas level and some new shippers enter the market to serve the larger Industrial and Commercial (I&C) and CCGT demand. However, the retail market remains at its current size and there is likely to be little development of competition at this end of the market due to low margins and a high cost to serve the end user.

The benefits to the Estonian gas market under this scenario are at the wholesale level as LNG provides access to international markets. This in turn leads to competitive pressure on the current dominant supply source and leads to a market price for gas. By capturing the value from switching to cleaner gas in power generation Estonia is able to make a significant step forward in delivering a lower carbon footprint and reach 78% of the 2020 target.

6.3.3 Regional liberalisation scenario

Under this scenario, a regional gas market is achieved that includes Estonia, Finland, Latvia and Lithuania. It is vital that Finland participates: it has the largest gas demand and its inclusion means that infrastructure projects are more likely to receive EC funding in support of the objective to remove the isolation of the Baltic States from the rest of the EU.

This will be achieved by the Balticconnector link between Estonia and Finland,, the Amber PolLit pipeline between Lithuania and Poland, enhanced interconnection between Estonia and Latvia and between Latvia and Lithuania and a medium sized LNG facility located at one of the proposed sites in the Baltic region. The investment into these five projects (see Section 5.6) will require capital costs of €810 million or €972 million of total costs, which if socialised across all regional consumers would equate to an additional €4.7/1000m^3 levy.

This scenario does not assume a switch to using CCGTs in Estonia, although such an additional switch would perhaps further secure gas supplies into the regional and increase its attractiveness to potential LNG developers. It is likely that access to new gas supplies will mean demand will grow across the region, meaning that the costs will be further diluted.

The regional market is operated by a single market operator that is able to optimise gas flows across the region. An Entry-Exit system is introduced and the market incumbents are able to compete in each other’s home markets.

A single gas trading hub, termed here as the Baltic Balancing Point (BBP), is established and entry-paid gas can be traded freely. This encourages further liquidity at the wholesale gas level which is reflected in competitive gas prices for I&C and residential sectors.

Due to the size of the regional gas market, new entrants are further encouraged to enter the market and begin to compete at the retail level. In addition, liberalisation of the retail electricity market means dual-fuel offerings can be made by all suppliers, further increasing the level of competition.

Security of supply to the region, as a whole is enhanced by the LNG terminal and the various interconnectors, and in particular the Balticconnector.

A region-wide gas release programme is established, which requires all the incumbents to auction a fixed percentage of their contracted gas supplies to new entrants, thereby encouraging greater competition and reducing barriers to entry.

This scenario will likely deliver the greatest benefits to the end consumers of the Estonian and other Baltic gas markets as the costs to all are lower than the alternative of a single

Estonian supply security scenario. However, we recognise that there will be significant political and logistical barriers (which are outlined in Section 5.8) to the achievement of such a regional approach and that it may realistically be some way into the future.

6.4 Implementation recommendations

Our conclusion from our analysis is that the scenario that delivers a liberalised market with the greatest overall benefits and for the most reasonable cost to consumers is the regional approach. This scenario includes new infrastructure including a LNG terminal and improved interconnection between the Baltic States. The interconnection between Estonia and Finland, via the Balticconnector, is vital as Finland is the largest market in the region. Although this scenario has the greatest potential benefits, it also faces the greatest challenges in terms of political will, investment incentives, coordination and timing.

The next option that delivers positive benefits to Estonia is to adopt a policy of switching from oil shale to gas-fired power generation. This would provide a very significant increase in demand in the country and provide the incentive for a medium-scale LNG terminal to be built. This has the benefit of providing competitive gas supplies and ending the reliance on a single supply source from Russia. Under this scenario, delivering ownership unbundling and mandating a gas release programme will further embed the benefits that can be achieved from the liberalisation process.

The option with little or no direct benefit to achieving a liberalised market and with the highest cost to Estonian consumers is that where a small scale LNG terminal is constructed to only improve security of supply. Small scale LNG will be unable to compete with Russian supplies on price, leading to low throughput and little incentive to external investors. Such a LNG terminal will need to reimbursed by a security of supply levy on Estonia consumers. In this scenario, ownership unbundling of Eesti Gaas will, by itself, have no direct benefit and cannot be seen as a precursor to other events, unless commitments are made to either transform the Estonian power generation mix and/or progress to a successful regional implementation plan.

6.5 Next Steps

To deliver our recommendations, the Estonian authorities need to take these next steps:

Increasing demand

- Encourage increased use of gas, especially in power generation, to increase the market attractiveness to new suppliers and new entrants. The most efficient way of achieving this is to commit to converting oil shale generation to new CCGT gas fired plants. This also has the additional benefits of lowering Estonia’s carbon footprint.

Developing a regional approach

- Commit to removing barriers and promoting options that allow the successful integration of the Baltic States.
- In particular, assist in facilitating the development of the Balticconnector and resolving the location of a new regional LNG terminal using an agreed set of benefits criteria.

Improving competition between gas suppliers

- Mandate a gas release programme whereby a fixed percentage of gas imported by Eesti Gaas is either auctioned or sold at an agreed tariff or at a level to reflect international prices (say NBP or TTF linkage) on the wholesale market.

Unbundling strategy

- Full ownership unbundling is recommended but only as part of the wider package of liberalisation measures.

National gas policy statement

- Development of an Estonian Gas Sector Development Plan to encompass the above changes as a clear and open statement of the commitment to bring about change.
- The plan should also consider whether, for security of supply benefits, a small scale LNG terminal should be built in Estonia, although without other changes, such as significant increases in demand or size of the market, this will have to paid for by a levy on all consumers. If the wider liberalised market is achieved there is a risk that such a small scale LNG terminal would not be required, unless it forms the start point for the expanded regional facility.

For liberalisation to be successful it will require progress to be made across all of these, as achievement of one, on its own, will not achieve the expected benefits. The Estonian government does not have direct control over all of these factors, but where it does, it will need to engage with stakeholders to bring about a common understanding and acceptance of the changes being made. For example, it should look to avoid the type of legal disputes happening in Lithuania in response to its new unbundling law. We have highlighted some best practice principles in Annex C.4 for consideration in developing the detailed activities.

6.6 Key dates

In order to deliver the actions identified above it is important to consider the short window of opportunity available to achieve successful liberalisation. As shown in Figure 27, the expiry of the existing gas contracts with Gazprom in 2015 provides the back-stop date by which many of other activities need to be completed.

The development of an Estonian Gas Sector Development Plan would signal to the market and to potential new entrants:

- the intention of the government to expand the role of gas in the energy mix;
- The key interdependencies between the various elements;
- the support mechanisms and deliverables that are required to achieve it; and
- the dates and key milestones that will need to be achieved.

Key elements of the Gas Sector development Plan will include:

- support mechanisms for new gas supplies and associated infrastructure on a national and regional basis;
- the achievement of ownership unbundling;
- the establishment of a gas release programme; and
- agreement between the Baltic states on how to integrate the markets with improved interconnection and access rules through a common system operator.

ANNEX A – THE LIBERALISATION PROCESS

This section discusses the theoretical benefits of gas market liberalisation. It is not the intention of this section to address the specific issues faced by the Estonian gas market unless this is clearly indicated.

This section also outlines the development of EU gas market legislation and provides an overview of the liberalisation process in several selected Member States.

A.1 Market conditions

Gas market liberalisation can bring a wide range of benefits which filter through to consumers if market conditions are favourable. The degree to which liberalisation is successful at generating such benefits and delivering them to consumers is driven by the following market conditions:

- ownership unbundling;
- access to competing sources of gas;
- access to infrastructure (transport and storage);
- legislation that facilitates switching between suppliers;
- investment incentives;
- transparency of aggregated market data and confidentiality of individual market data;
- decoupling of contractual and physical flows;
- market liquidity;
- existence of a secondary market for transport and storage capacity; and
- competition with alternative fuels.

This section discusses the above conditions and addresses the requirement that the benefits of liberalisation need to exceed any additional costs resulting from liberalisation.

A.1.1 Ownership unbundling

In the context of gas markets, unbundling means the separation of the different activities of a gas company, for example the separation of transmission and distribution from production and supply. Unbundling is a fundamental pre-condition for gas market liberalisation, as it enables cost reflective pricing of the different services[32]. This is essential if new entrants are to be able to compete fairly. In particular, it enables an efficient Third Party Access (TPA) regime in gas transportation, in which incumbent companies are prevented from giving favourable access to their own supply businesses. This in turn enables the entry of gas traders into the market who compete with supply companies through gas price arbitrage, promoting competition and liquidity in supply. Where unbundling is not undertaken in full, the incumbent may have the power to disadvantage new entrants by:

- restricting access to sources of supply or creating an artificial shortage of supply;
- restricting access to transport infrastructure; and

[32] International Energy Agency, 2000. ‘Regulatory Reform: European Gas’

- pricing new entrants out of the market.

Unbundling can take different forms. In order of ascending strength (weakest form first) these are[33]:

- **Accounting separation:** commodity purchases and sales and transportation accounted for separately within the same vertically integrated company. Vertically integrated entities charge the same price for transportation for themselves and for others.
- **Functional separation:** accounting separation plus 1) use of same information on the transportation network when buying and selling gas by all market actors, and 2) separation of employees involved in gas purchasing and sales from those involved in transportation.
- **Operational separation:** ownership of the transmission grid remains with the gas merchant, but a fully independent entity has responsibility for operation and takes decisions on investment in the network.
- **Ownership separation (divestiture):** gas sales and transportation are separated into distinct legal entities with no significant common ownership.

Ownership unbundling is the strongest form as it removes the capability as well as the incentive for a vertically integrated company to discriminate in favour of its own supply business on transportation access. Under the 3rd EU Gas Directive[34], the options for unbundling of Independent Transmission System Operator (ITO), Independent System Operator (ISO) and full ownership unbundling are based respectively on functional separation, operational separation and ownership separation.

Which form of unbundling is appropriate is a question of striking a balance between price competition and greater long-term security of gas supply. In a situation where supply is abundant and the infrastructure already exists, the most efficient structure is one which allows most efficient use of these resources. This is where pure competition in the absence of discrimination (and strong unbundling) is the more efficient model.

However, vertical integration of utilities enables a reduction of risk and transaction costs. The alternative of agreements between separate organisations each with their own profit motive inherent risk of one party reneging on contractual agreements, increasing the cost of capital involved. Where new sunk investments might be required, these risk are particularly expensive. During periods when infrastructure investments are required, the vertically integrated structure can be the most efficient. For import dependent countries weaker forms of unbundling may therefore be appropriate in order to secure the conditions for investment and diversification.

The differences between the economics of transmission and distribution network imply that these should generally be unbundled. A transmission network is not a natural monopoly, as extensions need to be made to meet project specific needs (for example, to ship gas from a new producer or to supply gas to a new power station) or to increase transportation capacity between two points already served by a pipeline, and in many cases these projects are profitable. Competition can occur between companies able to undertake these kinds of projects. Experience in Germany and the US has shown that freedom to build and operate transmission pipelines (and hence the possibility of parallel pipelines) is not economically inefficient. Distribution networks are closer to a natural

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33 International Energy Agency, 2000. 'Regulatory Reform: European Gas'

34 Directive 2009/73/EC.

monopoly as in most cases duplications of distribution system by a newcomer would be a loss-making project. Achieving economically efficient use of transmission and distribution systems therefore tends to require different approaches to regulation, for which vertical separation is a pre-requisite.

A.1.2 Access to gas supplies

Access to gas supplies is crucial for new competitors to enter the gas market. The existence of a range of supply sources is favourable for attracting new entrants. Having a number of sources of supply from which to choose reduces the risk of depending on a single supply channel and enables each competitor to make a commercial decision on how to source gas and which customers to target.

Additional sources of supply may become available through market integration. Given sufficient access to interconnection, retailers will be able to contract with producers from other countries. Producers may have access to different sources of gas and diverse channels of supply, increasing diversity of supply for the market.

Long-term supply contracts to incumbents need to be taken into account when analysing availability of supply to new entrants. Liberalisation legislation needs to address situations where incumbents have long-term contracts for access to a proportion of available or transportable supplies that would prevent competition. One way of addressing this issue is to mandate the incumbent to introduce a 'release gas' programme whereby a percentage of the incumbent's gas supply is auctioned to new entrants.

New sources of supply may deliver gas of different quality from existing supplies. To avoid differences in quality restricting competition, access to treatment and blending facilities needs to be available. If required, investment in treatment and blending facilities should be recoverable from all network users to incentivise building of sufficient capacity.

A.1.3 Access to infrastructure

Non-discriminatory access to existing infrastructure is required to ensure new entrants are able to serve their customers without commercial disadvantage when compared to the incumbent. New market entrants should have equal access rights to:

- *Transport infrastructure (including interconnection)*: establishing non-discriminatory access to transport infrastructure for all market participants.
- *Storage facilities*: access to storage facilities is important for security of supply in case of an emergency, for network optimisation, and for matching customer demand with access to supply. For example, customers may not switch to new entrants if these cannot meet demand from storage facilities in case of an emergency.
- *Balancing services*: each gas supplier has to meet balancing requirements. The requirements set by transport companies should be non-discriminatory. Artificially small balancing zones may disadvantage new entrants compared to incumbents. As an alternative to balancing services provided by transport companies, a market for balancing services can be established where feasible.

A.1.4 Legislation to facilitate switching between suppliers

Competition is only possible in an environment in which consumers can easily change suppliers. The ability of customers to seek lower prices and better terms from their existing suppliers and to switch between suppliers is important drivers of competition.

Legislation driving liberalisation can facilitate inexpensive and convenient supplier switching for customers by:

- ensuring customers have non-discriminatory access to the relevant information needed to make an informed switching decision; and
- giving customers the right to withdraw from supply contracts without charge.

A.1.5 Investment incentives

Liberalisation measures should create long-term investment incentives for establishing:

- new sources of supply;
- transport infrastructure; and
- storage facilities.

If such incentives are not in place any future increase in demand may lead to capacity constraints and drive new entrants from the market.

If the right investment incentives for new entrants are in place, potential barriers to competition may be reduced. For example, if new entrants have an incentive to invest in new sources of supply and storage infrastructure, incumbents should not be able to create artificial supply shortages.

Market players may need permission to exclude competitors from access to new infrastructure to incentivise sufficient investment. Where this is necessary, it is important to find the right balance between investment incentives and allowing non-discriminatory access to infrastructure to ensure competition is not detrimentally affected.

A.1.6 Transparency and confidentiality of data

To allow efficient decisions, network users require access to aggregate (real-time) information on:

- supply availability;
- consumer demand;
- available transport capacity;
- available storage capacity; and
- market prices.

Whilst aggregated information should be publicly available, the transportation system operator needs to ensure that individual data from the network users remains confidential. Otherwise market participants with access to this information may have an unfair advantage in relation to their competitors.

A.1.7 Decoupling of contractual and physical flows

Where contractual rights and physical flows are decoupled new entrants may gain immediate access to unused physical capacity. Where this is not the case, contractual congestion may occur through long-term contracts between the incumbent, producers, and the transport operator blocking the physical flows of new entrants and preventing them fulfilling their contracts with customers and suppliers. One way of achieving this is to introduce a use-it-or-lose-it (UIOLI) mechanism whereby unutilised transportation capacity is made available as interruptible capacity. This encourages the primary capacity holder to make unutilised capacity available on a secondary market.

A.1.8 Market liquidity

Market liquidity is a key driver of effective competition and according to the International Energy Agency 'determines the scale and scope of the benefits of a liberalised market for end-users'[35]. A large number of market participants able and willing to trade are required for gas markets to be liquid.

A.1.9 Secondary market for transport and storage

The existence of secondary markets in which market participants can buy and sell unused transport and storage capacity drives more efficient use of the network by reducing the amount of unused spare capacity. Transport bottlenecks may be resolved by secondary markets when market participants requiring urgent access to transport and storage capacity are able to buy access from other network users which require access less urgently.

Successful secondary markets can be supported by anti-hoarding mechanisms such as UIOLI that provide an incentive for the primary capacity holder to sell capacity to other system users.

A.1.10 Competition with alternative fuel types

In markets with a power station fleet fired by a mixture of fuels, gas suppliers compete with suppliers of other fuels for supply contracts with electricity generators. If a liquid short-term market for gas is established, traders and consumers should be able to purchase gas at the lower price which results from cross-fuel competition.

A.2 Benefits of liberalisation

The European Commission believes the criteria for judging whether gas market liberalisation has been a success are:

- Significant real reduction in transportation costs, but still with sufficient incentives for grid operators to increase capacity in line with demand.
- Reduced retail and wholesale gas prices.
- Gas border prices being driven down to the long-run costs, which in turn will be continually reduced, but under conditions where producers were still encouraged to develop new large gas sources which could be brought onto the market smoothly without supply disruptions and associated price hikes.[36]

This section now develops a list of potential benefits from gas market liberalisation including those recognised by the European Commission.

The benefits created by liberalisation are highly interlinked. One benefit may give rise to a number of other benefits. For example, creating a liberalised competitive gas market may

35 'Regulatory Reform: European Gas', International Energy Agency, 2000

36 'Report for the European Commission – Directorate General for Transport and Energy to determine changes after opening of the Gas Market in August 2000 – Volume I: European Overview', DRI WEFA, July 2001

be a pre-requisite for integration with the gas markets of neighbouring countries. Market integration may give companies access to additional sources of supply which will increase security of supply and availability of supply. New entrants may be incentivised to enter the market and increase competition. Increased competition should in turn lead to lower consumer prices.

A.2.1 Competition, costs and efficiency

In gas markets which meet the conditions introduced in Section A.1, liberalisation may lead to increased competition through incentivising:

- new gas producers to supply the market; and
- new gas suppliers to enter the retail market.

Competition drives both producers and retailers to increase efficiency and reduce costs to be able to compete on price:

- Producers will look to develop new sources of supply at lowest cost and to make more efficient use of existing resources.
- Retailers will aim to reduce supply and transport costs by negotiating new contracts and by using the network more efficiently.
- Retailers will aim to develop innovative products tailored to customer requirements to attract customers.
- Both producers and retailers will aim to maximise the efficiency of their operations by optimising their business structure[37].

A.2.2 Benefits for consumers

Where liberalisation drives competition in upstream and downstream gas markets, benefits should filter through to consumers. The range of benefits that consumers may receive includes:

- more efficient gas prices linked to supply and demand balance;
- increased choice;
- higher quality of service;
- increased security of supply;
- better consumer protection; and
- access to innovative products that are tailored to specific consumer requirements.

A.2.3 Synergies of merging electricity and gas transport functions

Merging electricity and gas transmission businesses can create operational synergies through shared expertise and best practice. A more efficient, effective, and secure operation of both networks, for example by reducing support functions or combining emergency planning may result.

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[37] In general competition is not introduced in the transport part of the network due to natural monopoly characteristics, meaning it would not be economically efficient to have multiple transport networks operating in parallel. However, where a market for transport is brought into existence the same competitive pressures will apply to transport operators. Strong regulation can also serve as a proxy for competition.

Shared knowledge about trends in electricity generation and availability of supply for gas-fired power stations can allow a combined gas and electricity transport operator to optimise the operation and design of both transmission networks.

A.2.4 Security of supply

Security of supply is one of the core concerns for gas consumers and regulators alike. Competition may bring about increased security of supply where:

- Market participants invest in the exploration of new sources of supply.
- Competition leads to market integration and access to a wider range of existing international sources of supply results.
- Market participants are incentivised to invest in storage facilities and other means to supply gas in an emergency.
- Network users have an incentive to maintain high operating standards to be able to provide high service quality.
- Secondary markets allow prioritising of customers with urgent requirements when there are bottlenecks.

