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ANALYSIS OF COSTS AND BENEFITS OF REGIONAL LIQUEFIED NATURAL GAS SOLUTION IN THE EAST-BALTIC AREA, INCLUDING PROPOSAL FOR LOCATION AND TECHNICAL OPTIONS UNDER THE BALTIC ENERGY MARKET INTERCONNECTION PLAN

FINAL PROJECT REPORT

Prepared for:

Directorate-General for Energy
European Commission

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Contents

INTRODUCTION

This document presents the results of a project commissioned by the European Commission with the aim of evaluating costs and benefits of LNG infrastructure, in connection with other infrastructures development to enhance quality of East Baltic gas market.

The report is structured according to the following sections:

1 - Executive Summary: in this section, we summarized the main findings and the outcome of the study.

2 –Understanding of the Situation: in this chapter we updated the general overview on Baltic market provided in the proposal, briefly analysing the gas and electricity market and introducing the current proposed infrastructures.

3 – Gas Demand Evolution in the Baltic Countries: in this section, natural gas demand evolution was analysed for each Baltic State. Two demand scenarios were defined: a base case and high demand case. All analyses run later in the study were based on these two scenarios.

4 – European Gas Market Trend: in this section, European gas market was analysed to better understand the general background in which the Baltic gas market would position itself. This analysis was not comprehended in any task, but it was considered as an essential study to properly assess the impact that LNG would have in the Baltic area.

5 – Assessment of Proposed Infrastructures: the goal of this section was to assess the impact that current proposed projects may have on Baltic infrastructures network in terms of gas supply and gas security.

6 – Assessment of LNG Options: in this step LNG options were assessed through the analysis of geographical (in terms of the best country that could host the terminal) and technical options and through the evaluation of costs and benefits for each alternative.

7 – LNG Value Proposition Assessment: in the last section, the value proposition of a LNG terminal in the Baltic Region was assessed, as well as other alternative strategies that could be followed to reach the same effects of a LNG terminal.

8 – Addendum: Assessment of LNG terminal in Finland: this addendum reports a high level strategic assessment of Finland as possible location for the Baltic LNG Terminal.

The study was conducted in close contact with stakeholders. The team actively contacted officials, company representatives and institutions of the four Baltic countries (Figure 1).

Figure 1 - Interviews and Meetings

	Role	Company
ESTONIA	Head of Repr. Office for the Baltic States	**E.ON**
	Top management	**Port of Tallin**
	Top Management of Paldiski LNG Team	**Baalti Gaas, Alexela Energy**
	Top Management of Tallin LNG Team	**Elering, Vopak, Port of Tallin**
	Top Management of Sillgas Ltd	**Sillgas Ltd**
	Top Management	**EG Vorguteenus (TSO)**
	Ministry of Energy Representatives	**Estonian Government**
	Member of Parliament	**Estonian Parliament**
LATVIA	Energy Department Representatives	**Latvian Government**
	Top Management	**Latvijas Gaze (TSO)**
	Top Management of Riga LNG Team	**Latvenergo**
	Top Management	**Ventspils Port**
	Top Management	**Port of Riga**
	Representative	**Ventspils City Council**
LITHUANIA	Representatives	**Lithuanian Government**
	Top Management of Klaipeda LNG Team	**Klaipedos Nafta**
	Top Management	**Liethuvas Dujos AB (TSO)**
FINLAND	Top Management	**Gasum (TSO)**
	Representative	**Finnish Government**
Video	LNG experts from Exmar, Excellerate, Vopak	

1. EXECUTIVE SUMMARY

The Baltic gas market (Finland, Estonia, Latvia and Lithuania) currently has an aggregated demand of about 10 Bcm/y, which is expected to remain flat (C.A.G.R. 0.3%) unless major discontinuities will take place. If gas supply diversification was enhanced and the required infrastructures were developed accordingly, market could grow up to 16 Bcm, with the additional upside, not considered within this report, of 1.5 Bcm for LNG bunkering. The main discontinuity may occur in Estonia, where the replacement of shale oil plant may be the key factor to enhance gas consumption.

Currently, the Great Baltic area relies entirely on Russian gas supplies and only Latvia and Finland are compliant with N-1 rule, which refers to the security of supply.

Several projects have been proposed to end isolation of the Baltic market, and some of them are included in BEMIP. These projects can be clustered in three groups:

- Upgrades of the existing interconnections “Intra-Baltic connections”;
- New pipeline connections as Balticconnector and GIPL;
- New LNG terminal (6 projects proposed in different port locations).

A joint implementation of Intra-Baltic connections, Balticconnector and GIPL would help the area to achieve some degree of supply diversification (about 33% of “diversified” gas, mainly in Latvia and Lithuania), but the security of supply in Lithuania would only marginally improve.

To expand supply options and achieve security of supply, a LNG terminal of 4 Bcm/y can be considered – with potential for future scalability. According to our simulation, in a base case demand this terminal will be probably utilized at 50% of its capacity and Russian contracts might be utilized at minimum quantity intake. The remaining LNG capacity could provide flexibility for peak shaving. This could help to diversify further the Baltic supply mix (ca. 60% of Russian gas, 20 % LNG, 20% gas imported from European network). A larger terminal would be almost unutilized in the base case demand.

With the assumption that each Baltic country would have to achieve the same diversification target and equally comply with N-1 rule, the location that minimizes further network upgrades and optimizes gas grid flows is Estonia.

Different port locations might be eligible for the realization of the LNG terminal. Muuga, Paldiski and Sillamae in Estonia, Riga and Ventspils in Latvia, Klaipeda in Lithuania would require similar investment spending (in the range of € 440-500 MM), while the key economic differences lie in the costs of connection from the terminal to the grid.

In order to compare different configurations of LNG terminal in the four Baltic States, Booz has based its valuation on the CAPEX connected to the implementation of the terminal and the related infrastructures (e.g. harbor preparation, new connections and upgrade of existing connections, …); given the very early stage of the different proposed projects operating expenditures have not been considered.

Klaipeda LNG terminal is the only project in the early stages of implementation, potentially allowing for a detailed assessment of the project cost. The adopted technical solution for Klaipeda terminal is a FSRU facility leased for 10 years; the lease fee of 43 Millions Euro/year covers for rent, financing cost and overheads. The total cash-out over the lease period would be 430 Millions Euro. Project promoter Klaipedos Nafta reports the overall investment (discounted lease fees and buy-back option) to be 250 Million Euros; details regarding the amounts, the calculation of the different components, and the conditions for the exercise of the buy-back option were not disclosed.

Booz and Company is not in the condition of properly compare the Klaipeda LNG project to the other proposed ones, since it has no access to the actual investment full life-time value

Since the investment in the LNG terminal is only one of the several dimensions considered in the assessment of the LNG in the Baltic area, Booz & Company believes that the lack of information on the Klaipeda terminal should not affect the overall project findings. Other dimensions such as balancing network flows in the area, scalability of the solution and integrated regional approach are more relevant

All analysed ports show a clear and well defined project to welcome the LNG terminal (excluding Sillamae that has a project at very early stage of definition). Besides, each project proved to consider the major technical issues potentially impacting the terminal effectiveness. The ice risk, even if not considered as a go-no-go criterion, has been evaluated: only Ventspils and Klaipeda are ice free ports, while Riga, Muuga and Paldiski would be reachable with ice-breaker assistance with no ice class vehicle (the area is provided by regular ice-breaking services).

A joint assessment of the required investments shows that Estonia (in particular Paldiski port in case of Balticconnector landing there) is the location that helps minimizing additional investments to connect the terminal to the main transmission system and to equalize benefits of supply diversification and supply security.

The overall investment for the LNG terminal and the proposed pipeline projects (Balticconnector, Intra-Baltic connections and GIPL) would be around € 1.3 Bn, covering the whole Great Baltic Area for an addressable demand of 11 Bcm/y with an estimated increase of the regional transportation tariff of about 0.5 US$/MMbtu. This will help the area to reach a diversification target of 63%, by accessing to the LNG market and western European gas hubs. Additional benefits are:

- Increased attractiveness of Incukalns storage, granting access to Poland and Finland;
- Incremented role of Baltic countries as a transit market for Russian gas to Europe;
- Balanced grid.

We have then identified other two possible implementation strategies that might grant incremental benefits for the area. Those two options have been developed with the objective of equally grant to all involved countries security of supply and supply diversification.

The first option considers the implementation of GIPL and Intra-Baltic connections: the overall investment spending would be in the range of € 690-815 MM, the investment will address an overall demand pool of 5.5 Bcm/y (Lithuania, Latvia and Estonia), with an estimated impact on the regional transportation tariff of about 0.65 US$/MMbtu. This will help the area to reach a diversification target of 63% by accessing western European gas hubs. Additional benefits are:

- Increase attractiveness of Incukalns storage, granting access to Poland and Finland;
- Incremental role of Baltic countries as a transit market for Russian gas to Europe.

The second option considers the implementation of LNG, Intra-Baltic connections and Balticconnector: the overall investment spending would be in about € 860 MM, covering the whole Great Baltic Area for an addressable demand of 11 Bcm/y, with an estimated impact on the regional transportation tariff of about 0.3 US$/MMbtu. This will help the area to reach a diversification target of 33% accessing to LNG markets. Additional benefits are:

- Increased attractiveness of Incukalns storage, granting access to Finland;
- Balanced grid.

In conclusion, an integrated approach to infrastructure development may balance the value from pipelines and from LNG:

- Proposed BEMIP pipeline investments alone do not fully allow all Baltic countries to meet N-1 rule. Conversely, a LNG terminal in Estonia with additional investments on interconnections would meet the target;
- The diversification opportunity offered by the LNG terminal would cap the Russian gas price, although it should be considered that, at current international LNG prices, this sourcing option might not be competitive compared to historical Russian price levels;
- A 4 Bcm terminal would be the optimal size to meet the limited demand of the Great Baltic area, and to support gas market growth through scalable investments. This dimension would also allow using storage capacity to further manage high peak demand;
- Countries involved have to take full responsibility that the initiators, owners and future operators of all the projects must be independent of the existing dominant supplier in all aspects so that is serves as real source diversification.

In addition to the project recommendation, as requested by DG ENER during the BEMIP High Level Group meeting held in Brussels on September 11th, Booz & Company has conducted a high level strategic assessment of Finland as possible location for the Baltic LNG Terminal, initially out of the project's scope. This assessment complements the findings proposed in the full report and it has been conducting assuming as possible Finnish regasification terminal the FinGulf project, as proposed for PCI candidate (project code G41).

The FinGulf LNG Terminal would fit within the strategic goal set by the European Commission to improve both S-o-S and diversification in the Baltic region. It would bring the same benefit to the region than a LNG terminal located in Estonia.

Furthermore, a LNG terminal in Finland has the advantage to be closer to the centre of biggest gas consumption in the region, namely Finland. However this consumption is fully covered with supplies from Gazprom and therefore it is unrealistic to expect the real need for LNG in Finland before the maturity of existing take-or-pay contract on 2025.

Hence, the Balticconnector would become a «sister project» that would grant the S-o-S to Estonia and would enable the supply diversification to the Baltic region.

The terminal in Finland should be dimensioned in line with the need to serve as a new supply source for whole area, an average yearly capacity of about 4 Bcm would be required, with a potential future scalability to accommodate possible demand growth.

The Inkoo project location, as currently proposed, has daily capacity of 19.2 Mcm/d; hence 7.2 Mcm/d could be dedicated to serve Estonia, Latvia and Lithuania. Inkoo port is kept open by the icebreakers of the Finnish Maritime Administration in wintertime. The ice conditions are easy at Inkoo during normal winters, and thus the channel is ice free almost always.

In conclusion, a regasification terminal in Finland would grant Baltic area same benefits of the Estonian one.

2. UNDERSTANDING OF THE SITUATION

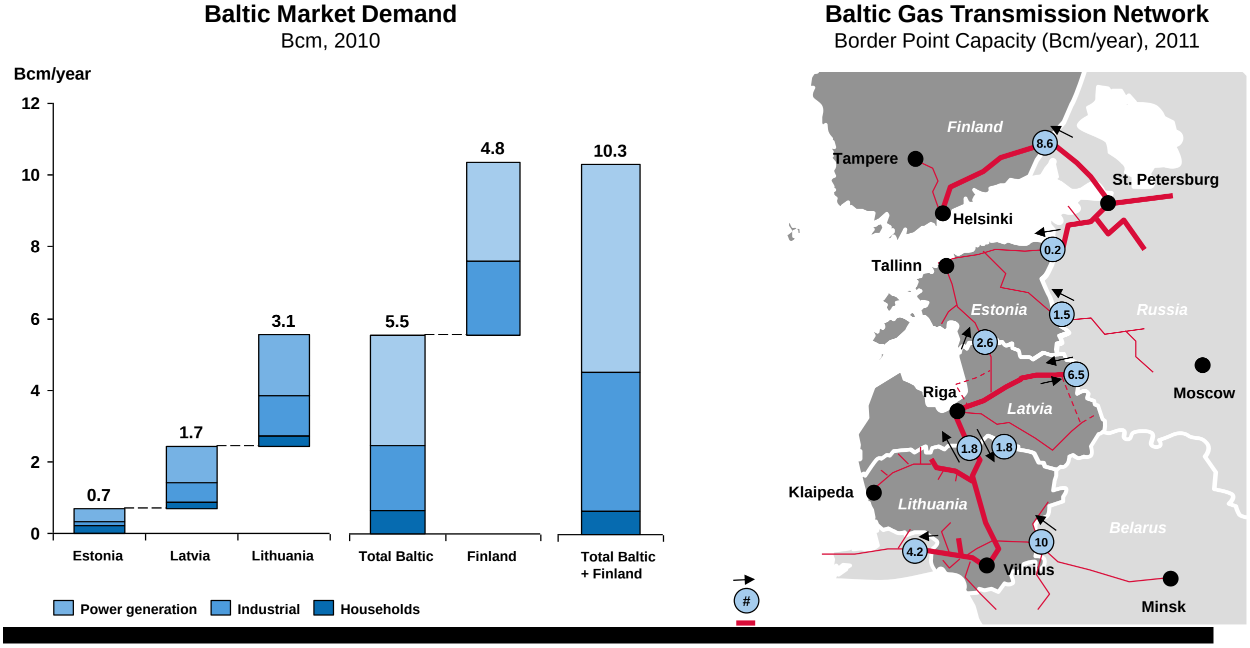
In order to pursue its energy policies, the EU Commission, in agreement with the Member States of the Baltic Sea Region, decided to set up a High Level Group (HLG) chaired by the Commission on "Baltic Interconnections". The HLG began to meet on November 20, 2008 and agreed on a very ambitious objective: provide a comprehensive plan on energy interconnections and market improvement in the Baltic Sea Region by July 2009, the Baltic Energy Market Interconnection Plan (BEMIP). The BEMIP brings together in a coordinated way the (mostly existing) projects involving all countries around the Baltic Sea (Finland, Estonia, Latvia, Lithuania, Poland, Germany, Denmark, Sweden and as an observer, Norway) for the development of:

- Internal market for electricity and gas;
- Electricity interconnections;
- New electricity generation capacity;
- Gas diversification of routes and sources;
- Oil.

With the ultimate goal of market integration and efficient market functioning in mind, the BEMIP should also provide a broader view on relative sequencing and potential dependency of specific actions, projects and/or work-streams and, thus, facilitating the coordination and harmonization of their implementation.

Currently Baltic gas market (Estonia, Latvia and Lithuania) accounts for 6 Bcm per year. As of 2010, gas demand for Estonia, Latvia and Lithuania was respectively of 0.7 Bcm, 1.7 Bcm and 3.1 Bcm, while Finland accounted for almost 5 Bcm. For each country, main utilization of this gas was power generation, followed by industrial and household. Overall, the Baltic Region demanded more than 10 Bcm of gas in 2010, which was totally supplied by Russia.

Figure 2- Current Baltic Gas Market and Infrastructures

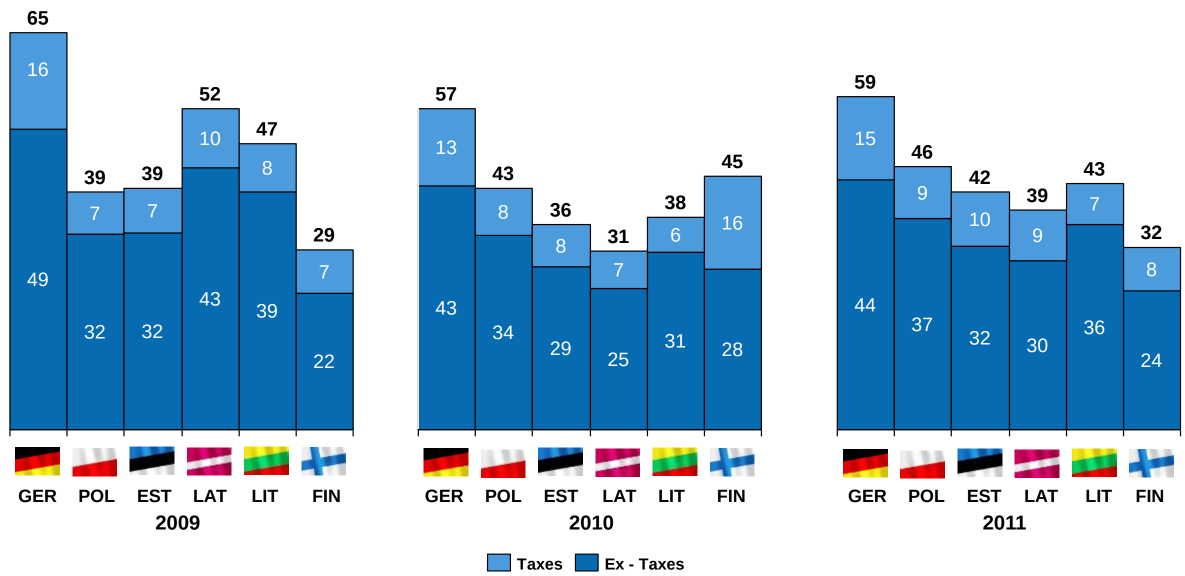


Source: Estonian Electricity and Gas Market Report 2010, Annual Report to the European Commission – Finland (2011); Annual Report; Latvia Public Utilities Commission (2010); Annual Report on Electricity and Natural Gas Markets of Republic of Lithuania to the European Commission

As can be seen from Figure 2, the energy market of the Baltic Sea Region is short of appropriate interconnection infrastructures and is too nationally oriented, with Estonia, Latvia and Lithuania lacking connections with European energy market and Finland. Indeed, all the gas is supplied with pipelines coming from Russia.

Nevertheless this situation has not led to higher prices for end-users than those of European country, as shown on Figure 3.

Figure 3 – Households Gas Total Price, €/MWh [dark blue is ex-tax price, light blue is taxes]

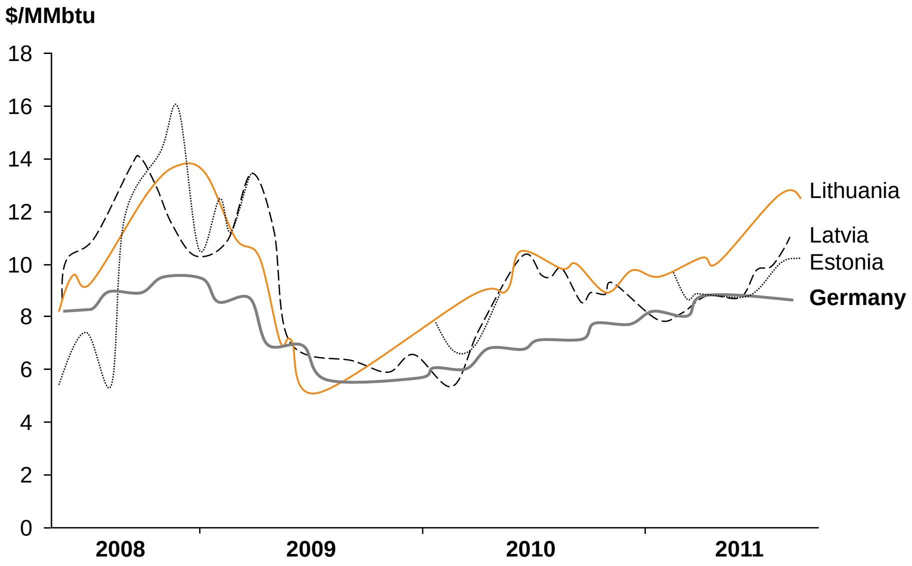


Source: IEA Taxes and Prices (2012), EUROSTAT

Import prices from Russia at border points were also analysed. German prices have always been lower than Baltic ones; besides, starting from 2010, prices have increased for Baltic countries (Figure 4).

Contracts' expiration dates indicate that for Estonia and Lithuania (whose contracts will expire after 2015) the issue of finding alternative sources should be addressed as soon as possible, while for Finland and Latvia contracts expire respectively after 2020 and 2030.

Figure 4 - Supply prices from Russia ($/MMbtu)



Source: Interviews with Baltic Stakeholders, Booz & Company Analysis

The gas industry is currently dominated by Gazprom and E.ON, both of which are the two major shareholders of the TSOs in each Baltic State. Over the past years the local Governments attempted to unbundle gas supply and transmission, but as of today none of the analysed countries has actually imposed a separation between the gas supplier and the TSO owner. In Estonia the unbundling is expected to be announced within the gas market liberalization law in summer 2012 and to be completed in 2015. In Finland and Latvia, the debate recently started at a preliminary stage. In Lithuania the unbundling is currently outgoing and will be completed in 2015. This lack of competition clearly prevents the market to become more efficient and implies some economic disadvantages such as a weak bargaining position during contract negotiation (Figure 5).

Figure 5 - Gas TSOs Shareholding structure

Source: Booz & Company Analysis on public available information

On the contrary, the electricity market is mainly controlled by each country Government (Figure 6), which owns both the TSO and the DSO. State companies are the sole producers with the exception of Lithuania, which presents a second producer controlled by a Russian company.

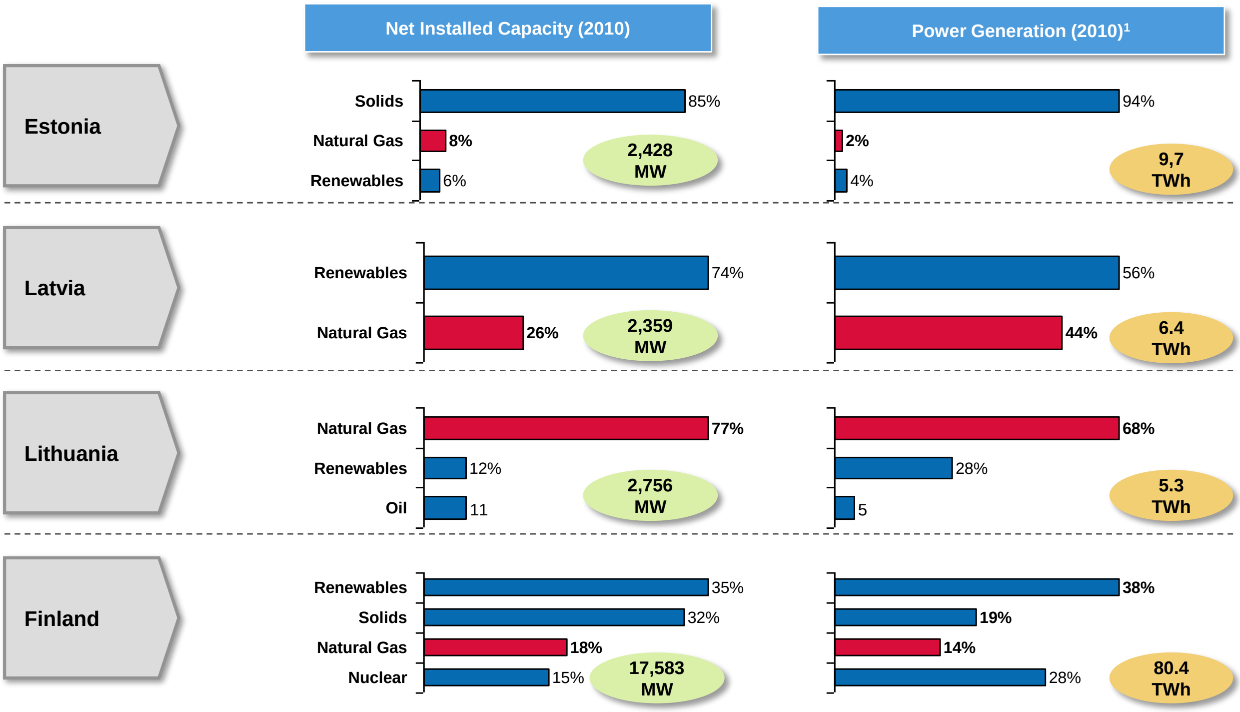
Figure 6 -Power Generation players Shareholding Structure

	Producer	TSO	DSO
Estonia	▪ AS Eesti Energia (state owned)	▪ Elering AS (State owned)	▪ 37 DSOs: Mainly controlled by Eesti Energia Jaotusvork (owned by Eesti Energia)
Latvia	▪ AS Latvenergo (state owned)	▪ AS Augstsprieguma Tikls (owned by AS Latvenergo)	▪ AS Latvenergo (state owned)
Lithuania	▪ Inter RAO Lietuva (controlled by Russian Inter RAO), Lietuvos Energija AB (public company)	▪ Litgrid UAB (owned by Visagino Atominè Elektrinè UAB, Lithuanian company	▪ Lesto AB (controlled by Visagino Atominè Elektrinè UAB)
Finland	▪ Fortum Power and Heat Oy (state owned), Phojolan Voima Oy (Finnish company)	▪ Fingrid (state owned)	▪ 85 DSOs: either municipalities or companies in which the major shareholders are municipalities

Source: Public Available Information

With regards to the net installed power generation capacity in 2010, natural gas plays a different role depending on the country considered. Gas contribution is only 8% in Estonia (whose total installed capacity is equal to 2.4 MW), 26% in Latvia (2.4 MW), 77% in Lithuania (2.8 MW) and 18% in Finland (17.8 MW). Similar considerations can be done looking at actual power generation in 2010: the contribution of natural gas in 2010 was 2% of total power generation in Estonia, 44% in Latvia, 68% in Lithuania and 14% in Finland (Figure 7).

Figure 7- Power Generation Installed Capacity and Power Generation



Source: DG Tren,National Gas Market Report 2010, Booz & Company analysis

In order to decrease the general energy dependence from Russia, several studies have been conducted to integrate the Baltic Region to the European network. In particular, gas market integration projects focus on finding the most economical solution to connect Finland and the three Baltic States to the integrated European gas network and to accelerate market opening. There are four main objectives that gas infrastructure development serves in the Baltic Sea Region:

1. End the energy isolation and decrease dependency from a sole external gas supplier;
2. Define and strengthen the role of Poland as an "energy bridge" to the other countries: supply systems to Poland from Germany, Denmark or LNG are necessary in order to bring gas from Poland further to the East Baltic Sea area;
3. Assess the potential of LNG infrastructure for diversifying supply sources in the Baltic Sea region;
4. Compensate for the decline in the Danish gas reserves and provide new gas sources to Denmark and Poland.

There have been very active discussions on the opportunity to develop the regional infrastructure. Specifically, some projects are under evaluation process (Figure 8, 9):

- The **Balticconnector** project is single pipeline linking Inkoo (Finland) to Estonia, with a capacity of 2.4 Bcm per year. Balticconnector would secure gas provision in case of disruption of gas supply from Russia. It would support Finland in the diversification of the supply sources, in reaching Incukalns and in gaining access to the European gas network in case other projects (such GIPL or LNG) would be implemented. The ownership of the project belongs to Gasum Oy, Eesti Gas, Latvijas Gaze (all participated by Gazprom). As of today, two alternatives routes have been proposed to reach Estonia: Inkoo-Paldiski and Inkoo-Tallin. The first route, with a length of 80 km offshore and 54 km onshore, would cost € 141 MM, while the second route, with a length of 110 km offshore and 25 km onshore, would cost € 161 MM.

- The gas interconnector Poland – Lithuania (**GIPL**) is a 562 km pipeline with a capacity of 2.3 Bcm per year (expandable to 4.5 Bcm per year) connecting Warsaw (Poland) to Vilnius (Lithuania): its estimated cost is € 537 MM (costs are intended for 2.3 Bcm capacity and do not include additional CAPEX to implement reverse flow). The infrastructure aims to diversify the gas supply sources and routes, therefore increasing competition. It would also improve gas security in Lithuania, integrate the Baltic countries in the western European gas system and therefore provide them an access to the global LNG market. 73% of the investment would be based in Poland.
- Some **Intra-Baltic connections** pipelines, such as the Latvia-Lithuania, the Latvia-Estonia and the Estonia-Russia upgrades of cross border capacity. This pool of projects aims to strengthen the internal market, upgrade the internal network, allowing bi-directional flows and put the bases for decouple commercial from physical flows and grid balance. The projects are:
  - Latvia-Estonia Pipeline: its current capacity is 7 Mcm/d, which would be boosted up to 10 Mcm/d (estimated cost of € 20 MM for the compressor), besides having installed a reverse flow (estimated cost of € 30 MM for the compressor). The estimated go- live of the project would be 2016;
  - Estonia (Narva)-Russia Pipeline: current capacity is only 0.5 Mcm/d. The project would increase the capacity up to 7.5 Mcm/d (bidirectional), with a cost of € 155 MM. The estimated go- live of the project would be 2022;
  - Latvia-Lithuania Pipeline: current capacity (bidirectional), is 5 Mcm/d, and two upgrades are possible: one would increase the daily capacity to 6 Mcm/d (with a cost of € 25 MM and an expected go live in 2016), while the other one would bring it to 12 Mcm/d (with a cost of € 30 MM and an expected go live between 2018-2020).
- **Incukalns storage facility**: it is an already existing strategic asset for the Eastern Baltic Region, located in the central area of Latvia. The whole Baltic network is designed to exploit the asset at its best. Hence, with a working gas of 3.2Bcm/y, the gas from Russia is injected during the summer season and is withdrawn during winter season at an average of 24 Mcm/d (Figure 10), split as follow:
  - 50% towards Latvian domestic consumption;
  - 25% towards Estonia;

– 25% towards Western Russia.

The storage works at 110 bars, while the system pressure is 55 bars. Hence the compressor is used to inject the gas and the withdrawal is performed at natural condition. Latvijas Gaze operates the facility, while the owners are the Republic of Latvia and some private landlords. Gazprom has rights on the capacity until 2017.

Currently, some modernization activities are planned to increase safety and reliability. With further investments for about € 20 MM, the working storage capacity could be increased to up to 3.2 Bcm. In addition, cushion gas of about 3 Bcm results in a commodity investment of around € 600 MM (the cost assessment is based on a commodity price of 8 $/MMbtu).