A.2.5 Social and economic benefits

Wider social and economic benefits may result from liberalisation of a gas market, such as:

- Reduction in the number of households in fuel poverty due to reduced gas prices.
- Reduction in the need for regulatory intervention thereby reducing cost to government and bureaucracy costs to market participants.
- According to the European Commission[38], competitive energy markets allow the introduction of policy tools, which can be used to correct market externalities, for example the environmental benefits from the emissions trading scheme.

A.2.6 Market integration

A liberalised gas market may be a requirement for getting permission to integrate with a neighbouring gas market. In this way gas market liberalisation could give a country access to additional sources of supply and hence drive a number of the benefits discussed previously.

A.3 Costs of liberalisation

Liberalisation may lead to inefficiencies where economies of scale and scope (synergies from providing more than one of the functions in the gas market) are eradicated through ownership unbundling.

Many activities in the gas market (e.g. billing) benefit from economies of scale, and therefore the introduction of competing suppliers reduces the benefit possible from such economies of scale. Suppliers are likely to need a critical mass of customers to be able to benefit from portfolio effects (for example the demand portfolio behaving more predictably

38 ‘Prospects for the internal gas and electricity market’, Communication from the Commission to the Council and the European Parliament, 10 January 2007

as the number of customers increases). There may also be minimum volumes at which storage and transportation can be booked, leading to increased costs for small suppliers.

Consumers switching suppliers will generate costs that did not exist when customers had no choice of supplier. Suppliers are also likely to incur costs in advertising and marketing that a single incumbent supplier would not incur. Competing suppliers could incur higher costs per unit than an incumbent supplier if they are unable to command the purchasing power that was previously held by the monopoly supplier. If gas is sourced from the open market this should not be an issue, but may be more significant in the face of a monopsony.

Economies of scope that arise from having a single party organising production, storage, transportation, and supply of customers will be lost when these functions are forcibly separated.

When designing liberalisation measures it is thus crucial to take the existence of market failures such as natural monopolies into consideration. Otherwise liberalisation could lead to:

- inefficient and more than likely higher gas prices;
- under recovery of investments; and
- lower quality of service.

For liberalisation to be successful, the benefits of liberalisation must exceed the costs. Many issues can be resolved through appropriate market design and regulation. Other costs (for example removing opportunities for economies of scale) will need to be outweighed by the benefits listed in Section A.2.

A.4 Liberalisation in EU gas markets

A.4.1 Background to EU liberalisation

The European Commission (EC) has attempted to liberalise the gas markets in the EU to bring the benefits of competition to consumers.

European reforms have had two primary principles:

- Completion of the EU internal market – to remove trade barriers between all EU countries.
- Establishment of a competitive European natural gas market based on the belief that competition will deliver the lowest prices for consumers and the most efficient outcome.

In addition there are some secondary objectives related to a view that monopolies were not in the best interests of consumers. In order to deliver the principles and the secondary objectives the various gas directives and regulations have aimed to be objective, non-discriminatory, transparent, efficient, economic, deliver security, protect consumers, achieve fair prices, be cost reflective, and environmentally friendly.

Achieving the liberalisation of the EU gas market has required a combination of five key deliverables:

- legal market opening;
- third party access (TPA);

- ownership unbundling;
- interoperability and harmonisation of rules; and
- independent regulators.

The EC continues to monitor the development of the liberalisation process and consults with the industry through a regular gas regulatory forum, the Madrid Forum. In addition to opening the markets to competition, the EC is also concerned with security of supply.

A.4.2 EU directives

The process of establishing a legal framework across all EU Member States led to a stage by stage delivery of the principles and objectives. The timetable and key features of the legal process can be summarised as follows:

- First gas directive 1998 – established market opening thresholds, initial steps towards changes in market structure and network access, with the introduction of legal unbundling and negotiated and regulated TPA.
- Second energy directive 2003 – required full market opening by 2007, regulated TPA for networks and negotiated and regulated TPA for storage, management unbundling, introduction of national regulatory authorities, and market based instruments favoured but none is specified.
- Third energy directive 2009 – established an independent regulatory requirement, unbundling, improved market operation, notably greater transparency, effective access to storage facilities and LNG terminals. Essential focus is on improving the operation of retail markets.

The impact of the legislative process on improving the deliverables is summarised in Figure 28.

Figure 28 – Legal market opening improvements

	Unbundling of networks	Access to networks	Market opening	National regulation
First legislative package	Separate management and accounts	Negotiated or Regulated TPA	33% by 2008	Mechanism for regulation
Second legislative package	Separate subsidiary	Regulated TPA	Fully open market by July 2007	Specific regulator for energy
Third legislative package	Separate ownership or operator including storage	Regulated TPA including storage	Achieved (see above)	Upgraded and harmonised powers for national energy regulators
	↓ Unbundled transmission	↓ Third Party Access	↓ Retail competition	↓ National regulator

A.4.3 Madrid Forum

In 1999 the European Commission took the initiative to set up the European Gas Regulatory Forum of Madrid consisting of national regulatory authorities, Member States, the European Commission, TSOs, storage operators, producers, gas suppliers and traders, consumer groups, network users, and gas exchanges.

The Forum convenes twice a year in Madrid and was set up to discuss issues regarding the creation of a true internal gas market, which are not addressed in the directive.

The most important issues addressed currently at the Forum concern cross border trade of gas; in particular the application of tariffs at cross border gas exchanges, the allocation and management of scarce interconnection capacity, and other technical and commercial barriers to the creation of a fully operational internal gas market.

A.4.4 Market opening status

Full market opening was required within the 2003 second energy directive. Except for a few derogations, full market opening was to be transposed by EU members by July 2007. Gas markets in all NWE countries have theoretically been fully opened to competition since then.

A.4.5 Trends in EU legislation

In February 2011, the European Council of Ministers conducted the first summit on energy. It was concluded that the safe, secure, sustainable and affordable energy contributing to European competitiveness remains a priority for Europe. To achieve this it was agreed to back four main commitments:

- Complete the common energy internal energy market by 2014.
- Eliminate ‘energy islands’ by 2014 – where some Member States are presently disconnected from the rest of the EU in terms of energy.
- Boost energy efficiency.
- Improve coordination and cooperation on energy with non-EU neighbours, particularly those to the east and the south.

At the summit it was stated that EU needs a fully functioning, interconnected and integrated internal energy market. The internal market should be completed by 2014 to allow gas and electricity flow freely. This requires national regulators and TSOs in cooperation with ACER step up their work on market coupling, guidelines and on network codes applicable across European networks.

Applying EU wide liberalisation guidelines to Baltic gas market, liberalisation on regional, rather than on national level, may be more sensible, given the proximity of Baltic States, enhanced economic ties between those, high cost of gas market infrastructure and comparatively small gas markets in each individual country. Liberalisation of the Baltic region as a whole may help transmission companies enhance their coverage area, due to exclusive rights to supply on a regional level, increase bargaining power of Baltic States and increase defensive power of Baltic States against Gazprom trying penetrate their transportation networks.

The Baltic Energy Market Interconnection Plan (BEMIP), described in detail in Section 5.1, is an action plan on energy interconnections and market improvement in the Baltic Sea region. This plan is an important part of this initiative in that it explicitly calls for and supports construction of new infrastructure required in the region and seeks solutions to the economic and political challenges it presents.

A.4.5.1 Financing

The bulk of the financing for infrastructure investments will have to be delivered by the market, with costs recovered through tariffs, which should be set in a transparent and non-discriminatory manner at levels consistent with financing needs and to the appropriate cost allocation for cross-border investments, enhancing competition and competitiveness and taking account of the impact on consumers.

It is envisaged that some projects, justified from a security of supply/solidarity perspective, will be unable to attract enough market-based finance and may require some limited public finance to leverage private funding. The Commission was invited to report by June 2011 to the Council on the size of investments likely to be needed, suggestions on how to respond to financing requirements and how to address possible obstacles to infrastructure investment. As of the end of September, no results have been published.

A.4.6 Experiences of selected gas markets

A.4.6.1 Germany

The German gas market had a highly fragmented structure with more than 700 integrated gas companies. However, this position has changed over recent years.

Germany produces about 10% of its gas requirement from its own onshore reserves, mainly located in the north-western state of Lower Saxony. Like Dutch gas it has a low calorific value. The majority is produced by BEB with about 20% split between companies such as RWE-Dea, GdF and Wintershall.

The remaining gas is imported and historically this has been purchased under traditional long-term take-or-pay contracts with oil indexation. However, in the last year pressure from cheaper gas from spot markets and decreased demand caused by the recession has led to German buyers wishing to reduce their obligations under the main import contracts.

The regulator, BNetzA, introduced rules requiring non-discriminatory network access based on an entry-exit system, which came into effect 1 October 2006. Operators were asked to unbundle sales and network activities and TPA tariffs were subject to regulatory checks. Incumbents were also ordered to end long-term supply contracts with only one supplier. 2006 also saw the start of competition in the gas household sector and in 2007 BNetzA standardised the market process for charging gas suppliers (GeLi Gas).

The supply market is still dominated by E.ON Ruhrgas, which sells around 50% of Germany's gas by volume and holds shares in 30% of the regional distribution companies. Further large market shares are held by RWE, VNG, Wingas, and BEB. New entrants to the German market currently tend to rely on the spot market and/or the balancing regime due to low balancing costs (based on spot prices).

In 2007 Germany had 14 different market areas. This was reduced to six in 2009 and from October 2011 there will only be two – GASPOOL and Net Connect Germany (NCG). GASPOOL will include the low calorie gas (L-gas) area Aequamus, which means that the hub operator will have to include a fee to convert high calorie gas (H-gas) to L-gas. The smaller number of hubs has helped improve hub liquidity.

A.4.6.2 Great Britain

Before the 1960s, gas in the UK was town gas distributed through distribution networks local to towns. Town gas was derived from coal.

A LNG terminal was opened at Canvey Island in 1964, taking gas from Algeria. A transmission pipeline was built to allow deliveries to the north of England.

With the discovery of the first North Sea gas field (West Sole off Humberside) in 1965, the nationalised gas industry (created in 1948) began a huge programme of infrastructure investment, creating a new pipelines network and replacing domestic and commercial boilers (necessary because the calorific value of the new fuel was different).

The Gas Council which had the first option to buy all the gas landed (Continental Shelf Act 1964). The Government owned the Gas Council and also granted the gas production licences, and had control of the taxation of the oil companies' profits. The Gas Council was under no obligation to charge market prices, only to recover its total costs. The Gas Council was therefore in a uniquely powerful position.

Long-term take-or-pay contracts between British Gas and the Gas Council were established, generally setting a price, over 25 year period (subject to price variation provisions). This had to be paid whether or not gas was actually taken, although there was provision for gas paid for but not taken to be credited to later years. The oil companies could be certain of the price component, which removed a significant element of risk from investment decisions and provided a favourable basis for developing the national gas infrastructure at a reasonable cost of capital.

The state owned vertically integrated monopoly gas company, British Gas, was privatised in 1986. Although British Gas remained a monopoly after privatisation, it was anticipated by the Government that accountability to shareholders would increase efficiency in the use of capital. In addition, as a private company it would be able to keep its profits, providing a further incentive for efficiency over a public company. Privatisation would also have the effect of separating ownership and regulation. In the British case, there was a political desire within the Government to create a share-owning democracy, and to raise money from the sale of the assets. The significant portion of debt in the sale (£2.5 billion out of £9 billion) also gave the Government some fiscal flexibility. It was regulated by a new body, Ofgas. The regime was light touch, with an RPI-X price cap, and a regulator charged with general duties.

A report by the Monopolies and Mergers Commission (MMC) (the UK competition authority) in 1993 concluded that there was an inherent conflict of interest between ownership of the natural monopoly transmission and distribution network, and the supply business. It proposed breaking British Gas in two, the costs of the break-up being reflected in a softer price cap (RPI-4 rather than RPI-5), and domestic competition in 2002. British Gas resisted break-up, instead proposing functional separation and competition from 1998.

The Gas Act 1995 removed the monopoly of British Gas. The long-term gas contracts with North Sea suppliers then became liabilities because the assumption that up-stream costs could simply be passed on to customers no longer applied; they could now defect to cheaper spot gas prices, which collapsed in the mid-nineties due to a supply surplus.

As a result of the contracts problem, to protect the transmission and distribution networks business, British Gas decided to split itself up, the take-or-pay contracts and supply contracts going to Centrica together with production rights from Morecambe Bay (as the contracts and supply business alone would have been loss making, making it legally impossible to set-up a company with on this basis alone). BG Plc was formed from the transmission business Transco and the international exploration and production business. The gas supply and transportation businesses within GB have therefore been fully ownership unbundled since 1997, although at the time the theoretical merits of this were a secondary reason.

Great Britain (GB) has therefore been at the forefront of the liberalisation process across Europe. It has an annual demand of around 90bcm (2009). With its indigenous supplies, interconnections to Europe and the worldwide gas market through LNG, it is a key market in Europe.

GB has various pipelines that provide access to gas from the continent. The first interconnector was built in 1998 linking Zeebrugge in Belgium to Bacton in GB. This pipeline has the ability to flow gas in both directions. The second, known as BBL, links the Netherlands to GB but can only flow gas into GB. In addition, GB has two import pipelines bringing gas from Norway into St. Fergus and Easington.

As indigenous supplies have declined, a number of LNG terminals were developed; with the main sites being at Milford Haven and Isle of Grain.

As a result of the above, GB has several ways of sourcing gas; all of which compete to sell gas at the National Balancing Point (NBP). There are many buyers of gas at the NBP including power generators and suppliers of gas to industrial and commercial users and residential homes. Significant gas shippers and suppliers of gas to end-users include Centrica (previously part of British Gas), E.ON, RWE, Scottish and Southern Energy, Scottish Power (owned by Iberdrola), and EDF.

A.4.6.3 France

Liberalisation of the French gas market has been completed in several stages and since July 2007 domestic consumers are allowed to choose their own supplier. The switching rates in the non-residential retail gas market (measured in volume of gas consumed) are significantly greater than in the residential market.

The French gas market has a total demand of around 47bcm in 2010 supplying over 11 million customer sites. The market is dominated by the former integrated utility Gaz de France, which has now merged with Suez to become GDF Suez; and by Total in the south-west of France.

With indigenous gas production only representing 2% of national consumption, France imports most of its gas. In 2010, about 29% of gas demand was met via imports from Norway through pipelines in the north. Russian imports, which transit via pipelines in Germany and Switzerland, amounted to 16% of demand in 2010. Other imports come from the UK and the Netherlands via Germany and Belgium. And, in the south a small amount of gas comes via pipeline from Spain whilst the rest is imported via the LNG terminals. 27% of total French gas demand was met by LNG in 2010.

Gas is traded at the borders or at one of the three balancing zone exchange points, called PEG Nord, PEG Sud and TIGF. In 2009, PEG Nord became an important market place when it merged with PEG Est and PEG Oest; however French hubs are not yet as liquid as other international hubs.

A.4.6.4 Ireland

The legal framework for the first phase of liberalisation of the gas market in RoI was given by the Energy (Miscellaneous Provisions) Act 1995[39] and Ministerial Directives issued under Sections 11 and 15 of the Gas Acts 1976[40]-2000[41]. These facilitated implementation of the European Gas Directive 98/30/EC[42].

BGE published a Transmission Code of Operations in October 1999. The Code sets out the operational rules that facilitate gas transportation on the high-pressure transmission system.

The next phase of gas market liberalisation took effect from 30 April 2002, facilitated by the enactment of the Gas (Interim) (Regulation) Act 2002[43]. In summary, this Act provides for the following:

- the independent regulation of the natural gas sector in RoI by the CER by transferring certain powers and functions from the Minister for Public Enterprise, including;
  - pipeline consents;
  - granting of gas supply and distribution rights;
  - tariff setting;
- the creation of new powers and functions for the CER, including;
  - licensing of gas undertakings (gas suppliers, pipeline operators and storage operators);
  - direction on and approval of codes of operation;
  - preparation of gas capacity statements; and
- the further opening of the gas market by reducing the threshold for third party access from 25 million cubic metres205 (mcm) per annum to 2mcm per annum (in addition to operators of gas-fired power stations, irrespective of annual consumption, as was previously the case).

In January 2003, the threshold for third party access was reduced to 0.5mcm per annum. This had the effect of increasing the number of eligible customers to around 250, representing around 85% of total gas demand, and including sites served by the distribution system.

In July 2004, the I&C market opened to third party access and this now means that RoI complies with Article 23 of the European Directive 2003/55/EC. Full residential market opening took place in 2007, having been delayed repeatedly.

RoI has extended deadlines for implementation of the unbundling requirements of the 3rd EU Gas Directive (2009/73/EC), due to the structural changes required[44].

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39 Energy (Miscellaneous Provisions) Act 1995.

40 Gas Act 1976

41 Gas (Amendment) Act 2000. No. 26 of 2000.

42 Directive 98/30/EC on common rules for the internal market in natural gas.

43 Gas (Interim) (Regulation) Act, 2002. No 10 of 2002

44 The International Comparative Legal Guide to Gas Regulation 2011. Global Legal Group.

BGE is the statutory body established under the Gas Act 1976. As a vertically integrated state-owned monopoly, BGE substantially developed the downstream transmission and distribution infrastructure in RoI. BGE is currently responsible for the transmission and distribution of natural gas in the RoI. It is also the incumbent gas supplier to the I&C and residential sectors. BGE is broadly split into 3 business units:

- Bord Gáis Networks – responsible for the ownership of the higher pressure transmission gas pipeline network, and the lower pressure distribution networks.
- Bord Gáis Energy Trading (BGET) – responsible for the buying and selling of wholesale gas (and electricity).
- Bord Gáis Energy Supply (BGES) – responsible for the sale of gas (and electricity) to end consumers, associated customer services and new product development.

Gaslink is the independent system operator with responsibility for developing, maintaining and operating the natural gas transportation system in Ireland. Gaslink was established in 2007 in compliance with the unbundling requirements of the EU Gas Directive 2003/55/EC.

The primary function of Gaslink is to ensure the secure, reliable and efficient operation of the transmission and distribution systems under economic conditions and with due regard to the environment. Also Gaslink ensures non-discriminatory access to the natural gas network and avoids conflicts of interest in the gas supply market.

Gaslink is also responsible for the planning and development of the gas network, with responsibility for preparing a seven year development plan and a five-year price control plan.

A number of the Gaslink roles are carried out by Bord Gáis Networks under an operating agreement. These roles include the operation of the grid control function and network analysis.

Today, the RoI imports over 90% of its gas requirements of around 5.2bcm/a. The majority of the gas (3.4bcm/a) is used in the power sector, with gas being the fuel source of around 60% of electricity generation. Available indigenous gas resources have declined sharply in absolute terms since 1996 when they made up 80% of the market's requirements.

Gas is imported to the RoI through two interconnectors which both connect to the GB transmission system at Moffat in Scotland. This overwhelming reliance on imported gas from the GB market will continue to increase until gas from the 28bcm Corrib gas field is developed (expected in October 2012).

The total gas demand in NI is around 1.5bcm/a; supplied principally via pipeline from GB which also transports gas directly to Ballylumford Power Station which generates over half of Northern Ireland's electricity needs, and feeds the gas distribution system in Belfast.

Phoenix Supply Limited was the previous monopoly gas supplier to the Greater Belfast Area and retains around a 90% market share. However in 2007, the gas market was fully liberalised, with all customers able to choose their gas and electricity supplier. A small number of commercial customers have switched to either Energia or firmus energy, a subsidiary of Bord Gáis. Firmus energy also has a monopoly to supply and distribute gas to ten towns along the route of the new Belfast to Derry pipeline and the south-north pipeline.