Latvijas Gaze operates the facility, while the owners are the Republic of Latvia and some private landlords. Gazprom has rights on the capacity until 2017.

Figure 8 -Description of Balticconnector and GIPL projects

Project	Description	Strategic Advantage
a Balticconnector 	▪ Single gas pipeline linking Inkoo (Finland) to Estonia ▪ Gas capacity: 2.4 Bmc/year ▪ Designed pressure: 8 MPa ▪ Design Gas density: 65 Kg/m^3 ▪ Ownership: Gasum Oy, Eesti Gas, Latvijas Gaze (all participated by Gazprom)	▪ Secure gas provision in case of disruption of gas supply from Russia ▪ Support Finland to diversify the supply sources and to have access to the European gas market network (With either GIPL or LNG projects implemented) ▪ Allow Finland to access to Incukalns
b Gas Interconnector Poland - Lithuania - (GIPL) 	▪ 562 km of gas pipeline linking Rembelszczyzna (Poland) with Jauniunai (Lithuania) ▪ Gas capacity: 2,3 Bcm/year (can be expanded to 4,5 Bcm/year) ▪ Maximum operating pressure: 8.4 MPa (Poland), 5.4 MPa (Lithuania) ▪ Estimated cost1): 537 mln € ▪ Ownership: Gaz-System (73%)	▪ Integrate the Baltic countries into the western European gas system facilitating – Access to western hubs – Access to western countries assets ▪ Potentially evolve the role of Latvia and Lithuania as transit countries and become a valid alternative to Ukraine and NordStream (depending on the GIPL capacity) ▪ Allow Poland to access Incukalns ▪ Improve gas security in Lithuania

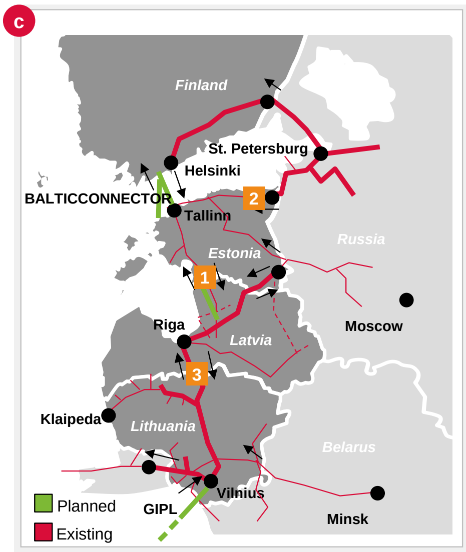
	Alternative Routes	
	Inkoo-Paldiski	Inkoo-Tallin
Offshore Pipeline Length	80 km	110 km
Onshore Pipeline Length	54 km	25 km
CAPEX1)	€ 141 M	€ 161 M

1) It does not include additional capex to implement a physical revers flow

Source: Balticconnector executive summary – Gasum (Feb 2011); Results of GIPL Business Case Analysis – Gaz Systems (Nov 2011); BEMIP Final Report of the HLG (Jun 2009); Interviews with Stakeholders

Figure 9 - Intra-Baltic Connections

Intrabaltic Connection Projects



Description

	Current Capacity	Projects	Capex	Estimated Go-Live
1 Latvia-Estonia Pipeline	7 Mcm/day	Reverse Flow[1)]	€ 30M (compressor)	2016
		+ 3 Mcm/day	€ 20 M (compressor)	
2 Estonia (Narva) – Russia Pipeline[2]	0.5 Mcm/day	+7 Mcm/day (bidirectional)	€ 155 M	2022
3 Latvia-Lithuania Pipeline[3]	5 Mcm/day (Bidirectional)	6 Mcm/day (bidirectional)	€ 25 M	2016
		Up to 12 Mcm/day (Bidirectional)	€30 M	2018-2020

Purpose

- Strengthen the internal network to be more resilient
- Upgrade the general internal network allowing bidirectional flows
- Put the basis for decouple commercial from physical flows (but requires more than one supply source) and grid balance

Included in the following analysis

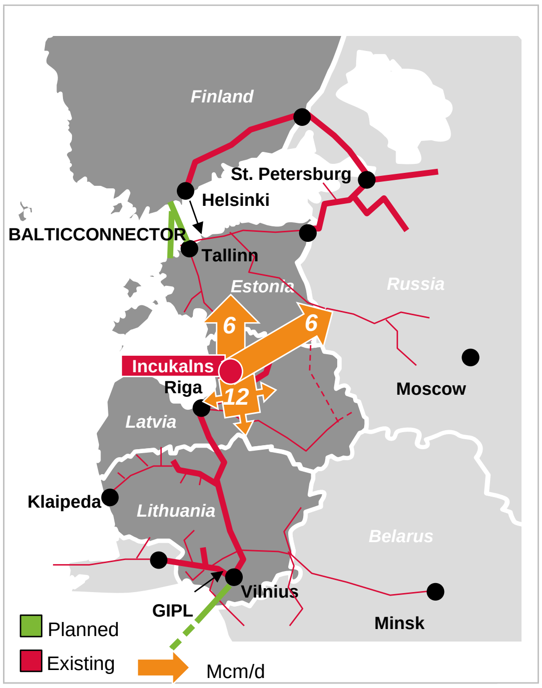
Projects foreseen by BEMIP (FID) and TSO

Projects foreseen by TSO

Potential increase not planned

Source: Balticconnector executive summary – Gasum (Feb 2011); Results of GIPL Business Case Analysis – Gaz Systems (Nov 2011); BEMIP Final Report of the HLG (Jun 2009); Interviews with Stakeholders

Figure 10 - Average winter flows (Mcm/d) from Incukalns



Source: Balticconnector executive summary – Gasum (Feb 2011); Results of GIPL Business Case Analysis – Gaz Systems (Nov 2011); BEMIP Final Report of the HLG (Jun 2009); Interviews with EG Vorguteenus, Latvijas Gaze and Ministry of Economics of Republic of Latvia

Different studies have been conducted for different LNG projects in Latvia, Lithuania, Estonia and Finland, but no agreement has been reached. Attracting large consensus around a specific project appears to be challenging from a technical, political and economic perspective:

- Technically, the infrastructure projects are closely interconnected, making complicated any technical decision on the location, capacity, etc. Moreover further analyses and coordination between Baltic States will be required, as many projects require an increase in gas transmission network throughout the whole area.
- Politically, there is a regional competition between the East-Baltic Member States about the location for the LNG terminal. All four countries of the East Baltic area have shown their strong interest in offering the location for the LNG terminal, but it is clear that only one LNG terminal is feasible in the region due to limited annual gas consumption. The host of the project will ensure national security of supply and benefit from the positive economic impact of a LNG terminal. Internal "pressure" on decision makers on the location of the LNG terminal is quite high and will be carefully followed not only by energy sector experts but also by the press, the Parliament, and the public.
- Economically, there is no agreement on who should finance each possible project and how costs should be split between different actors. In parallel, if the regulatory system will not be well defined in a comparatively short time period, this will cause uncertainty on the pay-back of investments and therefore the private investments will be delayed or cancelled.

Furthermore, possible upgrades along main EU corridors may impact the gas flows to the Baltic area and should be taken into consideration:

- North-South Interconnection in Central and South Eastern Europe: the Energy Infrastructure Package has identified a variety of projects in order to improve the diversification of supply sources, enhance security of supply and create a connection between the Adriatic and the Baltic Seas. These interconnections would facilitate gas flows from Norway, western hubs and LNG to South East Europe, potentially increasing competition for Norwegian gas;
- Interconnections between Germany and Poland: although the exact points of connection have not been defined yet, the cross border pipeline would transmit about 3 Bcm of natural gas per year and would facilitate flows from Norway, western hubs and LNGs to Poland and Baltic countries.

Specifically to the LNG, a Reflection Paper has been submitted by the Commission, describing the strategic options and recommendations on infrastructure investment, cost allocation and a common entry-exit model in the East Baltic Gas Market. In addition, the Member States agreed on a set of high level criteria for the realization of the LNG terminal:

- The LNG should be able to serve the region;
- The initiators and the owners of the project must be independent from the existing dominant supplier in all aspects;
- There should be a single LNG project supported at least by Lithuania, Latvia and Estonia.

Currently no project has been implemented yet; however, a LNG terminal in Lithuania has passed the technical feasibility test: a LNG plant has been approved in 2010 in Klaipeda by the company Klaipedos Nafta (major shareholder is the Ministry of Energy of Republic of Lithuania, with 70.63% of total shares). The LNG terminal project would consist on a FRSU (Floating Storage Regasification Unit), with an annual capacity of regasification up to 3 Bcm. The terminal would be located in Klaipeda and it would require an upgrade in order to sustain the new gas capacity. In 2011, a Letter of Intent was signed with the American energy company Chenier regarding the supply of natural gas via the Lithuanian LNG terminal. On January 2012, the Norwegian company Höegh LNG was assigned to manufacture the floating storage with the regasification equipment. The terminal could supply Latvia through its pipelines or by deploying the FSRU directly to Riga. However, no decision has been made reached on whether Lithuania will have priority for LNG supply ahead of Latvia.

During the meeting of the BEMIP HLG on October 24th 2011, the Member States decided to conclude during 2012 the cost-benefit analysis on LNG solutions, which is the object of the present work.

3. GAS DEMAND EVOLUTION IN THE BALTIC COUNTRIES

3.1. APPROACH

In the present study, two different gas demand scenarios were identified for each country: a base case and high case (Figure 11). The whole research was then structured taking into consideration these two possible gas scenarios in order to gather a wider understanding of possible future outcomes in terms of gas supply-demand equilibrium. In this section, the two cases are described in their hypotheses and outcomes.

3.2. METHODOLOGY

First, a base case was defined. In terms of the evolution of gas mix, actual data were taken from TSO's reports for year 2010, while forecasts data until 2030 were taken from DG Tren. For each country, the gas mix was split in households, industrial and power generation. For some countries, power generation included also district heating when data were available. Moreover, the total power generation mix development for the period 2010-2030 was taken in order to understand the role of gas in electricity generation for the future, as power generation is the most relevant driver for gas consumption (data were taken from DG Tren).

After a base case was defined, some adjustments were undertaken in order to obtain a high demand scenario. This scenario was developed in order to identify which share of power generation could be addressed by gas in substitution of other sources. Moreover, different hypothesis from those of DG Tren regarding GDP growth rate and households' efficiency rates were considered.

Figure 11 - Definition of scenarios, methodology

Scenario	Methodology	Assumptions
Base Case	▪ 2010 TSO Actual data of gas consumption as starting point and DG ENER estimates for Gas consumption 2015-2030 ▪ Gas mix trend evolved based on key drivers	▪ Power generation kept as DG ENER estimates ▪ Industrial grow at GDP rate on DG ENER ▪ Households kept constant
High Scenario	▪ Base case scenario adjusted by: – Identification of the gas addressable market as share to capture in power generation consumption – Increase of national GDP growth rate expectations – Efficiency rate in households consumptions	▪ Gas cannot capture power generation market shares from renewables and nuclear energy ▪ 20 % of Renewables energy consumption should be achieved within 2020

3.3. Hypotheses

The following hypotheses were considered in the base case (data taken from DG Tren):

- The GDP growth rate was that assumed by DG Tren;
- Industrial consumption growth rate was assumed to be the same as GDP growth rate;
- Households' consumption was kept constant over time.

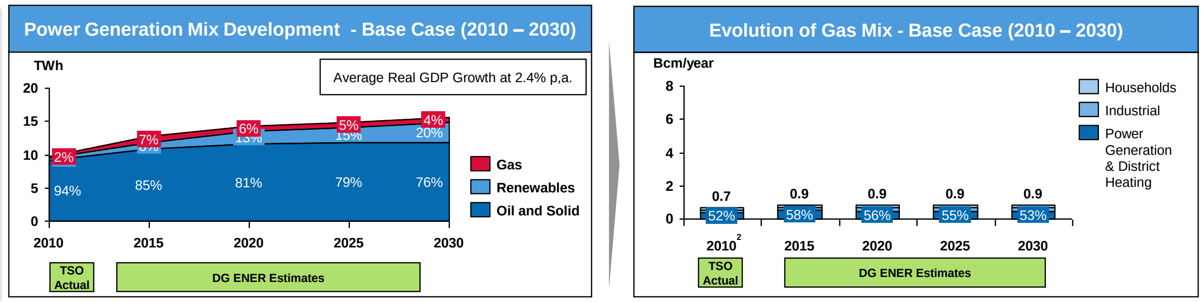
For the high scenario, the hypotheses were the following:

- The GDP growth rate was taken from Global Insight's World Overview (August 2011);
- For industrial consumption growth rate, the percentage of GDP growth that translates in industrial energy consumption in 2030 was assumed to be 70%, therefore setting the 2030 energy intensity at 70% (as in 2010);
- For households growth rate, it was assumed that the increase in energy efficiency would offset the impact of the GDP growth;
- For total power generation, it was assumed that gas could achieve a bigger share by substituting other sources (except for renewable and nuclear energy, as European Union recommended that within 2020 20% of power generation mix should derive from renewable sources, and Government energy policies ruled out gas substitution over nuclear energy).The total TWh of power generation was supposed to stay at the same level.

3.4. Estonia

In Estonia, the annual real GDP growth rate was set at an average of 2.4% for all the considered years. DG Tren forecasted an evolution of gas mix from 2015 to 2030 and a power generation mix development, all represented in the figure below (Figure 12):

Figure 12 - Power Generation and Gas Mix Development in Estonia



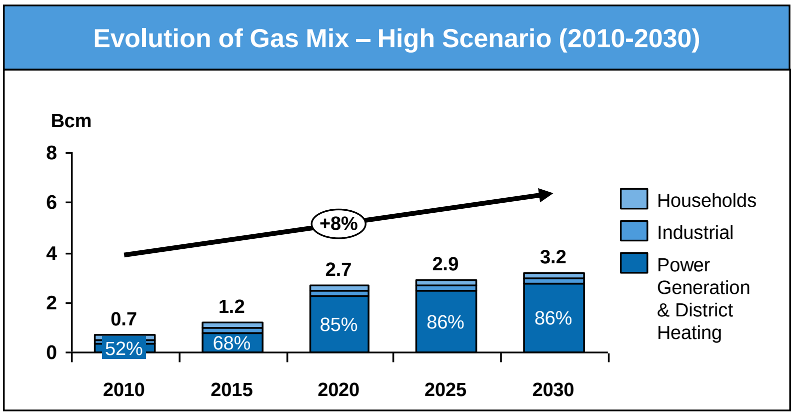
Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

For the high case, some assumptions were modified:

- The GDP growth rate was assumed to be 3.2%;
- Households' consumption was assumed to be constant, due to the offsetting effect on GDP growth of efficiency increase;
- Industrial growth consumption was affected by a real GDP growth annual rate of 3.2% against 2.4% of base case and by an energy efficiency of 70%;
- Power generation was the most affected area: substitution of 2 GW oil shale plant with CCGT at a cost of € 2 MM by 2020 was assumed in order to meet environmental regulation. Power plant was assumed to run at base load. Other relevant assumptions were the power generation efficiency at 35% and 55% for oil shale and gas (CCGT) respectively; the 20% share of renewable and 70% share of gas in power generation production within 2020.

The resulting evolution of gas mix was the following (Figure 13):

Figure 13 - Evolution of Gas Mix in Estonia, High Scenario

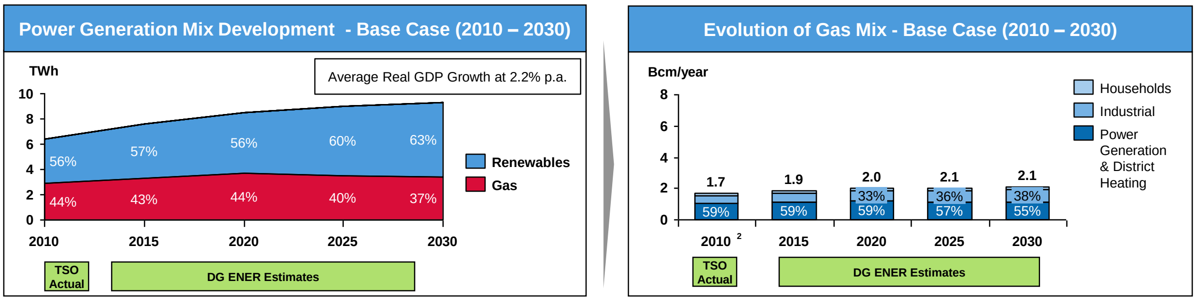


Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Liberalization of the Estonian gas Market (Poyry for Elering AS 2011), Booz & Company

3.5. Latvia

In Latvia, the annual real GDP growth rate was set at an average of 2.2% for all he considered years. DG Tren forecasted an evolution of gas mix from 2015 to 2030 and a power generation mix development, all represented in the figure below (Figure 14):

Figure 14 - Power Generation and Gas Mix Development in Latvia



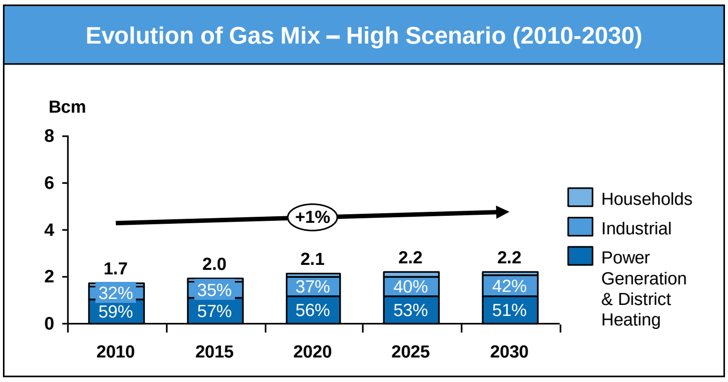
Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

For the high case, some assumptions were modified:

- GDP growth rate was assumed to be 3.4%;
- Household's consumption was assumed to be constant due to the offsetting effect on GDP growth of efficiency increase;
- Industrial growth consumption was affected by the real GDP growth annual rate of 3.4% against 2.2% of base case and by an energy efficiency of 70%;
- Power generation showed little addressable demand due to already relevant utilization rate (40% in 2010) while the rest of power generation comes from renewable sources and it is unlikely that gas could capture relevant market share over renewable, due to environmental targets.

The resulting evolution of gas mix was the following (Figure 15):

Figure 15 - Evolution of Gas Mix – Latvia, High Scenario

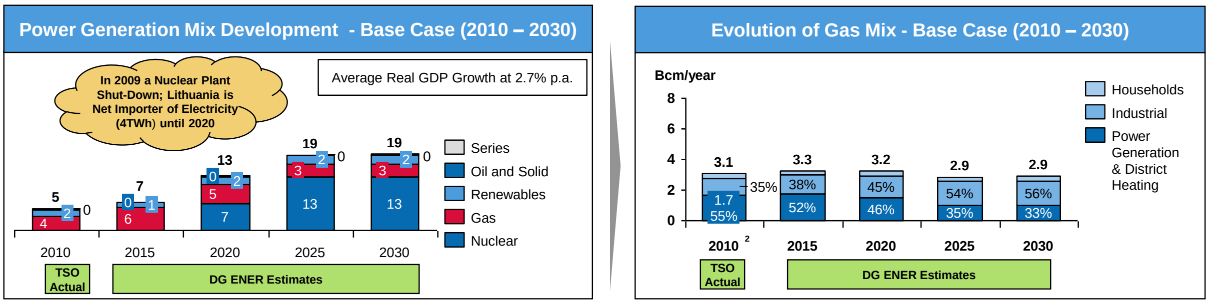


Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

3.6. LITHUANIA

In Lithuania, the annual real GDP growth rate was set at an average of 2.7% for all he considered years. DG Tren forecasted an evolution of gas mix from 2015 to 2030 and a power generation mix development,all represented in the figure below (Figure 16):

Figure 16 - Power Generation and Gas Mix Development - Lithuania



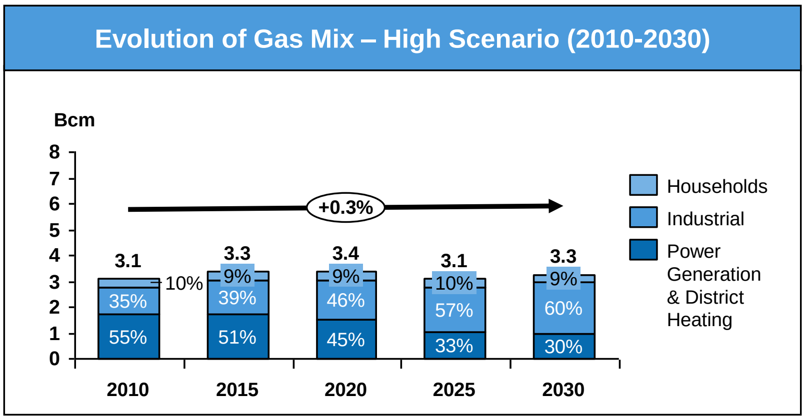
Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

For the high case, some assumptions were modified:

- GDP growth rate was assumed to be 3.8%;
- Households' consumption was assumed to be constant due to the offsetting effect on GDP growth of efficiency increase.
- Industrial growth consumption was affected by the real GDP growth annual rate of 3.8% against 2.7% of base case and by an energy efficiency of 70%. Power generation was forecasted to grow after the shutdown of a nuclear plant in 2009 that turned Lithuania in an electricity importer.

The resulting evolution of gas mix was the following (Figure 17):

Figure 17 - Evolution of Gas Mix in Lithuania, High Scenario

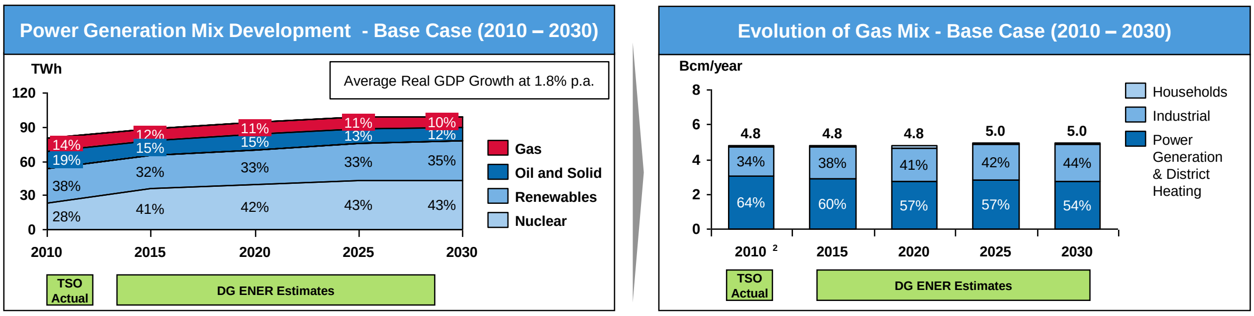


Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

3.7. Finland

In Finland, the annual real GDP growth rate was set at an average of 1.8% for all he considered years. DG Tren forecasted an evolution of gas mix from 2015 to 2030 and a power generation mix development,all represented in the figure below (Figure 18):

Figure 18 - Power Generation and Gas Mix Development - Finland



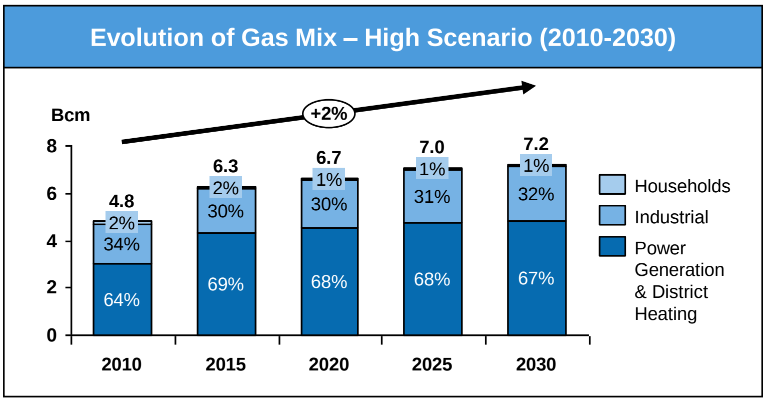
Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

For the high case, some assumptions were modified:

- GDP annual growth rate was assumed to be 2.1%;
- Households' consumption was assumed to be constant due to the offsetting effect on GDP growth of efficiency increase;
- Industrial growth consumption was affected by a real GDP growth annual rate of 2.1% against 1.8% of base case and by an energy efficiency of 70%;
- Power generation was the most affected area: it was forecasted to be driven by nuclear power plants, although natural gas would reach a share of about 18% in 2030.

The resulting evolution of gas mix was the following (Figure 19):

Figure 19 - Power Generation and Gas Mix Development - Finland



Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

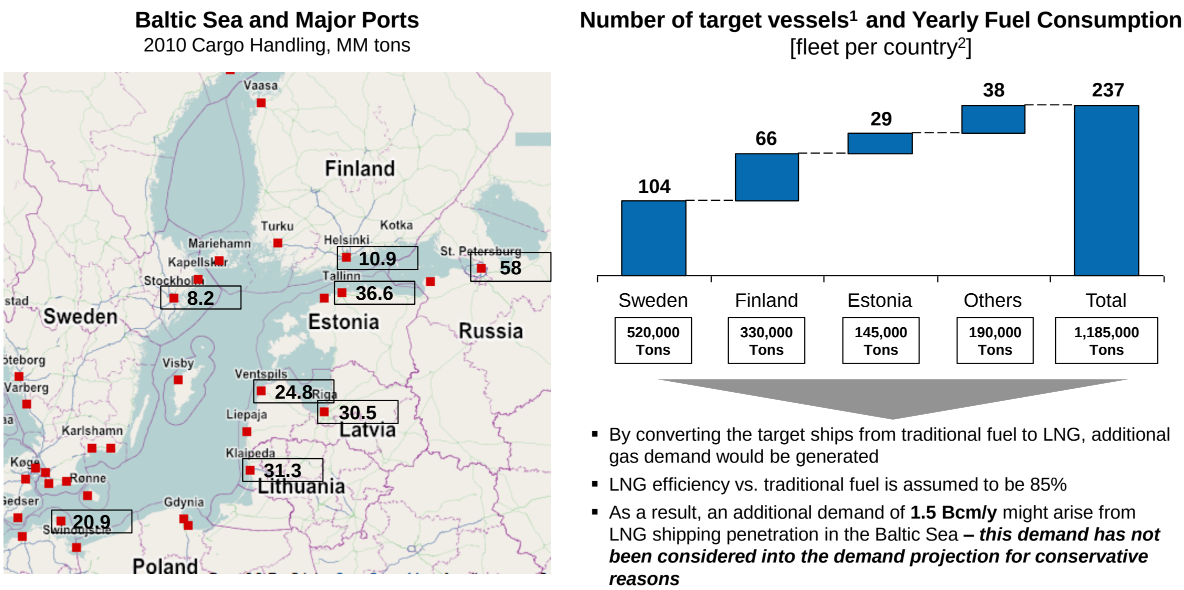
3.8. ADDITIONAL POTENTIAL DEMAND

Potential further demand of LNG may come from the substitution of Ro-Ro and Ro-Pax vessels that currently utilize fuel with vessels that utilize LNG (Figure 20). Target segments were Ro-Ro, Ro-Pax and Feeder, chosen by two main drivers:

- Point-to-Point segments (due to limitation of LNG bunkering infrastructure and presence in ECA region);
- Most energy intensive (percentage of fuel cost on total operational costs) and major impact on costs.

The number of the target vessels that sail within the Baltic Sea (therefore excluding those vessels that sail on longer routes) was estimated, along with the average annual fuel consumption. Total Ro-Ro and Ro-Pax fleet that sail in the Baltic Sea is 327 vessels (Sweden 104, Finland 66, Estonia 29, others 38). The average annual fuel bunker consumption for this segment is around 5,000 Tons of fuel bunker per vessel. Therefore, total fuel bunker consumption is about 1.2 Mln Tons per year. Assuming LNG efficiency vs. traditional fuel of 85%, an additional demand of 1.5 Bcm/y might arise.

Figure 20 – Maritime LNG for Transportation in Baltic



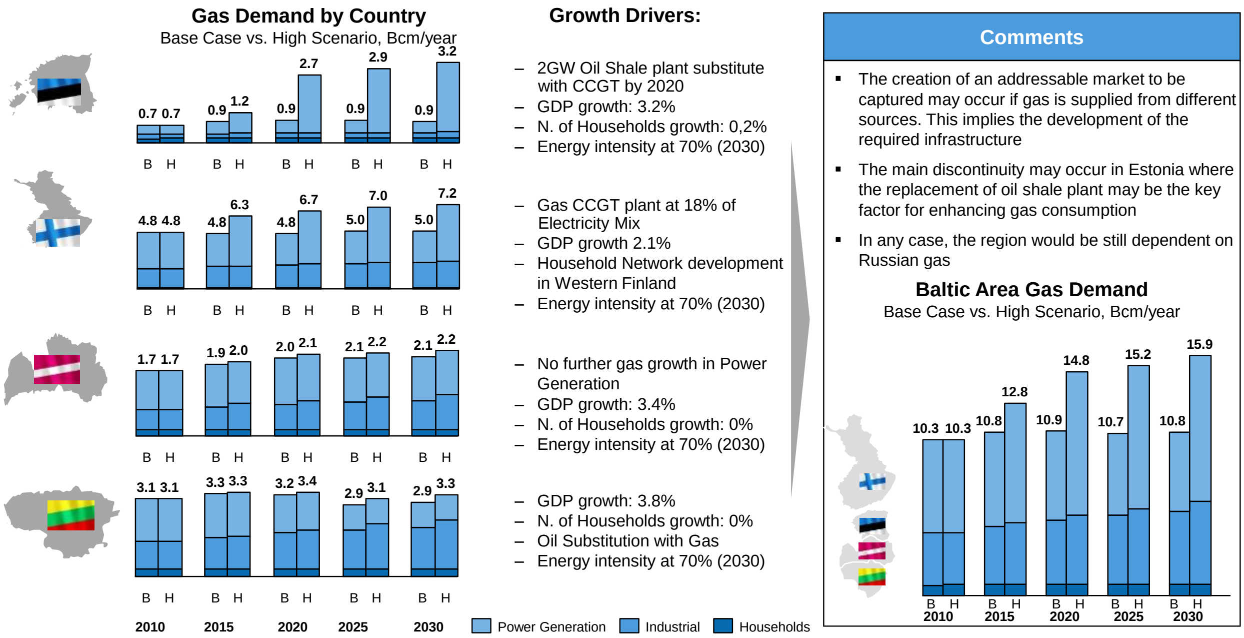
1) Roll-on/Roll-off vessels were selected (freight and passengers); 2. Country has been defined based on the company headquarter of vessels owners

Source: Klaipeda Cargo Handling report (2010); Booz & Company

3.9. OVERALL COMMENTS

The high case scenario shows how natural gas may acquire a relevant position in the power generation mix of Baltic Area, generating an additional demand of about 5 Bcm (Figure 21).