Competition has been slow to develop in both the RoI and NI markets, particularly for the retail sector. The Common Arrangements for Gas (CAG) project which is expected to result in an all island market will address some of the issues that are preventing competition from becoming established and will introduce common retail arrangements for both markets.

The ultimate goal of the CAG project is to secure economies of scale. Both jurisdictions, in isolation, are of a size in which meaningful competition (e.g. in energy supply or in electricity generation) is difficult to achieve organically. By combining the markets, they become more attractive to potential entrants whilst offering the possibility of real savings in system operation and in capacity planning.

We anticipate that the material benefits from a single gas market should derive from economies of scope or scale, in that future arrangements reduce operational costs, increase investment efficiency and attract new entry (especially in the retail sector). At a **minimum**, the revised arrangements should, in the short term, support gas nominations and flows between all entry and exit points on the island (which is not presently the case), and in the medium term must ensure that there are no distortions to incentives to invest in assets (whether these relate to gas infrastructure, or gas-using infrastructure such as generation). As part of the CAG development, it is likely that a single system operator will be appointed to undertake all system operation duties. The structure of the system operator is yet to be decided. An entry/exit regime will be introduced for the all-island arrangements along with a single transmission network code. A second phase of the project will consider distribution and retail arrangements.

The gas markets of the Republic of Ireland (RoI) and Northern Ireland (NI) are on target to merge by 2012.

A.4.6.5 The Netherlands

The Netherlands has significant indigenous natural gas reserves. The Groningen gas field was discovered in 1959. The White Paper on Natural Gas in 1959 laid down a strong emphasis on security of supply through State involvement in the management of reserves. In the original gas market arrangements, production and sales were closely integrated in a public-private partnership called Maatschap Groningen, in which the state owned a 40% share and the private sector concession consisting of Shell and Exxon (Nederlandse Aardolie Maatschappij, or NAM) owned the remainder. The supply of gas was the responsibility of the state, but exploitation and marketing gas were to be carried out by the private sector.

Domestic gas supply was realised through a two-tier structure, with a single dominant transmission company (N.V. Nederlandse Gasunie, known as ‘Gasunie’). Gasunie was owned by the state (50%), Shell (25%) and Exxon (25%) and was exclusively responsible for co-ordination and marketing of gas purchasing activities. It purchased domestic gas or imported gas under long term take-or-pay contracts and delivered it to distribution companies, power generators and large industrial consumers. The distribution companies then provided gas to households and smaller industrial users.

Gasunie was also required to follow a strict depletion policy in order to ensure that adequate supplies of gas were available to domestic customers and to future generations. In addition, as a result of the Energy White Paper 1974, the Netherlands also pursued a ‘Small Fields’ policy, according to which, small gas fields were exploited in order to limit the depletion of the Groningen gas field. Depletion of the Groningen field was further limited by Government initiatives aimed at constraining demand through energy efficiency drives, increased gas prices and restrictions on exports.

The Dutch Government strongly opposed the liberalisation of the gas market until the mid-1990s, primarily based on the belief that a liberalised market based on short term contracts would undermine investment in multiple gas fields and hence weaken security of supply. There was also little inefficiency in the Dutch gas market due to the desire of the partly state owned monopoly to maximise profits from the sale of gas. However distribution companies and large industrial consumers were supportive of liberalisation due to their extremely limited negotiating power, and a desire for lower gas prices than available from Gasunie.

A change of Government in 1994 together with revised proposals for the Gas Market Directive which incorporated the concepts of Public Service Obligations (PSOs) and negotiated third party access led to the pro-liberalisation Third Energy White Paper in 1996. The White paper contained measures providing for:

- the separation of the transmission and supply activities of energy utilities and the creation of non-discriminatory third party access to networks;
- a transition from a supply driven to a demand driven market, mainly through a free choice for consumers, resulting in improved services and lower energy prices; and
- continued involvement of the state in the management of natural gas resources

The strong continued desire of the Dutch Government for Gasunie to remain partly state owned prevented privatisation of the gas industry at the same time as liberalisation, the Dutch Government also considering that the experience in other countries indicated that liberalisation needed to come before privatisation. Parliamentary debates at the time focused on a level playing field vis-à-vis other European gas markets leading to the introduction of a reciprocity clause allowing refusal of network access to markets which themselves refused network access to domestic suppliers.

As a result of developments in the wider EU (including unanimous acceptance by Member States of the First EU Gas Directive), the decision in 2000 of the regulator to break up all of its long-term supply contracts with distribution companies, and the realisation that under EU competition law that the European Commission had the power to break up national monopolies, Gasunie gave all its customers a free choice of supplier from 2004. This was not required under the EU Gas Directive until 2007.

The activities of Gasunie were split up in July 2005. The trading activities were transferred to a new company, GasTerra, owned by the state (50%) and Shell and ExxonMobil (25% each). The remainder of Gasunie became 100% state owned, with a new subsidiary Gas Transport Services (GTS) owning and operating the transmission system.

The sole gas TSO has therefore been ownership unbundled since July 2005, which went beyond the legal and functional unbundling requirements of the second gas directive. The Netherlands did not take advantage of the unbundling exemptions available to DSOs serving less than 100,000 customers.

Prior to the requirement of legal unbundling required in the Gas Act 2000, the distribution network was owned and operated by regional energy companies, which were in turn owned by public sector regional authorities (provinces and municipalities). The regional energy companies also had gas trading and supply arms. Legal unbundling of the supply and network elements of the regional energy companies had occurred by the end of 2005 and tended to be implemented through a subsidiary company in the form of a Plc. Following this, the distribution network was owned and operated by 12 regional network operator companies, and supply and trading activities occurred in legally separate companies.

Due to the strong desire (based on security of supply concerns) on the part of the Government to ensure the continuing state ownership of distribution networks, and the complexity of achieving this under other models, the Unbundling Act 2006 was passed. This required full ownership unbundling of the distribution networks from supply and trading activities. This was controversial as it went far beyond the requirements of the 2nd EU Gas Directive then in force. The energy companies opposed ownership unbundling because they feared it would make them easier targets for foreign takeovers, and their financing of investments would become subject to a higher cost of capital due to a perceived increase in risk on the part of lenders, negatively impacting security of supply. The Unbundling Act was ruled contrary to EU law on the free movement of capital by the Court of Appeal of the Hague in June 2010. The Government prohibition on the privatisation of distribution networks would also appear to be a barrier to the free movement of capital and therefore also unenforceable.

At present, the Netherlands has the largest indigenous gas reserves in north-west Europe and production of 73.5bcm/a. The Groningen gas field accounts for most of it, with 42.5bcm/a.

Despite declining indigenous reserves, the Dutch government is keen to see the country become a gas hub for North-West Europe by raising its transit activity. The Netherlands already has an extensive pipeline network, which it uses to transit its own production and gas from Norway to other parts of Europe. The BBL pipeline, which links the Netherlands to the UK will be introducing non-physical interruptible reverse flows (i.e. from Bacton to Balgzand) in January 2011.

In addition, Gate LNG terminal in Rotterdam is due to become operational in September 2011. Its initial capacity of 12bcm is due to be expanded to 16bcm with the commissioning of the fourth tank in 2015.

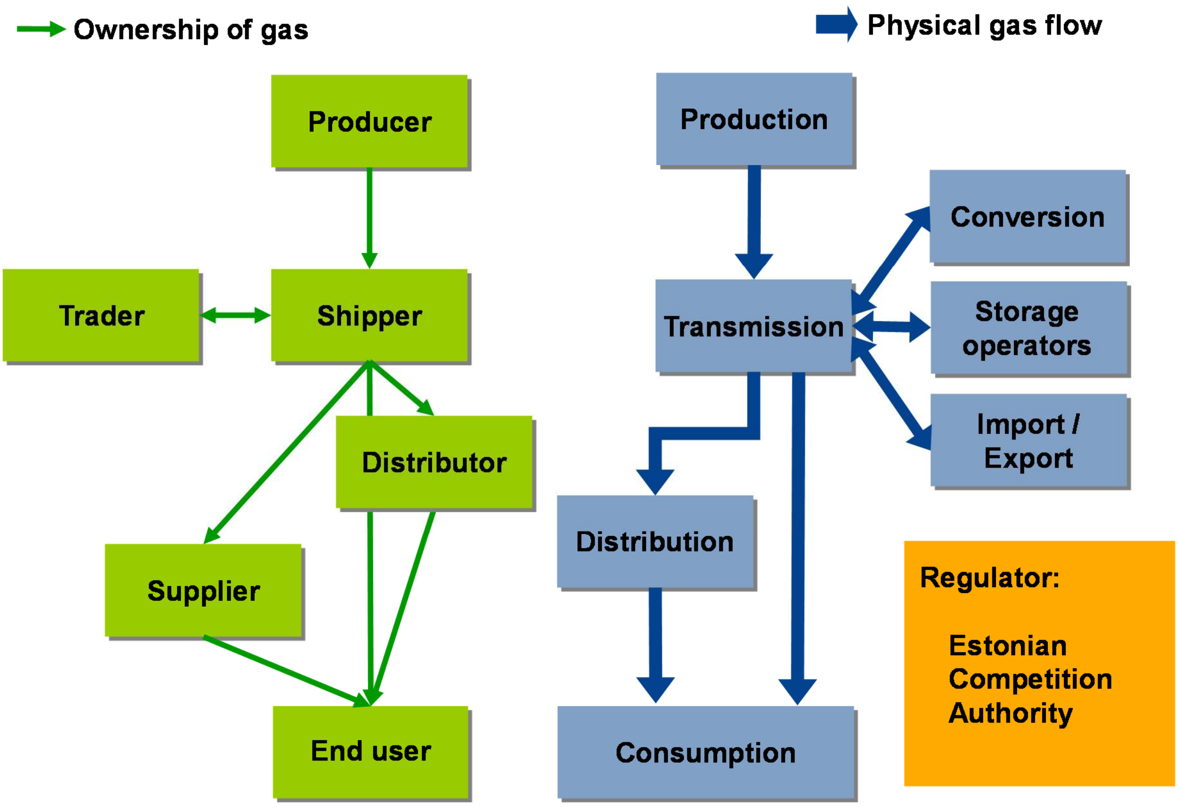
ANNEX B – MARKET DESIGN

In considering how the liberalisation process should proceed and the unbundling requirements of the EU Regulations it is important to identify the market design that will best facilitate the process. In this section we review market designs used across Europe and how these match against the EU regulation requirements.

B.1 Market roles and stakeholders

A successful post-liberalised gas market requires all parties to be able to access the market in a non-discriminatory manner to allow the development of effective competition. There will be different roles performed by different parties, which together will ensure a functioning gas system, see Figure 29.

Figure 29 – Schematic gas market structure



B.1.1 Regulator

Regulators oversee the market to ensure that there is fair competition, usually intended to bring the benefits of liberalisation to the end customers. The regulator therefore has a strong interest in whether the market rules that are in place are working effectively and encouraging the market participants to behave in an appropriate way. The regulator is commonly a government agency. In Estonia this is currently the Competition Authority.

B.1.2 Transmission System Operator

The Transmission System Operator (TSO) will be responsible for managing the high-pressure gas transmission system. This is typically recognised as a natural monopoly, and thus there will often be a single TSO for each country or balancing zone. The TSO will be responsible for managing the system pressure within appropriate safety margins and is also responsible for managing the physical balance of the system.

The TSO will provide physical and commercial access to the transmission network under published terms and conditions that are the same for all market participants. Market rules should encourage the TSO to invest in upgrading the network where this is required by users, but should not allow the TSO to benefit from investment in capacity that is not required.

The TSO should be unbundled from the incumbent supplier and operated as a separate entity which earns revenue through providing the pipeline capacity required. The TSO should not be involved with gas production, trading, or supply. The return that can be earned by the TSO is usually set by the regulator.

B.1.3 Shippers

Shippers are the users of the gas transmission network. All shippers require non-discriminatory access to the transmission network. Therefore shippers will encompass companies from across the value chain outlined in 1.1.

Shippers will be able to book capacity to have gas transported physically through the system. The market rules that determine the commercial terms and conditions on which the shippers use the transmission system should incentivise each shipper to balance their supply and demand. Though the TSO will be ultimately responsible for system balance on a cash-neutral basis; i.e. the cost of any action taken by the TSO to manage system balance will be re-charged to the shippers which caused the imbalance.

Shippers are free to enter whichever areas of the gas value chain that appear attractive. For example some shippers may specialise in gas production and storage, whilst others focus only on supplying customers.

B.1.4 Distribution System Operators

Distribution System Operators will be responsible for taking gas from the high-pressure transmission network and delivering it to end-users throughout their zone. As with a TSO this role is a natural monopoly, so there is typically only a single DSO per zone the DSO will also earn a regulated rate of return.

B.2 Network access, capacity allocation and pricing

When considering the market design it is important to correctly define how the gas network is accessed, its capacity allocation and pricing and capacity regimes. Considering each one of these decisions in turn we have assessed the different implementation options and where relevant we have presented our recommendations on which is the most appropriate.

B.2.1 Network Access

As a part of the Third Energy Package, the European Commission has set a requirement for all Member States to make public the criteria it uses to define when and how Third

Party Access should be applied. This Regulation sets out a number of rules that are intended to ensure third party access is provided on an objective, transparent and non-discriminatory basis. To ensure this they must develop access arrangements that are compliant with the Gas Regulation and relevant provisions of the Gas Directive, as transposed into domestic legislation.

Building on the rules set out in the Second Gas Directive, the Third Package introduces a number of additional requirements for the access regime for gas markets intended to strengthen regulatory powers to ensure the facilities are operated in a technical and economically efficient basis. These additional rules include:

- strengthening provisions to prevent discrimination in respect of TPA;
- requiring the unbundling of vertically integrated companies;
- increasing information provision and transparency requirements; and
- enhancing monitoring duties and enforcement powers of the national regulatory authority.

Under these arrangements the EU legislation allows for access to be either negotiated, regulated or a hybrid of the two. Below we have reviewed each of the three access arrangements.

B.2.1.1 Negotiated TPA

Negotiated Third Party Access refers to arranging supply contracts on the basis of voluntary commercial agreements. Contracts will be negotiated with the relevant gas asset owner, who will publish the commercial conditions on an ex-ante basis. Under this approach any disputes relating to access will be settled by an independent regulator and in the event of cross-border disputes, the authority that covers the facility shall act as the settlement authority.

B.2.1.2 Regulated TPA

Regulated Third Party Access refers to a system of access based on published tariffs and/or other terms and obligations determined by the regulator. As a minimum the information published under an rTPA regime would be equivalent to those of the negotiated TPA (nTPA) regime; however, additional obligations would also be in place. For instance, such additional obligations may include having to apply to the regulatory authority for approval of methods for calculating a tariff and for verification of the resulting tariff.

B.2.1.3 Hybrid TPA

The Hybrid framework of Regulation is a mix of regulated and negotiated access, whereby some service elements of the contracts are negotiated. Whereas other elements, such are capped by a level of 'fair profit'. Negotiations will also be undertaken with the regulator about the length of contracts.

B.2.1.4 Regulatory compliance

Recent decisions show that there is not a strict adherence to these guidelines by Member States. For example in the storage market in the UK has followed a policy to implement negotiated Third Party Access for all new storage facilities, however if this decision was based solely on an assessment of the list above then a number of the storage facilities in the UK would need to have regulated Third Party Access in place (although regulators have enforced a series on undertaking and requirements on Storage Operators to ensure that the spirit of the CEER's guidelines is maintained). This indicates that there is some leeway for the Estonian regulator when it decides upon access rules for gas infrastructure.

B.2.2 Capacity allocation

The capacity regime sets out the way in which gas transporters sell pipeline capacity. In the case of a regulated monopoly transporter of gas, the structure of the capacity product and the capacity tariff are of particular importance as they are likely to determine the revenue recovery for the transporter necessary to finance its business and make a reasonable return on assets and future investments.

In order to assist in the determination of the most suitable capacity regime, this section outlines the principles, advantages and disadvantages of the entry/exit and postalised models.

B.2.2.1 Entry/exit

Under entry/exit regime shippers book entry and exit capacity independently of one another and can book different amounts to reflect load diversity considerations or to allow for specialisation within the gas chain. Once gas is in the system it can be traded and then notionally offtaken at any exit point (subject to adequate capacity being held by whoever holds title at that point). There is no doubt that this form of capacity regime or capacity type is preferred by both shippers and regulators. It is seen as more flexible and also offers a number of additional benefits; in particular entry/exit creates the concept of 'entry paid' gas and a notional or virtual balancing point. For example, the GB market saw the rapid development of a traded hub where gas can be bought and sold within the system – the NBP. Additional market liquidity is facilitated because trading of a homogeneous commercial product can take place at one point rather than being divided between a number of entry points.

Regulators are keen to encourage new entrants into the market to compete with the incumbents. Entry/exit has two main advantages for new entrants, firstly it allows new shippers to book capacity in a more flexible way and at less risk and secondly the formation of a balancing point offers more choice for sourcing gas for the new shipper's customers. The so-called portfolio effect which appears to favour the incumbent under point-to-point is also reduced (when compared to point-to-point regimes) under an entry/exit regime.

A downside is that there is less capacity available for sale under an entry/exit regime compared with point-to-point regimes. The problem for the transmission operator is that in selling entry capacity independently of exit capacity it needs to make (conservative) assumptions about the likely pattern of usage of the system at peak conditions. (In practice most transmission operators make similar assessments under point-to-point regimes as well, at least in designing and sizing their networks.) It is notable that the GB regulator has sought to financially incentivise National Grid Gas to increase the level of entry capacity which it declares as available, even at the risk of needing to buy back capacity subsequently.

Advantages

The main advantages of entry/exit regimes are as follows:

- Enables the TSO to offer innovative capacity services that may lead to a more efficient utilisation of the pipeline capacity, particularly through the introduction of short-term and interruptible capacity services.

- Enables the TSO to determine capacity quantities available at individual system points on both a firm and interruptible basis enhancing transparency.
- Investment signals are clear under an entry/exit system although in order to produce long-term investment signals appropriate long-term capacity booking opportunities should be made available.
- Separate tariffs for each system point can provide locational signals to gas producers and large end users indicating where to land gas or to site facilities.
- Enhances flexibility for shippers so that gas can be entered at a number of entry points and offtaken by the same end-user at exit.
- Allows shipper imbalances to be aggregated at a notional balancing point encouraging spot trading to minimise imbalances given appropriate balancing incentives.
- Allows shippers to trade entry paid gas at a balancing point within the system.
- It can reduce the competitive advantage enjoyed by the incumbent via the portfolio effect that can be seen in point-to-point regimes.
- It can encourage new entrants to the market, especially if a trading point is created.
- It can further encourage the development of competition in shipping and supply.
- It facilitates a secondary market for capacity, particularly at entry points enabling shippers to match their gas supplies and capacity holdings leading to a more efficient distribution of capacity.
- More efficient use of the pipeline system, if the transporter or TSO offers short-term capacity services.
- Increased incentives for investment in new indigenous gas sources.
- It complies with existing and forthcoming EU Directives on tariff and capacity regimes.

Disadvantages

The main disadvantages of an entry/exit regime are as follows:

- The amounts of capacity offered for sale under entry/exit may be reduced when compared to other regimes such as point-to point as there is greater uncertainty of gas flow route.
- Compared to point-to-point regimes, there will be more uncertainty where gas will enter the system and how the scheduling of the system should be optimised, although entry/exit nominations provided by shippers at the day-ahead stage should greatly alleviate this.
- The entry/exit systems requires a high degree of cooperation between the network operators.