Figure 21 - Baltic Area Overall Gas Demand Trend



Source: DG trends 2010-2030; National Energy Reports; Booz & Company Analysis

The creation of an addressable market to be captured by natural gas may occur if gas is a convenient alternative to other sources. This would imply the development of new infrastructures. The main discontinuity may occur in Estonia, with the replacement of oil shale. In any case, the region would be still dependent on Russian gas.

Finally, it was also assessed the potential shift from shale oil to gas. The analysis was run for 2010 and 2020 to understand whether or not the switch could be convenient. By taking into consideration energy efficiency and costs for CO_2 emissions, it was computed the cost of producing 1 MWh with shale oil gas, and therefore it was defined the maximum price that gas could cost in order to be competitive.

Some assumptions were taken for 2010:

- Oil Shale Oil Commodity Price at 30 €/MWh (11.5 $/MMbtu);
- Oil Shale Oil power plant efficiency at 40%;
- CO_2 Emission for Oil Shale = 0.106 ton/Gj;
- Gas CCGT efficiency at 50%;
- CO_2 Emission for Gas = 0.055 ton/Gj;
- CO_2 Emission cost: 13€/t.

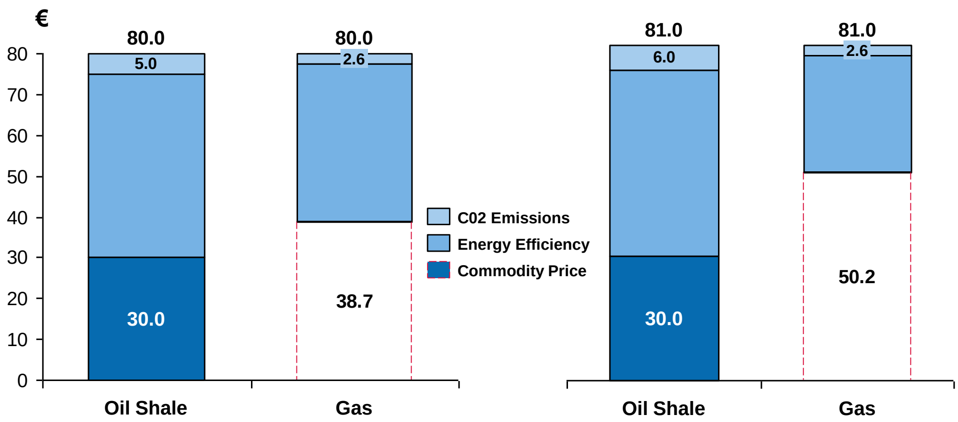
As well as for 2020:

- Oil Shale Commodity Price at 30 €/MWh (11.5 $/MMbtu);
- Oil Shale power plant efficiency at 40%;
- CO_2 Emission for Oil Shale = 0.106 ton/Gj;
- Gas CCGT efficiency at 64%;
- CO_2 Emission for Gas = 0.055 ton/Gj;

- CO_2 Emission cost: 15.5 €/t;

As can be seen from the figure below (Figure 22), in 2010 the gas breakeven price was 39 €/MWh (14.8 $/MMbtu), while in 2020 it would be 51 €/MWh (19.1 $/MMbtu). Compared to oil shale, gas price in 2020 should not be higher than 20 €/MWh. The capacity of required CCGTs has been estimated to be 1.5GW at a capital cost of around € 1.4 Bln. The expected costs of replacing the planned 600MW of the existing oil shale based power generation have been estimated to be € 1 Bln.

Figure 22 - Commodity Spare Price (€/MWh)



4. EUROPEAN GAS MARKET TRENDS

In the present study, it was crucial to analyse the European gas market in order to define the context in which the Baltics may be involved. At the moment, the Baltic countries are limitedly impacted by European gas market because they totally rely on Russia.

If Baltics were connected to the European gas system, they would necessarily be impacted by the European gas system dynamics. Additionally, in order to assess the viability of gas diversification, it was required to understand if there are possible gases (e.g. Norwegian) that could flow in the Baltic region.

4.1. Approach

This analysis aims to give an overview of what dynamics would drive the European gas market, what impacts they would have on Europe in the period 2010-2030 and what specific outcomes may be drawn for Baltics.

Two major steps have been followed in order to perform this analysis:

1) Assessment of European gas demand and supply trends in the period 2010-2030;
2) Assessment of European gas infrastructure utilization (pipelines and LNG facilities).

Finally it has been drawn conclusion on possible impact and consequences in case Baltics were connected to the European gas system.

4.2. ANALYSIS

This section was based on gas flows simulations performed with the Booz & Company proprietary Global Gas ModelMain input data of the analysis were taken from DG Tren 2010 Report: trends 2009-2030 and IEA 2010 report.

European gas demand is expected to be almost flat in the future (Figure 23). Western European countries will still be the main gas consumers. Europe is a mature gas market mainly due to limited economy growth (GDP as proxy), major governments committed to support alternative energy sources (Renewables, Nuclear) and further technology improvements that enhance the energy efficiency.

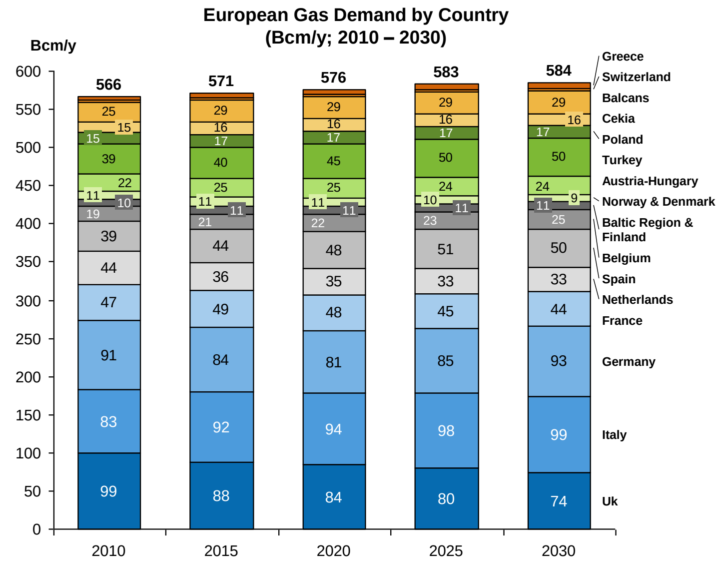
Power generation is the main driver for gas demand and nuclear energy and enewable sources are the main competitors of gas.

After recent events in Fukushima Nuclear plants (Japan – March 2011), the social awareness on Nuclear energy negative effects has driven some countries, like Germany, to plan the total Nuclear Phase-out within 2030 while others, like Italy, abandoned the plan to develop new nuclear power generation plants.

However, there is still some uncertainty on the role nuclear energy will play in the future. In Lithuania the biggest nuclear power plant has been closed-out in 2009 (Ignalina) but a new generation plant will start to be operating from 2020 (Visaginas). Germany as well, has announced significant delays on nuclear phase-out initial plan.

In addition, there is the "EU's Target for Renewable Energy: 20% by 2020" plan that would further challenge the develop of European gas market in the coming years.

Figure 23 - European Gas Demand



Detail on Adjustments

	Data	2015	2020
Italy	European Trends Data	*86*	*89*
	Adjustments (According with SRG view)	*+6*	*+5*
	Total	***92***	***94***
Germany	European Trends Data	*89*	*90*
	Adjustments (According with Government view)	*- 5*	*- 9*
	Total	***84***	***81***

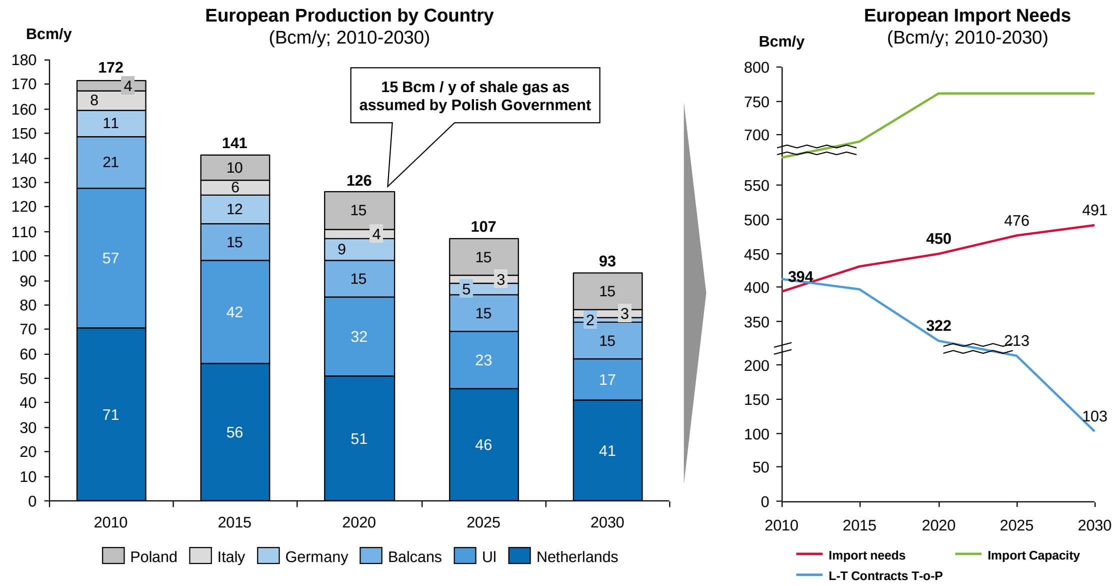
Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

The European gas production is expected to decrease considerably because of The Netherlands and UK reserves that are rapidly decreasing. An upcoming new gas supplier as

Poland, thanks to new shale gas discoveries, has planned to produce almost 15 Bcm per year. However, all these three countries will become gas net importers.

Therefore Europe is going to further increase import needs (Figure 24).

Figure 24 - European Gas Production



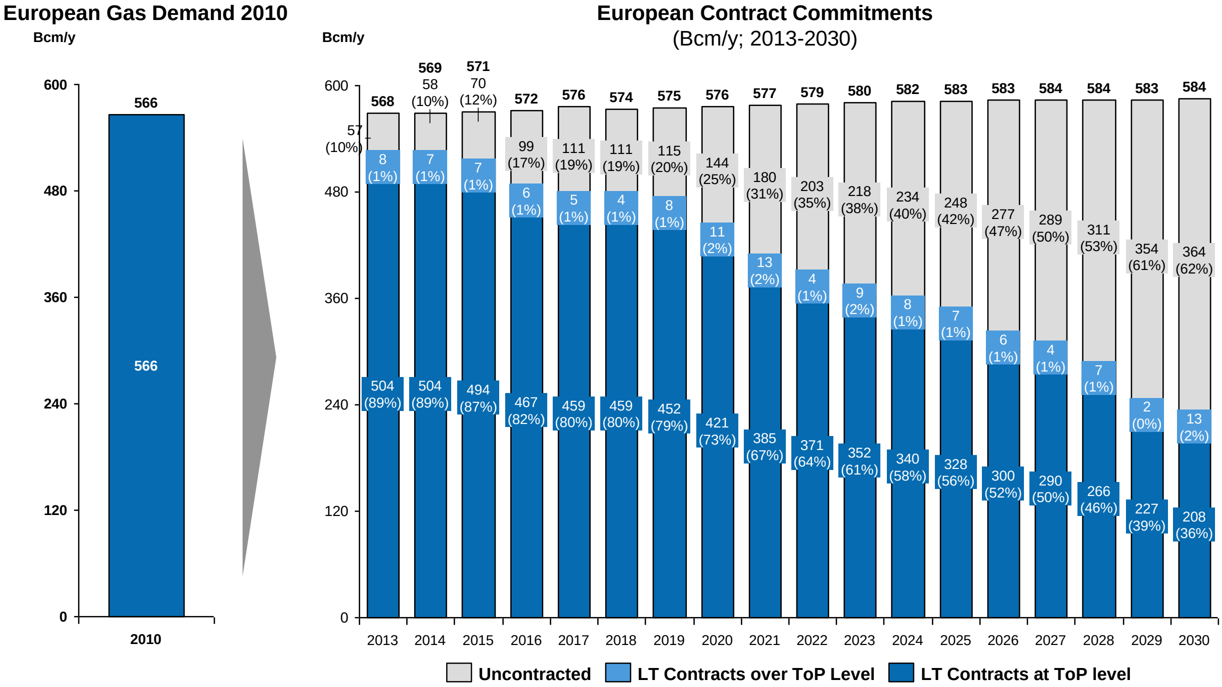
Source: DG trends 2010-2030; Estonian Electricity and Gas Market Report 2010; Booz & Company

In 2010, European demand was totally over-contracted (Figure 25). The minimum quantity intake varies per country from 75% to 90%. This comes as effect of long term contracting strategy taken by main European energy players over the past 10 years. They committed to Take-or-Pay (T-o-P) long term contracts that have resulted being oversized compared to the actual consumption needs. Some players decided to get rid of unnecessary volumes in the major European Hubs while other preferred to pay without take. This has significantly impacted the gas spot market where prices plummeted. Some major gas players experience long term contract prices higher than current spot prices.

From 2015 contracts start to expire and un-contracted demand will start to find space. Germany is the most over-contracted European country and if no negotiations with producers will be effective, there would be no space for new contacts until 2022. From the other side Italy, the second most important gas market in Europe, is almost fully contracted until 2019. In 2016 Italy could start to exit from small T-o-P contracts (Gas Terra - 6Bcm per year), while in 2019 the commitment with Algeria for 19 Bcm per year will expire.

From 2017 Transitgas, the pipe currently connecting Italy with Germany from North to South, should be operating in Reverse Flow as well. This may create conditions from gas coming from Africa (Algeria) and Caspian to land in central and northern Europe as well. However, until Germany starts to exit from over-contracted demand situation (2022), there won't be spare demand to be fulfilled.

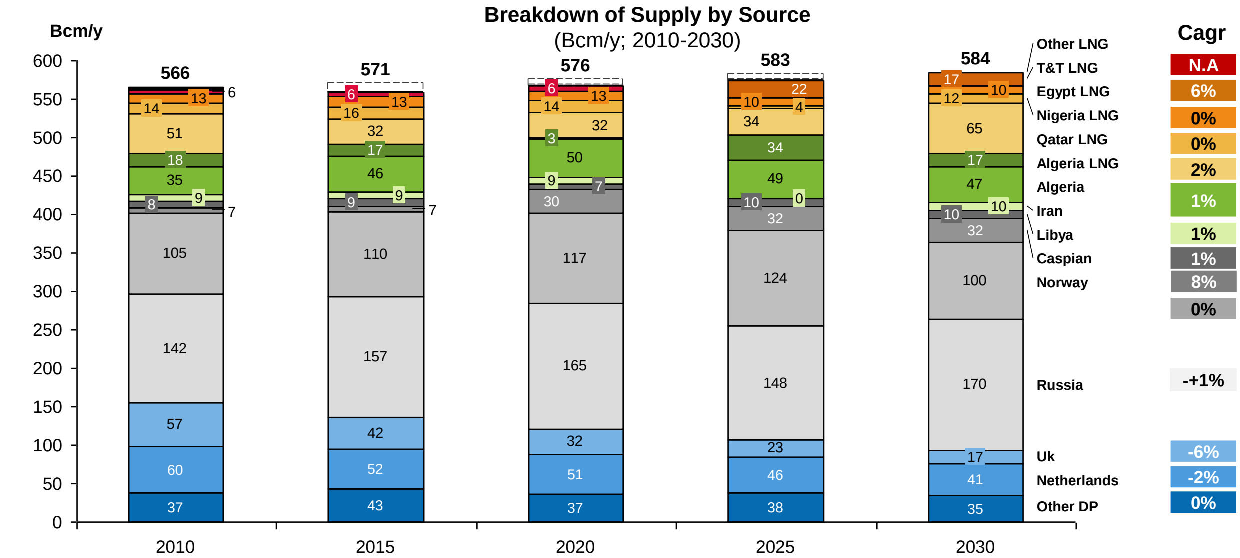
Figure 25 - European Contracted Demand



Source: Booz & Company Gas Model Analysis

The demand supply balance analysis shows that Norway and Russia may keep significant share on European supply also in the future (Figure 26). The additional gas imports would be mainly served by pipe gas. The European pipe network seems to have a critical import value at 370-380 Bcm (with 80% of capacity utilization); after that level the LNG starts to gain shares over pipe on gas supply. Qatar would lead the LNG supply with Algeria and Trinidad & Tobago to keep a significant position as well. Such analysis shows that LNG prices could rarely reach Asian level until the import needs of Europe are higher than 460-470 Bcm /y needs, (technical capacity of an import of 380 Bcm/y with a utilization rate of 80%)

Figure 26 - European Demand–Supply Balance



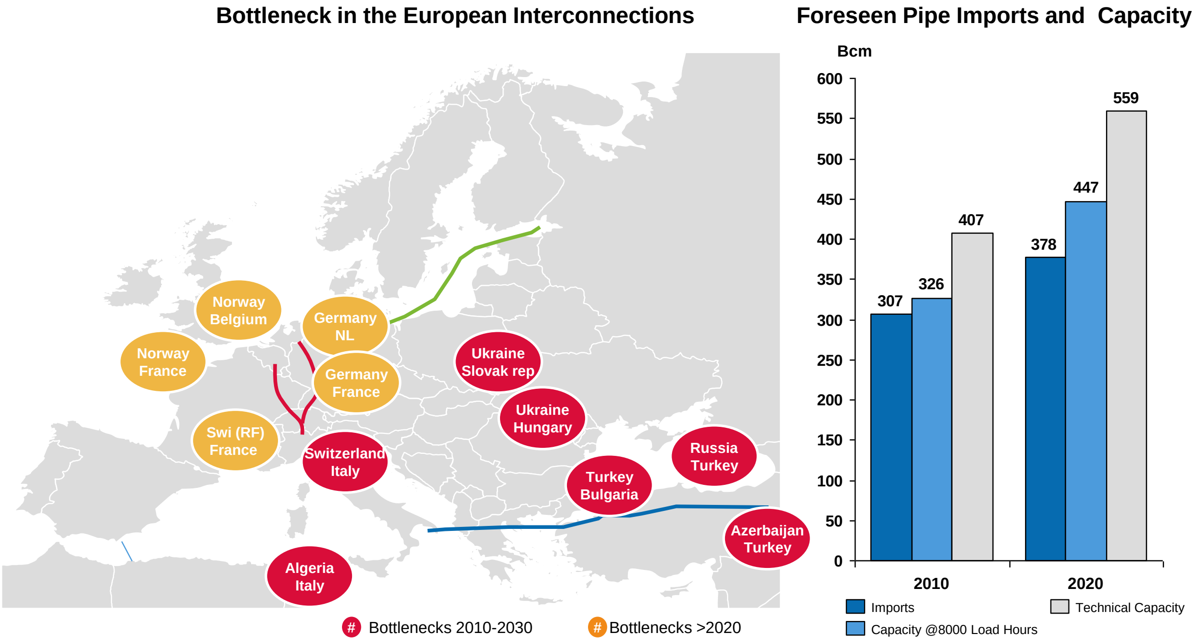
	2010		2015		2020		2025		2030	
	#	Share	#	Share	#	Share	#	Share	#	Share
LNG	102	16%	84	15%	70	12%	107	18%	121	21%
Pipe	307	55%	338	60%	378	67%	363	63%	370	61%
Prod.	155	29%	137	24%	120	22%	107	19%	93	19%

Source: Booz & Company Gas Model Analysis

As shown in Figure 27, the Europe entry pipe border points have shown high utilization rate and major bottlenecks within the European interconnections would still remain. Russia, Norway, Algeria and Caspian producers may not totally exploit their gas production and infrastructure capacity without boosting the European network. From West (France) to East (Ukraine, Slovak Republic, Bulgaria, Hungary etc...) and from North (Netherlands, Belgium) to South (Italy) there are several bottlenecks that will need to be unlocked.

The European network is currently not up to date, leading to low competition between different gas producers in serving countries. Italy's bottleneck favours Russian gas to serve central Europe without entering into competition with Algeria and Caspian gas, whose prices would be lower.

Figure 27 - Bottlenecks in the pipeline network and foreseen pipe imports and capacity



Source: Booz & Company Gas Model Analysis

The LNG prices are expected to be less competitive than pipe gas. The LNG prices are driven higher by the significant increase of Asian gas consumption. For this reason the increase of imports need would be primarly fulfilled by pipe gas and then by LNG.

At current market conditions pipeline would be preferred, while when pipe bottlenecks occur at border points, the LNG would be exploited.

4.3. RESULTS

There may be opportunities to be exploited connecting Baltic area to Europe through pipeline, i.e. the Poland-Lithuania interconnector (GIPL). In this case a German-Poland interconnector should be implemented in reverse flow as well, since currently operates only from east to west.

In this study, GIPL capacity was assumed to be 10 Bcm per year, because:

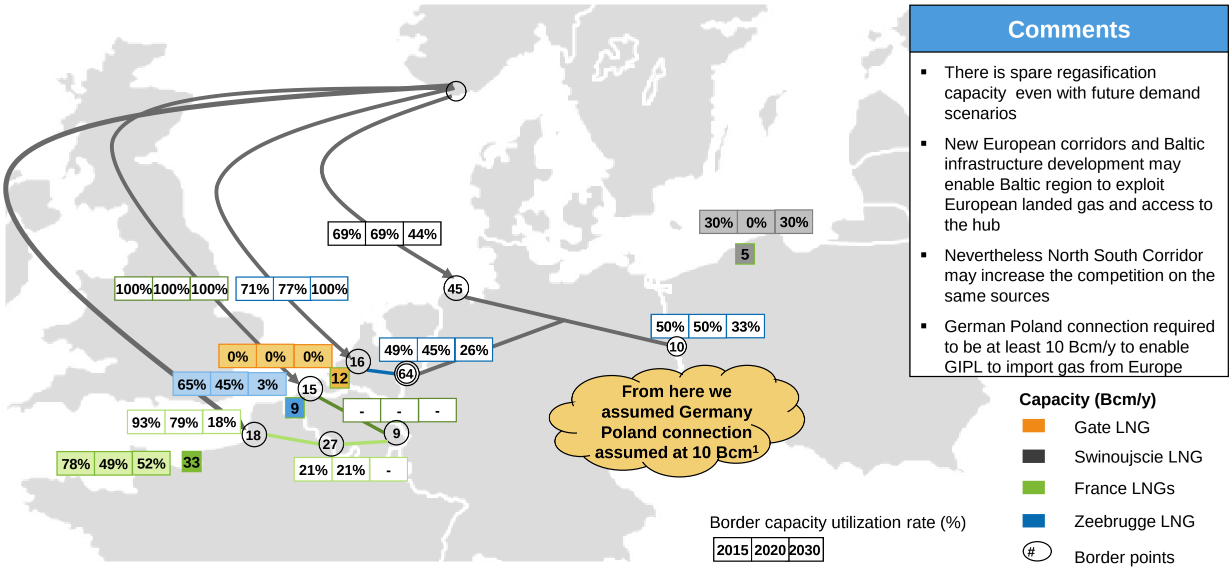
- The simulation performed with Booz & Company Global Gas Model showed gas flows to land in Poland would exploit at maximum about 5 Bcm per year technical capacity;
- The GIPL technical capacity is planned at 4.5 Bcm per year.

Therefore, it could be assumed the German-Poland interconnector should have at least 10 Bcm per year of technical capacity in order to not to create a bottleneck for the gas on the way to Baltic States (Figure 28).

There are no major pipe bottlenecks from Northern-Western Europe on the way to Baltic countries. Furthermore, LNG infrastructures in Poland, Belgium and Netherlands would have spare capacity as well. If LNG price would be competitive, the Baltic area may exploit European interconnections to access most of European LNG regasificators; also Norway gas pipe may be the most suitable solution to be exploit in order to diversify the supply sourcing until 2015, when Transitgas reverse flow will be operating; also pipe gas from Southern Europe may be considered. Nevertheless, North South Corridor may increase competition on the same sources.

Finally, connecting Baltic region to Europe would benefit the region's supply because of the spare infrastructure capacity to be exploited with bringing gas from North-Western Europe.

Figure 28 - European Infrastructure Network to Baltic Area



Source: Booz & Company Gas Model Analysis

5. ASSESSMENT OF PROPOSED INFRASTRUCTURES

The goal of this section was to assess the impact that the proposed projects may have on the Baltic infrastructures network. The information gathered was then used to understand whether a LNG terminal could serve as a source of supply diversification and grant security of supply.

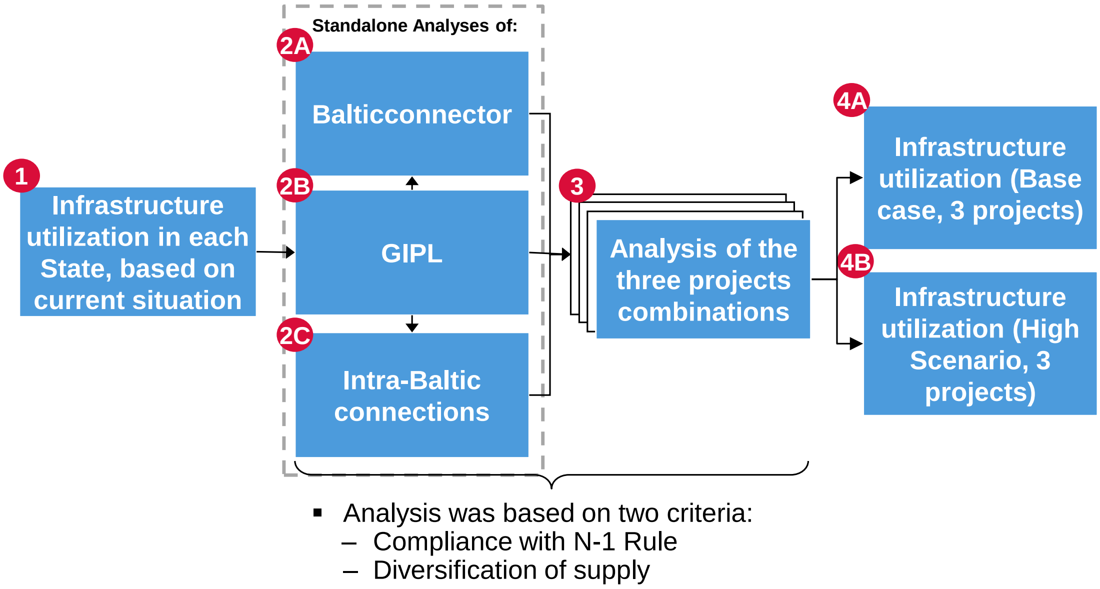
The analysis was conducted considering two scenarios for the demand of gas: a base case and a high case (see section 2).

5.1. Approach

Three projects were taken into consideration: the Balticconnector, the GIPL and some of the Intra-Baltic Connections, specifically the Latvia Estonia and the Latvia-Lithuania pipelines.

A four steps approach was adopted in order to analyse the impact of these proposed projects in the Baltic region (Figure 29):

Figure 29 – Fours Steps Approach



Source: Booz & Company Analysis

Step 1 – Infrastructure utilization in each State, based on current situation: this step aimed to understand how much the existing pipelines will be used to supply each State from today to 2030, assuming that Russia would still be the sole supplier.

Step 2 – Stand-alone analysis of:

- Balticconnector;
- GIPL;
- Baltic Intra-Baltic Connections.

The rationale of this step was to gather information on how each project, taken stand-alone, could improve security of supply and diversification in the Baltic area.

Step 3 – Analysis of the three projects combinations: the goal was to understand whether the three proposed infrastructures might reach a higher level of supply security and diversification.

Step 4 – Analysis of potential infrastructures utilization rate: this step assumed that the proposed infrastructures were implemented and studied their utilization rate in 2030. Both bas-case and high-case scenario were analysed.

The output of the overall analysis was the building block to better comprehend the potential role of LNG terminal in the Baltic area.

5.2. UTILIZATION OF CURRENT INFRASTRUCTURES BY COUNTRY

5.2.1.Methodology

In this analysis, the gas pipelines network was assumed to remain as it is today (i.e. the technical capacity of each pipe would remain stable in the future). The network of pipelines that connect each Baltic State to another and to Russia was supposed not to change. The Global Gas Model was then used to determine the gas import flows to supply each country, along with the utilization rate of each pipeline: in this way it was possible to observe from which pipelines the gas comes from and by how much the capacity of those pipelines is utilized. An utilization rate below 30% was considered "low", a rate between 30% and 70% was defined "medium", and a rate above 70% "high".

5.2.2.Analysis

To run this analysis, the base-case and high-case demand scenarios for years 2010, 2015, 2020, 2025 and 2030 were considered, as synthesised in the tables below (Table 1, 2).

Table 1 - Gas Demand – Base Case

Year / Country	2010 (Bcm/y)	2015 (Bcm/y)	2020 (Bcm/y)	2025 (Bcm/y)	2030 (Bcm/y)
Finland	4.8	4.8	4.8	5.0	5.0
Estonia	0.7	0.9	0.9	0.9	0.9
Latvia	1.7	1.9	2.0	2.1	2.1
Lithuania	3.1	3.3	3.2	2.9	2.9
Total	10.3	10.9	10.7	10.9	10.9

Table 2 Gas Demand – High Case

Year / Country	2010 (Bcm/y)	2015 (Bcm/y)	2020 (Bcm/y)	2025 (Bcm/y)	2030 (Bcm/y)
Finland	4.8	6.3	6.7	7.0	7.2
Estonia	0.7	1.2	2.7	2.9	3.2
Latvia	1.7	2.0	2.1	2.2	2.2
Lithuania	3.1	3.3	3.4	3.1	3.3
Total	10.3	12.8	14.9	15.2	15.9

For each country, all the pipelines that could supply the gas were considered. All the four countries are connected to Russia with direct pipelines while only Finland does not have any connection to other countries. Also, the network presents pipelines connecting Latvia to Estonia (single flow south to north) and Latvia to Lithuania (both directions).

The actual capacity considered was the border nominal capacity with a load factor of 8,000 hours per year (Table 3).

Table 3 – Actual Capacity Of Pipelines At Border Points

Russia-Finland	Russia-Estonia	Russia-Latvia	Belarus-Lithuania	Latvia-Lithuania	Lithuania-Latvia	Latvia-Estonia	Estonia-Latvia
6.9Bcm/y	1.3Bcm/y	5.3Bcm/y	6.5Bcm/y	1.8 Bcm/y	1.8 Bcm/y	2.9 Bcm/y	2.9 Bcm/y

All the data were imputed in the Booz Global Gas Model. Gas was always supplied by Russia, as the infrastructure network was supposed to remain the same. The output observed was:

- gas flows to each country;
- pipeline utilization rate.

5.2.3.Results

In the base case demand scenario, Russia is forecasted to maintain its dominant position in the future. In particular, as shown in the figure below, the four countries receive exclusively Russian gas. In particular, the gas would come directly from Russia, therefore excluding flows of gas across Baltic countries. No new connections would be needed, as the demand would be fully satisfied with Russian gas.

With regards of infrastructures utilization (Figure 30, 31):

- Finland: it is equal or above 70% in each year considered, implying that full technical capacity might be reached if the demand would turn to be higher than the one forecasted in the base case.
- Estonia, Latvia and Lithuania: the utilization rates vary from 32% in Latvia to 72% in Estonia; therefore bottlenecks in supply are not foreseen.
- The cross countries pipelines are not utilized.

Figure 30 - Breakdown Supply & Infrastructure Utilization – Base Case: Current Infrastructure

Source: Booz & Company Analysis, Booz & Company gas Model

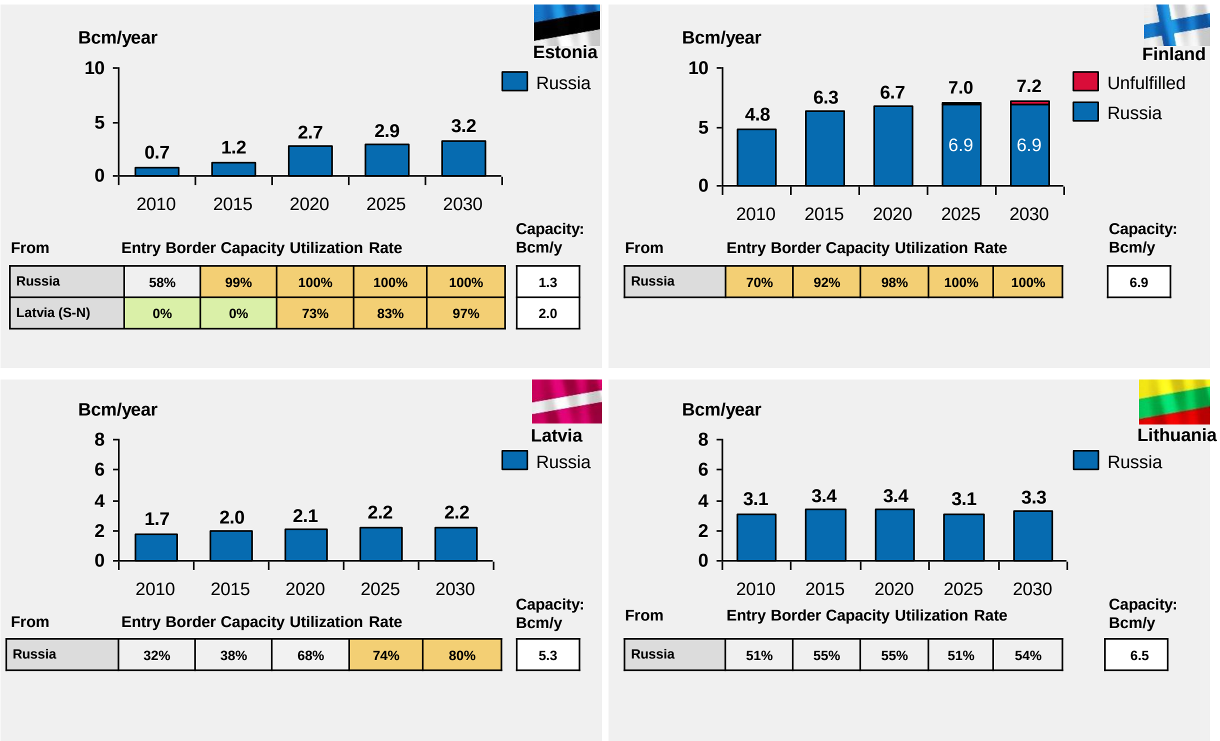
In the high-case demand scenario, Russia would remain the sole gas exporter to the Baltic area (see Figure 20). The absence of other gas importers leaves Finland with an unfulfilled demand of 0.3 Bcm in 2030. However, there are flows of gas across countries. In particular there are flows from Latvia to Estonia.

In terms of capacity utilization:

- In Estonia, gas flows from Latvia utilize more than half of the Latvia-Estonia pipeline; gas from Russia utilizes the entire capacity;
- Latvia receives gas from Russia, utilizing up to 80% of capacity;
- Lithuania and Finland receive gas only from pipelines coming from Russia.

In conclusion, in case of high gas demand, gas would be still supplied only by Russia, but Russian pipelines capacities may not be enough in order to completely fulfil the demand, since an unbalance of 3.0 Bcm in Finland is left.

Figure 31 - Breakdown Supply & Infrastructure Utilization – High Case – Current Infrastructure



Source: Booz & Company Analysis

5.3. Stand-alone analysis of proposed new infrastructures

5.3.1.Methodology

For assessing the possible effects of the proposed projects on the Baltic gas market, the analysis focused on the study of compliance of each project (Balticconnector, GIPL and Intra-Baltic connections) with the N-1 rule (i.e. to grant security of supply) and supply diversification. Again base case and high case demand scenarios were simulated at peak demand (Peak demand was computed by considering the impact of the current peak of residential, industrial and power gas-to-power demand and projecting it to year 2030).

Each project was tested independently from the other (i.e. when the project under analysis is implemented the other two are not implemented). Two tests were performed for a country at a time:

- The first test was related to the security of supply (N-1 rule). The N-1 formula describes the ability of the technical capacity of the gas infrastructure to satisfy total gas demand in the calculated area in the event of disruption of the single largest gas infrastructure during a day of exceptionally high gas demand. Gas infrastructure includes the gas transmission network including interconnectors as well as production, LNG and storage facilities connected to the calculated area. The technical capacity of all remaining available gas infrastructure in the event of disruption of the single largest gas infrastructure should be at least equal to the sum of the total daily gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. The results of the N-1 formula, as calculated below, should at least equal 100%.

$$N-1[\%] = \frac{EP_m + P_m + S_m + LNG_m - I_m}{D_{max} - D_{eff}} \times 100, \; N-1 \geq 100\,\%$$

Peak demand was computed as follows:

- Peak demand data were collected for 2010 and 2030;
- For each state, peak gas demand was split between households, power generation and industrial, assuming that only households would demand more gas than average on peak days. Therefore, the increase in gas demand was attributed to households only and projected to 2030.

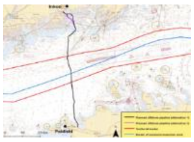
All the three project infrastructures were taken into account to assess whether or not they could improve the situation in each state (first they were taken stand alone and then they were combined). Moreover, Incukalns storage facility was assumed to work at a capacity of 3.2 Bcm/y, with a maximum withdrawal capacity of 12 Mcm/d, providing gas only to Latvia.

- The second test was related to the diversification of supply. This test was performed for a country at time and independently form the first test (i.e. no pipelines were closed).

5.3.2. Analysis

The team considered three projects: the Balticconnector, the GIPL and the Intra-Baltic Connections, taken stand alone, and assessed their potential effects in terms of gas security and supply diversification.

Figure 32 - Three Projects considered

Project	Description
Balticconnector 	▪ 80 km single gas pipeline linking Inkoo (Finland) to Paldiski (Estonia) ▪ Gas capacity: 2.4 Bmc/year ▪ Designed pressure: 8 MPa ▪ Design Gas density: 65 Kg/m³ ▪ Estimated capital costs: 141 mln € ▪ Ownership: Gasum Oy, Eesti Gas, Latvijas Gaze (all participated by Gazprom)
Gas Interconnector Poland Lithuania - (GIPL) 	▪ 562 km of gas pipeline linking Warsaw (Poland) and Vilnius (Lithuania) ▪ Gas capacity: 2,3 Bmc/year (can be expanded to 4,5 Bcm/year) ▪ Maximum operating pressure: 8.4 MPa (Poland), 5.4 MPa (Lithuania) ▪ Estimated cost: 537 mln € for a 4.5 bcm/y capacity ▪ Ownership: Gaz-System (73%)
Intra-Baltic connections 	▪ Latvia-Lithuania: upgrade of bidirectional cross border capacity of 0,4 Bcm/year (25 mln €) – FID project ▪ Latvia-Estonia: upgrade of cross border capacity of 1 Bcm/year and Reverse Flow (50 mln€ with compressor) ▪ Expand Inkukalns UGS up to 3.2 working capacity (20 mln €) ▪ Total Estimated Cost: 95 mln € + € 600 Mn. Cushion gas for UGS[1]

1) cost assessment based on a commodity price at about 8 $/MMbtu

The analysis aimed to assess the impact of current proposed infrastructures on the possibility to diversify the gas supply and grant gas security across Baltic countries.

In terms of gas diversification, each project was observed in terms of how it could open the Baltic gas market to other sources of supply.

Speaking of security of supply, the N-1 rule was used to verify whether the selected infrastructure could ensure continuous supply. Gas demand was considered at its peak for each country (Peak demand was computed by considering the impact of the current peak of residential, industrial and power gas-to-power demand and projecting it to year 2030: Estonia (7 Mcm/d base case, 13 Mcm/d high case), Latvia (15 Mcm/d base case, 16 Mcm/d high case), Lithuania (24 Mcm/d base case, 26 Mcm/d high case) and Finland (23 Mcm/d base case, 30 Mcm/d high case). It was assumed a reverse flows on Lithuania-Latvia and Estonia-Finland at an equal capacity of both flow directions.

5.3.3.Results

The results of the analysis are identical, with the exception that the high scenario would require further infrastructure development in order to comply with higher demand. Only base case scenario results are shown.

First, the figure below shows the N-1 resulting situation that would occur in case no project was implemented.

Figure 33 - Current and Future N-1 rule respect

	2010 Actual
Lithuania	27%
Latvia	154%
Estonia	60%
Finland[3]	102%

	2030 Expected	
	Base Case	High Case
Lithuania	21%	20%
Latvia	147%	141%
Estonia	60%	36%
Finland	101%	70%

As can be seen from figure above, only Latvia and Finland currently respect the N-1 rule. Finland's N-1 calculation was provided by the Finnish TSO and was computed as following: there are two pipelines from Russia to Finland and the outlet pressure of the nearest compressor station in the Russian side is set so that the pressure in the interconnecting point is at normal contractual level. In this situation, the capacity of the two parallel pipelines according to hydraulic simulation is 31.8 Mcm/d. When the biggest infrastructure (the larger diameter pipeline) is cut off, the capacity in this situation is reduced by 10.5 Mcm/d. In addition, Finland is able to use 1.3 Mcm/d of demand side measures. The estimated highest demand is estimated to be 22.1 Mcm/d. This situation will lead into N-1 figure of: 102.4%. There are no production, no storage, no LNG taken into account.

Estonia and Lithuania, on the other hand, are far away from being secured.

Figure 34 - Effects of Proposed Infrastructures on Supply security and Diversification

Project	Country	Supply Security (N-1)	Supply diversification	Project Cost
A Balticconnector	Estonia	?	✗	€ 100 M
	Latvia	✓		
	Lithuania	✗		
	Finland	✓	✗	
B GIPL	Estonia	✗	✓	€ 550 M
	Latvia	✓	✓	
	Lithuania	✗	✓	
	Finland	✓		
C Baltic Interconnections	Estonia	✗	✗	*€ 95 M*
	Latvia	✓	✗	
	Lithuania	✗	✗	
	Finland	✓		

✓ Granted ✗ Not Granted Impacted but not 100% certain to be granted

Source: Booz & Company Analysis

A – Balticconnector: Connecting Finland to Estonia with flows in both directions with a capacity of 7 Mcm/d, Balticconnector impacts the Estonia N-1 rule, because it creates a new entry border to Estonia. However, there are no further gas sources available as Finland is connected only to Russia. Furthermore, the Balticconnector would support Estonia N-1 rule only if there would be spare transmission capacity in Finland during the Estonia daily peak. However, it is reasonable to assume that if harsh winter conditions arise in Estonia, they would occur also inFinland, therefore not allowing gas to flow north-south direction.

B – GIPL: Connecting Poland to Lithuania on South-North direction with a capacity of 14 Mcm/d, and considering a peak demand in Lithuania of 24 Mcm/d, GIPL would improve the national security of supply: N-1 from 20% to 80%. GIPL would enable the regional diversification, except for Finland.

C - Baltic Interconnections: Strengthen connections on the Lithuania-Latvia-Estonia track, increasing the first entry capacity to 6 Mcm/d (N-S-N flow) and the Latvia-Estonia border capacity to 10 Mcm/d**.** The projects would not bring further benefit on the N-1 rule of the Baltic Region nor supply diversification. Estonia would not be granted respect of N-1 as the capacity enhancement involves the current biggest entry border. The "no FID" Narva connection project would technically give S-o-S to Estonia, although no further gas sources would be granted.

Overall, the three projects taken separately would not efficiently address either security of supply or diversification needs.

5.4. COMBINED ANALYSIS OF PROPOSED NEW INFRASTRUCTURES

5.4.1.Methodology

For assessing the effects of the three different projects taken in combination, the same methodology used in the analysis above was applied. This analysis tested again the compliance with the N-1 rule using 2030 peak demand data and the possible diversification of supply. Four different combinations were considered: one taking the projects all together and three pairing two projects at a time.

As in the previous paragraph, only the results for the base case are reported. The results for the high case are similar.

5.4.2.Analysis

The projects were grouped in order to obtain four combinations:

(D) Balticconnector + GIPL;

(E) Balticconnector + Intra-Baltic connections;

(F) Intra-Baltic connections + GIPL;

(G) Intra-Baltic connections + GIPL + Balticconnector.

Assumptions were the same as those of the former analysis: gas demand was considered at its peak (Estonia 7 Mcm/d, Latvia 15 Mcm/d, Lithuania 24 Mcm/d and Finland 23 Mcm/d) and reverse flows on Lithuania-Latvia and Estonia-Finland were assumed at an equal capacity on both directions.

With this information, respect of the N-1 rule and effects on supply diversification were tested.

5.4.3. Results

This time the effects of the grouped infrastructures on the Baltic gas market were wider, although not all combinations appeared to significantly address the relevant issues.

The results of the analysis are summarized in figure below.

Figure 35 - Effects of Combinations of Infrastructures on Supply Security and Diversification

Project	Country	Supply Security (n-1)	Supply diversification	Project Cost
D Balticconnector + GIPL	Estonia	?	✓	€ 650 M
	Latvia	✓	✓	
	Lithuania	✗	✓	
	Finland	✓	✓	
E Balticconnector + Baltic Interconnections	Estonia	?	✗	€ 195 M
	Latvia	✓	✗	
	Lithuania	✗	✗	
	Finland	✓	✗	
F Baltic Interconnections + GIPL	Estonia	✗	✓	€ 645 M
	Latvia	✓	✓	
	Lithuania	✗	✓	
	Finland	✓	✗	
G Baltic Interconnections + Balticconnector + GIPL	Estonia	?	✓	€ 745 M
	Latvia	✓	✓	
	Lithuania	✗	✓	
	Finland	✓	✓	

✓ Granted ✗ Not Granted ? Impacted but not 100% certain to be granted

Source: Booz & Company Analysis

- **Projects (D), (F) and (G)**: Whenever GIPL is implemented, diversification of supply is granted due to possibility to connect Baltic area to European Gas network;
- **Project (E)**: Intra Baltic Connections and Balticconnector would only support Russian supply.

Overall, a joint implementation of the three projects may favour supply diversification of the region, nevertheless without granting supply security to all the countries.

- **Project (G):** Current projects would not support Lithuania to achieve security of supply. However the all "three projects" implemented would improve Lithuania S-o-S from 20% to 82%. Balticconnector + GIPL + Intra-Baltic connection empowerment will be the most comprehensive solution to grant supply diversification to the Baltic area and improve the S-o-S in the region:
  - Lithuania would reach 82% vs. 78% in case of no Baltic Interconnections;
  - Finland would be linked to Baltic region and European gas system as well;
  - Estonia would be compliant to "N-1 rule" only if during the daily peak there would be spare transmission capacity in Finland during the Estonia daily peak, which is very unlikely considering that harsh winter conditions are likely to occur at the same time in the whole area.

In the next analysis of the impact of the proposed infrastructures on Baltic gas market only project (G) was considered, as it combines the three infrastructures.

5.5. IMPACT OF THE THREE PROJECTS ON BALTIC GAS MARKET

5.5.1.Methodology

The goal of this step was to understand the impact of project (G) on the Baltic infrastructure network from 2010 to 2030. Both base-case and high-case scenarios were considered in two different simulations with the Global Gas Model.

5.5.2.Analysis

After assessing that the most effective combination of projects was that when all the proposed infrastructures were taken together, the team proceeded with the analysis therefore considereing only project (G).

Two different demand scenarios were tested: the base demand scenario and the high demand scenario, described early in this chapter. The following tables show again the two different demand scenarios data for each country.

Table 4 - Gas Demand – Base Case

Year / Country	2010 (Bcm/y)	2015 (Bcm/y)	2020 (Bcm/y)	2025 (Bcm/y)	2030 (Bcm/y)
Finland	4.8	4.8	4.8	5.0	5.0
Estonia	0.7	0.9	0.9	0.9	0.9
Latvia	1.7	1.9	2.0	2.1	2.1
Lithuania	3.1	3.3	3.2	2.9	2.9
Total	10.3	10.9	10.7	10.9	10.9

Table 5 - Gas Demand – High Case

Year / Country	2010 (Bcm/y)	2015 (Bcm/y)	2020 (Bcm/y)	2025 (Bcm/y)	2030 (Bcm/y)
Finland	4.8	6.3	6.7	7.0	7.2
Estonia	0.7	1.2	2.7	2.9	3.2
Latvia	1.7	2.0	2.1	2.2	2.2
Lithuania	3.1	3.4	3.4	3.1	3.3
Total	10.3	12.9	14.9	15.2	15.9

The Global Gas Model was used in order to better understand the impact of this new pool of infrastructures on the future gas demand supply balance; the three new projects were added to current infrastructures: the Balticconnector, the GIPL and the Intra-Baltic connections. The technical capacity used was at border points, with a load factor of 8,000 hours per year. This time, however, technical capacity was increased by Intra-Baltic connections and new routes were available, as synthesised on the table below.

Table 6 - Technical Capacity of Pipelines at Border Points – New infrastructures implemented – Bcm/y

Russia-Finland	Russia-Estonia	Russia-Latvia	Estonia–Latvia	Lithuania-Latvia	Estonia-Finland	Poland-Lithuania
6.9	1.3	5.3	2.9	1.8	1.9	3.6

5.5.3.Results

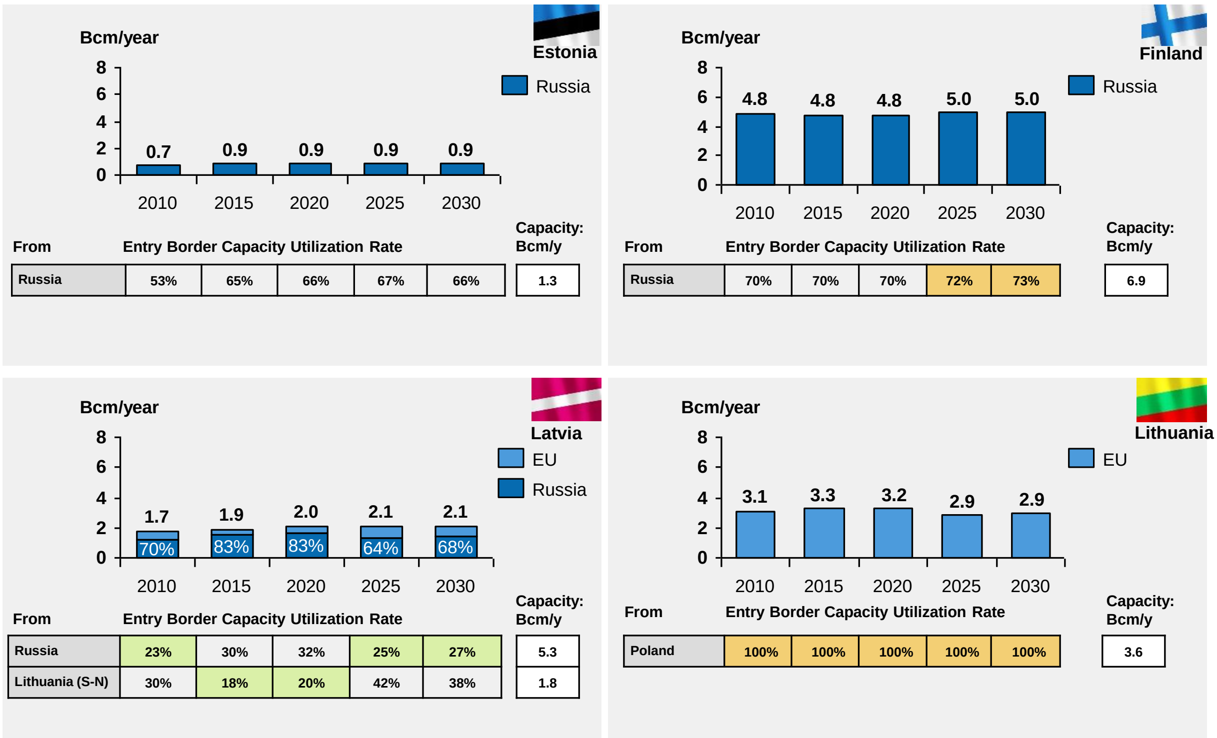
The results obtained in the two scenarios were significantly different from those obtained from the first analysis of infrastructures utilization rate (see section 5.2). This time, Russia was not the sole supplier, as connections to Europe through GIPL were granted.

In the base case scenario, gas imported from EU was the alternative source of gas, with a share of 33% out of a total supply of 11 Bcm/y in 2030 (Figure 36). Demand from Baltic States accounted for almost 6 Bcm/y.

Concerning the infrastructure utilization rate, the base case scenario shows that:

- Latvia experiences a light diversification in gas supply as some demand is satisfied by Lithuania (therefore Europe);
- Lithuania would theoretically receive all gas from GIPL, as the model runs based on gas prices, which are influenced by transportation costs. However, depending on existing contracts at the time, flows might be different.

Figure 36 - Breakdown of Supply and Infrastructure Utilization - Base Case

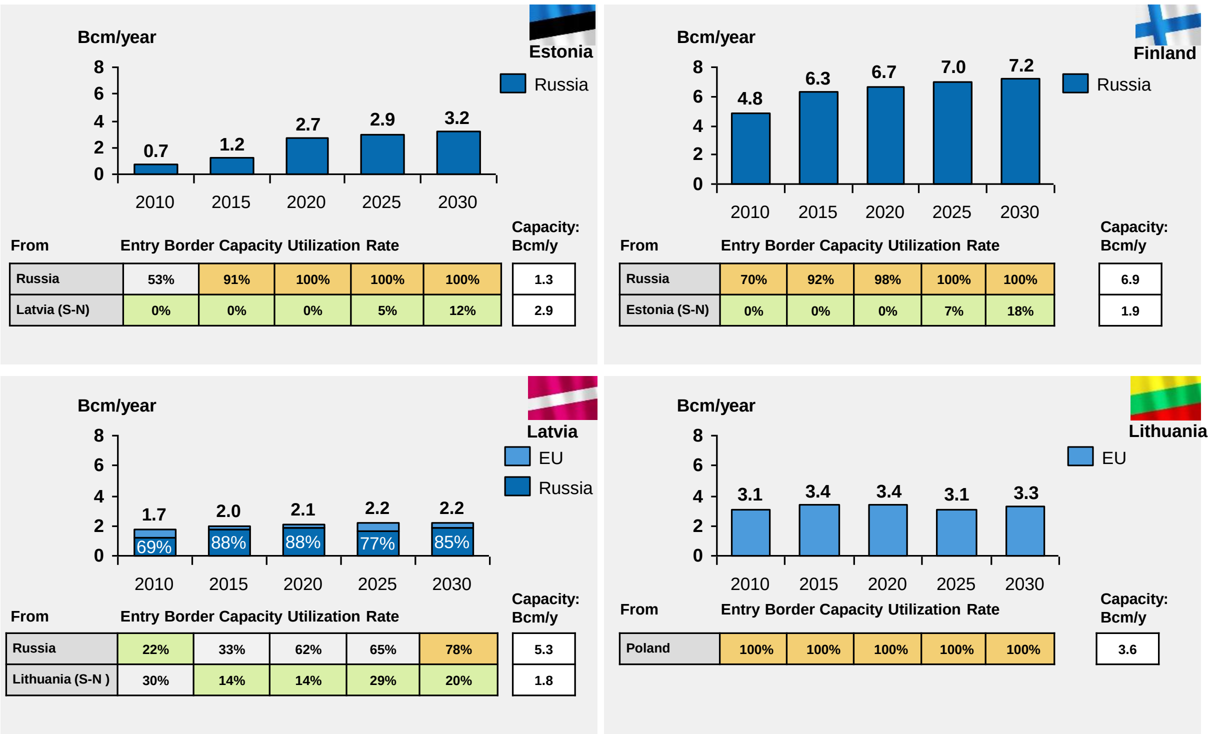


Source: Booz & Company Gas Model; Booz & Company Analysis

Moving to the high-demand scenario (Figure 37):

- Finland would be supplied only by Russian gas. However, some of the supply would come from Estonia as the pipeline capacity from Russia would be totally utilized;
- Estonia would be supplied only by Russian gas coming mainly from Russia, but also from Latvia;
- Latvia would benefit of some supply diversification, receiving gas from EU through GIPL. However, major share of gas will come from Russian pipeline;
- Lithuania would fulfil its demand only through EU gas, utilizing GIPL capacity;
- Overall, EU would supply 23% of the total 16 Bcm demanded in Baltic region.

Figure 37 - Demand – Supply Balance and Infrastructure Utilization – High Case



Estonia – Entry Border Capacity Utilization Rate

From	2010	2015	2020	2025	2030	Capacity: Bcm/y
Russia	53%	91%	100%	100%	100%	1.3
Latvia (S-N)	0%	0%	0%	5%	12%	2.9

Finland – Entry Border Capacity Utilization Rate

From	2010	2015	2020	2025	2030	Capacity: Bcm/y
Russia	70%	92%	98%	100%	100%	6.9
Estonia (S-N)	0%	0%	0%	7%	18%	1.9

Latvia – Entry Border Capacity Utilization Rate

From	2010	2015	2020	2025	2030	Capacity: Bcm/y
Russia	22%	33%	62%	65%	78%	5.3
Lithuania (S-N)	30%	14%	14%	29%	20%	1.8

Lithuania – Entry Border Capacity Utilization Rate

From	2010	2015	2020	2025	2030	Capacity: Bcm/y
Poland	100%	100%	100%	100%	100%	3.6

Source: Booz & Company Analysis

5.6. OVERALL RESULTS OF THE ASSESSMENT OF PROPOSED INFRASTRUCTURES

Implementation of the three proposed projects may improve supply diversification, but would not ensure full security of supply (N-1 rule).

Security of supply:

- **Existing situation**: Only Latvia and Finland are compliant with N-1 Rule:
  - Latvia would exploit UGS to ensure Security of Supply;
  - Finland would benefit from National regulation requiring double fuel for power generation plant. Therefore the latter would not be included in N-1 calculations.
- **Standalone project**: No projects would solve N-1 rule for the region:
  - Estonia border enhancement would involve the already highest border point capacity. No further benefit for N-1 rule indeed;
  - Lithuania would benefit from both GIPL and Baltic interconnection but it would not be enough (N-1 from 20% to 78%).
- **All three projects combined**: The combined GIPL and Baltic interconnections would improve S-o-S in Lithuania (N-1 from 20% to 82%). In Estonia S-o-S is not improved by Balticconnector (unless spare demand would be left from Finland during peak days) and Baltic interconnections either. In order to grant S-o-S it would be required to implement either Narva connection enhancement or an alternative pipe connecting Estonia to Latvia. The Narva interconnection would become a project of strategic importance for Estonia to fulfill "N-1 rule" even if it would reinforce the power of Russia as gas supplier.

Regional Diversification:

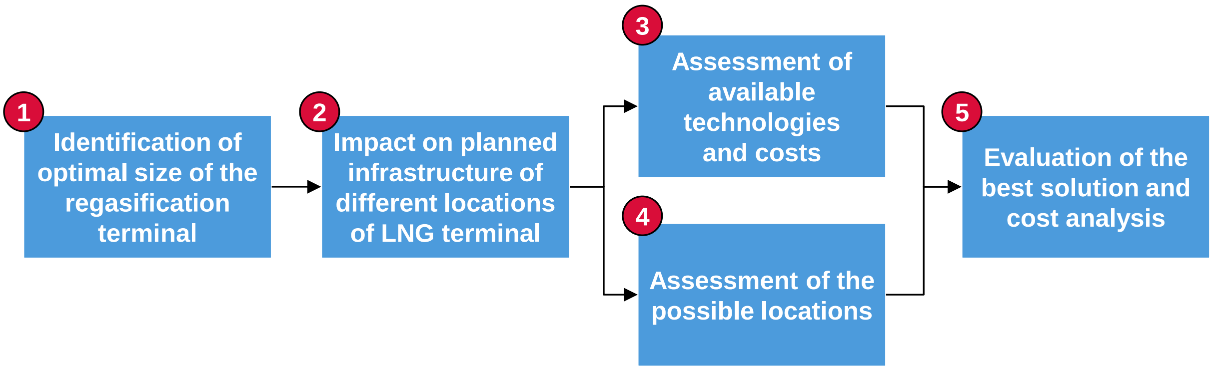
- **Existing situation** – Russia is the only gas supplier.
- **Project standalone** – GIPL would create the conditions for regional diversification except for Finland. Balticconnector would not grant further gas sourcing in Finland. Baltic Interconnections would not bring any further diversification to the Region.
- **All three projects combined** – In the base case 33% of the overall demand could be covered by Europe, while in the high case gas from Europe could just cover 23% of demand. Russia would keep a dominant position in the Baltic supply (up to 80% vs. 20% of European gas).

6. ASSESSMENT OF LNG OPTIONS

6.1. Approach

In order to evaluate the best LNG terminal solution in terms of size, technology, location and costs, a five steps approach was followed (Figure 38).