B.2.2.2 Postalised

Under a postalised regime, shippers book capacity, with no reference to the entry or offtake point. Postalised pricing seeks to charge each user of the service a standard flat price regardless of points of entry or exit, just as per a postage stamp. The advantages of such an approach are that it is simple to implement and administer, and is seen to be politically ‘fair’. However, there are several disadvantages of postalisation – it provides no price signals and therefore destroys any ability for a market to generate efficient practices, and that it affords no opportunities for wholesale trading.

Advantages

The main advantages of a postalised regime are as follows:

- It is relatively simple to implement and administer.
- Recovery of revenue for transportation assets is spread equally across all tariffs and therefore all consumers (this may also be a disadvantage, particularly if tariffs for some consumers increase).
- It provides greater levels of transportation flexibility for shippers (although it limits choice).
- The system appears to be more fully utilised as ‘spare’ capacity is minimised due to the permissive structure of the capacity type.

Disadvantages

The main disadvantages of a postalised regime are as follows:

- The regime limits shippers choices and flexibility to balance their portfolio.
- Lack of investment signals since there is little indication about where supplies might enter the network in the future.
- Loss of ability to differentiate capacity charges at entry and at exit and thus provide locational signals.
- The gap between commercial model and physical reality may create constraint issues requiring extra rules and/or costs.
- Regulators may be concerned about loss of ‘cost reflectivity’, although this could be partly mitigated through differential commodity tariffs.
- A TSO may use a less physically accurate model as an excuse to build extra capacity or otherwise increase costs of transport through constraint rules.
- A lack of cost-reflectivity in charging at an entry or exit point level, although this could be partly mitigated through differential commodity tariffs.
- It becomes complex to manage the transportation network in a postalised regime with more than one entry point, particularly when dealing with constraint management.
- It does not comply with forthcoming EU requirements to implement entry/exit tariffs.

B.2.3 Other forms of capacity allocation

Other forms of capacity allocation exist, however these are considered illegal or unpalatable under European legislation, e.g. point-to-point (where the contract with the transporter is for specific routes, and therefore requires a form of balanced portfolio for each route) or bundled capacity (which is linked to a sale or purchase agreement). In addition the CEER have stated they regard the point to point regime as inflexible, and a shipper with a large portfolio of customers a will have a competitive advantage since this shipper can use internal swaps in a way a new shipper with perhaps only one entry point cannot. There is also a view that it will inhibit the development of trading hubs.

B.2.4 Capacity tariffs

It does not necessarily follow that adopting a certain capacity allocation regime automatically means that the same tariff charging regime is required. However, that said the entry/exit capacity type does naturally lends itself to entry/exit tariffs.

For example, entry/exit tariffs avoid some of the design problems which confront point-to-point regimes, typically involving distance related tariffs, such as distance capping, back-haul allowances and average distance travelled calculations. In addition compared with a postalised regime, entry/exit retains the ability to provide differential 'cost reflective' signals within the capacity charge, allowing commodity charges to be kept relatively simple, as required.

B.2.5 Conclusions

Table 16 below summarises the pros and cons of the two regimes. Taking into account the assessment above alongside the current structure and maturity of the Estonian gas market, it is our recommendation that an Entry-Exit regime for capacity allocation and tariffs should be implemented. We believe that this regime should lead to flexible capacity services and will facilitate the development of gas and capacity trading. Although the postalised scheme would also lead to increased flexibility we feel that it would create a number of uncertainties into a developing market which would not be outweighed by the advantages.

As a reference we have also presented in Table 17 below combinations of capacity allocation and tariff type across a number of countries.

Table 16 – Summary of Entry/exit and Postalised capacity models

Criteria	Entry/exit	Postalised
Revenue certainty	✓	✓
Maximises capacity available for sale	✓	✓✓
Maximises system utilisation	✓✓	✓✓✓
Flexibility for shippers	✓✓✓	✓✓
Encourages competition in gas shipping and supply	✓✓✓	✓
Simplicity for shippers	✓✓	✓
Simplicity for transmission operator	✓	✓
Encourages capacity trading	✓✓✓	✓
Provides investment signals	✓✓	✓
Encourages gas trading	✓✓✓	✓

Table 17 – Examples of combinations of capacity allocation and tariff types

Capacity allocation	Tariff type		
	Entry-Exit	Postalised	Distance based
Entry-Exit	GB	For electricity, most EU TSOs	
Postalised		Some US pipelines	
Point-to-point	Northern Ireland	Spain	Germany

Note: Germany to be checked

B.3 Transmission balancing

The main product for a gas transporter is pipeline capacity; however the main day-to-day task of the TSO is the safe and efficient operation of the gas network. This involves the management of gas within the system, ensuring that there is a balance between gas entered into the network and gas taken out of the network is maintained. We have identified two options for the further development of the gas balancing regime:

- a full residual balancing regime with stronger shipper incentives; and
- a DM/NDM regime in which the transporter balances NDM load on behalf of shippers.

B.3.1 Residual balancing regime

Under a residual gas balancing model, shippers are given greater financial incentives to balance on the day. Additional balancing tools are developed for the transporter to enable access to shorter-term balancing contracts. This should lead to greater cost reflectivity and cost targeting of balancing costs, since the incentives placed on shippers to balance reduces the requirement for the transporter to take balancing actions.

In Section B.3.1.1 and B.3.1.2 below, we have set out the main advantages and disadvantages of a residual balancing regime from the point of view of the TSO and the view of shippers and regulators.

B.3.1.1 Advantages

The main advantages of a full residual gas balancing regime from the view of the TSO are that it would provide:

- strong incentives on shippers to balance leading to:
  - a reduced requirement for transporter balancing actions;
  - a greater requirement for within-day trading by shippers;
  - greater responsibility taken by shippers for their own balance position;
- an opportunity to develop new products such as a linepack or daily tolerance services leading to greater utilisation of the pipeline system and potentially higher transporter revenues; and

- potential for commercial incentivisation of the transporter creating opportunities for unregulated revenue, however, this may also have a downside and lead to some limited financial exposure.

Whereas the main advantages of a residual gas balancing regime from the view of shippers and the regulator, are that it would introduce:

- a high degree of cost-reflectivity and cost-targeting;
- more efficient gas balancing price discovery;
- potential for lower balancing charges;
- greater shipper participation in the balancing mechanism; and
- more within-day trading-out of imbalances leading to greater spot market liquidity.

B.3.1.2 Disadvantages

The main disadvantages of a residual gas balancing regime from the view of the TSO are that it would introduce:

- more complex arrangements for procuring short-term balancing gas; and
- the need to support a shipper to transporter trading mechanism.

The main disadvantages of a residual gas balancing regime from the view of shippers (and possibly the regulator) are that it would introduce:

- greater exposure to more variable cashout prices;
- greater requirement to source within-day flexibility tools;
- more complexity in managing within-day balance positions; and
- greater requirement to accurately forecast within-day gas demand.

B.3.2 Daily Metered / Non-Daily Metered (DM/NDM) regime

This regime separates between the daily metered and non-daily metered sectors of the gas market. Under this regime the daily metered sector would be exposed to incentives to achieve within-day balance whilst the non-daily metered sector would be balanced within-day by the TSO.

Gate closure would also be introduced for shipper nominations of gas for the non-daily metered sector. After this gate closure had expired, no changes to shipper nominations would be permitted. Cashout for the non-daily metered sector would be based on the differences between shipper nominations at gate closure and input allocations after the day. The TSO would be responsible for taking balancing actions if non-daily metered offtakes varied to such an extent that a balancing action was required. The cost of these balancing actions would be targeted back to non-daily metered shippers.

As in Section B.3.1above, we have again set out the main advantages and disadvantages of this balancing regime (in B.3.2.1 and B.3.2.2 below) from the point of view of the gas TSO and the view of shippers and regulators.

B.3.2.1 Advantages

The main advantages of a DM/NDM gas balancing regime from the view of the gas TSO is that it would introduce:

- greater transporter control over gas flows for the NDM sector;
- greater incentives on DM shippers to balance;
- removal of within-day uncertainty as to whether or not NDM shippers will respond to demand changes; and
- encouragement of new entrants and approval from regulator.

The main advantages of a DM/NDM gas balancing regime from the view of shippers and the regulator are that it would introduce:

- Greater simplicity for NDM shippers and less exposure to uncontrollable risks such as weather variation, leaving them to concentrate on market development.
- Potential for more efficient balancing of the NDM sector by the transporter, leading to lower overall costs.
- Ability to gradually move towards a full DM residual balancing regime by shifting the DM/NDM boundary over time based on experience.

B.3.2.2 Disadvantages

The main disadvantages of a DM/NDM gas balancing regime from the view of the TSO are that it would introduce:

- A greater requirement for gas balancing actions by the transporter on behalf of NDM shippers.
- A greater degree of responsibility on the transporter to ensure that demand forecasts are accurate and reconciliation volumes are kept to a minimum.
- Greater pressure from NDM shippers for the transporter to procure gas at cheaper prices.
- A requirement to identify balancing actions due to NDM sector and those due to DM sector, if possible, otherwise a methodology would have to be developed to distribute costs between sectors equitably.

The main disadvantages of a DM/NDM gas balancing regime from the view of shippers and the regulator are that it would lead to:

- Less control for NDM shippers over their costs.
- Removal of competitive advantage, whereby one shipper may be able to manage its gas portfolio better than another for the NDM sector, leading to a detrimental effect for competition.
- Less within-day trading between shippers, making development of a spot market less likely.
- Uncertainty over reconciliation volumes.

B.3.3 Conclusions

Our recommended entry/exit regimes capacity allocation is compatible with either of the gas balancing proposals (residual or DM/NDM) discussed in this section. The relative merits of the two proposed balancing models is summarised in Table 18 below.

Taking into account the assessment above alongside the current structure and maturity of the Estonian gas market we believe that the DM/NDM model could provide an acceptable approach by both the regulator and shippers. However, the residual gas balancing model is considered more attractive in terms of the intent of minimising the role of the TSO through incentivising of individual shippers to balance their own deliveries and offtakes to the system through strong incentives (it is also considered more technically challenging and as such would require a more sophisticated and commercial approach to balancing by the TSO).

It is therefore our recommendation that the TSO develops a residual balancing role. The balancing will be done using traditional flexibility tools, such as storage facilities, LNG storage, gas linepack, etc.

Table 18 – Summary of proposed gas balancing models

Criteria	Residual	DM/NDM
Incentivises shippers to balance	✓✓✓	✓
Maintains revenue neutrality	✓	✓
More flexibility for shippers	✓	✓✓
Reduced role for transmission operator	✓✓	✓
Simplicity for transmission operator	✓✓	✓
Simplicity for shippers	✓	✓✓
Efficient balancing prices	✓✓	✓
Encourages competition in shipping and supply	✓✓	✓✓✓
Encourages traded market development	✓✓	✓
Reduces overall cost of balancing	✓✓	✓✓✓

B.3.4 Interaction between balancing and the recommended capacity regime

It is our recommendation that there is an introduction of an entry/exit capacity regime and a balancing regime that is based on the TSO taking a residual balancing role. We believe that by introducing an entry/exit capacity regime and the strengthening of the incentives on shippers to balance could contribute to the development in time of a spot market for gas.

B.4 Consumption estimation, metering rules

The frequency of gas meter reading is likely to be separated into segments, depending on the consumption of the end users. For significant users (e.g. a power station), it is important to know consumption closer to real time than for small users.

B.4.1 Frequency of meter readings

Balancing the system will depending upon live metering for some sites alongside estimations for groups of smaller consumers. The market rules, imposed by the regulator will need to set out the obligations for reading meters for both entry and exit flows from the system. For example, in GB any site with annual seasonal normal consumption greater than 2196MWh (203,286cm) must have a daily meter reading. The choice of transmission balancing mechanism will determine the most appropriate rules for consumption estimation (particularly the relevant responsibilities of the shippers and the TSO) and metering rules.

B.4.2 Consumption estimation

The TSO may be responsible for estimating consumption each day and providing signals to the shippers relating how much of the demand on the transmission system will be allocated to their accounts. TSOs often have the best information for estimating demand on the entire system as they have access to live metering at various points on the network, and can assist shippers by providing an estimate of demand. For example in the Netherlands, each shipper submits an estimate of its portfolio demand ahead of the day in question. The system operator then tracks the difference between the forecast and the real-time data it can see in the market on the day itself, and communicates this difference to each shipper.

The estimate may be provided purely to help shippers with their own forecasting, or the forecast may itself be the level of demand to which the shipper should match supply (with the TSO taking responsibility for any difference between the forecast and the actual demand).

Alternatively, the TSO could make provision for the information it has to be made public and shippers decide for themselves how best to forecast demand and then balance their portfolio.

B.4.3 Reconciliation

In most countries there is a process for post-period reconciliation where the estimates at the time are reconciled with the meter readings as data is collected from end user sites in the days and months following the day concerned. This data can then be used to adjust shipper balances for the calculation of imbalance penalties, entry and exit capacity charges, and transportation charges, if required. For example, in the Netherlands, the real time data is used to calculate any position imbalance for each shipper. Any difference between this data and the final allocations is settled at a neutral (not imbalance) gas price (e.g. system average price in Great Britain).

B.5 Wholesale and retail gas markets

Next we have undertaken an assessment of the requirements for competitive wholesale and retail gas markets. As part of this assessment we have considered EU initiatives for developing competitive wholesale gas markets, including measures to improve liquidity through trading. We then consider the requirements of a well-functioning retail market. As part of our assessment of the retail gas supply market we have proposed a number of supply models that could increase competition given the current dominance of Eesti Gaas in the market.

B.5.1 Wholesale market

Well-functioning wholesale markets should lead an increase in transparency and efficiency within a gas market. As a wholesale market develops there should be an increase in the accuracy of market signals on price, capacities, flows, etc. in a transparent and non-discriminatory manner to market participants. While at the same time, they increase the efficiency of trading and associated functions such as balancing and settlement thereby reducing transaction costs.

Previous EU gas directives did not explicitly set out wholesale market design as a key objective, instead there was a view that the development trading would develop on its own once the other objectives of the EU directives were implemented (for example through the implementation of rules on transportation, generation, distribution and supply). Although trading has historically been the responsibility of the member state the EU now believe that the efficiency of a wholesale market (e.g. power exchanges, gas hubs and OTCs), can be improved by a number of initiatives. The initiatives set out by the EU are as follows:

- **Efficient development of markets related to trade**: for example, within-day balancing markets and access to storage and short and long-term supplies and capacity. Where one or more of these elements is missing, there is likely to be discrimination within the market leading to a decrease in in efficiency.
- **Transparent provision of information**: it is essential that relevant information in regard to the gas market (trades, flows etc.) is accessible to all market participants. All market participants need transparent information on the processes for accessing the networks and therefore it is essential that information is provided by TSOs and operator of gas storage facilities and LNG facilities.
- **Development of spot markets and (regional or national) gas hubs:** price differentials between the hubs will lead to trade and thereby competition. Again there is a requirement that market participants have non-discriminatory access to storage, suitable tariffs and balancing system for trade between the regions.
- **Upstream gas production:** this initiative is designed to keep the overall level of production at a certain level.

B.5.2 Trading and the development of products related to trading

We will now review the development of power exchanges, gas hubs and OTCs and the impact on the liquidity and ultimately the efficiency of a wholesale market. Liquidity in trading and transparent prices is necessary to achieve an efficient wholesale market. A liquid trading hub will help existing gas market participants gain access to gas and provide an incentive to potential new entrants. In an illiquid market new entrants are likely to find it difficult to trade gas, and may ultimately they not be able to purchase capacity or gas when needed. This has historically been a problem in markets dominated by incumbents who already have long-term contracts.

The development of trading hubs, described in Section 3.7.1, has been a key determinant of liquidity in other EU Member States. Most of the trading at these hubs is OTC (over-the-counter, i.e. trader to trader sometimes via a broker) but many of the hubs also have exchanges for clearing futures and short-term trades, e.g. APX at TTF and NBP, ICE at NBP and Endex at NCG. However, it is important to note that the creation of a hub does not automatically lead to an increase in liquidity, in the majority of EU hubs issues of transparency and liquidity still remain. In France, for example, despite the presence of two hubs, the main price driver has recently been Germany's NCG and the Dutch TTF. Prior to this, the main influence on French hub prices was Zeebrugge.

B.5.3 Retail markets

In addition to the development of wholesale markets, it is also vitally important that there is the development of a competitive retail market for gas to ensure competition for end users. New suppliers will only consider entering markets if they perceive them to be sufficiently attractive and profitable. Anything that reduces this attractiveness and profit incentive can be considered a potential barrier to entry.

However, in considering barriers it is important to account for the complexity of their impact. For example, they may limit some types of entrant rather than preventing entry in total (e.g. requiring a minimum scale of operation or some degree of vertical integration), and they may differ in their materiality on the performance of the market, making some uneconomic and costly to overcome.

The main incentive for new suppliers to enter is the headroom that exists between their potential cost of supply and the tariff offered by the incumbent supplier. This headroom arises from the ability of the new entrant, through greater efficiency, flexibility and innovation, to reduce their costs of supply. The cost elements where there is scope for differential costs between new entrants and incumbent suppliers are:

- wholesale purchase costs of electricity or gas; and
- supply business costs (including billing, metering, customer service, customer acquisition and the supply margin).

B.5.4 Retail supply market models

A critical factor in the development of retail market competition is the dealing with the commercial advantage the incumbent has enjoyed through economies of scale and scope. This advantage relates to the fixed costs of entering markets and in the asymmetric risk exposure of operating with a small, less diversified portfolio. To the extent that this asymmetry can create a fundamental distortion, we consider a number of options that could mitigate this incumbent advantage and help promote competition. Below are two possible options to delivering a fundamental restructuring:

- the promotion of a shallow supply model that removes the obligation for providing many of the supply activities that incur set-up costs for new entrants from the supplier and put them on an independent entity; and
- mechanisms for divesting market share or targeting market share loss of the incumbent in certain market segments to overcome initial portfolio asymmetries.

Whereas the former is intended to alter the cost structures of supply companies and then rely on commercial decisions to change market structure, the latter mandates a change in structure over a set period.

B.5.4.1 Shallow Supply model

One of the problems in a small market may be that economies of scale in retail activities are so large that they are a complete barrier to entry for independent suppliers, thereby restricting the market to either the incumbent or a small number of integrated, established market players. If it is possible to restrict the role of a supply company so that it does not have to develop or procure some of these high fixed cost elements independently, then suppliers may focus on competing around energy costs – enabling greater focus on product innovation whilst maintaining economies of scale in the other activities.

B.5.4.2 Divestment of the incumbent and/or restrictions on bidding

The shallow supply model addresses some of the problems related to economies of scale and set-up costs. A more radical option would be to pursue a policy that aims at a fundamental restructuring of the supply market. This may involve some or all of the following:

- forced divestment of part of the existing customer portfolios of the incumbents;
- agreement on market share reduction targets with the incumbents; or
- restrictions on competition by the incumbents – this may be in the form limitations on the response to competing tariff offers by the incumbent (e.g. restricting the incumbent to fixed regulated tariffs rather than offering them the flexibility to alter tariff offers) or preventing the incumbent from re-signing a customer for a set period after they first lose the contract.

This option is likely to help new suppliers achieve a larger market share over a shorter period of time.