Figure 38 - Approach used for Assessing LNG Options



Step 1 – Identification of the optimal size of the regasification terminal: the goal was to understand what is the size of the LNG that best fits the needs of the entire region. Hence, the analysis was focused on finding the LNG size that :

- Fills the seasonal demand needs (*which is the right LNG size that can cover the seasonal modulation?)*
- Offers enough flexibility (*considering a L/T contracts from Russia and Europe – GIPL- which is the right LNG size that minimizes the utilization of L/T contract flexibility?)*
- Is right-sized (*what is the size of the LNG that, reaching the first two goals, is not under-utilized?)*

The analysis was run combining the base and high case scenarios with two size of LNG terminal: 4 Bcm/y and 8 Bcm/y. Only the reasonable combinations of demand / LNG size were kept for the following steps of the analysis

Step 2 – Impact on planned infrastructures of different locations of LNG terminal: based on the output of step 1, the goal was to analyze the impact of LNG plants located in different countries in terms of gas supply security and diversification. Namely, the objective of this step was to understand which is the LNG location that minimizes infrastructure developments and balances the strategic weight of the three countries in the Baltic region.

Step 3 – Assessment of available technologies and costs:the goal was to analyze different technologies options in order to identify the technology that minimizes the investment and can fullfill the size requirements addressed in step 1. Such analysis was a preliminary assessment of the technologies that must be deepen in the analysis of the ports. Indeed, a technology can be more suitable to a location than another and the investment is related not only to a given technolgoy but also to the easiness of implementation of that technology in the chosen port.

Step 4 – Assessment of possible locations: the object of this step was to identify the best location through the analysis of ports in the Baltic area.

Step 5 – Evaluation of the best solution and cost analysis:the objective of this step was to summarize the results of the previous 4 steps and assess quantitatively and qualitatively the strategic drivers and required investments in order to evaluate the most suitable country for hosting the LNG terminal.

6.2. IDENTIFICATION OF THE OPTIMAL SIZE OF THE REGASIFICATION TERMINAL

The first step aimed to identify the optimal size of the LNG terminal, based on the utilized capacity and the effects it would have on seasonal modulation and utilization of assumed long-term contracts coming from other sources (Russia and Europe). The analysis was run for year 2030 (gas year, March-April).

6.2.1.Methodology

Four scenarios were defined, combining the base case and high case demands with two sizes of the LNG terminal: 4 Bcm and 8 Bcm. Each scenario was analysed through a process that can be summarized as follows:

- **Aggregation of the three countries:** Estonia, Latvia, Lithuania and Finland were virtually aggregated in order to form a sole country, with one gas demand. The infrastructure network was therefore considered as it belonged to one country, eliminating capacity constraints related to cross border capacities;
- **Identification of gas contracts that will serve Baltic area:** this process implied the identification of the predicted gas suppliers of the Baltic region in 2030, and assumptions on their utilization;
- **Definition of seasonality of demand:** each monthly demand was obtained as follows:
  - Analysis of the historical (2008-2010) consumption seasonality of each country;
  - Application of the seasonality pattern of each country to the forecasted 2030 gas consumption in base case and high case;
  - Aggregation of monthly gas consumptions of each country in order to simulate the profile of the region;

- **Storage definition:** the storage utilization was structured in order to meet the demand in each month and be empty at the end of gas year;
- **Supply sources prioritization:** the gas suppliers (namely Russia, Europe, LNG and stock) were prioritized in order to simulate real gas flows.
- The output of the analysis is, for each scenario:
  - The size of the LNG to modulate the seasonal needs;
  - The utilization of contract flexibility in each scenario;
  - The utilization of the LNG in order to evaluate the size.

6.2.2.Hypotheses

The study of the four scenarios was based on the following assumptions:

- **Timing:** the analysis was run at year 2030, specifically the gas year 2030 (March to April).
- **Infrastructures:** the integration of the Baltic region was assumed (i.e. Estonia, Latvia and Lithuania were assumed to be one sole country, with an aggregate demand and its seasonality). No technical capacity limitations within the area were considered. Moreover, it was assumed that by 2030 all the current proposed new entry interconnections; basically the GIPL would be implemented. This implied that by 2030 contracts with European gas market would be into force. Storage infrastructure was assumed to remain as it is today, with a technical capacity of 3.2 Bcm.
- **Contracts:** the European gas was supposed to be competitive with the Russian one, therefore allowing gas flows to reach the Baltic area through the GIPL. The European contract was set to a level of 3.6 Bcm/y: the value derives from the average utilization of the GIPL technical capacity (4.5 Bcm with a load factor of 80%). The Russian contract is supposed to supply 8 Bcm/y; this value was derived from the assumption that Russia will have a decreasing role in supply of Baltics, as current contracts will expire starting from 2015. Both European and Russian contracts are long term take or pay contracts with a flexibility of 20%. LNG contract was assumed similar to a full-supply contract with maximum value of 80% of the technical capacity of the LNG. Such assumption is required in order to prioritize the flows and simulate the role of the LNG as a source for seasonal modulation
- **Seasonality:** the seasonality of the gas demand of Baltic area was obtained by computing the weighted average of the seasonal demand of each state, where the weights were their own gas demand in 2030. The results of this assumption can be seen in the table below (Table 7).

Table 7 - Seasonality of Baltic Gas demand

April	May	June	July	August	September
6%	5%	3%	3%	4%	5%

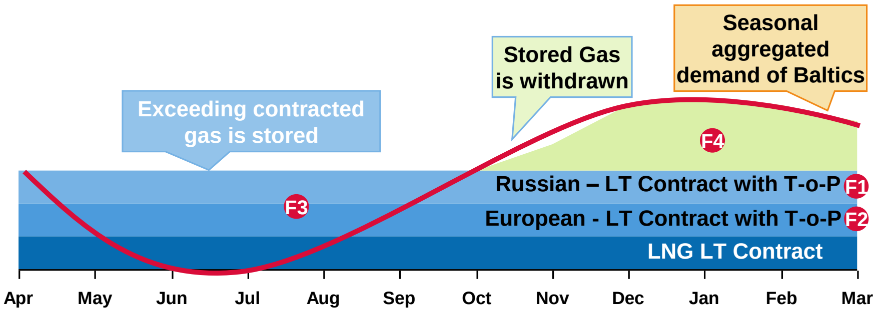
October	November	December	January	February	March
9%	11%	15%	13%	14%	12%

Source: Booz & Company Analysis

- **Supply sources priority**: the European and then Russian contracts were taken at 80% of their volume, according to a possible T-o-P (Figure 39). In case of spare demand, other sources were used in the following order: LNG (at a load factor of 80%), European and Russian contracts using their flexibility (up to 120% of the contracted volume). If the demand was still not fulfilled, storage reserves were used. The storage gas has been prioritized as first. In summary, the priorities have been assigned as follows:
  - Summer:
    1. European gas at T-o-P;
    2. Russian gas at T-o-P;
    3. LNG (first consumption after storage);
    4. European gas at maximum flexibility;
    5. Russian gas at maximum flexibility.
  - Winter:
    1. European gas at T-o-P;
    2. Russian gas at T-o-P;
    3. Storage (if at the end of the season there would not be an empty storage);
    4. LNG (consumption);
    5. Storage;
    6. European gas at maximum flexibility;
    7. Russian gas at maximum flexibility;

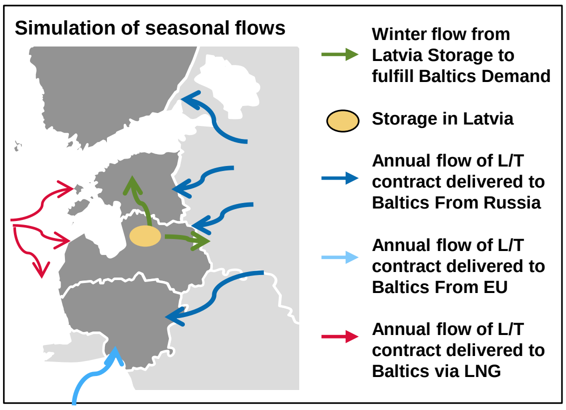
    The theoretical simulation of the contract allocation is shown in figure below.

Figure 39 - Theoretical prioritization of the flows



List of Available Flexibilities

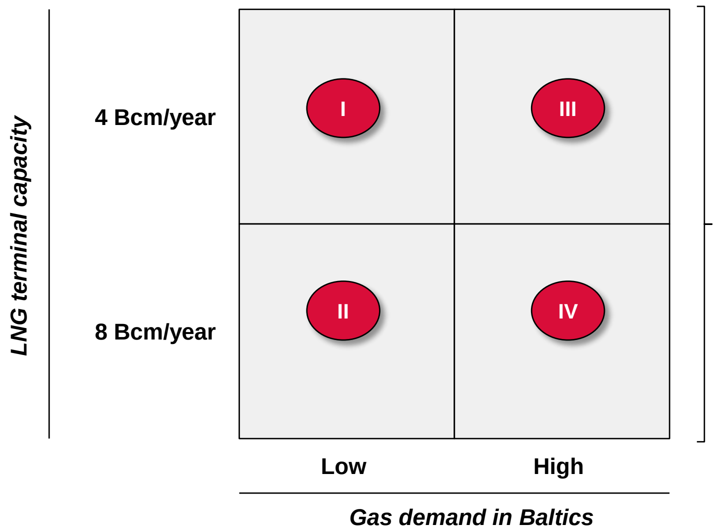
F1	Russian LT contract Flex (20%)
F2	European LT contract Flex (20%)
F3	Storage Injection in Latvia
F4	Storage Withdrawal in Latvia



Source: Booz & Company Gas Model, Booz & Company Analysis

The analysis and the results of the four simulated scenarios (Figure 40) are shown in next paragraphs.

Figure 40 – Drafted Scenarios



- A 4 Bcm and 8 Bcm LNG terminal has been considered, as it represents a sound discontinuity in terms of technology, investment and capacity
- Different size could be reached from the standard size LNG Terminal scalability

- Gas Demand consumption at 2030 based on scenario considered in “Gas demand evolution in the Baltic countries” section

Source: Booz & Company Analysis

6.2.3.Analysis& Results

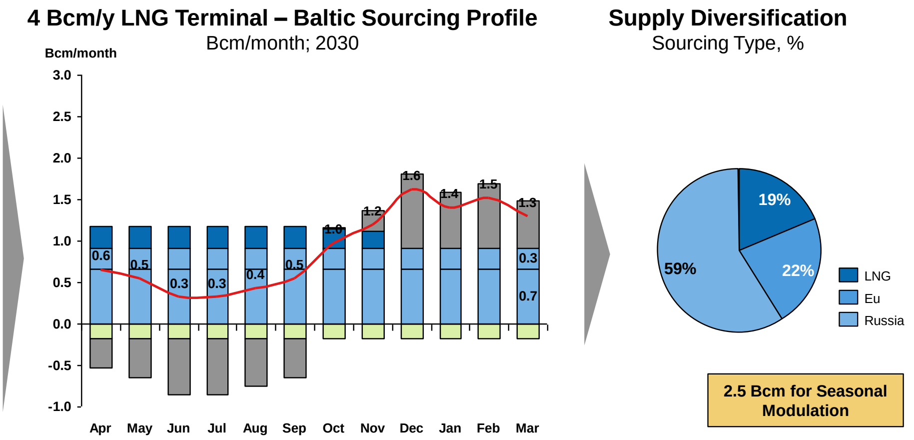
Scenario 1 – Base case demand & 4 Bcm LNG terminal

The findings of this scenario are shown in the figure below (Figure 41):

Figure 41 - Analysis results in the case – Low Demand 4 Bcm/y LNG

Utilization of Simulated Contracts (%)[1)]

	EU	LNG	RUSSIA
Apr	80	80	80
May	80	80	80
Jun	80	80	80
Jul	80	80	80
Aug	80	80	80
Sep	80	80	80
Oct	80	70	80
Nov	80	60	80
Dec	80	0	80
Jan	80	0	80
Feb	80	0	80
Mar	80	0	80
MEAN	80	51	80



- 51% of LNG capacity would not be exploited
- EU and Russian gas would be kept at lowest contractual volumes

- The LNG would be totally exploited over the spring and summer time to fill up the storage (100% of storage capacity utilized).
- Storage withdrawals in winter to allow effective stock utilization would limit LNG supply in that season
- Climate issues would have a minimal impact on LNG supply

- Russia would keep its dominant position at about 60% of total supply
- Low gas demand scenario impact LNG supply share

Demand | Stock Withdrawn (+) - Stock Injection (-) | Flexibility | LNG Terminal | EU pipe gas | Russian Gas

Source: Booz & Company Analysis

On the left and middle section of the figure above, utilization of each contract is shown. European and Russian contracts are utilized for 80% of the total contracted volume. LNG supplies the region for 8 months. From December until March, the terminal is not utilized, as gas reserves are taken from the stock to meet the spare demand left from European and Russian supply.

With this kind of allocation, the total stock required to properly fulfil winter demand is 3.2 Bcm (100% of storage capacity). Climate issues would be a minimal impact on LNG supply. Overall, Russian and European gas supply would be kept at lowest contracted capacities, while the LNG terminal would be used at 51% of its technical capacity.

On the right of figure above, supply diversification effects are shown. Russia would keep its dominant position at about 60% of total supply.

Therefore, such analysis suggests that

- **A 2.5 Bcm/y LNG is the required size to supply seasonal needs**, according to this calculation:
  - 51% utilization of a 4 Bcm/y LNG Terminal = 2 Bcm/y;
  - 2 Bcm/y is the commercial capacity the Baltic region needs in order to fulfil the seasonal modulation in this scenario;
  - Usually, commercial capacity is between 80% to 90% of technical capacity, hence a 2.5 Bcm/y LNG is the size to fulfil seasonal modulation.

- **Other contracts are used at their minimum intake leaving enough flexibility in case of hard winter or particular high peak demand;**
- **With a 4 Bcm / y LNG, it would be possible to reduce the role of Russian gas down to 40%,** according to this calculations:
  - With a 4 Bcm/y LNG, it would be possible to fully utilize the LNG rather than using it to for seasonal modulation;
  - That means 2 more Bcm coming from LNG to be reduced from Russian imports.
  - Hence Russian gas would decrease from 6 Bcm/y to 4 Bcm/y, reducing the share from 59% to 40%.
- **LNG size is right sized to cover the demand needs.**

Scenario 2 –Base case demand & 8Bcm LNG terminal

The findings of this scenario are shown in the figure below (Figure 42):

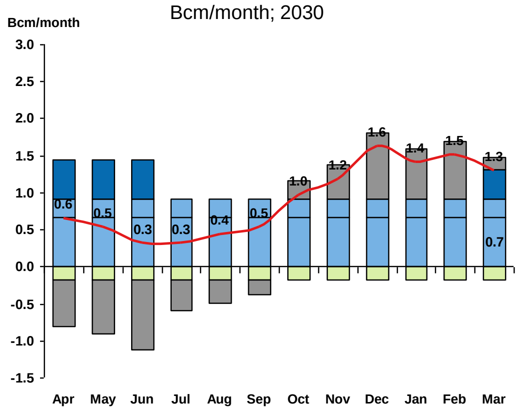
Figure 42 - Analysis results in the case – Low Demand 8 Bcm/y LNG

Utilization of Simulated Contracts (%)1)

	EU	LNG	RUSSIA
Apr	80	80	80
May	80	80	80
Jun	80	80	80
Jul	80	0	80
Aug	80	0	80
Sep	80	0	80
Oct	80	0	80
Nov	80	0	80
Dec	80	0	80
Jan	80	0	80
Feb	80	0	80
Mar	80	60	80
MEAN	80	25	80

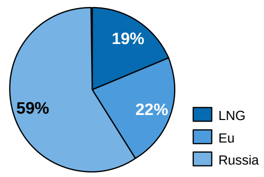
- Only 25% of LNG capacity would be exploited
- EU and Russian gas would be kept at lowest contractual volumes

8 Bcm/y LNG Terminal – Baltic Sourcing Profile
Bcm/month; 2030



- The LNG seems definitely oversized because of the low utilization rate (25%) given Storage capacity (100% utilized)
- the storage would be filled-up very quickly while it would take long time to get empty leading to higher storage costs
- No impact of climate conditions on LNG supply are expected

Supply Diversification
Sourcing Type, %



2.5 Bcm for Seasonal Modulation

- The supply diversification would still be far away from Western Europe benchmarks
- LNG supply share would be limited by the Low demand

Demand | Stock Withdrawn (+) - Stock Injection (-) | Flexibility | LNG Terminal | EU pipe gas | Russian Gas

Source: Booz & Company Gas Model; Booz & Company Analysis

On the left and middle section of the figure above, utilization of each contract is shown. European and Russian contracts are utilized for 80% of the total contracted volume. LNG supplies the region for only 4 months (from March until June) filling the storage facility. For the remaining months, the terminal is not utilized, as gas reserves are taken from the stock to meet the demand not satisfied from European and Russian supply. Overall, Russian and European gas supply would be kept at lowest contracted capacities, while the LNG terminal would be used at 25% of its technical capacity. The LNG terminal seems oversized. The required storage (equal to 3.2 Bcm) would be filled up very quickly while it would take quite a long time to get empty again, leading to high storage costs. As LNG would not be operating during winter months, no impact of weather conditions is expected.

On the right side of the figure, supply diversification effects are shown. Russia would keep its dominant position at 59% of total supply.

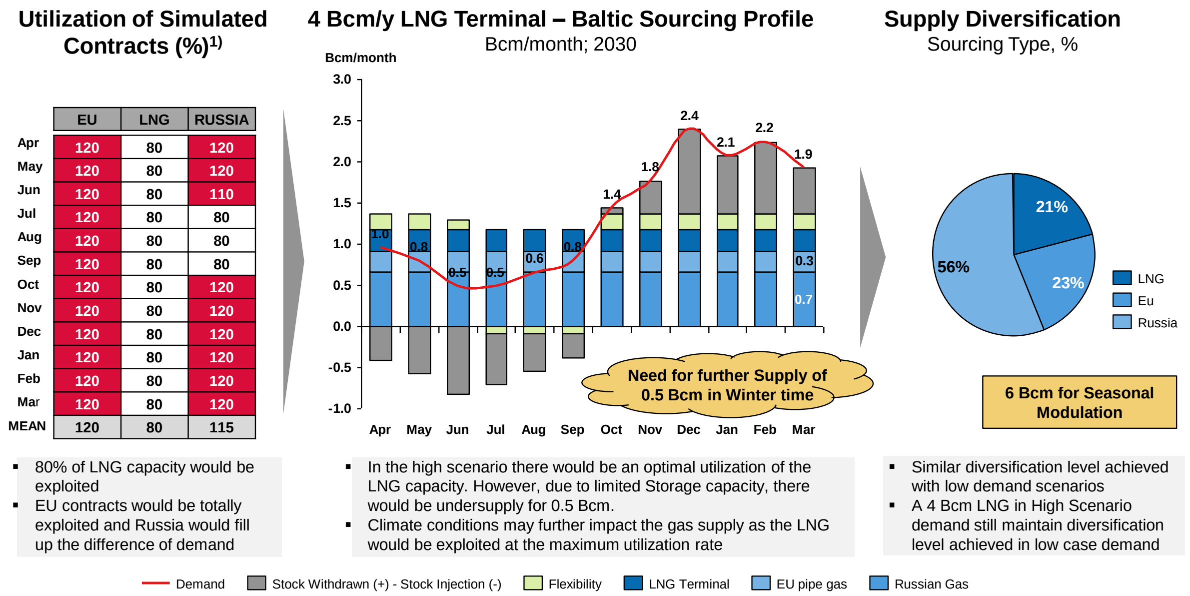
Therefore, such analysis suggests that:

- **A 2.5 Bcm/y LNG is the required size to supply seasonal needs**, according to this calculation:
  - 25% utilization of a 8 Bcm/y LNG Terminal = 2 Bcm/y;
  - 2 Bcm/y is the commercial capacity the Baltic region needs order to fulfil the seasonal modulation in this scenario;
  - Usually, commercial capacity is between 80% to 90% of technical capacity, hence a 2,5 Bcm/y LNG is the size to fulfil seasonal modulation.
- **Other contracts are used at their minimum intake leaving enough flexibility in case of hard winter or particular high peak demand**;
- **Even if with a 8 Bcm/y LNG would be possible to reduce the role of Russian gas even further, such result would be misleading** because it would just change the gas dependence from a source to another;
- **LNG size is over-sized to cover the demand needs as it would be exploited only for four months.**

Scenario 3 –Highcase demand & 4Bcm LNG terminal

The findings of this scenario are shown in the figure below (Figure 43):

Figure 43 - Analysis results in the case – High Demand 4 Bcm/y LNG



Source:Booz & Company Gas Model; Booz & Company Analysis

On the left and middle section of the figure above, utilization of each contract is shown. European contract would be totally exploited while Russia would be fully exploited for 9 months. LNG supplies the region throughout the whole year at 80% of its technical capacity, filling the storage in the summer season and meeting the demand left by European and Russian contracts during winter season. The high scenario leads to a full utilization of storage, LNG and pipe gas. There would be a further demand of 0.5 Bcm in winter time.

On the right side of the figure, supply diversification effects are shown. Russia would keep its dominant position at 56% of total supply, similar to the diversification level achieved in a base case demand scenario.

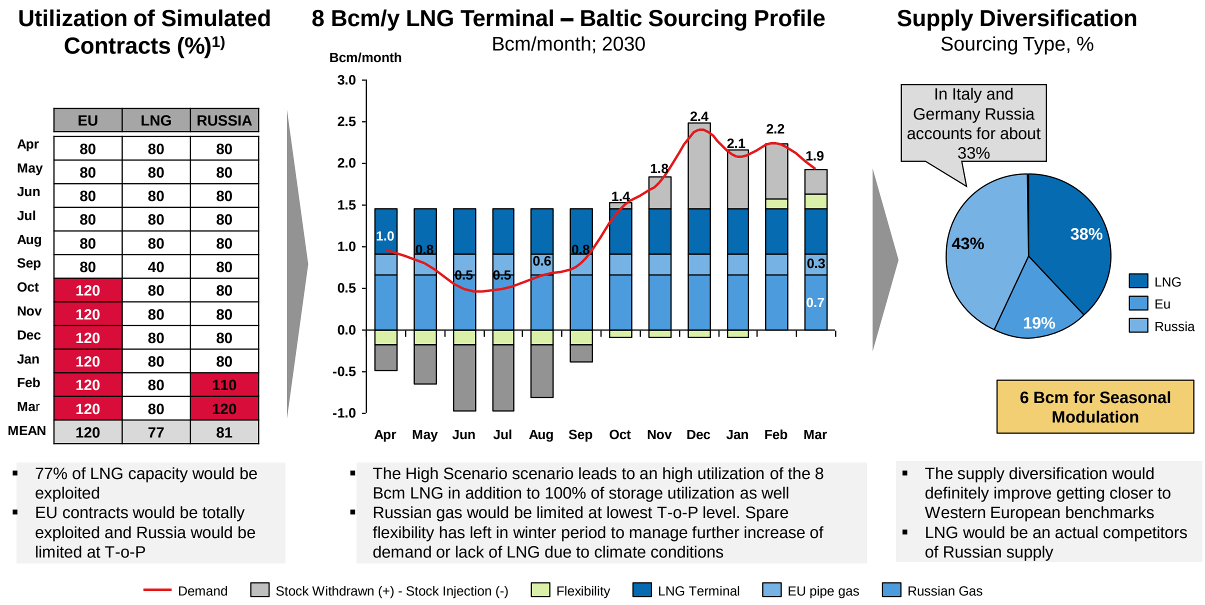
A 4 Bcm LNG would be undersized in such scenario, barely filling the seasonal modulation requirements. Climate conditions may further impact the gas supply as the LNG would be exploited at the maximum utilization rate.

Hence, in such scenario, it would be recommended to increase capacity from Europe or implement an LNG of a greater size. Both strategies could benefit the gas diversification of the region.

Scenario 4 –High case demand & 8Bcm LNG terminal

The findings of this scenario are shown in the figure below (Figure 44):

Figure 44 - Analysis results in the case – High Demand 8 Bcm/y LNG



Source: Booz & Company Analysis

On the left and middle section of the figure above, utilization of each contract is shown. European contract would be exploited throughout the year, while Russian contract would almost be limited at take or pay. Spare flexibility was left to manage further increases of demand or lack of LNG due to possible negative effects of adverse weather conditions. LNG supplies the region throughout the whole year at almost 80% of its technical capacity, filling the storage in the summer season and meeting the demand left by European and Russian contracts during winter season. The high scenario leads to a high utilization of the 8 Bcm LNG capacity in addition to 100% storage utilization as well.

On the right side of figure, supply diversification effects are shown. This time, LNG would be a true competitor of Russian gas, as both these two sources would reach about 40% each of total supply. Therefore, supply diversification would definitely improve, getting closer to Western European benchmarks (in Italy and Germany, Russia accounts for about 33% of total supply).

In such scenario the 8 Bcm/y LNG would be the right size to:

- Cover seasonal modulation requirements;
- Lead to a gas diversification similar to Western Europe countries.

Nevertheless such scenario is designed on an aggressive gas demand forecast, that should be taken in consideration only if regional consumption starts reaching yearly value of about 15-16 Bcm/y.

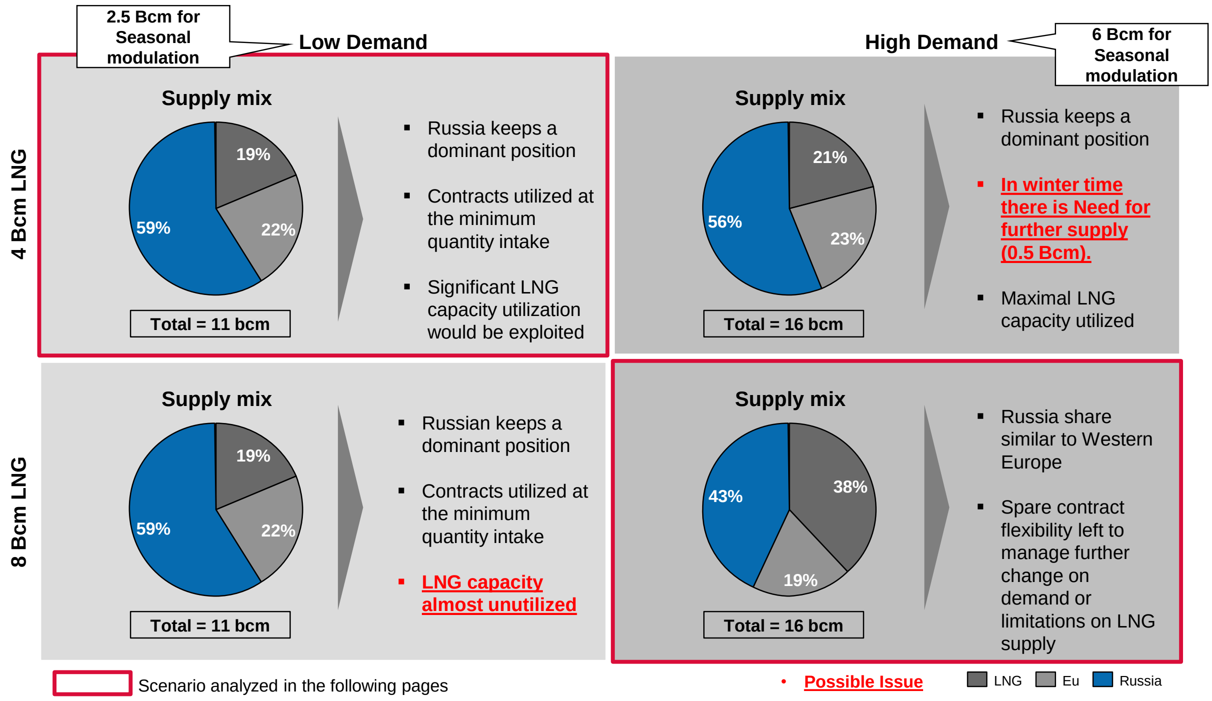
In that case alternative strategies of boosting LNG capacity to 8 Bcm/y would be (always in order to reduce the Russian gas share to the one it has in Western Europe):

- Boost Storage capacity up to 6 Bcm and LNG capacity up to 6 Bcm/y;
- Boost storage capacity up to 6 Bcm and GIP capacity to 6 Bcm/y (and LNG of 4 Bcm/y);
- Boost GIPL capacity up to 8 Bcm/y (and LNG of 4 Bcm/y).

6.2.4. General considerations

The overall results of this step are shown in figure below (Figure 45).

Figure 45 - Overall Results of the analysis



Source: Booz & Company Analysis

Scenario 1 – Base case demand & 4 Bcm LNG:

- Russia could keep its dominant position, although fully exploiting LNG capacity it could be reduced up to 40%;
- Supply contracts would be utilized at the minimum quantity intake leaving enough flexibility in case of harsh winters;
- LNG seems right sized;
- An LNG of 2.5 Bcm/y is the minimum size to cover seasonal modulation of the whole region;
- *Overall such scenario is a viable strategy.*

Scenario 2 – Base case demand & 8Bcm LNG:

- LNG capacity would be oversized without benefiting the region more than a 4 Bcm/y LNG;
- *Overall such scenario is NOT a recommended strategy.*

Scenario 3 – High case demand & 4 Bcm LNG:

- Russia would maintain its dominant position as a supplier;
- Supply contracts would be utilized at the maximum quantity intake without tleaving enough flexibility in case of harsh winters;
- LNG capacity would be fully exploited;
- An LNG of 6 Bcm/y is the minimum size to cover seasonal modulation of the whole region;
- *Overall such scenario is NOT a recommended strategy.*

Scenario 4 – High case demand & 8Bcm LNG:

- Russian share of total supply would be (about) aligned to the ones it has in Western European countries;
- LNG capacity would be fully exploited ;
- Only European contracts would be used for 120% of the contracted volume, leaving spare contract flexibility in case of harsh winters. Nevertheless Russian gas would be the only available gas
- An LNG of 6 Bcm/y is the minimum size to cover seasonal modulation of the whole region
- *Overall such scenario is a viable strategy; however, in case of higher demand other alternative strategies could be put in place in order to achieve similar (or better) results.*

To sum it up:

- The minimum requirement for an LNG for seasonal modulation is 2.5 Bcm/y in the base case and 6 Bcm/y in the high case;
- A 4 Bcm/y LNG seems the recommended size in case of supply diversification purpose (to be further deepened in the following analysis);
- A 8 Bcm/y LNG could be a viable option in case of high demand (to be further deepened in the following analysis);
- Other scenarios can be discharged;
- The actual size of the Storage (3.2 Bcm) seems right sized only in the base demand scenario.

In the following step, the Base demand scenario was combined with a 4 Bcm/y LNG while the High demand scenario was combined with an 8 Bcm/y LNG.