B.5.4.3 Improving contract market liquidity

The ability of new suppliers to secure efficient wholesale purchase is a key determinant of their ability to undercut the incumbents offer. As a consequence, any wholesale market imperfections are a major barrier to competition.

A liquid wholesale market would allow suppliers to have access to various physical purchasing options as well as financial hedging instruments. This type of 'liquid' wholesale market would allow suppliers to reduce significantly their wholesale procurement risks, and allow a better hedge to peak price exposure.

One way of implementing this option would be to develop bulletin boards to enable greater trading of specific products between companies and as liquidity begins to increase it is likely to attract more brokers to the market, which would further increase liquidity.

B.6 Customer switching process

A customer's ability to choose between alternative suppliers is a key feature of any competitive retail market. Switching is particularly important for SME and domestic customers who are normally offered standard contractual terms and conditions by suppliers and are not able to negotiate their contracts on an individual basis. Therefore the ability to choose between alternative tariffs (offered by competing suppliers) is essential to the development of competition in these markets.

In Estonia there has been some limited switching in the last couple of years, peaking at 1539 customers in 2009. One reason for this may be customer perceptions and experiences of the transfer process, which play an important part in determining whether they believe switching is worthwhile. However, the 2009 Competition report (produced by the Estonian Competition Authority) suggests that the switching process in Estonia appears relatively efficient. This report states that "sellers of gas have to enable the termination of contracts within in one month following receipt of an application to switch by the seller provided that the obligations related to the contract that is to be terminated are fulfilled", these timescale are similar to the ones used in the GB market, which is often seen as a 'best practice' for switching processes. However, the same report also highlights that the majority of consumers are choosing to switch to the incumbent Eesti Gaas[45]; this would appear to indicate a lack of competition in the market more than issues with the switching process

Given the Competition Authority report appears to shows that an efficient switching process is in place the proportion of customers switching is still small. Therefore the remainder of this section focuses on measure that can be used to improve customer participation in the switching process. These measures include:

- customer is awareness;
- price transparency;
- dual fuel strategies; and
- quality and availability of data

B.6.1 Customer awareness

A precondition for effective supply competition is that customers are aware of their right to choose an alternative supplier and thereby save money on their bills. The extent to which customers are aware and the extent to which they exercise these choices could have far reaching implications for the structure of the market and the conduct of suppliers within the market. For instance, a decrease in customer awareness could act to lower switching rates, which could in turn deter future growth and entry by suppliers into the market.

B.6.2 Price transparency

If customers do not have pricing information that they can easily understand, they may not be making informed choices about switching. If customers find the available pricing information unhelpful, confusing or misleading then the regulator will need to assess whether this is because prices are inherently complex, or whether there is a need for additional information to be provided to customers. Most research shows that it is vital that pricing information is transparent, relevant and accurate for the customers who use it, particularly where it underpins the decision to switch supplier.

B.6.3 Dual fuel strategies

For suppliers the ability to offer dual fuel deals provides a means through which they can offer sufficient discounts to encourage switching behaviour. The discounts can reflect the economies of scope associated with a wider product offering including lower costs of customer acquisition, combined customer service operations, joint metering services and better cash flow management.

Furthermore, the addition of another margin stream may increase the profitability of the operation. Where the dual fuel offer is extending a single-fuel supply arrangement (i.e. where the supplier is the incumbent gas or electricity provider); it can be a means of securing the existing customer base. In these circumstances, the supplier's marketing costs are often lower – they already have access to, and reputation with, the potential customer – and they are able to focus their discounts onto the new fuel, thereby maximising the perceived benefit for the customer.

45 Studies have shown that price is not the only factor in switching, customers will stay with a marginally more expensive company as a result of loyalty, marketing / service quality etc.

From the customer's perspective, while cost savings may be the primary driver for switching, they also offer the added benefit of dealing with a single company for both electricity and gas –single direct debit payments, single point of contact on customer service, etc.

B.6.4 Quality and availability of data

Incomplete or imperfect information on potential customers has several implications for new entrants:

- It makes it more difficult to formulate appropriate tariff offers to customers as knowledge of their consumption patterns is incomplete, thereby preventing some more efficient contract options from being exploited.
- Similar to the above, it makes suppliers less willing to tender for new customers. However, without reliable data against which to assess the risk associated with the contract some suppliers either will not tender or will impose risk premium that may overstate the actual impact of the customer on the supplier's portfolio.
- Wholesale costs will generally rise as suppliers over hedge their positions.

Therefore reliable information available on a timely basis to all suppliers would lower the transactions costs of acquiring customers and increase benefits to consumers.

B.6.5 Conclusions

Customer switching in the Estonian Gas market is already taking place and the processes put in place to facilitate switch customers appear to be well developed. However given the limited number of customers who have switched it does appear that their needs to be more encouragement (through increased customer awareness, price transparency, offer strategies and the quality / availability of data) to ensure, where competition is available, that more customers are in a position to make an informed decision regarding whether to switch supplier or not.

B.7 Consumer price differentiation

The key requirement of tariffs design is that the supply company is able to recover its revenue and provide signals to customers the costs of resources. Properly designed tariffs should also minimise distorting effects, for example around the boundary between different tariff prices.

B.7.1 Supply Tariff design

As we briefly highlighted above supply tariffs serve two main functions, to collect revenues, and to provide signals to customers about the cost of the gas they are consuming. Both of these functions are obviously important, the first allows a supply company to cover the costs of supplying the gas while the second enable smaller customers to be unmetered and charged on the basis of annual estimated costs. While it is cost effective to meter large sites individually, suppliers are required to group small consumers, into tariff categories. This enables the suppliers to group consumers with similar marginal cost characteristics (while taking account of any administrative costs of identifying separate consumer groups).

This second function can also as an incentive on consumers to alter their level and pattern of gas use, however it is important to consider that certain customers (e.g. domestic) have limited ability to change their consumption patterns demands (e.g. heating and cooking requirements in the evening).

B.7.2 Structuring the Supply Tariffs

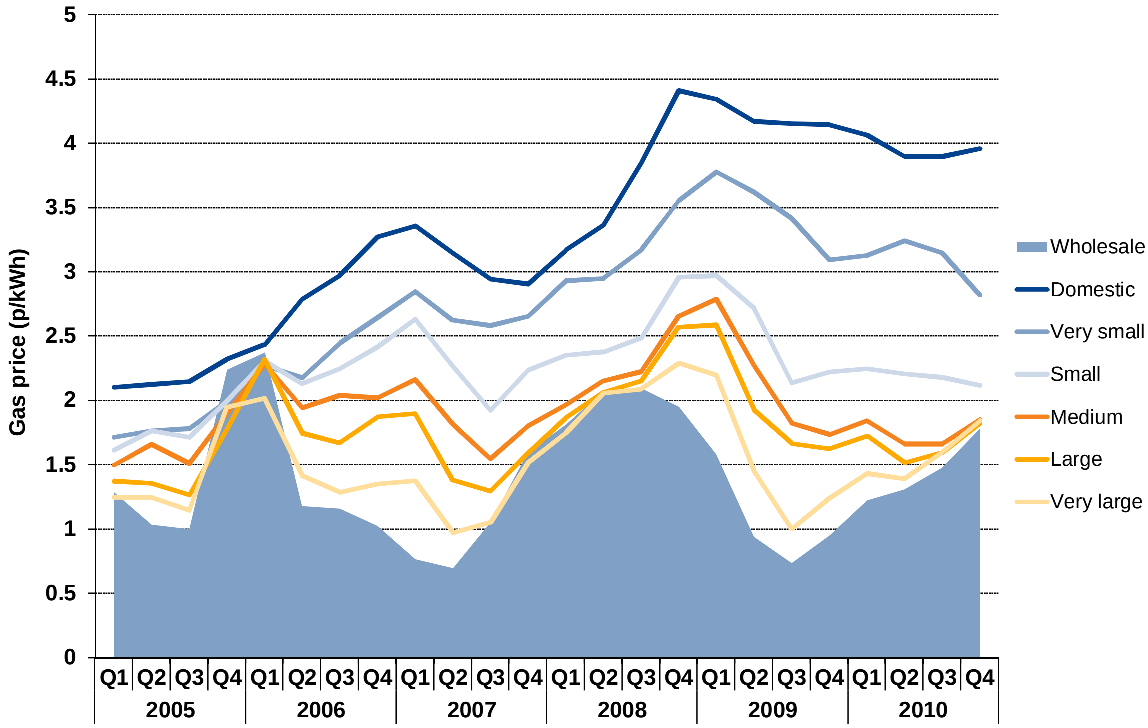
Below we set out the components that are used to develop an appropriate gas tariff. Some of these components are fixed and will be consistent between suppliers while others will be at the discretion of the supplier. Ultimately though these components only form a guide since in a competitive market a supplier is in principle able to set the tariff at any level they see fit.

- **Connection Charges** – the connection charge element cover incremental cost incurred in connecting a new customer to the network. This cost usually covers the actual cost of connection together with the meter installation cost).
- **Fixed Customer Charges** – these charges relate to charges which are paid irrespective of a consumer’s gas consumption or peak demand. Although these charges can be considered fixed they can vary based on a suppliers number of customers. For example these costs include meter reading, billing, and account management in general.
- **Demand Charges (Daily Metering)** – reflect the costs associated with the costs of procuring and transporting gas at peak times. For daily metered customers the charges may be levied either on the basis of actual peak demand in the billing period or on the basis of a forecast of peak demand that is estimated from the previous year’s metered peak consumption.
- **Demand Charges (Non-Daily Metering)** – high metering costs (relative to the potential benefits of metering) mean that for the majority of domestic and SME customers demand are estimated. For these customers, demand-related costs can be charged on the basis of a fixed (monthly, bi-monthly, quarterly or annual) charge but will not be reflective of marginal costs.
- **Commodity charges** – relate to the non-demand costs of purchasing gas, although they may also include a small amount of network costs that are associated with each kWh of gas flowing through the network.
- **Interruptible discounts** – the flexibility provided by interruptible customers is important as it allows a supply company to contract for less gas, therefore saving significant costs. Interruptible discounts are offered to daily metered customers, as a discount on the usual tariff. The tariff will set out the period of time a customer is willing to be ‘interrupted’, which is usually set out as a maximum number of days within a year.

B.7.3 Examples of tariff differentiation

In Figure 30 below we have presented the GB retail and wholesale prices for the 2005-2010 period. The chart shows that in general retail market prices loosely follow wholesale market prices, but they vary significantly for different customers groups. This chart highlights how GB energy suppliers have continued to set and develop tariffs to target particular customer groups, with the differential between the small scale and large scale tariffs increasing over time. Without this ability to develop targeted tariffs it will become difficult for a supplier to remain competitive across the different market sections

Figure 30 – GB retail market prices for different customer groups



*Wholesale price shown here is spot market price. Sources: IEA, DECC and Heren.

B.7.4 Conclusion

In this section we have highlighted the importance of tariff differentiation in developing cost reflective tariffs in retail supply market and set out the components that are used to develop an appropriate gas tariff. Through tariff differentiation a new entrant will be able to target selective customer groups where they feel they can offer more competitive tariff compared to the incumbent supplier. Through building on its position in one market the new entrant may eventually to be able to hedge its gas purchasing to enter additional markets, thus eventually increasing competition across all consumer groups.

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ANNEX C – REGULATORY CONSIDERATIONS

Reviewing transmission assets, it is important to understand regulatory considerations, as it is the regulator who establishes the tariff. Two types of tariffs are usually used as described in Section B.2.4. Choosing the right type of tariff, one needs consider advantages, disadvantages and appropriateness of these.

Transmission assets have high capital requirements and, therefore, the tariff set for transmission assets' operation depends to a large part on the initial capital requirements of transmission assets. In order to determine a reasonable tariff, which will cover transmission assets' costs and will provide a desired return in the future, one needs to value transmission assets correctly. There is no liquid market for transmission assets, and they are valued according to different method described in Section C.3, as opposed to conventional valuation methods.

C.1 The role of a regulator

The role of an energy regulator is to ensure that energy wholesale and supply markets are competitive. To achieve this, a regulator needs to balance the interests of three stakeholder groups: the government, energy service suppliers and customers. Each of these groups has potentially conflicting interests.

A key element of the regulator's role is striking the balance between encouraging investors and protecting consumers, while fulfilling government objectives. The regulator should ensure that both suppliers and consumers uphold their obligations relating to commercial operations. The utility has the obligation (via licensing) to provide a service under the approved tariffs and quality standards. Consumers have an obligation to pay for that service to ensure the financial viability of the sector.

The purpose of regulation is to ensure that price reflects the least cost of service and meets required quality and reliability standards. To do this a prudent regulator monitors prices paid by customers for energy in the retail supply markets and produces regular reports on competition in the retail sector, covering customer switching rates and other indicators.

C.1.1 Energy transportation regulation

Energy transportation businesses are natural monopolies – there is no realistic means of introducing competition. A regulator protects customers' interests by regulating the companies through price control periods, which include limits on expenditure as well incentives to be efficient and to innovate technically.

The price controls set the maximum amount of revenue which energy network owners can take through charges they levy on their networks' users to cover their costs and earn a return. The users in this case are shippers which use gas networks to transport gas to customers.

Regulators may be responsible over the following exemplary items for which they must both monitor current practice and intervene if necessary:

- approval of network access tariffs and conditions, including transmission, distribution and LNG facilities;
- the level of transparency and competition issuing authorisations and licenses;
- monitoring the security of energy supply;

- management and allocation of interconnection capacity;
- mechanisms to deal with congested capacity within the national system;
- the time taken by transmission and distribution undertakings to make connections and repairs;
- the effective unbundling of accounts to avoid cross subsidies and the unbundling compliance programme;
- organisation, monitoring and control of the tendering procedure for generation;
- deciding on derogations in relation to take-or-pay commitments for gas; and
- dispute settlement arrangements for access to upstream gas pipelines.

C.1.2 Associations of regulators

Europe's national regulators of electricity and gas cooperate at an international level through a number of associations.

Energy Regulators Regional Association (ERRA) is a voluntary organization of independent energy regulatory bodies primarily from the Central European and Eurasian regions, with affiliates from Africa, Middle East and the United States.

Council of European Energy Regulators (CEER) is a non-for-profit association, where the national regulators cooperate and exchange best practice. A key objective of the CEER is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest.

CEER works closely with and supports the work of the Agency for the Cooperation of Energy Regulators (ACER). ACER, which has its seat in Ljubljana, is an EU Agency with its own staff and resources. CEER, based in Brussels, deals with many complementary (and not overlapping) issues to ACER's work such as international issues, smart grids, sustainability and customer issues.

C.1.3 The role of Agency for the Cooperation of Energy Regulators

Agency for the Cooperation of Energy Regulators (ACER) is a European Union body established in 2010. The aim of the agency is to assist National Regulatory Authorities (NRA) in exercising the regulatory tasks in gas and electricity areas that they perform in the Member States and to coordinate their action.

ACER monitors European Networks of Transmission System Operators (ENTSO), NRAs, cross-border infrastructure, provides consultations and transparency to market participants and reports on the electricity and gas sectors.

ACER is assisting the entry into force of the third energy package and setting of a firm regulatory, institutional and political background to achieve completion of the internal energy market by 2014.

In 2006, the previous regulator, ERGEG, under the framework of Regional Initiatives created seven electricity and three gas regions (North West, South South-East and South) as an interim step to complete the single energy market. At present, Baltic States are not a part of any of these regions.

According to the Gas Regional Initiatives, ACER and the European Commission promote the integration of the gas markets in close cooperation with the stakeholders of the gas sector and Member States. This implies development and more efficient use of the infrastructure. Network code on capacity allocation, hub-to-hub trading in the EU and transparency monitoring are required to achieve this goal.

C.2 Tariff setting

Transmission tariff and capacity regimes set by the regulator are of fundamental importance to transmission network owners, operators and gas transporters as they determine the way in which the primary product, pipeline capacity, is sold.

According to the previous gas regulatory group (ERGEG) tariff structures should take into account following fundamental principles:

- The tariff structure should be simple and transparent, contributing to the development of the European gas market and its liquidity.
- Tariffs structure should support efficient development and operation of the network by the TSOs.
- The tariff structures should encourage the efficient use of the network by all users and should deliver predictable results.
- The tariff structures should allocate total costs between users in a non-discriminatory and transparent manner.
- Tariff setting should avoid cross-subsidies among network users. A limited level of cross-subsidisation can be justified if other advantages are introduced by a specific tariff model.

Capacity tariffs determine recovery of the revenue necessary to finance its business, return on assets and need for the future investments. The first stage in developing a tariff is to consider the Annual Revenue Target (ART) for the network assets. The ART is derived from:

- Recovering the annual operating costs of operating a safe, reliable and efficient transmission system.
- Delivering a financial return on the assets that have been invested in the past.
- Recovering the asset depreciation costs.

C.2.1 Operating Costs

Typically there are two categories of operating costs:

- Direct Costs – those that are directly controlled under the transmission budget such as direct labour, contractor, staff payments, etc.
- Indirect Costs – those that are shared with other parts of an organisation such as IT, HR, corporate services, sales & marketing costs.

Establishing the levels of direct costs should be relatively easy – depending on the levels of financial reporting, whereas, identifying the indirect costs can be much more difficult.

When introducing competition, the normal corporate reaction is to load as much of the shared costs to the monopoly elements of the company to limit the potential impact of competition on their financial performance. However the regulator will be well aware of this, and may specifically require the cost allocation methodologies to be disclosed.

Activity Based Costing is typically an accepted approach, whereby a cost driver is selected to allocate the costs, i.e. employees is the cost driver for HR costs, PC users can be the cost driver for IT costs, etc.

C.2.2 Return on investment

The concept of recovering an ongoing financial return for an investment (the pipeline assets) is equally relevant for a state-owned enterprise, as it is for a commercial organisation. Hence a transmission company needs to determine the required level of return on asset.

This will involve determining the current value of the transmission assets, followed by calculating a required rate of return.

Obtaining an accurate inventory of transmission assets in itself can be an impossible task, never mind trying to determine the depreciated value of these assets. Typically old records are lost or destroyed, so that operational knowledge is the only way to verify some of the older assets. However, their current value would of course be minimal.

A tariff based purely on a commodity element with no capacity charge increases the risk of the utility not being able to generate adequate cash flows to service debt in years with lower than expected consumption. This risk needs to be reflected in the required rate of return, one of the most contentious areas on setting the ART. Transmission companies are typically relatively low risk and capital intensive, and have long term views on investments; hence they tend to have fairly modest rates, i.e. 6.5-7.5%.

There are various ways of determining the rate of return by assessing the Weighted Average Cost of Capital (WACC). The methodology for determining the WACC, and the elements included are described in detail on the webpage of the CA. WACC of gas transmission in 2010 calculated by CA is 7.76%. By applying the rate of return to the current asset value, one can derive the required return on asset.

C.2.3 Depreciation

Again depending on the treatment of the asset valuation, there are a number of methodologies for determining the depreciation costs.

Typically straight-line depreciation is used, with asset lives allocated to each category of asset. It will also be appropriate to allow residual values for certain assets.

C.2.4 The Treatment of Other Income

Depending on your connection policy, there will also be annual income from connection fees and capital contributions. This income will need to be netted-off the ART to avoid double recovery of assets.

C.3 Principles for valuing transmission assets

The value of transmission assets is based on historical investment costs and represents the value upon which companies earn a return in accordance with the regulatory cost of capital (WACC) and receive a regulatory depreciation allowance.

Due to the capital intensive nature of typical transmission networks the value of the Regulatory Asset Base (RAB) forms a critical input into determining the regulated tariffs and is as an important indicator of efficient pricing and future investment.

Different methods can be used for valuation of specific assets. These include:

- Indexation
- Replacement cost analysis; and
- Modern equivalent asset analysis.

Indexation is used for assets which undergo little technological change and most direct costs incurred for those assets would have to be incurred again if the assets were replaced. The value obtained by this method is directly linked to the historical value of the relevant assets, thereby ensuring that all of relevant costs are included in the valuation.

Replacement cost analysis (RCA) is used in valuing assets which undergo little technological change and in cases for which the first method is not applicable. This method values the relevant assets at their current unit prices. Such prices may be referenced to the purchase price of like assets or to documented quotations for the sale of similar assets in the recent past. The prices should include the usual purchasing discounts and are adjusted to cover relevant design, procurement, construction and commissioning costs. Therefore, this method simply updates the assets cost without updating technical parameters (efficiency, capacity, etc.).

Absolute valuation using modern equivalent asset (MEA) analysis values assets at the cost of modern equivalent assets with a similar service potential (e.g., an asset which replicates at least their current capacity and functionality). This method is used when it is not possible to determine the current replacement cost for an asset, e.g. because that asset is no longer manufactured.

C.3.1 Optimised Depreciated Replacement Cost method

Transmission assets are usually specific; they either do not have a market or the market is illiquid and therefore, their market value is not possible to determine. To value transmission and distribution networks an Optimised Depreciated Replacement Cost (ODRC) methodology is typically used. ODRC value is the minimum cost of replacing the service potential with modern equivalent assets in the most efficient way, given the service requirements, the age and condition of the assets.

This method is a variation of RCA method. As the name suggests, according to this method, assets' replacement costs are depreciated and optimized. The difference of this method from the parent, RCA method, is that it takes into account inefficiencies of current assets, i.e. it removes assets' excess capacity and requires thinking on assets' optimization.

This approach is used to assess the value of assets where:

- The value of assets can be based on historical asset costs, indexed replacement costs or on a MEA base.
- An optimisation component is introduced to ensure that assets are constructed in the most efficient manner possible while maintaining required service standards.

ODRC method determines a hypothetical market value of the assets in cases when market value for specialised assets is not known. The ODRC is calculated based on the gross current replacement cost (GCRC) of assets that are adjusted for over-design, over-capacity and/or redundancy and includes a deduction for depreciation.

For a range of assets there is a quoted price and a liquid market. The assets for which a market GCRC is appropriate will be valued based upon their market value. In cases where there is no market value, the ODRC value assumes that the maximum amount a potential purchaser would be prepared to pay for an asset is represented by the purchaser's lowest alternative cost to replicate the asset, given its existing age and condition. The GCRC of individual assets is based on the required level of service potential consistent with the future growth in demand. In other words, users will only pay for those assets that are required in a commercial context, disregarding any excess capacity or over-engineering embodied in the existing assets.

The ODRC methodology follows generally accepted valuation principles and involves the following steps:

- defining and identifying the assets;
- assessing replacement costs of the identified assets;
- optimising the configurations of the assets; and
- calculating the ODRC value.

C.4 Best practice for consulting with stakeholders

In a course of either a liberalisation process or as part of regulating the transmission assets mentioned above the regulator will need to consult with stakeholders to provide timely, accurate and transparent information. The consultation process improves the quality of decisions, prioritisation, general understanding of the course of work by stakeholders and enables progression towards the best solution. In this section we outline some best practice that regulators follow in order to have the maximum engagement with stakeholders and to gain consensus on the outcomes proposed.

Typically before deciding on an issue requiring regulatory intervention the regulator or government should engage stakeholders to collect their views on issues of concern for the following year. After an issue is chosen, the regulator should publish a consultation document, setting out the issue, options for consideration and inviting views. More consultation documents may be published later to seek further views.

A consultation may also be supplemented by seminars and presentations with stakeholders, e.g. groups representing customers' interests and industry players. These events should be structured to enable attendees to participate effectively, to improve the effectiveness of overall consultations.

Every consultation document should include a timetable for responses, seminars or workshops, progressing with the proposals and a contact name for all responses and requests for more information or guidance.

A regulator or government should provide sufficient time period for a consultation, at least four weeks, and leave sufficient time to obtain written responses depending on the nature and timing of the consultation. Comments on the published documents should be taken into consideration by the regulator, when implementing its policy.

After the consultation period is closed, the regulator or government should publish its decision document on the policy in question. The decision document should contain their response to the views expressed by stakeholders, its decisions and invite further comments.

C.5 Liberalisation checklist

In our review we have developed a set of criteria and actions that regulators and/or government authorities would need to undertake in order to deliver a successful gas market liberalisation, including those needed to support moves to a regional market.

- General Regulation
  - Develop a competition law.
  - Ensure independence of regulatory authorities.
  - Develop provisions relating to autonomy in the implementation of the regulatory authority budget.
  - Develop a list of objectives, duties and powers of a regulation authority (including refusal of certification to TSOs that do not comply with unbundling rules; ability to issue incentives, binding decisions and impose penalties on natural gas undertakings which fail to comply with their obligations).
  - Monitor the balance between gas supply and demand and report the situation to the European Commission.
  - Develop a transparent, objective and non-discriminatory system of authorisation to build and operate natural gas facilities, or to supply natural gas; and a procedure to appeal against authorisation refusals.
  - Encourage cooperation on a regional and pan-European level to promote efficient allocation of resources, risk hedging and new entry.
  - Provide clear and comprehensive guidelines to consumers about their rights in the gas sector.
- Transmission, storage and LNG
  - Unbundle transmission systems and transmission system operators.
  - Develop a procedure for approval and designation of TSOs.
  - Develop a procedure for designation of storage and LNG operators.
  - Develop a procedure for designation of an independent SO.
  - Unbundle transmission system owners and storage system operators.
  - Develop a system providing exemptions for access of new gas infrastructure for a defined period of time for small and closed distribution system operators.
  - Ensure independence of storage system operators and develop a regulatory framework for storage operators.
  - Develop efficient, non-discriminatory and cost-effective balancing mechanisms.
  - Develop a procedure ensuring independence of the staff and management of TSOs (appointment and renewal, working conditions including remuneration, and termination of the term of office).
  - Develop transparent and cost-effective tariffs for non-discriminatory connection to gas sources (storage, LNG terminals, industrial customers to transmission system), which will provide investment incentives.
  - Develop a procedure encouraging cooperation of transmission system operators at a regional level, including on cross-border issues, and integration of the isolated gas systems.
- Distribution and supply
  - Designate a distribution system operator, which will not discriminate between system users.

  - Unbundle distribution system operators.
  - Unbundle accounts.
  - Encourage development of interruptible gas contracts.
- Access to the transmission and distribution system
  - Ensure implementation of third party access.
  - Ensure implementation of access to storage facilities and transparency of storage capacity offered to third parties.
  - Ensure access to upstream pipeline networks.
  - Develop a process of access refusal provisions to enhance competition in gas supply and security of supply.
- Wholesale market
  - Encourage new entry into the Estonian gas supply market.
  - Develop alternative sources of gas supply apart from Russian gas.
  - Auction a percentage of contracted gas on the wholesale market or mandate a gas release programme.
  - Generate competition between gas suppliers.
  - Ensure liquidity and security of supply on the gas supply market.
  - Develop gas flexibility arrangements.
- Trading
  - Promote a gas trading market.
  - Stimulate competition on the trading market.
  - Set liquidity targets for the gas trading market.

ANNEX D – GLOSSARY

D.1 Conversion units

Table 19 – Conversion factors used in calculations

To -> From	bcm	mt LNG	TJ	TWh	mmbtu	Gcal	Mtoe
bcm	1	0.758	0.039	10.80	3.686E+07	9.29	0.955
mt LNG	1.320	1	0.051	14.26	4.865E+07	12.26	1.261
TJ	25.72	19.48	1	277.79	9.479E+08	238.85	24.56
TWh	0.093	0.070	3.600E-03	1	3.412E+06	0.860	0.088
mmbtu	2.713E-08	2.055E-08	1.055E-09	2.931E-07	1	2.520E-07	2.591E-08
Gcal	0.108	0.082	4.187E-03	1.1631	3.969E+06	1	0.103
Mtoe	1.047	0.793	0.041	11.310	3.859E+07	9.72	1

D.2 Names, definitions and acronyms

€/MWh	Euros per Mega-Watt hour.
ACER	The Agency for the Cooperation of Energy Regulators is a European Union body established in 2010 performing regulatory, transmission system related, consultation, monitoring and reporting tasks.
APX-ENDEX	Europe energy exchange, operating spot and futures markets for electricity and natural gas in the Netherlands, the United Kingdom and Belgium.
Balticconnector	A possible natural gas interconnector pipeline between Finland and Estonia.
bcm	Billions of cubic metres.
BBP	Baltic Balancing Point.
BEMIP	Baltic energy market interconnection plan initiated in 2009, covering energy market integration, electricity interconnections and power generation and gas diversification of routes and sources.
BnetzA	Bundesnetzagentur is German federal networks agency overseeing electricity, gas, telecommunications, postal and railway markets.
Calorific value	Calorific value or heating value is a measure of heating power of a fuel and is dependent upon the composition of the fuel.
CCGT	Combined cycle gas turbine plant is a gas turbine generator producing electricity. Heat in the exhaust of the turbine is used to make steam, which in turn drives a steam turbine to generate additional electricity. Many of the new installed gas fed power

	plants operating according to this technology.
CEER	The Council of European Energy Regulators is the organisation representing Europe's national regulators of electricity and gas at EU and international level.
Conventional gas	Gas produced from reservoirs, which are typically underground formations composed of sandstone.
EBRD	European Bank for Reconstruction and Development providing financing for major European projects.
EEPR	European Energy Programme for Recovery (EEPR) introducing by European Parliament to finance defined strategic sectors, address the lack of confidence among investors and strengthen overall economy.
Natural gas market directives	Legislative acts of the European Union, requiring Member States to achieve directives objectives. 3 directives have been published so far.
Energy island	Energy market isolated from the pan-European energy markets.
ENTSO	European network of transmission system operators existing in gas and electricity areas
ERGEG	European Regulators' Group for Electricity and Gas is a former advisory group to the European Commission on internal energy market issues in Europe currently presently known as a Council of European Energy Regulators.
ERRA	Energy Regulators Regional Association is a voluntary organization of independent energy regulatory bodies primarily from the Central European and Eurasian regions.
IEA	The International Energy Agency (IEA) is an autonomous organisation working on energy security, economic development and environmental awareness
I&C	Industrial and commercial customers, customers consuming more than 70MWh of gas per annum.
ISO	Independent System Operator is an organization formed at the direction or recommendation of the regulator, coordinating, controlling and monitoring the operation of the gas system.
ITO	Independent Transmission Operator is an organisation that owns, operates, maintains and develops the gas system.
ITGI	Interconnection Turkey Greece Italy is a proposed pipeline between Caspian Sea, Middle East and Europe.
GASPOOL	German trading point for natural gas.

GeLi Gas	Business processes of a change of supplier gas introduced in Germany in 2007.
H-gas	According to gas classification in Germany, gas with a high calorific value, higher than 10kWh/m3.
L-gas	According to gas classification in Germany, gas with a lower calorific value.
Litgrid AB	Lithuanian transmission system operator.
LitPol link	A proposed new power interconnector between Lithuania and Poland.
LNG	Liquid Natural Gas.
LRMC	Long run marginal cost is the total cost incurred in producing each unit of output in the long run.
mcm/d	Millions of cubic metres per day.
NBP	National Balancing Point a virtual gas trading point in the UK. The most liquid trading point in Europe.
NCG	NetConnect Germany is a joint company created between German regional gas network companies, involved in balancing management and operation of the German virtual trading point.
NRA	National regulatory authority is a public authority or government agency responsible for exercising autonomous authority over an area of activity in a regulatory capacity.
Network code	A legal and contractual framework to supply and transport gas, which has a common set of rules for all industry players, ensuring that competition can be facilitated on level terms.
OECD	Organisation for economic cooperation and development.
Oil indexation	A method of calculating gas prices based on the prices of oil, typically in long-term gas purchase contracts.
Offtake	Collection, a channel or a point for such a collection.
Offtake agreement	An agreement between a producer and a buyer to purchase future production, negotiated prior to the construction of a facility to secure a market for the future output of the facility.
p/therm	Pence per therm.
PEG	Virtual gas trading point in France, run by Powernext.
Proven reserves	Proven gas reserves are the reserves, which, by analysis of geological and engineering data, can be estimated with a high degree of confidence to be commercially recoverable from a

	given date forward, from known reservoirs and under current economic conditions.
PSE Operator S.A.	Polish Transmission System Operator.
PSV	Virtual gas trading point in Italy.
Take-or-pay contracts	According to these contracts a buyer either takes the product from the supplier or pays the supplier a penalty. Up to an agreed-upon ceiling, the company has to pay the supplier for products they do not take.
TAG	Trans Austria Gas pipeline between the Slovak-Austrian border at Baumgarten an der March and Arnoldstein in the south, near the border with Italy.
TEN-E	Trans-European energy networks is a program specifying objectives and priorities for the security and diversification of supply, interconnection, interoperability and development of electricity and gas transporting networks.
TGL	Tauern Gas Pipeline from Bavaria through Upper Austria, Salzburg and Carinthia and on to Tarvis in Italy.
TIGF	French logistics coordinator company also active in gas trading.
TTF	Title Transfer Facility, a natural gas virtual trading point in the Netherlands.
TPA policy	Third party access policies require owners of natural monopoly infrastructure facilities to grant access to those facilities to parties other than their own customers, on commercial terms comparable to those that would apply in a competitive market.
nTPA	Negotiated Third Party Access policy.
rTPA	Regulated Third Party Access policy.
TSO	Transmission System Operator, a company transporting gas or electrical power on a national or regional level.
Unconventional gas	Natural gas resources which require greater than industry-standard levels of technology or investment. The three most common types of unconventional gas are tight gas, coal bed methane gas and shale gas.

D.3 Exchange rates

Table 20 shows the projected real exchange rates used in our analysis, which are constant from 2015 onwards. The real exchange rates convert dollar-denominated oil and coal price projections into the currency used for our costs analysis, which is in Euros for all markets except the UK.

The Euro is assumed to strengthen against the dollar so that by 2014, it is 1.5% stronger than at present. Sterling also strengthens significantly between now and 2015 – by 6% against the dollar and 8% against the euro. Sterling has strengthened against the Euro throughout the modelled period, particularly in the long-term.

Table 20 – Real exchange rates (real 2010 money)

	US$ per £	US$ per €	£ per €	$/mmbtu per €/MWh	US	UK	Euro-zone
2010	1.56	1.34	0.86	4.58	1.6%	3.3%	1.6%
2011	1.64	1.37	0.83	4.66	2.3%	4.0%	2.2%
2012	1.67	1.35	0.81	4.62	1.9%	2.0%	2.0%
2013	1.71	1.33	0.78	4.53	2.1%	1.9%	1.9%
2014	1.73	1.33	0.77	4.54	2.1%	2.0%	1.9%
2015	1.74	1.35	0.77	4.59	2.0%	2.0%	2.0%
2016-2035	1.74	1.35	0.77	4.59	2.0%	2.0%	2.0%

Source: Bloomberg and Pöyry analysis

The real exchange projections are driven by assumptions about nominal exchange rates and inflation[46]. Real exchange rates are constant from 2015 onwards because nominal exchange rates are constant, and the inflation rate is the same across all zones.

Nominal exchange rates out to 2014 are based on the median composite Bloomberg forecast of the spot rate. We hold nominal exchange rates constant from 2014 onwards.

Inflation rates for 2010, 2011 and 2012 have been derived by using the median composite CPI forecasts from Bloomberg based upon forecasts from approximately 40 financial institutions. In 2013 and 2014, the inflation rate trends between the 2012 value and the long-term assumption of 2% for all three economic areas.

[46] For example, if inflation is higher in the US than in the euro-zone, the dollar will be weakened in real terms (assuming no change in nominal exchange rates).

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ANNEX E – ABOUT PÖYRY

E.1 Corporate Structure, history and services

Pöyry Management Consulting (UK) Ltd is part of Pöyry Plc.

Pöyry Plc is a global consulting and engineering firm focusing on the energy, forest industry, water and environment, transportation and construction service sectors. The company operates in 50 countries, employing over 7000 experts and had an annual turnover in 2009 of €674m. Pöyry PLC is listed on NASDAQ OMX in Helsinki.

Further information and corporate accounts can be obtained from www.poyry.com.

Figure 31 – Ownership structure

Pöyry's Management Consulting practice employs over 450 staff globally, our energy practice consists of 200 experts in 14 European offices.

E.1.1 History

Pöyry Management Consulting (UK) Ltd was formerly ILEX Energy Consulting which was founded in 1990 with the aim of meeting the challenges of the opening of the electricity market in England and Wales. ILEX rapidly expanded to advise on electricity and gas markets in the UK, Ireland, Italy and Spain.

Following the purchase of the company in 2003 by the Jaakko Pöyry Group, ILEX worked with our sister companies Electrowatt-Ekono and Verbundplan to offer pan-European energy consulting services.

A natural progression for the companies was to unite under one Pöyry brand, and so from 19 June 2006, ILEX along with Electrowatt-Ekono and Verbundplan, became part of the consultancy arm of Pöyry Energy Business Group. ILEX became Pöyry Energy (Oxford) Ltd, trading as Pöyry Energy Consulting.

In 2006 Convergence Utility Consultants also joined as part of the consultancy section of the Pöyry Energy Business Group. Pöyry was further strengthened in 2007 with the arrival of Econ Analysis AS.

Pöyry's vision is to become the global thought leader in engineering balanced sustainability for a complex world. Pöyry aims to be one of the world's leading consulting engineering companies by 2020.

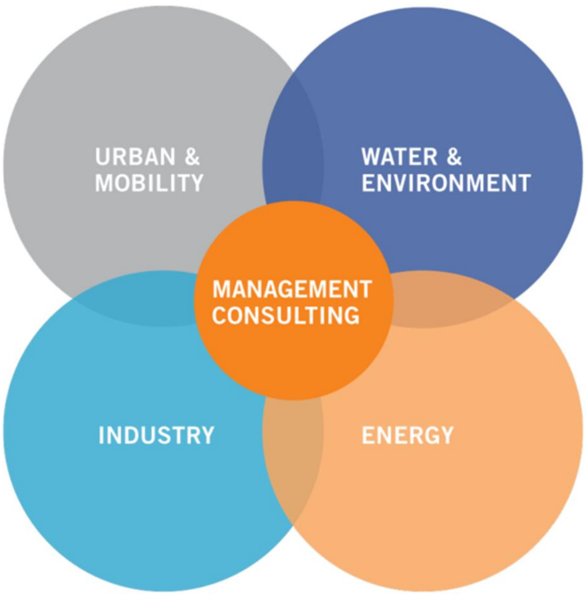
The Group's business structure was changed in January 2010 to better support the implementation of the new vision. The five new business groups are:

- Energy;
- Industry;
- Urban & Mobility;
- Water & Environment; and
- Management Consulting

In January 2011 Pöyry Energy (Oxford) Ltd (trading as Pöyry Energy Consulting) was renamed as Pöyry Management Consulting (UK) Ltd as part of the Management Consulting business group of Pöyry Plc.

Pöyry is now Europe's leading management consultancy specialised in the energy sector employing 250 experts in 14 offices across12 countries.

Figure 32 – Pöyry's 5 business groups



E.1.2 Services

Pöyry Management Consulting advises governments, regulators, banks and the full range of energy market participants, from niche players to some of the largest energy companies in the world.