6.3. IMPACT ON PLANNED INFRASTRUCTURES OF DIFFERENT LOCATIONS OF LNG TERMINAL

6.3.1.Methodology

Second step of the analysis was to assess the impact that the LNG would have on countries' supply security and diversification, depending on its location.

The analysis was run for year 2030 and for two scenarios: the base case demand with a 4 Bcm/y terminal and the high case demand with a LNG terminal of 8 Bcm/y. It was assumed that the current three proposed infrastructures (Balticconnector, GIPL and Intra-Baltic interconnections) would be already implemented at the time in which the LNG terminal is installed. Scope of the work was to understand if the LNG would diversify the supply, provide supply diversification or both.

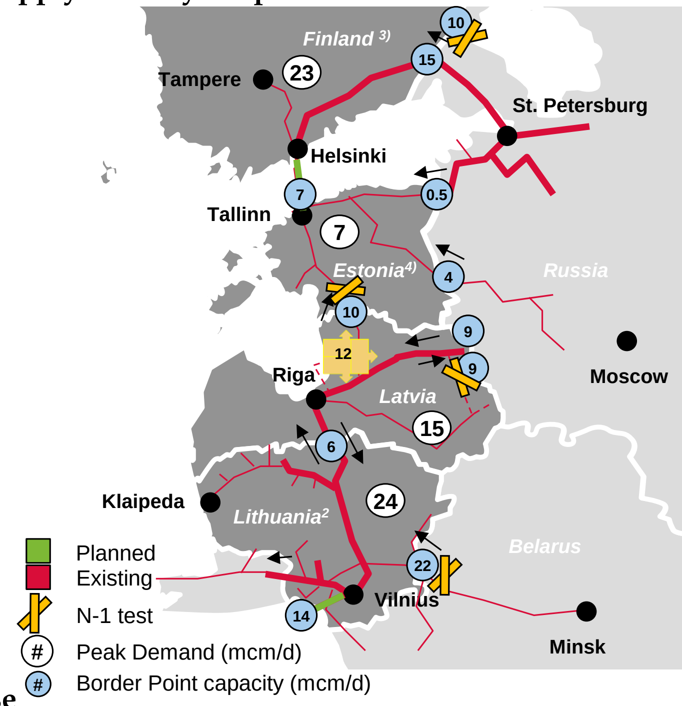
First analysis, hence, was the analysis of the impact on supply security: the goal was to understand by how much the cross border capacity needs to be boosted to satisfy the peak gas demand in 2030 for each Baltic country and Finland, according to N-1 rule. To assess that:

- The LNG was positioned in Estonia, in Latvia and in Lithuania;
- For each LNG location theN-1 rule was assessed;
- The supply security was considered granted if peak demand was fulfilled;
- Peak demand for each country was as following:
  - Finland:23Mcm/d base case, 30 Mcm/d high case;
  - Estonia: 7Mcm/d base case, 13 Mcm/d high case;
  - Latvia: 15Mcm/d base case, 16 Mcm/d high case;
  - Lithuania: 24Mcm/d base case, 26 Mcm/d high case;
- 100% of the technical capacity (Mcm/d) was assumed to serve the peak demand;
- Lithuania-Belarus border point was reduced by the reserved transit capacity for Kaliningrad (1.75 Bcm/y).

It was also assumed that no other fuel could be used in order to comply with the N-1 rule.

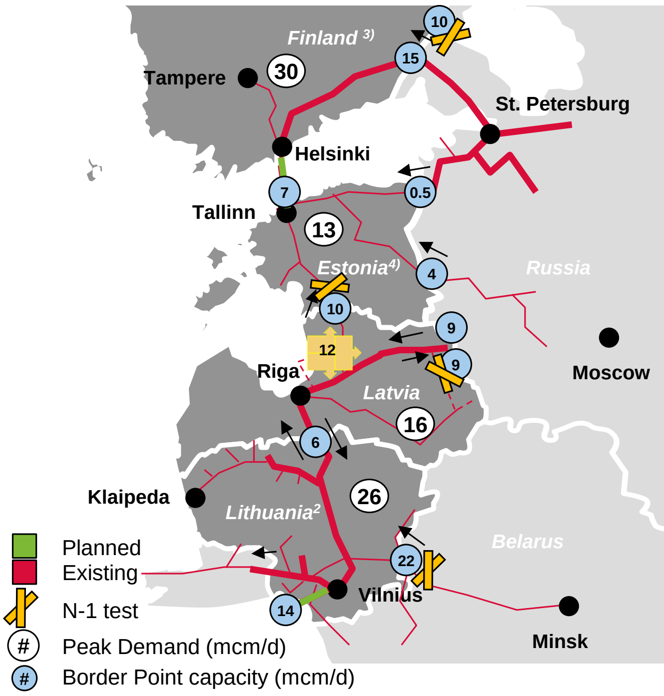
The map below shows which pipelines were closed (for one country at time) in order to test the N-1 rule (Figure 46, 47).

Figure 46 - Supply Security: map of the considered infrastructure for base case



Source: Booz & Company Analysis

Figure 47 - Supply Security: map of the considered infrastructure for high case



Source: Booz & Company Analysis

The following pipelines were closed, one at time:

- Finland: connection to Russia (pipeline coming from St. Petersburg);
- Estonia: pipeline coming from Latvia;
- Latvia: pipeline coming from Russia;
- Lithuania: pipeline coming from Belarus.

The second analysis aimed to assess the supply diversification. Annual demand of each country at 2030 was considered. In the Booz & Company Global Gas Model (that was used for the analysis), a merit order was defined, assuming that LNG would be competitive with Russian gas in 2030. The merit order set was: LNG, Norway, (through GIPL) and then Russia. The LNG was moved through the three possible locations (Estonia, Latvia and Lithuania) and then the model simulations were performed. The goal was to identify the location that minimizes the utilization of Russian gas: such value was selected as target. For the other two locations, it was analysed the expected capacity boost that would be required in order to reach the target value of Russian supply. After, a possible value of the investment for the capacity boost was calculated. For the whole analysis it was used 0.03 €/m3 expansion as cost benchmark. Such benchmark is the cost per m^3 afforded for TAG capacity expansions project at European border points.

If two or more location would result equally convenient hosts for LNG terminal, then the simulation was run using winter flows, to test what would happen with tougher demand/capacity conditions.

The figure below summarizes the analyses run (Figure 48).

Figure 48 - Drafted Scenarios

Further Analyzed Winter Flows[1]

			Simulated scenario	
			Low Demand / 4 bcm LNG	High Demand / 8 bcm LNG
LNG country location		Estonia	A	D
		Latvia	B	E
		Lithuania	C	F

Source: Booz & Company Analysis

Cases from (A) to (F) were considered for running both the supply security and the supply diversifications analysis.

6.3.2. Analysis

Security of Supply: Base Case Demand & 4 Bcm LNG

The results of the analysis are shown in the figure below (Figure 49):

Figure 49 - Supply security analysis results (A B C Scenarios)

Development of Gas Grid:

Capacity:	A LNG Estonia		B LNG Latvia		C LNG Lithuania		Route:
	Mcm/d	Bcm/y	Mcm/d	Bcm/y	Mcm/d	Bcm/y	
Estonia	-	-	2.5	0.9	2.5	0.9	Latvia/Russia – Estonia
Latvia	-	-	-	-	-	-	
Lithuania	4	1.6	4	1.6	-	-	Latvia – Lithuania or GIPL
Finland[3]	-	-	-	-	-	-	

Source: Booz & Company Analysis

- **Estonia:** Balticconnector may impact N-1 for Estonia but cannot grant 100% S-o-S at peak demand. In case of LNG located outside Estonia it would require an alternative pipe coming from Latvia of at least 3 Mcm/d technical capacity. Enhance the highest entry point would not improve "N-1 rule". Otherwise enhance the Estonia-Russia connection at Narva Border Point (currently at 0.5 Mcm/d) at € 155 MM but would enhance Russian supply dependence;
- **Lithuania:** GIPL and Baltic interconnections improve Lithuania S-o-S. However without a LNG further entry border capacity required would be at least 4 Mcm/d.

Security of Supply – High Case Scenario & 8 Bcm terminal

The results of the analysis are shown in the figure below (Figure 50):

Figure 50 - Supply security analysis results (D E F Scenarios)

Development of Gas Grid:

Capacity:	A LNG Estonia		B LNG Latvia		C LNG Lithuania		Route:
	Mcm/d	Bcm/y	Mcm/d	Bcm/y	Mcm/d	Bcm/y	
Estonia	-	-	8.5	3.1	8.5	3.1	Latvia/Russia – Estonia
Latvia	-	-	-	-	-	-	
Lithuania	6	2.1	6	2.1	-	-	Latvia – Lithuania or GIPL
Finland[3]	-	-	-	-	-	-	

Source: Booz & Company Analysis

- **Estonia:** Balticconnector may impact N-1 for Estonia but cannot grant 100% S-o-S at peak demand. In case of LNG located outside Estonia it would require an alternative pipe coming from Latvia of at least 8.5 Mcm/d technical capacity. The enhancement of the Estonia-Russia connection at Narva Border Point could reach 7 Mcm/d while Varska can reach 5.1 Mcm would be further required.

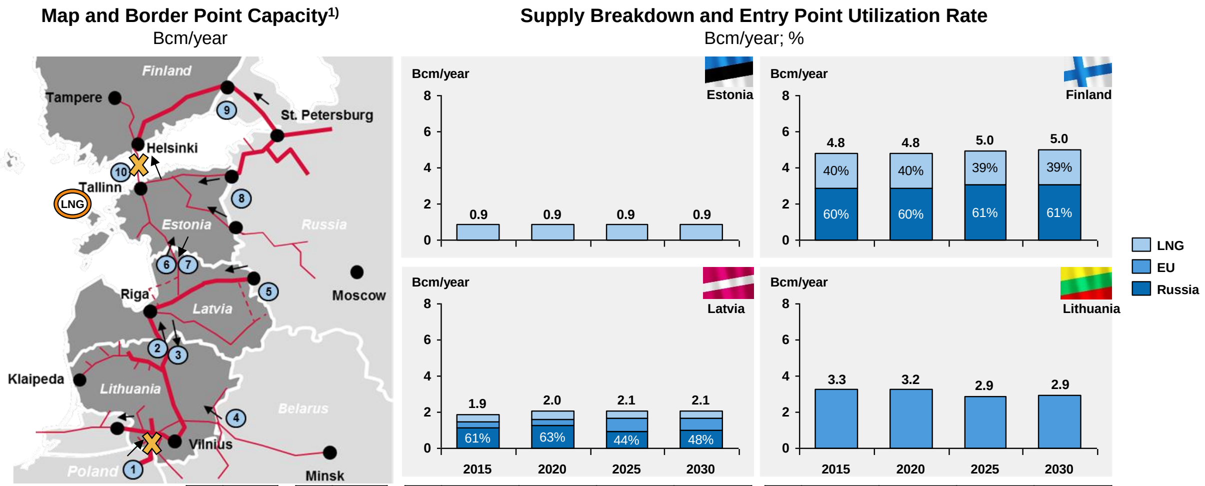
- **Lithuania:** GIPL and Baltic interconnections improve Lithuania S-o-S. However, without a LNG, further entry border capacity required would be at least 6 Mcm/d.

In both scenarios (the base case demand with a 4 Bcm terminal and the high case demand with a 8 Bcm terminal), it can be seen that regardless of the LNG terminal size, the gas network capacity at cross border points should to be increased, in order to supply the peak gas demand in 2030, accordingly to the N-1 rule.

Supply diversification: Case (A)

In the scenario of a base case demand with a 4 Bcm terminal, LNG in Estonia would favour gas diversification in the entire area, as shown in figure below (Figure 51):

Figure 51 - Supply diversification analysis results (A Scenario)



LNG	LNG Location
X	Bottlenecks (2030)

1	3.6	6	2.9
2	1.8	7	2.9
3	1.8	8	1.3
4	6.5	9	6.9
5	5.3	10	1.9

	2015	2020	2025	2030
1	100%	100%	100%	100%
2	18%	20%	42%	38%
3	-	-	-	-
4	-	-	-	-
5	22%	24%	17%	19%
6	-	-	-	-
7	14%	14%	14%	14%
8	-	-	-	-
9	42%	42%	44%	44%
10	100%	100%	100%	100%

>70%
70%-30%
<30%

Source: Booz & Company gas Model; Booz & Company Analysis

On the left, the map shows the bottlenecks that would occur: specifically, the Balticconnector and GIPL would be utilized at their maximum capacity (with a load factor of 8,000 hours).

On the right, graphs show supply diversification for each country. Considering model simulation (*Writer note: the model assumes the same border price for all the Baltic Countries, therefore the country that is closer to the entry point of a specific gas is advantaged – although such flows within the region can change according to the stipulated contracts the message regarding the whole region would not change*):

- LNG could flow, after fulfilling Estonian demand, to Finland and Latvia;
- Lithuania is the best positioned country to exploit GIPL;

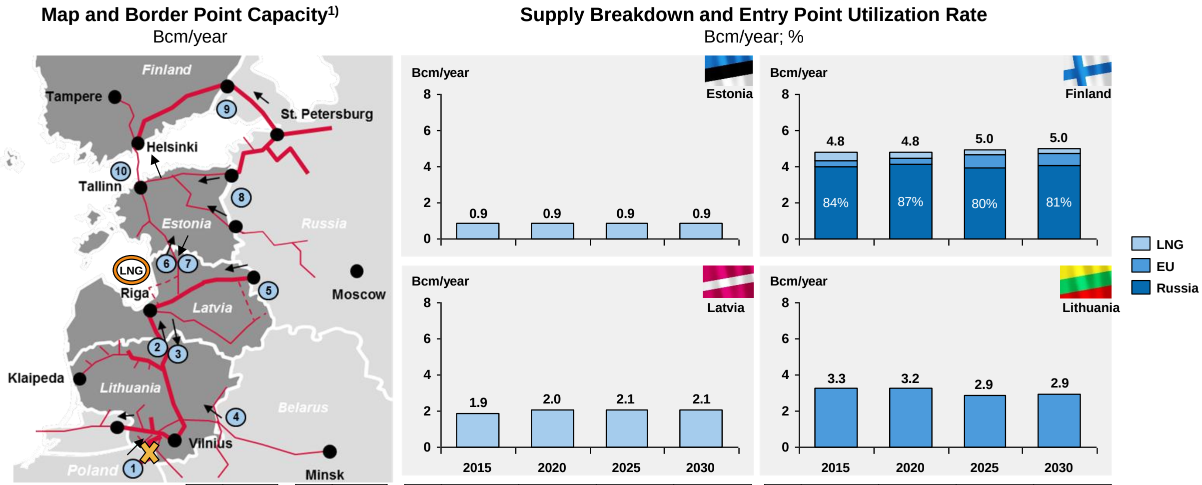
- Russia would supply gas only to Latvia and Finland.

Such scenario illustrates also that there are not bottlenecks within the Baltic region; hence gas could possibly flow without further investments on the network. Moreover gas swaps would be facilitated.

Supply diversification: Case (B)

In the scenario of a base case demand with a 4 Bcm terminal, LNG in Latvia would have a positive impact in the three Baltic countries, while leaving Estonia mainly supplied by Russian gas. Results are shown in figure below (Figure 52):

Figure 52 - Supply diversification analysis results (B Scenario)



LNG Location

Bottlenecks (2030)

1	3.6
2	1.8
3	1.8
4	6.5
5	5.3

6	2.9
7	2.9
8	1.3
9	6.9
10	1.9

1	100%	100%	100%	100%
2	18%	20%	42%	38%
3	-	-	-	-
4	-	-	-	-
5	-	-	-	-

6	56%	52%	65%	61%
7	-	-	-	-
8	-	-	-	-
9	59%	60%	58%	59%
10	40%	33%	53%	48%

>70%

70%-30%

<30%

Source: Booz & Company gas Model; Booz & Company Analysis

The only bottleneck in the entry points would be GIPL (with a load factor of 8,000 hours), meaning that piped gas from Europe is utilized as much as possible.

On the right, graphs show supply diversification for each country. Considering model simulation (*Writer note: the model assumes the same border price for all the Baltic Countries, therefore the country that is closer to the entry point of a specific gas is advantaged – although such flows within the region can change according to the stipulated contracts the message regarding the whole region would not change*):

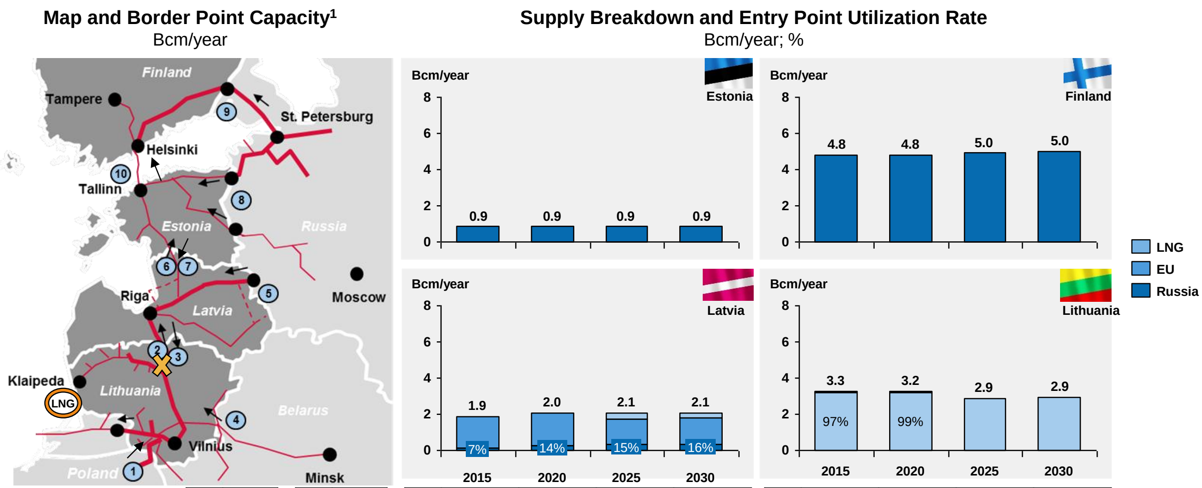
- LNG Gas could flow, after fulfilling Latvian demand, to Estonia and Finland. Since the Balticconnector is not fully exploited, the degree of which the gas flows from Latvia to Finland or Estonia depends on the stipulated contracts and demand needs;
- Lithuania is the best positioned country to exploit GIPL;
- Russia would supply gas only to Finland.

Such scenario illustrates also that there are no bottlenecks within the region; hence gas could possibly flow without further investments on the network. Moreover gas swaps would be facilitated.

Supply diversification: Case (C)

In the scenario of a base case demand with a 4 Bcm terminal, LNG in Lithuania would enter in competition with European gas rather than Russian gas. Results are shown in figure below (Figure 53):

Figure 53 - Supply diversification analysis results (C Scenario)



1	3.6
2	1.8
3	1.8
4	6.5
5	5.3
6	2.9
7	2.9
8	1.3
9	6.9
10	1.9

	2015	2020	2025	2030
1	51%	50%	39%	41%
2	100%	100%	100%	100%
3	-	-	-	-
4	-	-	-	-
5	3%	6%	6%	6%
6	-	-	-	-
7	-	-	-	-
8	65%	66%	67%	66%
9	70%	70%	72%	73%
10	-	-	-	-

>70% · 70%-30% · <30%

Source: Booz & Company gas Model; Booz & Company Analysis

In this scenario there would not be any bottleneck at the entry points, meaning that piped gas from Europe is not fully exploited.

On the right, graphs show supply diversification for each country. Considering model simulation (*Writer note: the model assumes the same border price for all the Baltic Countries, therefore the country that is closer to the entry point of a specific gas is advantaged – although such flows within the region can change according to the stipulated contracts the message regarding the whole region would not change)*:

- LNG Gas would compete, rather than with Russian gas, with gas coming from Europe;
- Rarely, (depends on contracts) other gas than Russian could flow to Finland.

Such scenario illustrates also that there is a key bottleneck within the region (point 2). In this way maximum gas availability is not reached and gas coming from GIPL and from LNG would cap each-other; hence further investments are required to make gas flow with the same degree of flexibility as it occurred when the LNG were located in Estonia or Latvia.

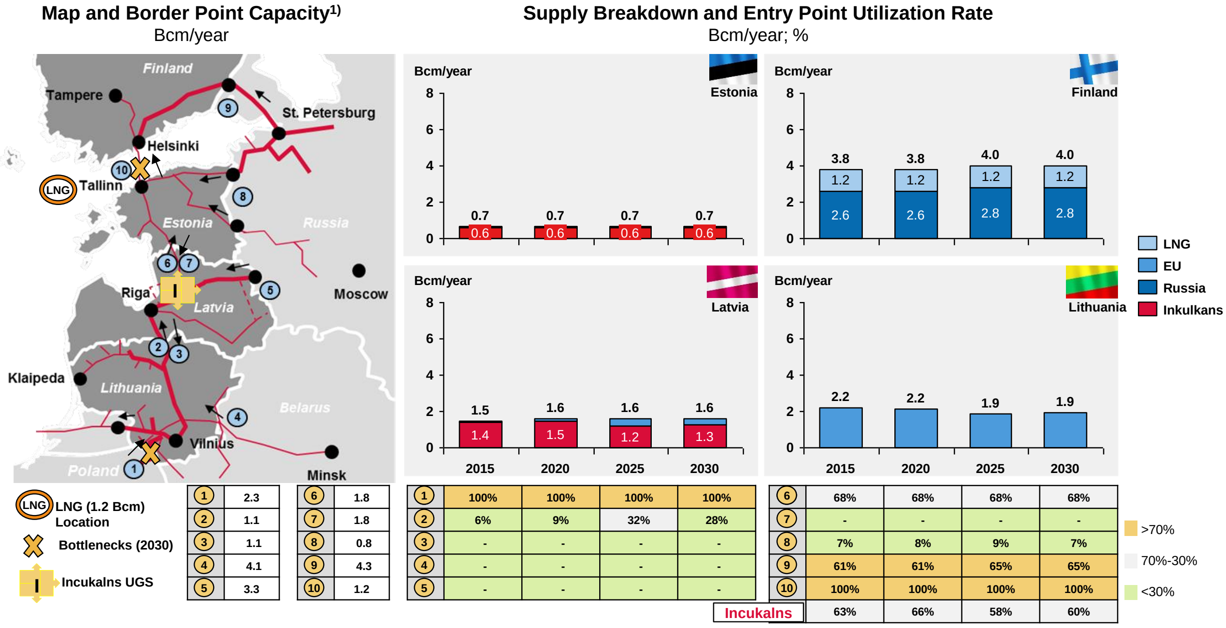
Moreover gas swaps are not facilitated, since the gas directions are only south-north or east-west.

Because case (A) and case (B) didn't show any significant difference in their results, it was decided to run another analysis to assess what would happen in case harsher winter conditions would occur. Therefore, winter gas flows were simulated for LNG located in Estonia and Latvia. Winter months go from September to March. Technical capacity was assumed to be at 50 % (six months). LNG size was assumed to be of 1 Bcm to simulate possible climate issues (that would prevent vessels to reach the port). Incukalns capacity was assumed to be 3.2 Bcm.

Supply Diversification: Case (A) Winter

In the scenario of a low demand and a 4 Bcm terminal, an LNG plant in Estonia would optimize gas flows within the region during the winter. The figure below shows results of the analyses (Figure 54).

Figure 54 - Supply Diversification Analysis Results in Winter Period, LNG Estonia



Source: Booz & Company gas Model; Booz & Company Analysis

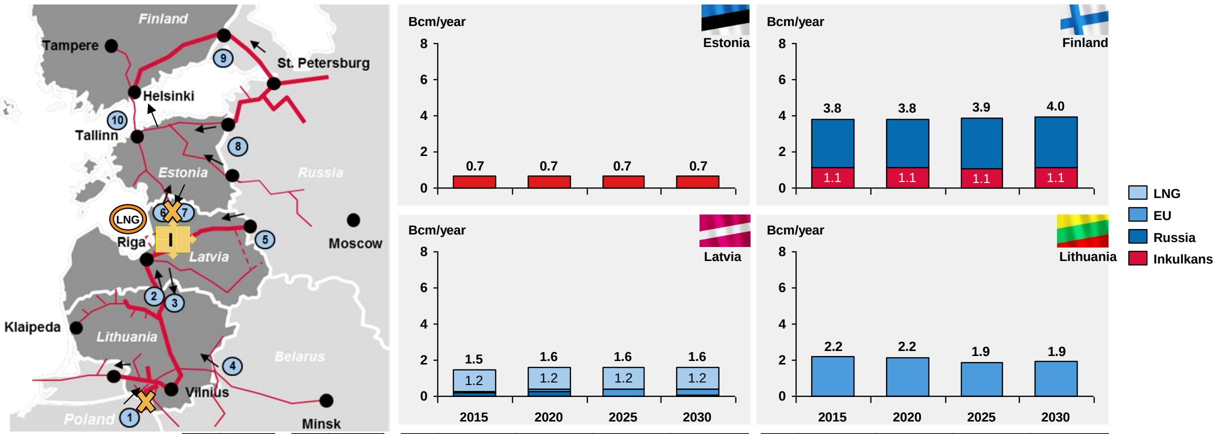
Supply Diversification: Case (B) Winter

If the LNG terminal will be located in Latvia, flows from UGS will start competing with the LNG terminal to serve Northern Baltic area. In this scenario, the Latvia-Estonia pipeline is expected to be a bottleneck (Figure 55).

Figure 55 - Supply Diversification Analysis Results in Winter Period, LNG Latvia

Map and Border Point Capacity[1)]
Bcm/year

Supply Breakdown and Entry Point Utilization Rate
Bcm/year; %



1	2.3
2	1.1
3	1.1
4	4.1
5	3.3

6	1.8
7	1.8
8	0.8
9	4.3
10	1.2

1	100%	100%	100%	100%
2	6%	9%	32%	28%
3	-	-	-	-
4	-	-	-	-
5	6%	9%	1%	3%

6	100%	100%	100%	100%
7	-	-	-	-
8	-	-	-	-
9	63%	63%	66%	66%
10	95%	95%	94%	95%
Incukalns	57%	57%	57%	57%

>70%
70%-30%
<30%

Source: Booz & Company gas Model; Booz & Company Analysis

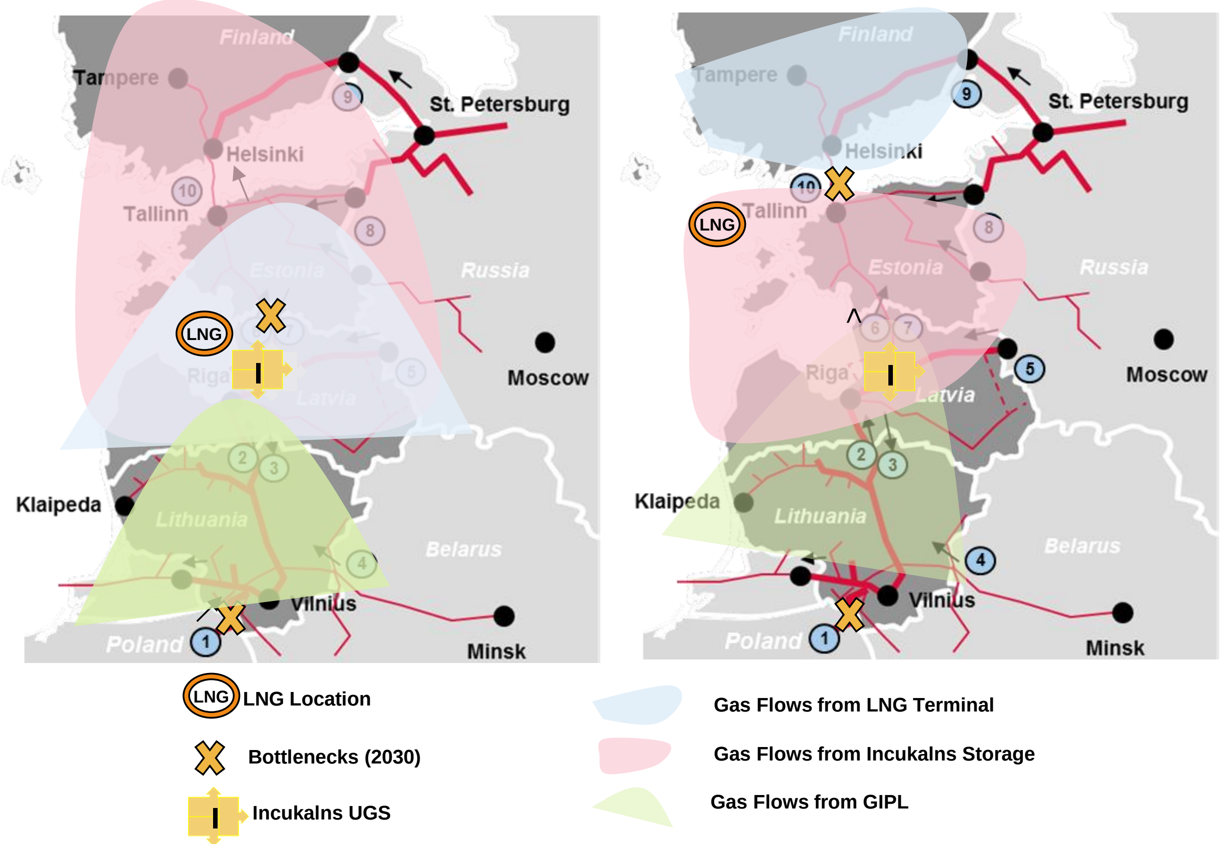
In summary, a LNG terminal in Estonia would enable the three gas assets to fulfil the region without entering into competition with each other.

The terminal located in Estonia would theoretically optimize the flows as LNG would supply only Finland, Incukalns would supply Latvia and Estonia and GIPL would supply mostly Lithuania and partially Latvia.

Terminal in Latvia would not be the optimal location to balance the existing grid as LNG would supply, only Latvia, Incukalns would supply Latvia and Estonia and GIPL would supply mostly Lithuania and partially Latvia.

The figure below shows gas flows in winter scenarios (Figure 56). When LNG is located in Latvia, the shadows overlap, indicating that gas flows compete with each other. On the contrary, when LNG is placed in Estonia, the shadows don't overlap.

Figure 56 - Map and Gas Flows in Baltic Region (Bcm/y)

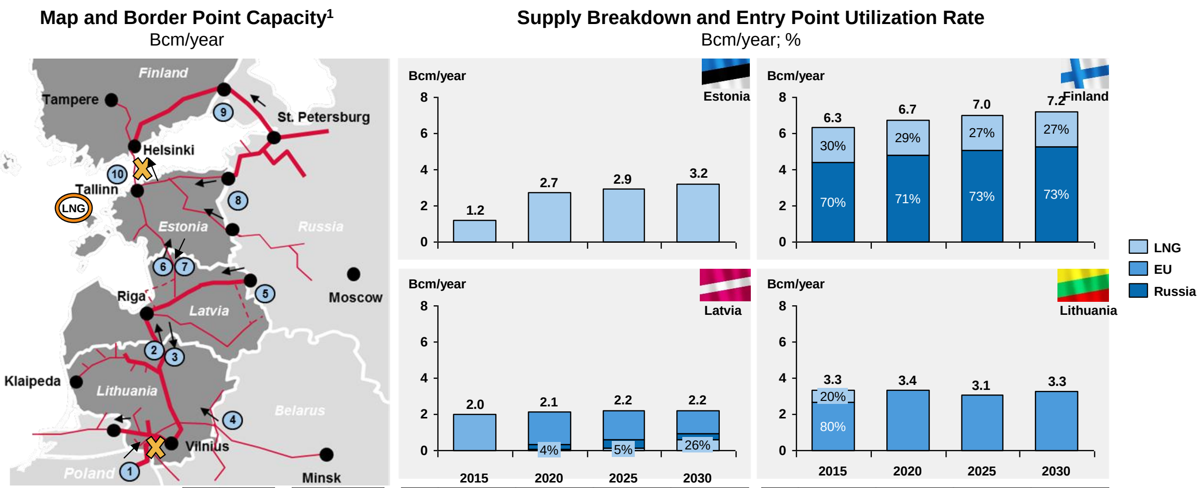


Source: Booz & Company gas Model; Booz & Company Analysis

Supply Diversification: Case (D)

Moving to the scenario with high demand and a 8 Bcm LNG terminal, in case the selected location is Estonia, there would be a high level of gas diversification, as shown in figure below (Figure 57):

Figure 57- Supply diversification analysis results (D Scenario)



1	3.6
2	1.8
3	1.8
4	6.5
5	5.3

6	2.9
7	2.9
8	1.3
9	6.9
10	1.9

	2015	2020	2025	2030
1	67%	100%	100%	100%
2	-	14%	29%	20%
3	53%	-	-	-
4	-	-	-	-
5	-	1%	2%	11%

	2015	2020	2025	2030
6	-	-	-	-
7	100%	61%	54%	44%
8	-	-	-	-
9	64%	70%	74%	77%
10	100%	100%	100%	100%

>70%
70%-30%
<30%

Source: Booz & Company gas Model; Booz & Company Analysis

On the left, the map shows the bottlenecks that would occur: namely, the Balticconnector and GIPL would be utilized at their maximum capacity (with a load factor of 8,000 hours).

On the right, graphs show supply diversification for each country. Considering model simulation (*Writer note: the model assumes the same border price for all the Baltic Countries, therefore the country that is nearer to the entry point of a specific gas is advantaged – although such flows within the region can change according to the stipulated contracts the message regarding the whole region would not change)*:

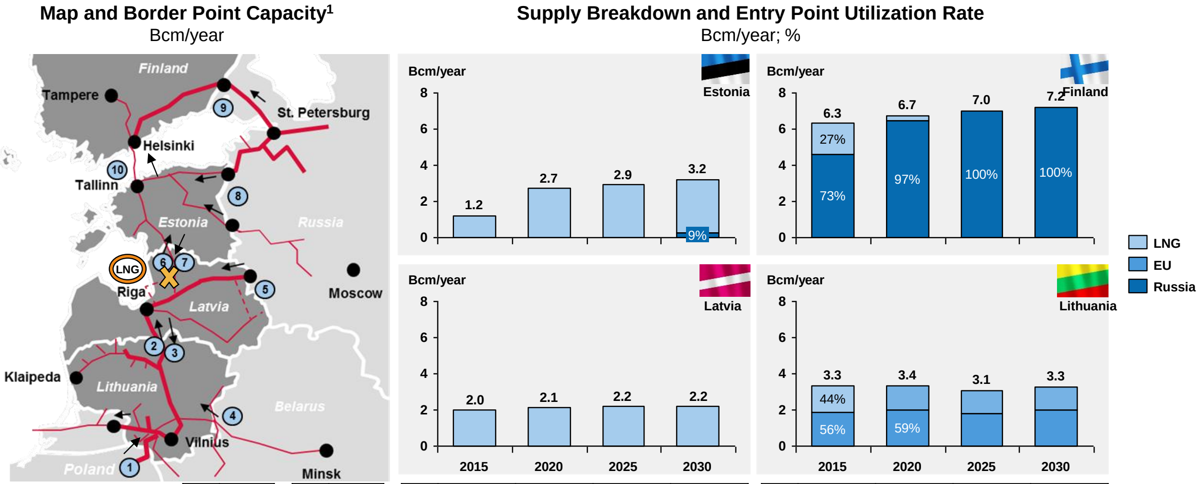
- LNG could flow, after fulfilling Estonian demand, to Finland, Latvia and Lithuania;
- Lithuania is the best positioned country to exploit GIPL;
- Russia would supply gas to Finland and to Latvia.

Such scenario illustrates also that there are no bottlenecks within the region; hence gas could possibly flow without further investments on the network. Moreover gas swaps could be facilitated.

Supply Diversification: Case (E)

In the high scenario, the LNG in Latvia would bring a positive contribution to the three Baltic countries and for a small amount to Finland (Figure 58).

Figure 58 - Supply diversification analysis results (E Scenario)



LNG Localization

Bottlenecks (2030)

Point	Capacity (Bcm/year)
1	3.6
2	1.8
3	1.8
4	6.5
5	5.3
6	2.9
7	2.9
8	1.3
9	6.9
10	1.9

Point	2015	2020	2025	2030
1	52%	55%	50%	55%
2	-	-	-	-
3	84%	79%	73%	73%
4	-	-	-	-
5	-	-	-	-
6	100%	100%	100%	100%
7	-	-	-	-
8	-	-	9%	47%
9	67%	95%	100%	100%
10	90%	11%	7%	18%

>70%
70%-30%
<30%

Source: Booz & Company gas Model;Booz & Company Analysis

On the left, the map shows that the two bottlenecks would be the one between Estonia and Latvia and the one connecting Russia to Finland. GIPL would be not fully exploited (about 90% of its commercial capacity, considering a load factor of 8,000 hours)

On the right, graphs show supply diversification for each country. Considering model simulation (*Writer note: the model assumes the same border price for all the Baltic Countries, therefore the country that is closer to the entry point of a specific gas is advantaged – although such flows within the region can change according to the stipulated contracts the message regarding the whole region would not change*):

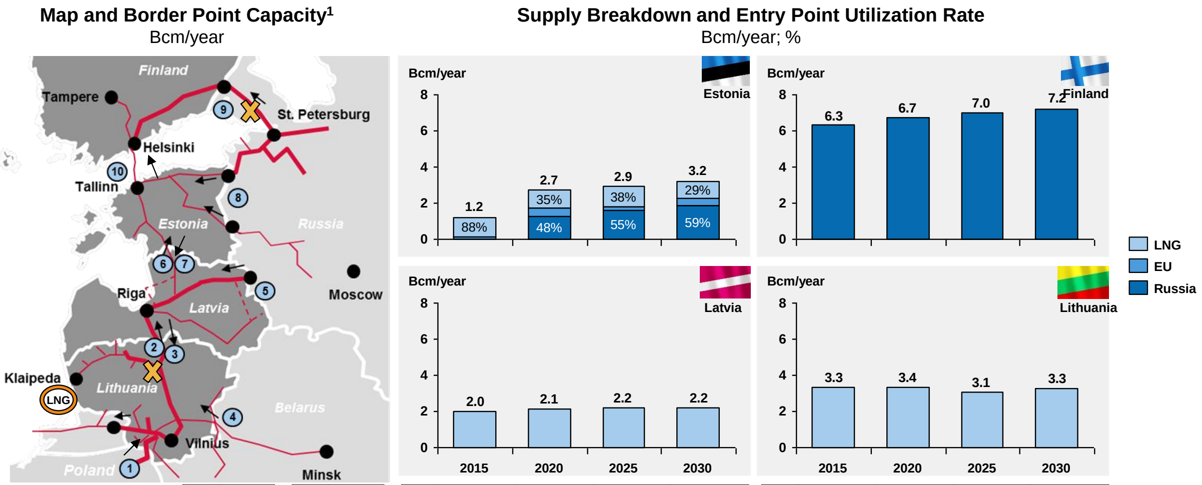
- LNG could flow, after fulfilling Latvian demand, to Estonia, Lithuania and Finland (although in Lithuania and Finland only in the short term);
- Lithuania is the best positioned country to exploit GIPL;
- Russia would supply gas only to Finland.

Such scenario illustrates also that there is a bottleneck within the region (point 6); hence further investments should be required in order to reach the same diversification target as the LNG was positioned in Estonia. Nevertheless, the impact on the GIPL utilization is limited, but gas swap could be limited between Estonia/Finland and Latvia/Lithuania.

Supply Diversification: Case (F)

Locating LNG in Lithuania in a high scenario would completely prevent the GIPL pipeline from supplying the Baltic area, therefore limiting the impact on gas diversification (Figure 59).

Figure 59 - Supply diversification analysis results (F Scenario)



LNG Localization

Bottlenecks (2030)

Point	Capacity	Point	Capacity
1	3.6	6	2.9
2	1.8	7	2.9
3	1.8	8	1.3
4	6.5	9	6.9
5	5.3	10	1.9

Point	2015	2020	2025	2030
1	-	-	-	-
2	100%	100%	100%	100%
3	-	-	-	-
4	-	-	-	-
5	5%	33%	41%	51%
6	0%	0%	5%	12%
7	-	-	-	-
8	91%	100%	100%	100%
9	92%	98%	100%	100%
10	0%	0%	7%	18%

>70%
70%-30%
<30%

Source: Booz & Company gas Model; Booz & Company Analysis

In this scenario there would be two bottlenecks with Russia, the entry point to Estonia and the one to Finland, meaning that Russia would keep the lever on gas prices. Such scenario illustrates also that there is a key bottleneck within the region (point 2). In this way maximum gas availability is not reached and gas coming from GIPL and from LNG would cap each-other; hence further investments would be required to make gas flow with the same degree of flexibility. Moreover gas swaps would not be facilitated.

On the right, graphs show supply diversification for each country. Considering model simulation (*Writer note: the model assumes the same border price for all the Baltic Countries, therefore the country that is closer to the entry point of a specific gas is advantaged – although such flows within the region can change according to the stipulated contracts the message regarding the whole region would not change)*:

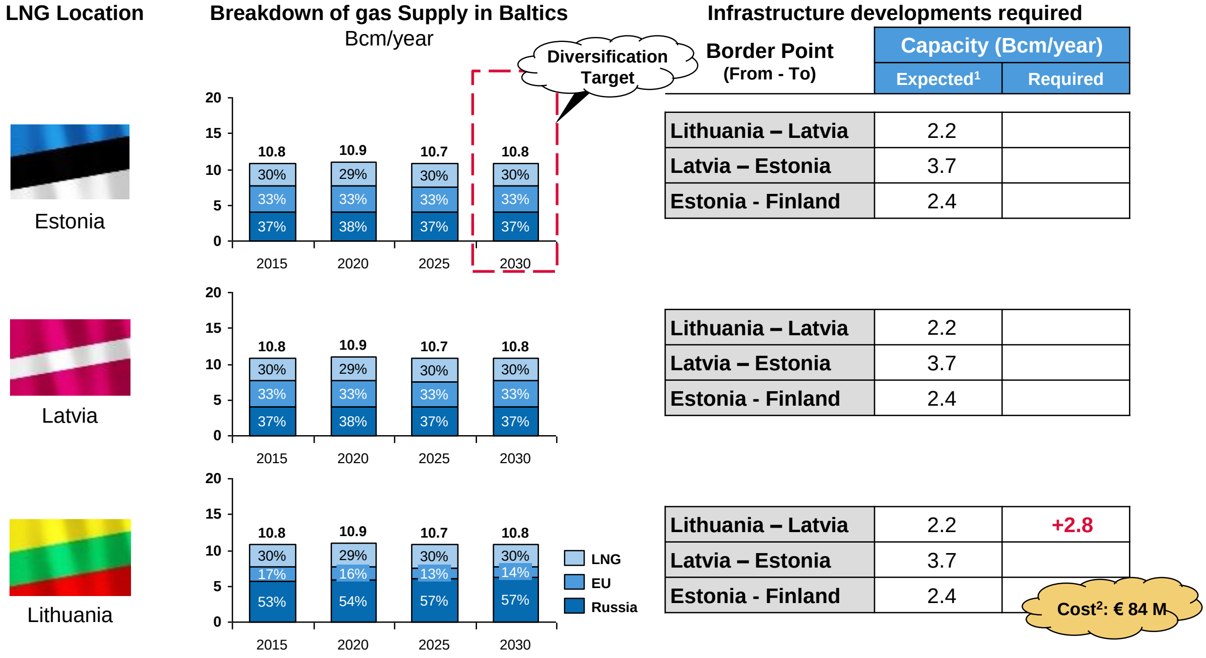
- LNG Gas would compete, rather than with Russian gas, with gas coming from Europe, offsetting the GIPL which would not be utilized;
- Unlikely, (depending on contracts) other gas than Russian could flow to Finland or Estonia.

General Considerations on Supply Diversification

Looking at the scenario with base demand and a 4 LNG terminal, the target share of Russian supply would be 37%, as this was the minimum percentage that could be reached among the three countries. Specifically, this share was found both for Estonia and Latvia, while for Lithuania minimum share of Russian gas at 2030 was 53%.

In summary, a 4 Bcm LNG terminal located either in Estonia or Latvia would not require further network capacity investments. If located in Lithuania, the terminal would require a boosting of 2.8 Bcm/y in the Lithuania – Latvia pipeline that would require an estimated investment of € 84 MM (Figure 60).

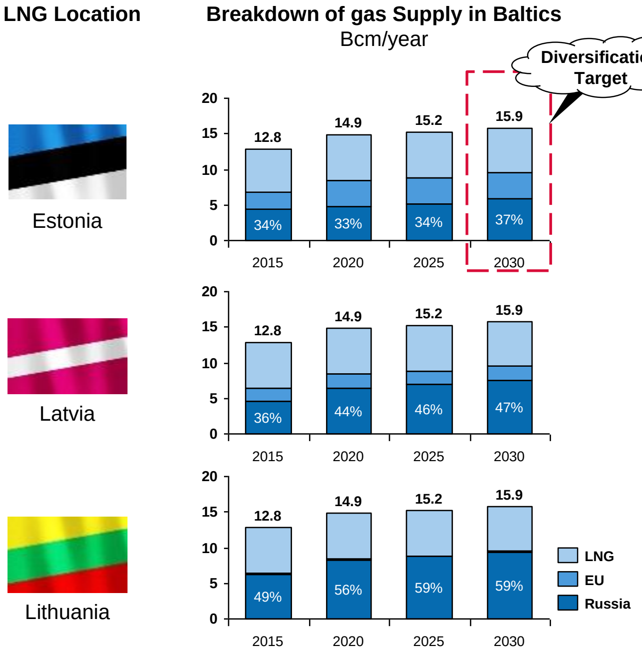
Figure 60 - Supply diversification analysis results (A B C Scenario)



Source: Booz & Company Gas Mode, Booz & Company Analysis

In the scenario with a high demand and an 8 Bcm/y LNG, the LNG would perfectly fit in the planned transmission network only if located in Estonia. Indeed, such placement would lead to the minimum share of Russian gas, without the need of further infrastructures improvements. On the other hand, if placed in Latvia or Lithuania, further investments on the capacity would be required (2.1 Bcm/y in the Latvia-Estonia pipeline if placed in Latvia, 6.3 Bcm/y in Lithuania-Latvia pipeline and 2.4 Bcm/y in the Latvia-Estonia pipeline), with a total investment of € 270 MM (Figure 61).

Figure 61 - Supply diversification analysis results (D E F Scenario)



Infrastructure developments required

Estonia:

Border Point (From - To)	Capacity (Bcm/year) Expected[1]	Capacity (Bcm/year) Required
Lithuania – Latvia	2.2	
Latvia – Estonia	3.7	
Estonia - Finland	2.4	

Latvia:

Border Point (From - To)	Capacity (Bcm/year) Expected[1]	Capacity (Bcm/year) Required
Lithuania – Latvia	2.2	
Latvia – Estonia	3.7	+ 2.1
Estonia - Finland	2.4	

Cost: 63 €

Lithuania:

Border Point (From - To)	Capacity (Bcm/year) Expected[1]	Capacity (Bcm/year) Required
Lithuania – Latvia	2.2	+6.3
Latvia – Estonia	3.7	+2.4
Estonia - Finland	2.4	

Cost[2]: 270 €

Source: Booz & Company Analysis

6.3.3. Overall Results

A comparison between the investments required satisfying supply security and supply diversification was done in order to understand what the purpose for the LNG would be (Figure 62).

Figure 62 - Investments required for Supply security (N-1 rule) and supply diversification

LNG Location	Network Upgrades for Supply Diversification[1] – Base Case: Capacity (Bcm/y)	Base Case: Cost (€ Mln)	High Case: Capacity (Bcm/y)	High Case: Cost (€ Mln)	Network Upgrades for Security of Supply[1] – Base Case: Capacity (Bcm/y)	Base Case: Cost (€ Mln)	High Case: Capacity (Bcm/y)	High Case: Cost (€ Mln)
ESTONIA	-	-	-	-	1.5	30[2]	2.1	30[2]
LATVIA	-	-	2.1	60	2.4	60[3]-185	5.2	120[3]-245
LITHUANIA	2.8	80	9.0	270	0.9	30[3]-155	3.1	90[3]-215

Source: Booz & Company Analysis

Supply Security: In Base case if LNG would be located in Estonia or Lithuania would require about € 30 MM. Investments to grant the Regional N-1 compliance. LNG would contribute to increase regional supply security only if placed in Lithuania or Estonia. In case the LNG is not built in Estonia, Narva Connection project (2.6 Bcm/y - € 155 MM) could be required, because during the winter the gas flows from Incukalns to Russia, hence gas cannot flow from Russia to Estonia.

Supply Diversification: The LNG located in Estonia would grant the highest regional diversification. In base case scenario the Lithuania location would require further investments. An LNG in Lithuania would require the highest investment as it would unbalance the gas network (all flows would go South to North).

It should be underlined that for running this analysis, when no suitable BEMIP project was identified, investment costs were estimated by European pipe capacity enhancements benchmarking resulting in 0.03 €/m^3. Moreover, the Lithuania-Latvia interconnection capacity enhancement of 2.2 Bcm/y was taken as foreseen by BEMIP No FID projects. Finally, the upgrade of Varska border point was estimated using European pipe capacity enhancements benchmarking of in 0.03 €/m^3.

In case all infrastructures would be implemented, Estonia would be the optimal location for a LNG terminal. Given the total Baltic demand (including Finland) two entry points would be required for gas diversification; they should be located as far as possible in order to optimize the existing grid. If Finland would not be included, then only one asset would be enough to grant diversification. The LNG location would be assessed based on whether Balticconnector and/or GIPL would be implemented.

If both the LNG and the Balticconnector were built, then Estonia would be the optimal location to maximize regional diversification. In case only Balticconnector project will be implemented, theoretically two LNG would be required, but diversification would be limited since the LNG supplier would be likely the same. GIPL is clearly a high strategic asset. Indeed, if GIPL is the only infrastructure implemented, it would be enough as it is the most economic viable solution to diversify supply in the Baltic area. Finally, if no infrastructures will be built, Lithuania would be the biggest market to serve (therefore requiring a LNG terminal), but at the same time Latvia could ensure an optimal grid balance (Figure 63).

Figure 63 - Optimal Locations for Different Infrastructure Scenarios

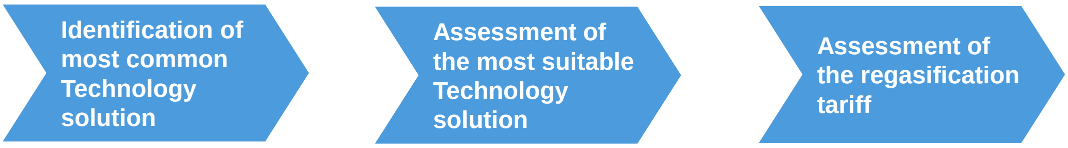
Balticconnector	GIPL	FINAL LOCATION
YES	YES	ESTONIA
YES	NO	ESTONIA + LITHUANIA
NO	YES	NO LNG
NO	NO	LITHUANIA or LATVIA

Source:Booz & Company Analysis

6.4. Assessment of available technologies and costs

Three steps were followed to identify the most suitable technology solution for the LNG terminal in Baltic region (Figure 64).

Figure 64 - Technology Screening Approach



Source: Booz & Company Analysis

Step 1 – Identification of most common technologies: five LNG technical solutions were identified. The main technical fetures are the following:

- Location: offshore or onshore;
- Structure: fixed or floating;
- Type of LNG vessel: shuttling or stationary;
- Regasification location: integrated or separated.

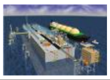
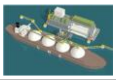
Step2 – Assessment of the most suitable technology solution: in order to select a shortlist of technologies , some filters were applied to exclude the less convenient options. Namely the five filters were:

- Distance from production sites;
- Availability of adaptable structures;
- Climate conditions and morphology of the area.

Step 3 – Assessment of the regasification tariff: for each shortlisted technical solution, CAPEX and OPEX were computed. A required rate of return on the terminal investment was set (same one for all the technologies) and the regasification tarif was estimated in order to detect the solution that could provide the most economically advantageous solution.

The first step of the analysis involved the characterization of the current available LNG technologies. As shown below, five solutions were identified (Figure 65).

Figure 65 - Available technologies solutions for a LNG terminal

	Onshore Terminal	Gravity Based Structure (GBS)	Standard[1] Regasification Vessel	FSRU (Floating Storage and Regasification Unit)	Platform with Regasification Units
					
Criteria:	▪ Conventional land-based terminal	▪ Integrated concrete / steel structure in shallow waters	▪ Ship containing regasification units shuttling in the sea	▪ Vessel containing regasification units permanently moored	▪ Offshore platform containing regasification units
Location	Onshore	Offshore	Offshore	Offshore	Offshore
Structure	–	Fixed	Floating	Floating	Fixed/Floating
LNG Vessel	–	–	Shuttling	Stationary	Stationary
Regasification Location	–	Integrated Regasification on GBS	Integrated Regasification	Integrated Regasification	On Platform
Functioning Description	LNG is pumped from an LNG carrier into cylindrical containment tanks; when required, LNG is regasified and sent out into the gas transmission system	LNG terminal built on an artificial island. Regasification facilities are located on the top of the surface. LNG is transferred from an LNG carrier similarly to a conventional terminal	LNG carrier with capability to regasify LNG onboard. The carrier is loaded with LNG at a liquefaction plant and gas is delivered via a subsea pipeline	FSRU is moored at one location and it is supplied by transfer from an LNG carrier into its own storage tanks. LNG is regasified onboard the vessel and gas is exported via a subsea gas pipeline	LNG terminal either moored at one location or fixed. LNG is exported via a subsea pipeline.

Source: Executive Summary Report for a pre-feasibility study to develop a Baltic LNG Terminal in Latvia (aug 2011), Booz & Company Analysis

The technologies can be grouped as onshore and offshore: on-shore technology is land based, which means that the vessels would have to enter the port to deliver the gas and regasification process is done in the port area. On the other hand, offshore technology doesn't need land at the port, as the vessel supplies the gas through a structure (whose characteristics may vary) that is located on the sea. In offshore technologies, gas is then transported to land through a sea pipeline.

A short description of functioning for each technology is provided below:

- **Onshore terminal:** LNG is pumped from a LNG carrier into cylindrical containment tanks located in the port area; when gas is required, LNG is regassified and sent out unto the gas transmission system.

- **Gravity based structure (GBS):** the LNG terminal is built on an artificial island. LNG vessels transport the LNG from site production to the terminal. Regasification facilities are located on top of the surface. LNG is pumped into the transmission system via a subsea pipeline.

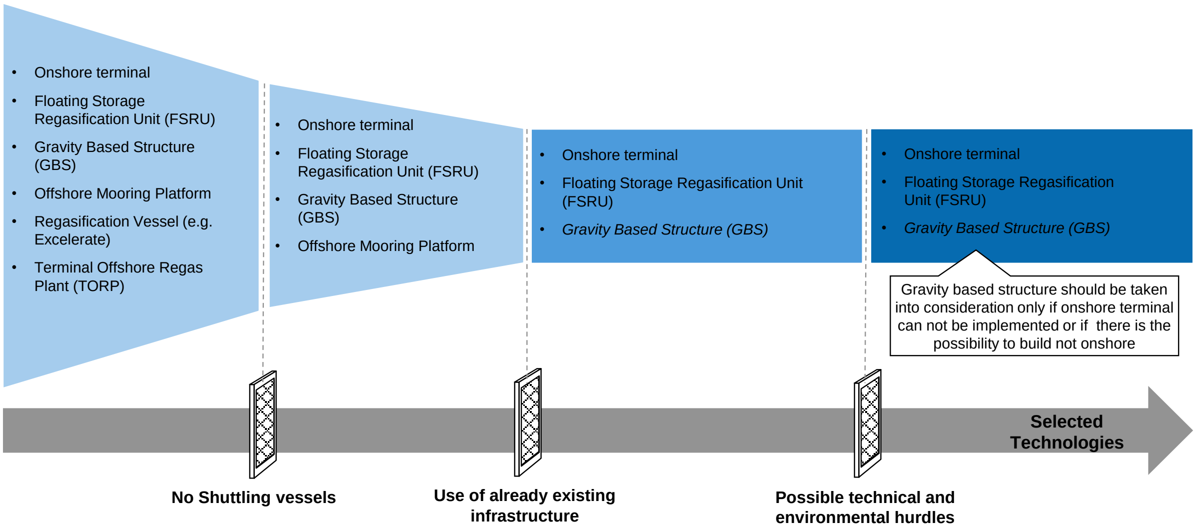
- **Standard regasification vessel:** The LNG carrier is provided with regasification facilities on board. The carries is loaded with LNG at a liquefaction plant, transports the LNG to the designed port, re-gassify it and delivers it via a subsea pipeline.

- **Floating storage and regasification unit:** FSRU is provided with LNG tanks and regasification units. It is moored at one location and it is supplied by gas by LNG carriers that transfer the LNG into its storage tanks. The vessel is therefore permanently moored close to the port, serving as storage for LNG. When gas is needed, LNG is regassified on board the FSRU and exported via a subsea pipeline.

- **Platform with regasification units:** the LNG terminal is generally obtained by adapting existing infrastructures to the scope. It is either moored at one location or fixed. LNG is regassified on platform and delivered through a subsea pipeline.

The second step focused on understanding which of the available technologies best fitted the needs of the projects. Three filters were applied, as shown in figure below (Figure 66):

Figure 66 - Technology Screening



Source: Booz & Company Analysis

Filter 1 –No shuttling vessels: due to long distances from gas site productions, standard regasification vessels were excluded from further analyses, as they imply that the carrier, which also incorporates the regasification facility, shuttles from production sites to the designed port, therefore requiring long time for the process to be completed and avoiding the possibility of some storage close to the port. The regasification vessels and the terminal offshore regasification plant were excluded.

Filter 2 – Use of already existing infrastructures: as none of the three countries already has LNG terminals, there are no existing infrastructures that might be re-used or adapted for the scope, so the offshore mooring platform was excluded, as it would imply large investments.

Filter 3 – Possible technical and environmental hurdles: ice conditions as well as uncertain morphology of the sea bed showed that the gravity based structure might be a hazardous solution.

The outcome of these filters was a shortlist of technologies that could be implemented in the Baltic area:

- The onshore terminal;
- The floating regasification unit (FSRU);
- The gravity based structure (GBS);

The third step aimed to assess a regasification tariff for each of the shortlisted technologies, in order to identify the most economical solution. In addition, some qualitative considerations were done regarding aspects like environmental impact, sizing of the terminal and permission for start of works. The analysis was done for both the 4 Bcm and the 8 Bcm terminal capacities. The results of this final steps are shown in the table below (Figure 67).

Figure 67 – Different Technical Solutions and relative expenses

		4 Bcm/y plant				8 Bcm/y plant				Environmental impact	Scalability of solution	Easiness of permitting
		Capex € M	Opex € M/year	Regasification tariff US$/Mbtu	Land Surface required Km^2	Capex € M	Opex € M/year	Regasification tariff US$/Mbtu	Land Surface required Km^2			
Onshore		300-400	9 – 13.5	0.63-1.34	100 – 150	450-600	21-29.8	0.47-1.15	100 – 150	●	○	○
FSRU		150-200	6.2-8	0.28-0.60	N/A	300-400	15-20	0.30-0.63	N/A	◐	◔	○
GBS		500-600	20-24	1.00-1.91	N/A	650-800	32.5-40	0.69-1.34	N/A	◐	○	◕

The technical solution should be reassessed considering location peculiarity

Low ○ ◔ ◐ ◕ ● **High**

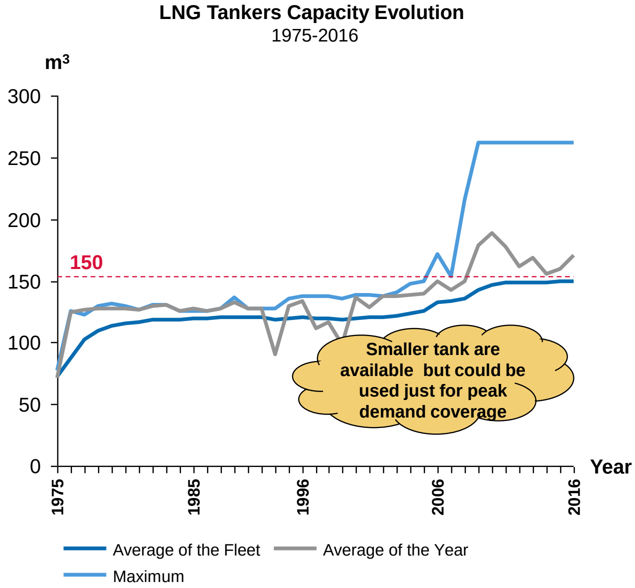
Source: Booz & Company Analysis

Provided that the technical solution should be reassessed considering location peculiarities, the analysis shows that the FSRU should be the most economical and fastest solution to implement, granting the lowest regasification tariff and requiring the lowest capital expenditures. Nevertheless the technology should be analysed considering also the port characteristics, as any port can be more suitable to a technology than another and require a lower magnitude of investments.

6.5. Assessment of possible location options

One of the essential requirements of the ports is the port ability to handle big cargos; therefore, the evolution of LNG tankers capacity was analyzed. Results are shown in the figure below (Figure 68).