The company comprehensively covers electricity, gas, renewables and emissions sectors. Our detailed understanding of energy markets allows us to advise our clients on how best to succeed and help policy makers and regulators design markets that work.

E.2 ILEX energy reports

Pöyry produces the renowned ILEX Energy Reports. ILEX Energy Reports provide detailed descriptions of European energy markets coupled with market-leading price projections for wholesale electricity, gas, carbon and green certificates. ILEX Energy Reports and price projections are currently available for the:

- electricity and/or gas markets including the following countries markets:
  - Belgium
  - Bulgaria
  - Cyprus
  - France
  - Germany
  - Great Britain
  - Greece
  - Ireland
  - Italy
  - the Netherlands
  - Poland
  - Romania
  - South East Europe
  - Spain
  - Switzerland
  - Turkey
- renewables markets in:
  - Italy
  - Poland
  - Romania
  - Spain
  - United Kingdom
- the biofuels market in Europe.

In addition to ILEX Energy Reports, Pöyry also produces a number of other reports, including electricity reports for Norway, Sweden and Finland, a renewables report for Sweden, and a report of the EU Emissions Trading Scheme with carbon price projections.

E.3 Pöyry's modelling capability

Pöyry has a wide range of models used to analyse the energy markets across Europe, see Figure 33. These provide an integrated suite to ensure that there is consistency between assumptions across the energy supply chain. The main model used to underpin some of the analysis used in this study is our worldwide gas model Pegasus. We have also included a description of our main electricity model, EurECa, as this provides the input into Pegasus for the elastic demand from power generation.

E.3.1 Pegasus

Pöyry forecasts the price of gas in a variety of zones worldwide using the pan-European and US gas model, Pegasus. The model examines the interaction of supply and demand on a daily basis in 20 European countries/zones, plus the US, the Far East and the Rest of the World. This gives a high degree of resolution, allowing the model to examine in detail weekday/weekend differences, flows of gas through interconnections between countries, and gas flows in and out of storage. Since the model comprises worldwide zones, it can examine the effect of LNG flows across the world, and how these impact differing markets.

Figure 33 – Pöyry's modelling suite for integrated energy markets

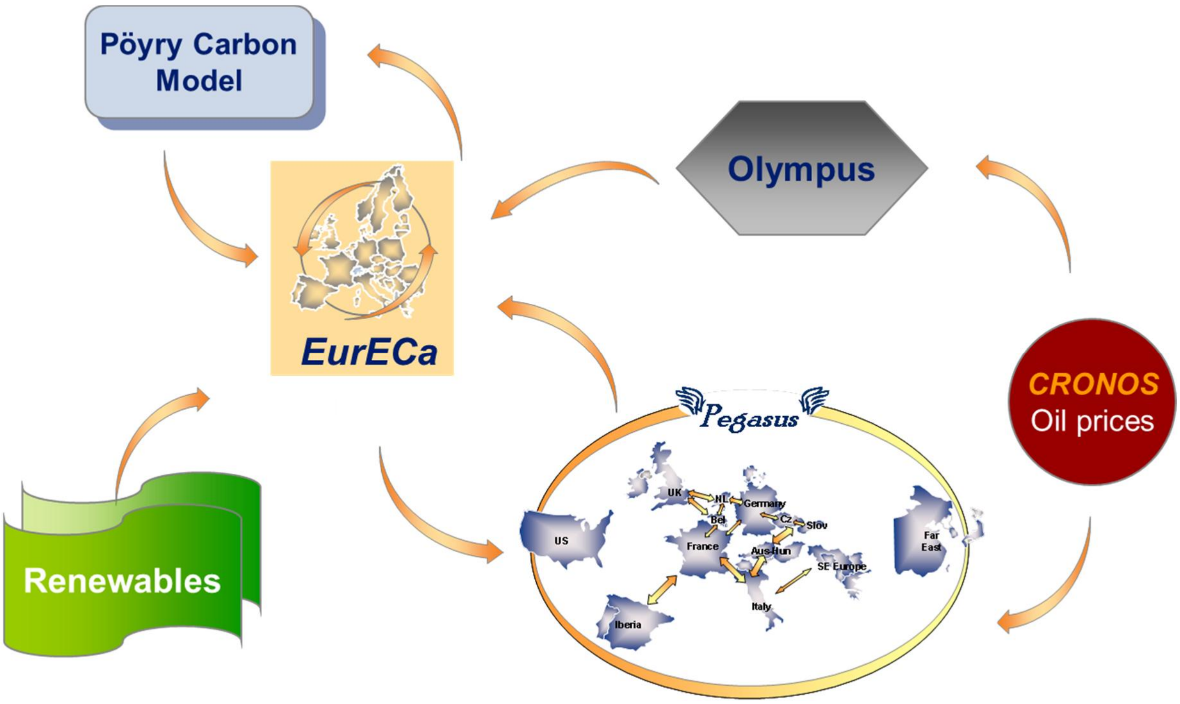
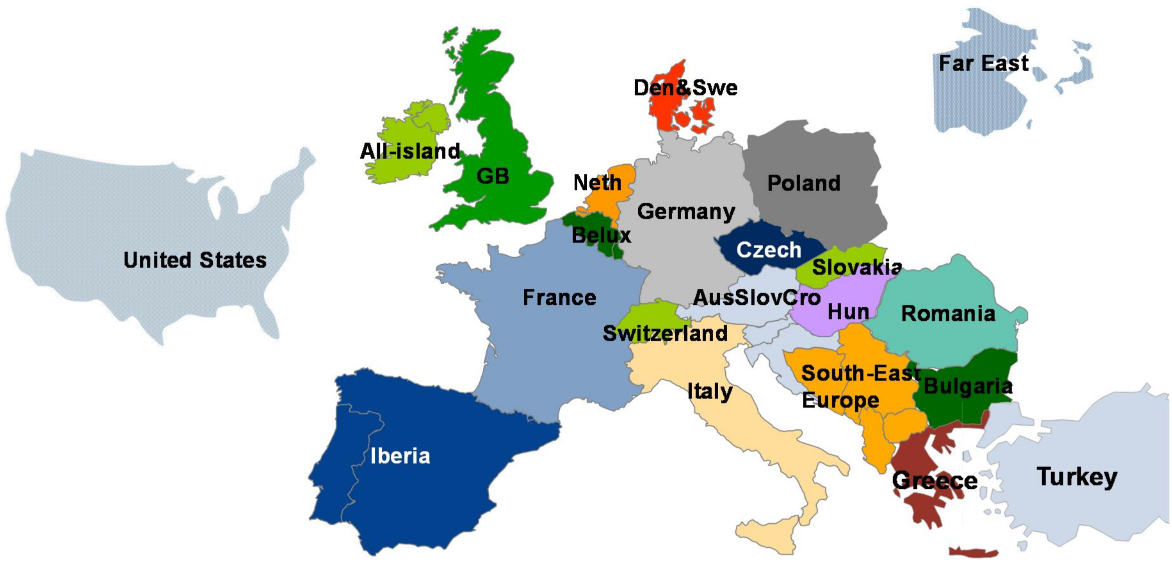
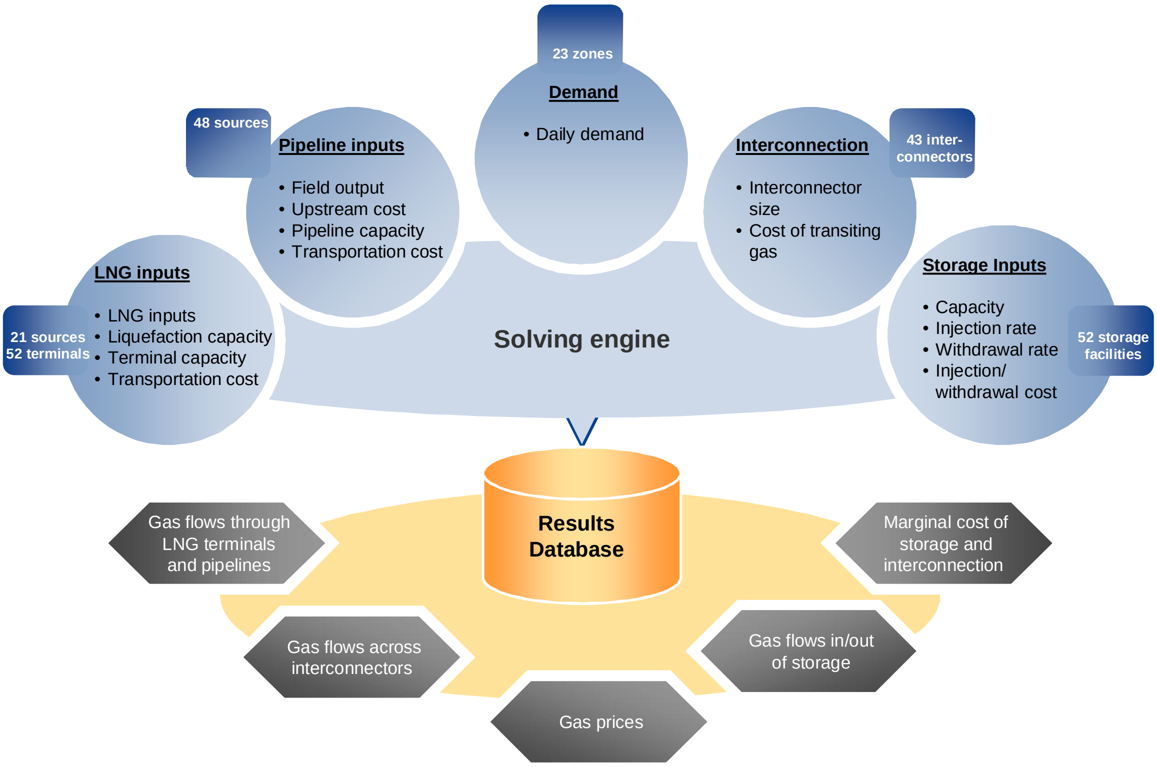


Figure 34 – Gas market zones in Pegasus



Pegasus itself is comprised of a series of modules, which is shown in Figure 35. The main solving module is based on XPressMP, a powerful Linear Programming (LP) package, which runs series of optimisations to find a least-cost solution to supply gas to all zones over a gas year. The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions. The solving module takes input files held in a database, which allows a variety of scenarios to be created by changing variables such as supply, demand, costs, storage and interconnectors. The outputs from the model, such as prices and flows of gas, are sent to a database to allow easy extraction of data at either a daily, monthly or annual resolution.

Figure 35 – Structure of Pegasus



Pegasus allows detailed modelling of gas flows in and out of all European countries. This allows effects such as the impact of new pipelines (such as Nord Stream), or new LNG terminals, to be investigated.

Figure 36 shows an example of gas flows in the GB market, and how Pegasus considers that they might change into the future.

Russia is a major gas supplier to Europe, and Pegasus uses the flow of gas from this source as a key input. Estimating the volume of gas that will be available to Europe from Russia to 2035 is subject to several constraints, including:

- the depletion of existing gas-producing provinces in West Siberia;
- the ability of Gazprom to launch new fields on schedule and the impact of potential delays on the availability of gas;
- Russia's domestic gas consumption; and
- the volume of gas that Russia will be able to import from Central Asia.

In our calculations, we use three scenarios to estimate the volume of gas that will flow to Europe. Our modelling also takes into account the gas supply routes from Russia to Europe. We examine the effect of new pipeline availability (e.g. Nord Stream, South Stream and Nabucco from the Caspian region) on deliveries of gas to individual European states.

Since Pegasus contains details of all worldwide liquefaction plants and regasification terminals, it has been used by a number of LNG providers and terminal operators to understand the future changes that the LNG market may bring.

The typical analysis shown in Figure 37 suggests that Far East and Spanish terminal utilisation rates may remain flat over time at 50%, whilst Italian import terminal are used heavily. US and GB import terminals are used in highly seasonal ways. Pegasus allows us to explore the implications of a multitude of policy, economic, and commercial scenarios.

Figure 36 – Illustrative Gas flows in the GB market

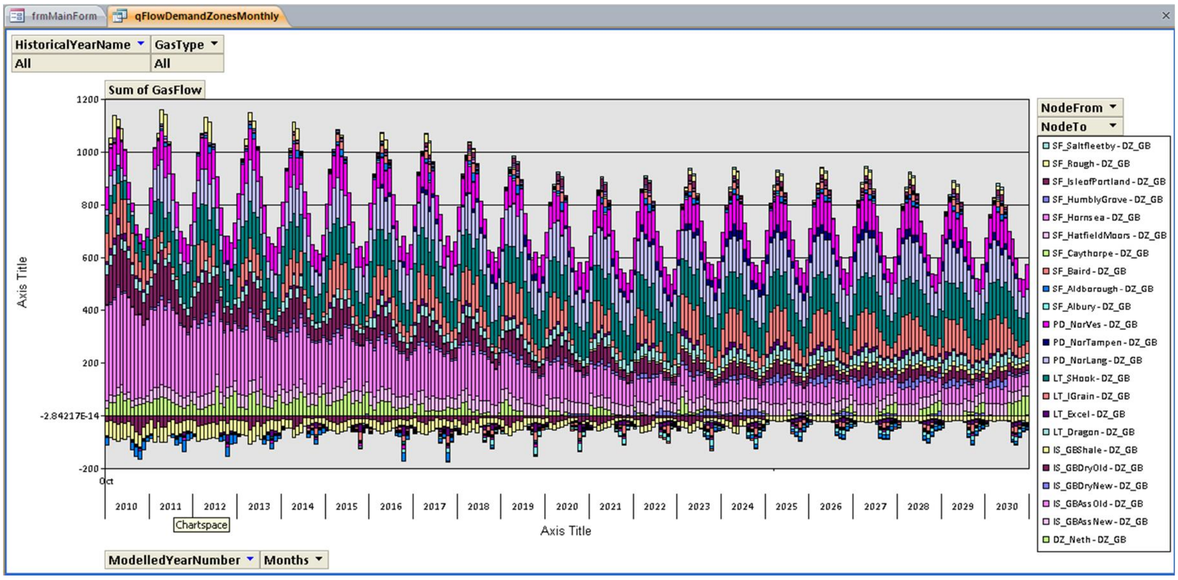
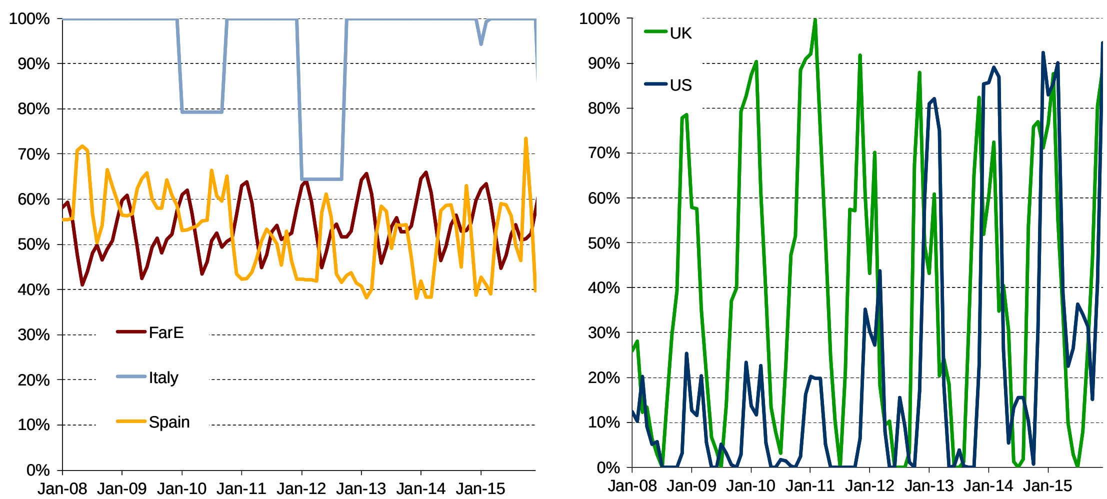
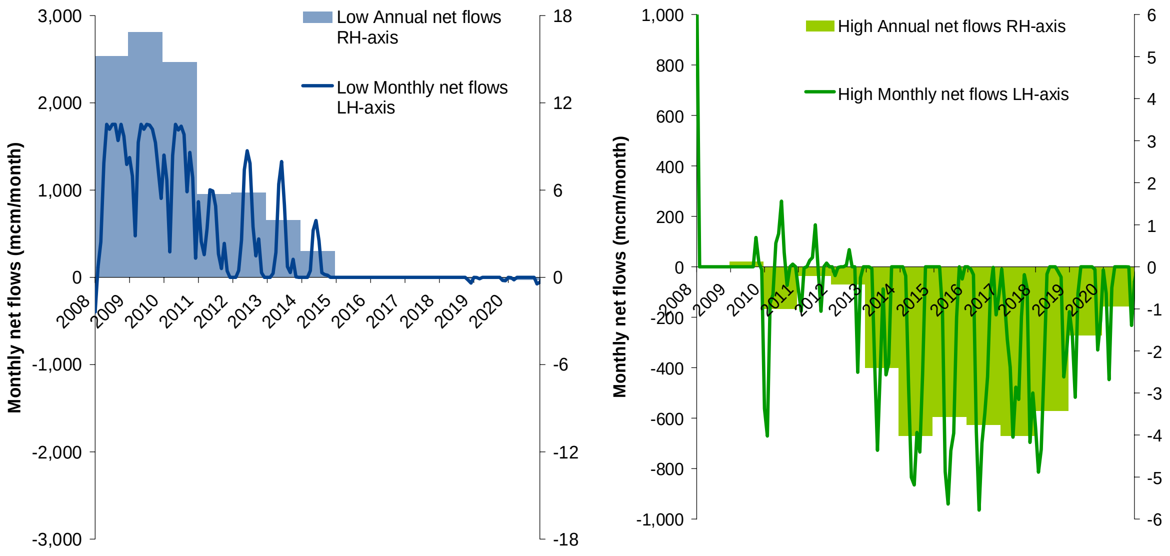


Figure 37 – Illustrative LNG terminal utilisation across Europe



Pegasus also allows detailed exploration of how gas will flow through interconnections in the future. This is key to understanding gas market development, as flows between interconnections determine the extent to which prices in nearby markets are linked.

Figure 38 – Illustrative interconnector flows in a variety of scenarios



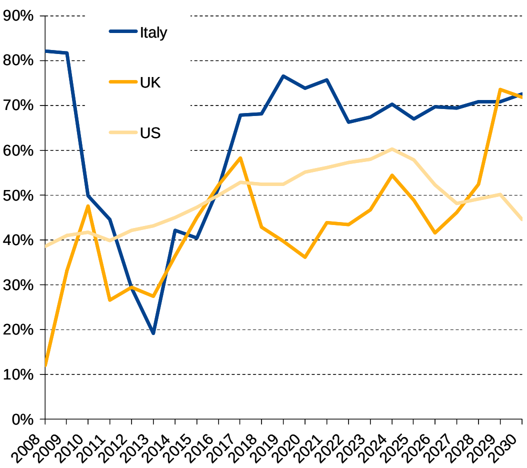
Modelling storage accurately is important for understanding price formation in European and international markets, as it affects both summer and winter prices, along with weekday/weekend prices. Pegasus models each current and future GB gas storage facility and groups of European and US sites, each with its own injection and withdrawal rates, total storage capacity and cost of injection/withdrawal. The optimisation algorithm used not only means that gas is injected into storage during the summer and withdrawn during the winter, as expected, but also that injection takes place for high cycle facilities during the winter weekends and Christmas periods due to lower demand, as seen in reality.

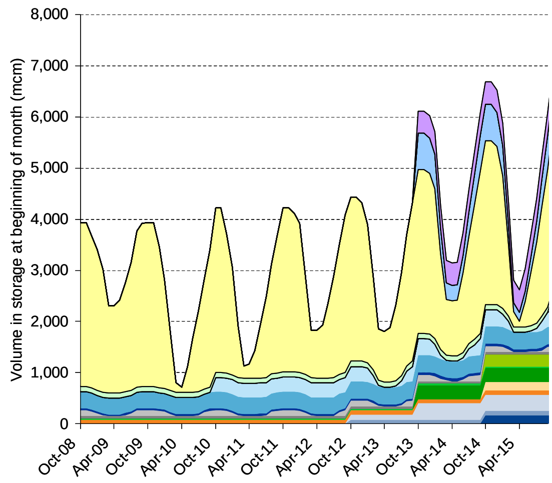
As shown in Figure 39, Pegasus can be used to understand how storage is used in different countries and how that varies over time, both annually, and on a detailed monthly basis.

The outputs from Pegasus are based on economic parameters (i.e. gas takes the cheapest route to the highest price market). The resulting flows of gas do not always represent an accurate picture of the contracted volumes. Therefore, in our modelling, we set the take-or-pay specifications to reflect the contracted gas which is planned to flow from one country to another. For instance, in the case of Russian gas flows into Germany, we factor in volumes that have already been contracted for Nord Stream. This means on occasion less gas flows via Ukraine than would economically optimum for all the zones.

Contract obligations will remain important into the future, as Gazprom has already renewed many of its contracts with its European customers to 2030 and beyond. Pegasus models the various European supply contracts, including considerations of take-or-pay obligations and oil indexation.

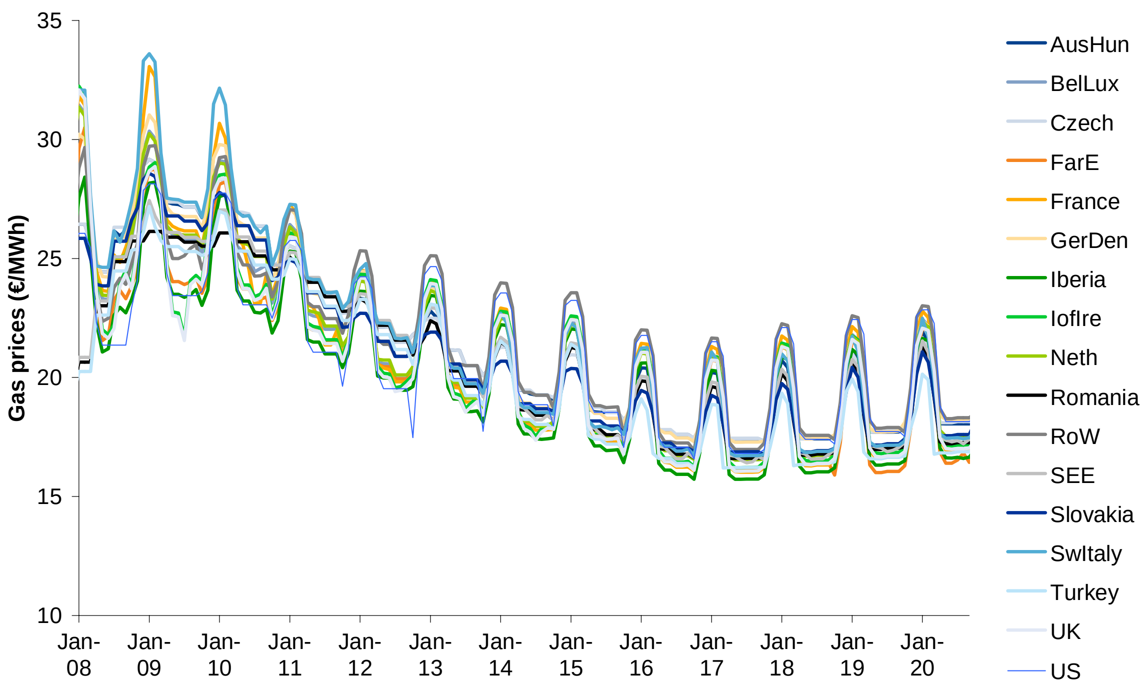
Figure 39 – Illustrative storage utilisation in Italy, GB and US





Pegasus allows the development of sophisticated future scenarios, and the creation of price tracks which represent these fundamentals. The example below shows monthly prices for all 18 zones, showing a convergence of prices over time as flows from interconnection and LNG increase.

Figure 40 – Illustrative European and worldwide gas prices



E.3.2 EurECa

EurECa is the model used on a quarterly basis by Pöyry to do price projections, and underpins the ILEX Energy Reports produced for most European electricity markets (see Annex C).

EurECa (European Electricity and Carbon model) is based on linear programming. The model has a database of every medium-large non-hydro genset in (nearly) all of Europe, and we update this database regularly. EurECa can model the whole of Europe or any portion of it. It can be used for projecting both physical behaviour (generator output, fuel use, electricity flows between countries, atmospheric emissions) and economic behaviour (electricity prices and generator revenues).

The inputs to EurECa are the power station database, hydro and pumped storage assumptions, demand assumptions and fuel prices. Twenty-four sample days per year are used to build up hourly results.

EurECa optimises electricity production across Europe by minimising the total variable cost of generation, subject to:

- meeting regional demand on an hourly basis, in each characteristic day;
- hydroelectric reservoir generation constraints in each country;
- pumped storage constraints in each country;
- interconnection constraints between countries or regions;
- pollution constraints (e.g. SO2 limits under the LCPD);
- commercial constraints (such as take-or-pay levels in fuel contracts);
- heat load requirements at CHP plants; and
- multi-fuel constraints that allow individual stations to switch between fuels.

From this optimisation the model produces a Merit Order Price (MOP) for each country and in each period based on variable costs (fuel costs, carbon costs, and variable other works costs), and the costs of starting and part-loading plant. In each country an additional component of wholesale price – the value of capacity or scarcity value – is spread throughout the year as a function of either the demand profile, so that it is highest when the demand is highest, or of the system margin, so that it is highest when the system margin is tightest. As an alternative, in cases where there is significant historical price data, the capacity element of the wholesale price may be spread on the basis of this historical evidence.

EurECa may be used not only to estimate future wholesale prices, but also to assess the commercial performance of individual companies or power stations. It can also be used to quantify the utilisation and value of interconnectors. With respect to CO_2, EurECa has been extensively used to develop abatement curves in the EU power sector, and the impact of the ETS on market prices. As well as the carbon intensiveness of each fossil fuel, we take account of the current and future degree of pass-through to electricity prices in each country separately.

EurECa is capable of modelling all European countries simultaneously, and is a very flexible platform. EurECa is summarised in Figure 41, together with some examples of typical inputs and outputs from the EurECa model shown in Figure 42 to Figure 45.

Figure 41 – Summary of EurECa – Inputs and Outputs

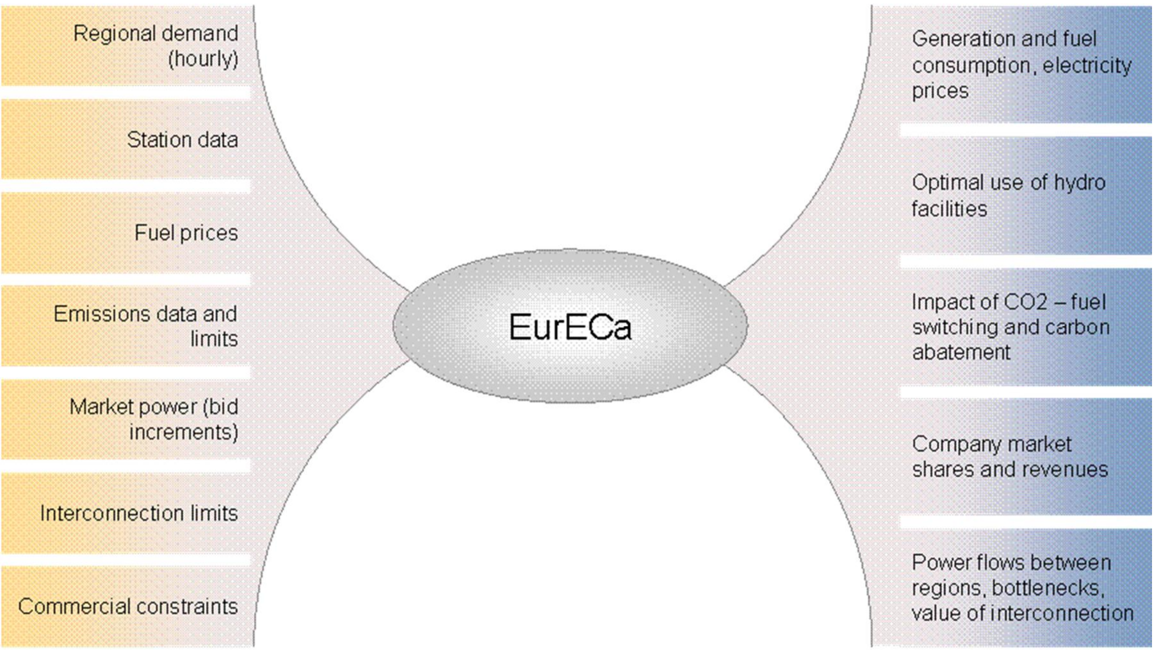


Figure 42 – Electricity prices at both annual and hourly granularity

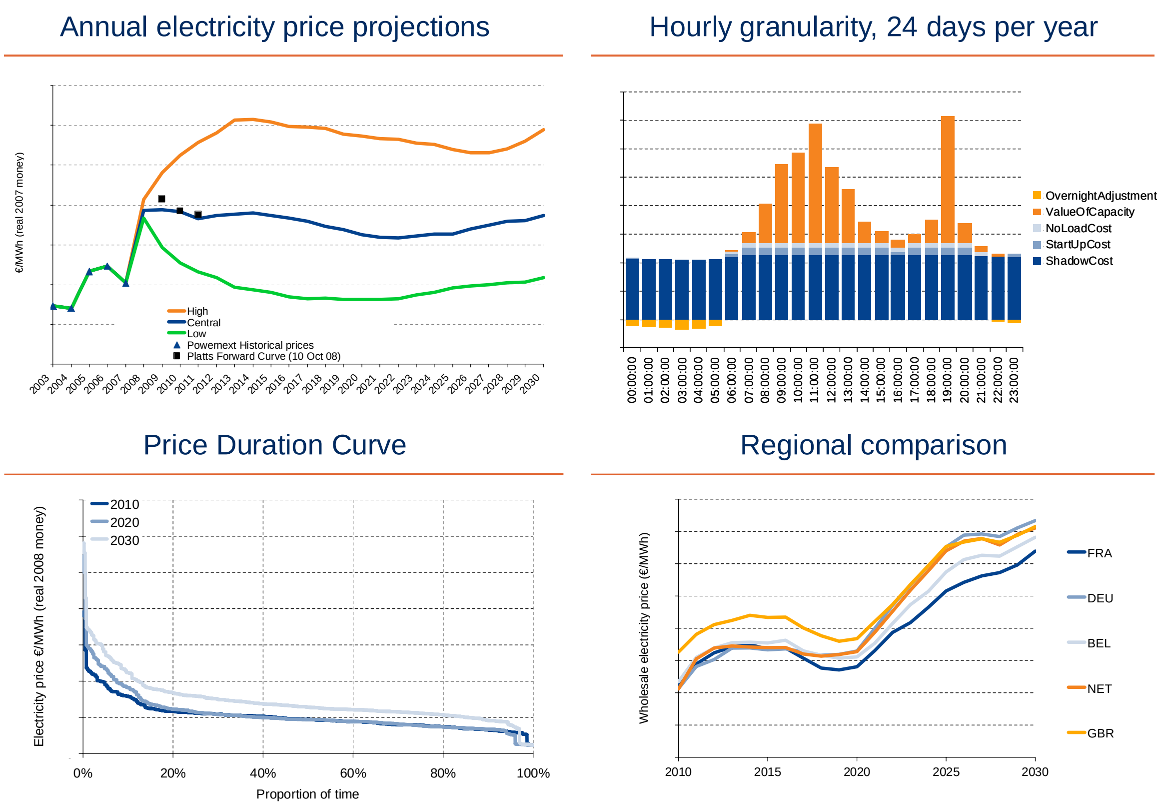
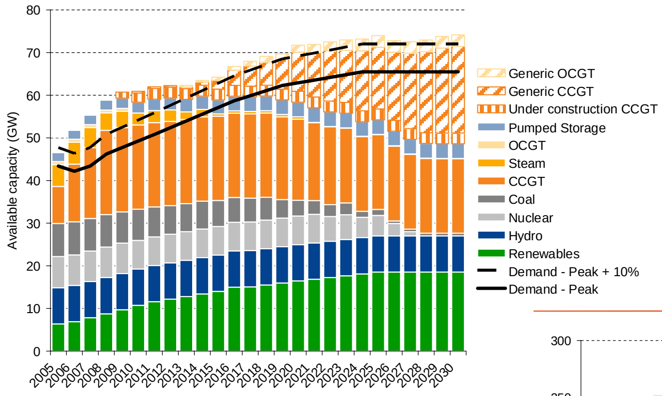


Figure 43 – Capacity charts

National capacity margin at peak



Capacity pictures show the balance between (statistically) available supply and peak demand. This is an important indicator of system reliability

Regional capacity picture

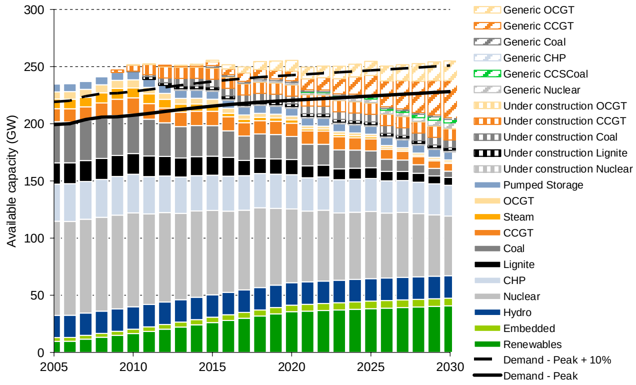
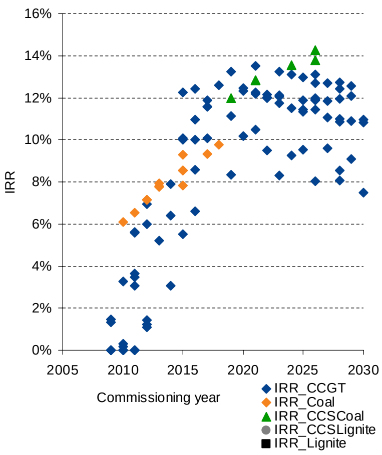
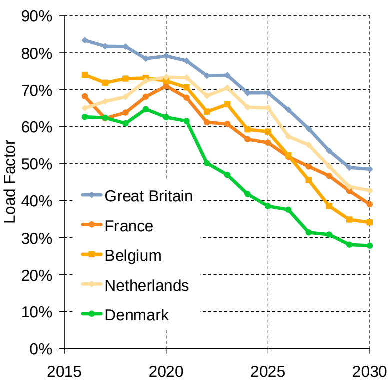


Figure 44 – Revenue/gross margins indicators

IRR



Load factor



Spark/dark clean/dirty spreads

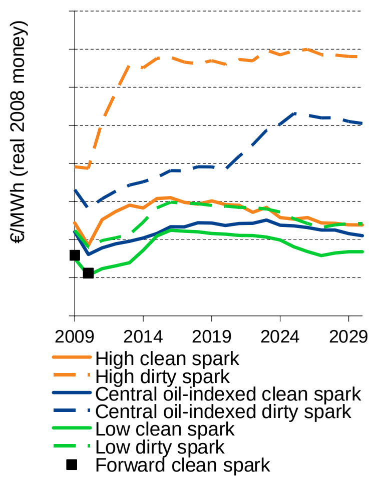
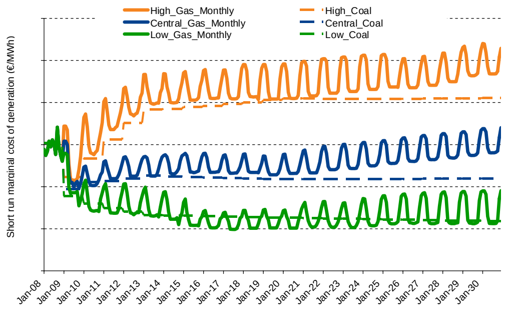


Figure 45 – Balance between different technologies

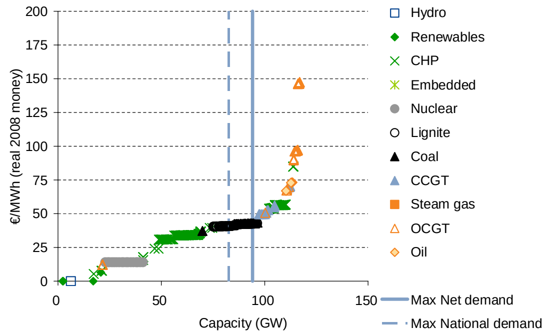
Short Run Marginal Cost for Coal/CCGT plant



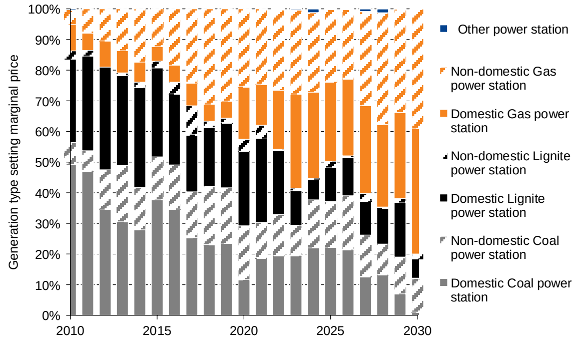
The short Run Marginal Cost comparison or Price setting chart help explain the behaviour of prices, as well as a first idea of merit order

The supply curve shows an approximation of the dispatch pattern

Supply curve



Price setting hours by fuel type



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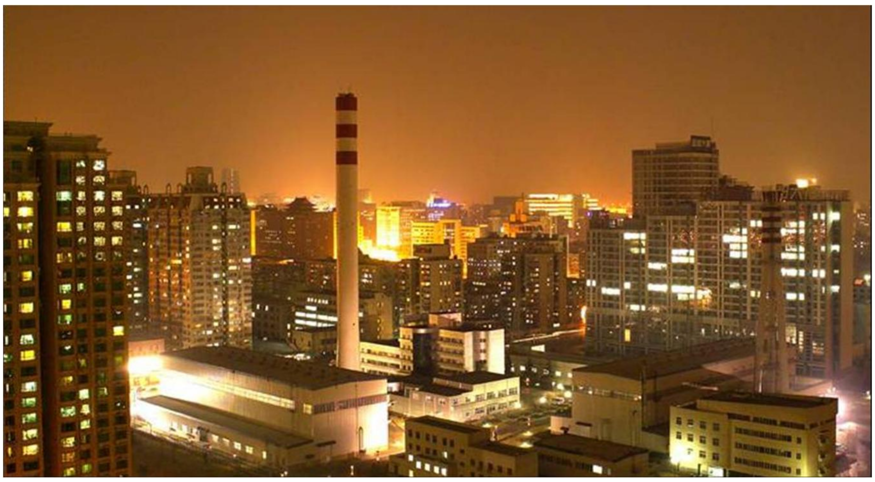

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