Figure 68 – Tanker Capacity Evolution and Vessel Types



Average Vessel Type

Capacity	Length	Width	Draft	Tonnage	4bcm LNG	8 bcm LNG
m3	m	m	m	GT	# trip	# trip
135	270	43	11,3	87.733	44	89
150	280	44	11,3	94.000	40	80
180	285	46	11,3	110.821	33	67
215	300	50	12	125.751	28	56
250	345	55	12	127.150	24	48

Source: Booz & Company Analysis

The average capacity of the fleet in 2016 is forecasted to be 150 m^3; therefore, looking at vessels characteristics, the expected average length of that type of vessels is about 280 m while the width is 44 m.

With this information, port characteristics were assessed to see if any of them did not satisfy minimum requirements.

Six ports were evaluated to address the best fit for a LNG terminal:

Port 1 – Muuga Harbor (Estonia): It is the biggest cargo harbor in Estonia, with a cargo volume of 30 Mln tons in 2010. It is located 20 km from Tallin, 300 km from Riga and 600 km from Vilnius the three capital cities of Baltic countries and major consumption centers. Its existing infrastructure is sufficient to host the LNG terminal. The harbor is subjected to icing during winter months and requires icebreaking intervention, part of which sustained by the government.

Port 2 – Paldiski Harbor (Estonia): Although being a small port (with a cargo volume of only 6 Mln tons in 2010), this port is a free economic zone. Its core activity is the handling of import and export cargos. It is located 50 km from Tallin, 320 from Riga and 620 from Vilnius. The terminal is foreseen to be connected to Finland via the Balticconnector. The harbor is subjected to icing during winter months and requires icebreaking intervention, part of which sustained by the government.

Port 3 – Port of Sillamae (Estonia): It's a small landlord port located in North-east Estonia, with a cargo handling of 5 Mln tons in 2010. It is located 180 km from Tallin, 390 km from Riga and 660 km from Vilnius. In case the LNG terminal would be built in this location, it would need to be connected to the Estonian network.

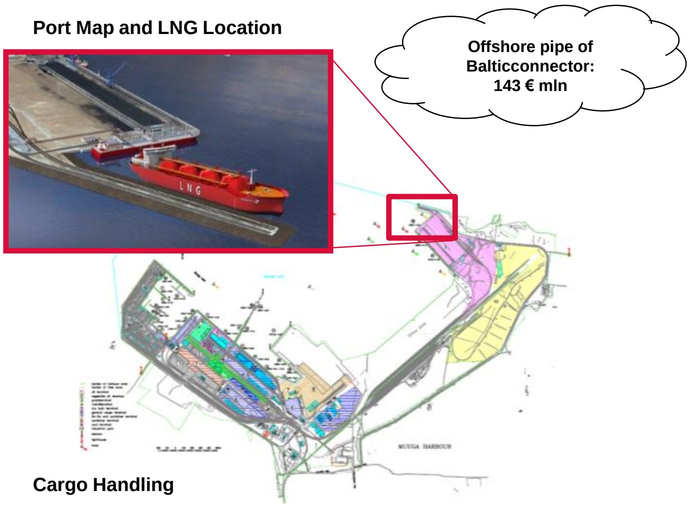
Port 4 – Port of Riga (Latvia): This port had a cargo volume of 30.5 Mln tons in 2010. It is located 300 km from Tallin and 300 km from Vilnius. The existing pipeline infrastructure at the port is sufficient to host the LNG terminal. There are several traffic restrictions during winter season, mainly due to icing. In 2010, 423 ships needed assistance and traffic restriction lasted more than 4 months.

Port 5 – Port of Ventspils (Latvia): This port had a cargo volume of 24.8 Mln tons in 2010. It is located 500 km from Tallin, 180 km from Riga and 500 km from Vilnius. The existing pipeline capacity connecting the port to the major transmission pipeline is not sufficient to host the LNG terminal. It is an ice-free port.

Port 6 – Port of Klaipeda (Lithuania): This port had a cargo volume of 31.2 Mln tons in 2010. It is located 550 km from Tallin, 250 km from Riga and 300 km from Vilnius. The Klaipeda Jurbarkas pipeline, already under construction, will provide connectivity to the main transmission line. The port is ice free.

The figure below summarizes main port characteristics (Figure 69-74).

Figure 69 - Muuga Port Characteristics



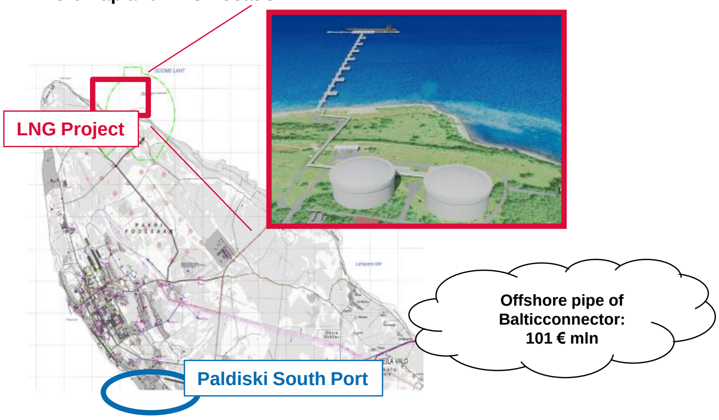
Port Characteristics	
Port dimension (ha) - terrain	525
Port dimension (ha) - water	750
Annual cargo handling (mil.t)	30
Experience with dangerous cargos	Superior
Land available (ha)	6.7 (6.3 to be reclaimed)
Ice issue	Average ice thickness of 30-40 cm during harsh winters

4 Bcm/y capacity / 360 km^3 tanks / 150k m3 vessel investments and requirements	
Planned technology	Onshore
Expandable	Up to 10
Regas Plant Cost (€ mln)	140
Storage (€ mln)	300
Land acquisition (€ mln)	3
Jetty / quay / berth adjustment (m)	250 (concrete)
Jetty / quay / berth adjustment (€ mln)	13
Dredging (m^3)	0
Dredging cost (€ mln)	0
Distance from Transmission network (Km)	25
Cost for connectivity(€ Mln)	18
Total (€ Mln)	474

Source: Booz & Company Analysis

Figure 70 - Paldiski Port Characteristics

Port Map and LNG Location



Cargo Handling

Not Available

Port Characteristics

Port dimension (ha) - terrain	139
Port dimension (ha) - water	137
Annual cargo handling (mil.t)	6
Experience with dangerous cargos	High
Land available (ha)	36
Ice issue	Average ice thickness of 30-40 cm during harsh winters

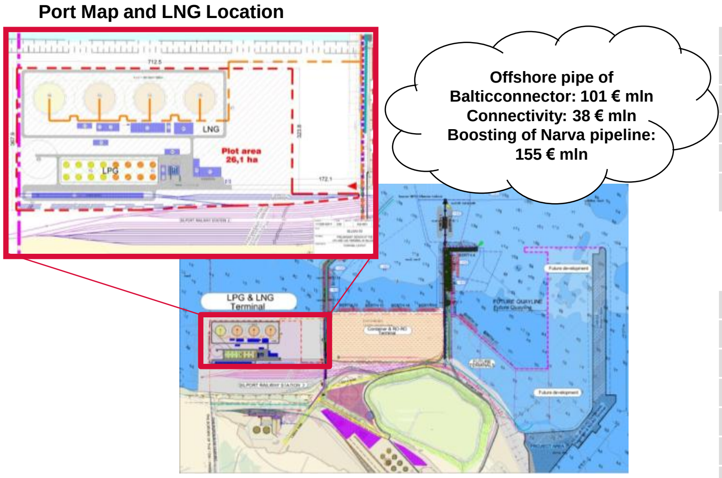
4 Bcm/y capacity / 360 km³ tanks / 150k m3 vessel investments and requirements

Planned technology	Onshore
Expandable	Up to 10
Regas Plant Cost (€ mln)	140
Storage (€ mln)	300
Land acquisition (€ mln)	-
Jetty / quay / berth adjustment (m)	900 (piles)
Jetty / quay / berth adjustment (€ mln)	23
Dredging (m^3)	0
Dredging cost (€ mln)	0
Distance from Transmission network (Km)	54
Cost for connectivity(€ Mln)	38 (0 if Balticconnector is implemented)
Total (€ Mln)	501

Source: Booz & Company Analysis

Figure 71 - Sillamae Port Characteristics

Port Map and LNG Location



Cargo Handling

Not Available

Port Characteristics

Port dimension (ha) - terrain	700[1)]
Port dimension (ha) - water	390[1)]
Annual cargo handling (mil.t)	5[1)]
Experience with dangerous cargos	Oil products and liquids[1)]
Land available (ha)	500[1)]
Ice issue	Average ice thickness of 60-70 cm during harsh winters

4 Bcm/y capacity / 360 km³ tanks / 150k m3 vessel investments and requirements

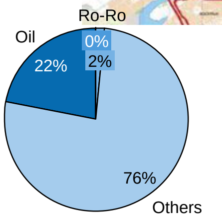
Planned technology	Onshore
Expandable	Up to 10
Regas Plant Cost (€ mln)	140
Storage (€ mln)	300
Land acquisition (€ mln)	-
Jetty / quay / berth adjustment (m)	1500 (concrete)
Jetty / quay / berth adjustment (€ mln)	60
Dredging (m^3)	0
Dredging cost (€ mln)	0
Distance from Transmission network (Km)	3
Cost for connectivity(€ Mln)	2
Total (€ Mln)	502

Source: Booz & Company Analysis

Figure 72 - Riga Port Characteristics

Port Map and LNG Location

Cargo Handling



Port Characteristics	
Port dimension (ha) - terrain	1962
Port dimension (ha) - water	4386
Annual cargo handling (mil.t)	34
Experience with dangerous cargos	Superior
Land available (ha)	36
Ice issue	Average ice thickness of 50-60 cm during harsh winters

4 Bcm/y capacity / 360 km³ tanks / 150k m3 vessel investments and requirements	
Planned technology	Onshore
Expandable	Up to 10
Regas Plant Cost (€ mln)	140
Storage (€ mln)	300
Land acquisition (€ mln)	-
Jetty / quay / berth adjustment (m)	300 (concrete)
Jetty / quay / berth adjustment (€ mln)	8
Dredging (m³)	0 (included in port operation)
Dredging cost (€ mln)	0
Distance from Transmission network (Km)	57
Cost for connectivity(€ Mln)	40
Total (€ Mln)	488

388 Mn. given saving of one tank if synergies with Incukalns are proved

Source: Booz & Company Analysis

Figure 73 - Ventspils Port Characteristics

Cargo Handling

Not Available

Port Characteristics	
Port dimension (ha) - terrain	2209
Port dimension (ha) - water	243
Annual cargo handling (mil.t)	28.5
Experience with dangerous cargos	Superior
Land available (ha)	34
Ice issue	Ice Free

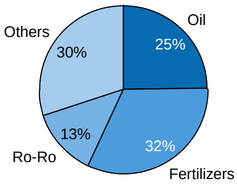
4 Bcm/y capacity / 360 km³ tanks / 150k m3 vessel investments and requirements	
Planned technology	Onshore
Expandable	Up to 10
Regas Plant Cost (€ mln)	140
Storage (€ mln)	300
Land acquisition (€ mln)	-
Jetty / quay / berth adjustment (m)	300 (concrete)
Jetty / quay / berth adjustment (€ mln)	8
Dredging (m³)	0
Dredging cost (€ mln)	0
Distance from Transmission network (Km)	225
Cost for connectivity(€ Mln)	136
Total (€ Mln)	584

Source: Booz & Company Analysis

Figure 74 - Klaipeda Port Characteristics

Port Map and LNG Location

Cargo Handling



Port Characteristics	
Port dimension (ha) - terrain	519
Port dimension (ha) - water	897
Annual cargo handling (mil.t)	37
Experience with dangerous cargos	Superior
Land available (ha)	N-A
Ice issue	Ice Free

4 Bcm/y capacity / 360 km³ tanks / 150k m3 vessel investments and requirements	
Planned technology	FSRU
Expandable	NO
Regas Plant Cost (€ MM)	250
Storage (€ MM)	NA
Land acquisition (€ MM)	-
Jetty / quay / berth adjustment (m)	300 (concrete)
Jetty / quay / berth adjustment (€ MM)	8
Dredging (m³)	0
Dredging cost (€ MM)	0
Distance from Transmission network (Km)	-
Cost for connectivity(€ MM)	29
Total (€ MM)	287[1]

1) Project promoter Klaipedos Nafta reports the overall investment (discounted lease fees and buy-back option) to be 250 Million Euros; details regarding the amounts, the calculation of the different components, and the conditions for the exercise of the buy-back option were not disclosed. Business model of the Klaipeda project does not allow for a like-for-like comparison to the other proposed projects

Source: Booz & Company Analysis

Second step of the analysis was to assess the best port, considering the following characteristics:

Port Infrastructure:

- **Land acquisition:** In case of an onshore terminal, a portion of port land will be acquired. In case of a land purchase, a price must be evaluated, while a royalty rate should be computed in case of a rent.
- **Land preparation**: A series of improvements and arrangements should be implemented, some of them for all the technical solution and some of them only for selected technologies. Main adaptations include jetty construction and pipe bridge.

Network Connection:

- Pipeline to Gas grid: From the port to the closest existing infrastructure, there will be the need of new pipeline, regardless of the chosen technology.

The results of the analysis are shown in the figure below (Figure 75).

Figure 75 - Evaluation of the selected Ports

		Drivers	Sillamae	Paldiski	Muuga	Riga	Ventspils	Klaipeda
Port Infrastructures	Land	**Total investment (€ MM)**	**-**	**-**	**3**	**-**	**-**	**-**
	Jetty (and pipe bridge)	Distance to be covered (m)	1500	900	250	300	300	300
		Price ('000 €/m)	40	13	23	27	27	27
		Total investment (€ MM)	**60**	**23**	**13**	**8**	**8**	**8**
Network Connection	Pipeline to Gas Grid	Distance (km)	3	54	25	57	225	-
		Price (000 €/km)	667	704	720	702	604	-
		Total investment (€ MM)	**2**	**38**	**18**	**40**	**136**	**29[1)]**

Source: Booz & Company Analysis

Ventspils is the furthest port from the transmission network, which would mean a higher required investment for the pipeline to the gas grid.

Klaipeda Jurbarkas pipeline is already under construction, its total estimated cost is € 130 MM. As the Lithuanian Authorities declared that the pipeline would have been built anyway, independently of the need to connect the LNG terminal, we have just considered the cost of connection between the terminal and the main pipeline.

Next, it was assessed the forecasted total investment for each port. The investment was computed for both a 4 Bcm and an 8 Bcm terminal. Moreover, additional infrastructure cost to implement Balticconnector if Muuga port would be chosen rather than Paldiski port were included.

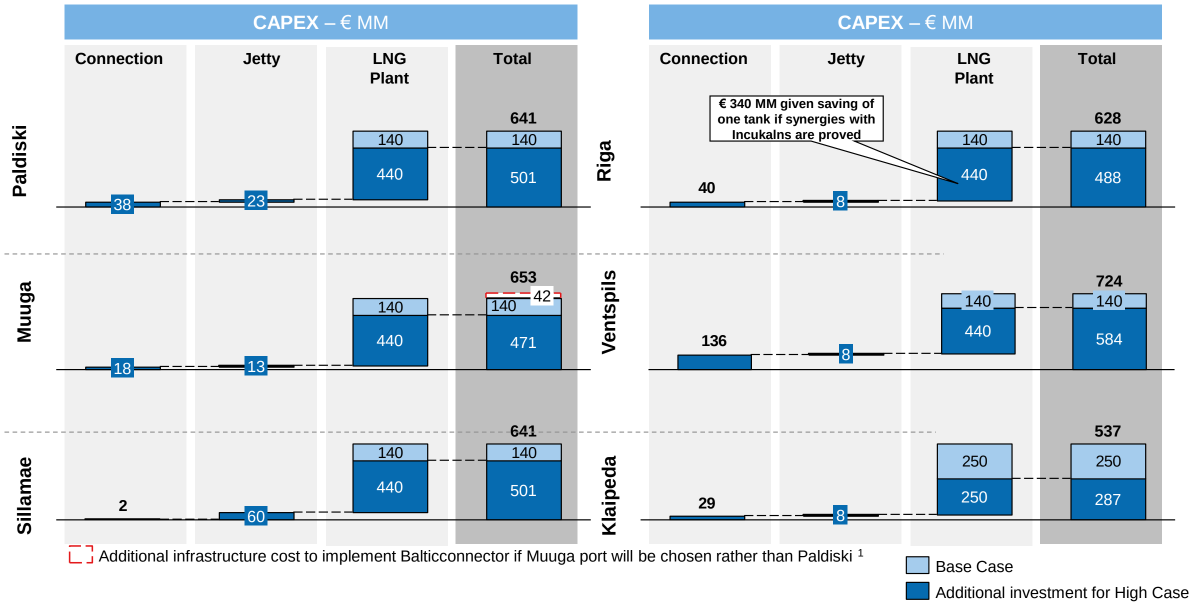
In order to compare different configurations of LNG terminal in the four Baltic States, Booz has based its valuation on the CAPEX connected to the implementation of the terminal and the related infrastructures (e.g. harbor preparation, new connections and upgrade of existing connections, …); given the very early stage of the different proposed projects operating expenditures have not been considered.

Klaipeda LNG terminal is the only project in the early stages of implementation, potentially allowing for a detailed assessment of the project cost. The adopted technical solution for Klaipeda terminal is a FSRU facility leased for 10 years; the lease fee of 43 Millions Euro/year covers for rent, financing cost and overheads. The total cash-out over the lease period would be 430 MM Euro. Project promoter Klaipedos Nafta reports the overall investment (discounted lease fees and buy-back option) to be 250 MM Euros; details regarding the amounts, the calculation of the different components, and the conditions for the exercise of the buy-back option were not disclosed.

Booz and Company is not in the condition of properly compare the Klaipeda LNG project to the other proposed ones, since it has no access to the actual investment full life-time value. Since the investment in the LNG terminal is only one of the several dimensions considered in the assessment of the LNG in the Baltic area, Booz & Company believes that the lack of information on the Klaipeda terminal should not affect the overall project findings. Other dimensions such as balancing network flows in the area, scalability of the solution and integrated regional approach are more relevant

Results are shown in figure below (Figure 76). Paldiski, indeed, is the best solution for an integrated development with Balticconnector

Figure 76 - Cost Breakdown per Port



Source: Booz & Company Analysis

In the study, factors as weather condition also took an important role to determine whether or not a port could be suitable for the LNG terminal. Therefore, winter season (which involves ice days) was taken into account as it could influence the LNG supply at the terminal.

Klaipeda and Ventspils ports are ice free ports, therefore the analysis focused on the remaining four locations.

First, it was assessed whether or not it was possible to reach a port after icebreaker intervention during winter season. Winters were divided in three clusters, following the classification proposed by the Estonian Maritime Administration: mild, moderate and harsh. Data of distances from ice fronts to ports were collected, as well as sailing times from ice fronts to port. Results are summarized in the figure below (Figure 77).

Figure 77 – Distances from Ice Fronts to Ports and Relative Sailing Times, Different Types of Winter

	Mild winter			Moderate winter				Harsh winter				
	Distance from ice front to port (miles)	Sailing time from ice front to port (h) depending on ice class		Distance from ice front to port (miles)	Sailing time from ice front to port (h) depending on ice class			Distance from ice front to port (miles)	Sailing time from ice front to port (h) depending on ice class			
		No ice class 8 knots	1C 10 knots		No ice class 6 knots	1C 8 knots	1B 10 knots		No ice class 4 knots	1C 6 knots	1B 8 knots	1A 10 knots
Sillamae	85	10.6	8.5	225	37.5	28.1	22.5	285	71.2	47.5	35.6	28.5
Muuga	0	-	-	135	22.5	16.9	13.5	200	50.0	33.3	25.0	20.0
Paldiski	0	-	-	85	14.2	10.6	8.5	150	37.5	25.0	18.8	15.0
Riga	30	3.8	3.0	100	16.7	12.5	10.0	140	35.0	23.3	17.5	14.0

Source: Estonian Maritime Administration

As can be seen above, sailing times from ice fronts to ports vary depending on the ice class of the vessel used. The relevant conclusion was that, with previous intervention of the icebreaker, each Estonian port is reachable even with vessels that have no ice class. Among the other ports, Paldiski shows the minimum sailing times for any type of winter considered.

In a second step, average ice thickness and ice period length were assessed, collecting data on past winters (2006 to 2010). Winters from 2007 to 2009 were defined as "extremely mild", while in 2010 all considered ports experienced a ice thickness higher than 30 cm. According to EHMI, in the past 15 winters Paldiski had ice thicker than 15 cm in only two of them, while Muuga in three of them. Relevant informations about ice thickness are provided below assuming uniform ice thickness (Figure 78).

Figure 78 – Average Ice Thickness and Observed Ice Days in Past Winters

	Average Ice Thickness in different winters (cm)			Average Ice Days[1)]	Number of days with ice thicker than 15 cm					Number of days with ice thicker than 30 cm				
	Mild	Moderate	Harsh		2010	2009	2008	2007	2006	2010	2009	2008	2007	2006
Sillamae	20-25	40-50	60-70	90-100	29	4	2	26	61	17	0	0	7	44
Muuga	5-10	25-30	30-40	65-80	28	0	1	0	45	8	0	0	0	5
Paldiski	Up to 5	20-25	30-40	60-70	20	0	1	0	20	14	0	0	0	0
Riga	5-15	25-30	50-60	80-90	37	0	0	0	65	10	0	0	0	14

Source: Baltice, Estonian Maritime Institute, Finnish Institute of Marine Search, Booz & Company Analysis

Moreover, the Baltic Marine Environment Protection Commission has provided some recommendations about the ice class that sailing vessels in the Baltic Sea should be provided with (Figure 79).

Figure 79- Ice Class Classification and Recommendation

Lloyd's Register Ice Classes	Helcom Recommendations
▪ 1 AS: design notional level ice thickness of 1.0 m ▪ 1 A: design notional level ice thickness of 0.8 m ▪ 1 B: design notional level ice thickness of 0.6 m ▪ 1 C: design notional level ice thickness of 0.4 m	▪ 1 A: ice thickness over 50 cm ▪ 1 B: ice thickness between 30 cm and 50 cm ▪ 1 C: ice thickness less than 30 cm

Source:Baltic Marine Environment Protection Commission Baltice, Lloyd's Register

In order to assess the impact that ice might have on LNG supply, the possible loss of natural gas deriving from impossibility to reach port was computed. A LNG terminal with a size of 4 Bcm per year was considered, assuming two possible utilization rates: full (100%, which means 18,000 Mcm/d) and half (50%, which means 9,000 Mcm/d). The terminal was supposed to have a storage capacity of 320,000 m^3 of natural gas, regardless of the utilization level. Therefore, when terminal was used at its full regasification capacity, storage would last 17 days, while when used at its half capacity; storage would last for 35 days. For each of the three types of winter (mild, moderate and harsh) it was computed by how much the storage facility should be boosted, depending on how long ice thicker than 15 cm would last. The required investment to boost the storage capacity was then computed for each port. Results are shown in figure below (Figure 80).

Figure 80 – Required Boosting of Storage Capacity and Relative Investment

	Mild			Moderate			Harsh			Investm. Range	Expected Investm.[1]
	Days of thick ice	Required Boosting		Days of thick ice	Required Boosting		Days of thick ice	Required Boosting		Mln €	Mln €
		Full (m^3)	Half (m^3)		Full (km^3)	Half (km^3)		Full (km^3)	Half (km^3)		
Sillamae	4	-	-	29	355	18	61	867	274	18-867	**272**
Muuga	0	-	-	28	190	-	45	502	91	91-502	**214**
Paldiski	0	-	-	20	45	-	20	45	-	0-45	**14**
Riga	0	-	-	37	210	-	65	794	237	210-794	**386**

Source: Booz & Company Analysis

Some overall conclusions can be drawn, as summarized in the following figure (Figure 81).

Figure 81 – 4 Bcm LNG Terminal Preparation

Port Summary - 4 Bcm LNG Terminal Preparation

Country	Port	Cost[1] (€ MM) Connectivity	Cost[1] (€ MM) Overall Port Costs	Ice Risk[2]
Estonia	Muuga	20	460	Need assistance of icebreaker
	Paldiski	40	460	
	Sillamae	2	500	Not assessed
Latvia	Riga	40	450	Need assistance of icebreaker
	Ventspils	140	450	Ice Free
Lithuania	Klaipeda	29	250[4]	Ice Free

Key Considerations

- **Port preparation**:
  – All ports would require similar investment spending
  – Key economic differences rely on connection to the network
- **Technical feasibility**
  – All ports analysed have a clear and well defined project to welcome the LNG terminal (excluding Sillamae project which is still under evaluation).
  – Major technical issues potentially impacting the terminal effectiveness seem to be considered by the project team (i.e. port width, infrastructures, dredging, etc.)
- **ICE Risk** (although not considered as no-go criteria for the assessment of strategic location of LNG**):**
  – **Both Muuga, Paldiski and Riga are reachable** with icebreaker even with no ice class vessels
  – Assuming assistance of icebreaker, with a *no ice class* vessels maximum delay, in harsh winter due to ice is around 1.5-3 days
- **Additional decision criteria**
  – Project team capabilities proven experience to run a LNG terminal
  – Economic development of LNG surrounding area.

1) Port preparation includes € 140 MM for a 4 Bcm regasification plant for onshore terminal. Klaipeda would be a FSRU therefore there are not port preparation costs but FSRU acquisition/leasing costs.
2) Ice risk assessed based on the winter conditions may impact LNG terminal operations through ice formations; 3) Qualitative assessment driven by cost and ice risk
4)Project promoter Klaipedos Nafta reports the overall investment (discounted lease fees and buy-back option) to be 250 Million Euros; details regarding the amounts, the calculation of the different components, and the conditions for the exercise of the buy-back option were not disclosed. Business model of the Klaipeda project does not allow for a like-for-like comparison to the other proposed projects
Source: Meeting with Baltic stakeholders; Estonian Maritime Institute, Finnish institute of marine research; Booz & Company Analysis

Source:Estonian Maritime Institute, Finnish Institute of Marine Searche, Booz & Company Analysis

Port preparation costs would be almost equal for each port. Key economic differences would rely on network connectivity.

Port preparation includes € 140 MM for a 4 Bcm regasification plant for onshore terminal. Klaipeda would be a FSRU; therefore there are no port preparation costs, but FSRU acquisition/leasing costs..

Ice risk, assessed considering different winter conditions, may impact LNG terminal operations through ice formation.

To sum it up:

Technical Suitability: All analysed ports have a clear and well defined project to welcome the LNG terminal (excluding Sillamae that is still under evaluation). Major technical issues may impact the effectiveness of the terminal have been managed by the project team (i.e. port width, infrastructures, dredging, etc.).

Strategic decision has to be taken: Once the country is defined, the final decision of the port should be based on other factors:

- Project Team capabilities proven experience to run a LNG terminal;
- Political consideration related to the economic development of LNG surrounding area. The LNG would bring positive externalities that should be taken into consideration by the selected country.

6.6. EVALUATION OF THE BEST SOLUTION AND COST ANALYSIS

Locating the LNG terminal in Estonia would ensure diversification of supply, full compliance with the N-1 rule. Such results would be obtained with lower investments compared to other locations based on an on-shore technical solution. Ice risk would be manageable, given the possibility to use icebreaking services in the winter (Figure 82).

Other reasons include the followings:

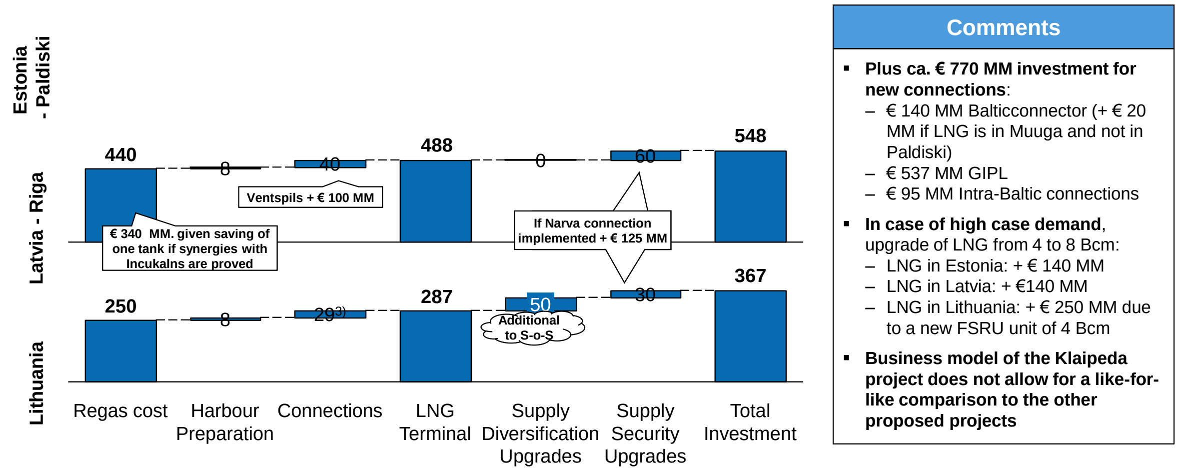
- In case LNG would not be located in Estonia, Narva project would gain strategic relevance;
- If placed in Estonia, the maximum additional investment required to get security of supply would be the lowest among the three countries;
- In terms of supply diversification, it would be granted if the terminal was placed in Estonia, while some adjustments would be needed in Latvia or Lithuania;
- LNG in Lithuania would over-strengthen the role of the country in the Region;
- Latvian (Ventspils) and Lithuanian ports would not be a risk for winter cargos, but Estonia ice issues are manageable.

Figure 82–Assessment of Strategic Decision

	Estonia	Latvia	Lithuania
Country Demand	< 1 Bcm	2 Bcm	3 Bcm
Additional capacity required for Regional Supply Security (Bcm/year)	1.5 – 2.1	2.4 – 5.2	0.9 – 3.1
Supply Diversification	Granted	Base Case: winter flows are not optimized High Case: requires investments	Requires investments in base and high cases
Ice Free Port	Manageable	YES (Ventspills) Manageable (Riga)	YES

Source: Booz & Company Analysis

Figure 83 - Analysis of Required Investments for LNG – Base Case (€ MM)



Source: Booz & Company Analysis

Estonia connection is nil because it would be the onshore continuation of the Balticconnector.

Lithuania-Latvia interconnection enchantment was included (bidirectional up to 6 Mcm/d), as well as the Latvia-Estonia (bidirectional up to 10 Mcm/d). Incukalns capacity was assumed to work with a capacity up to 3.2 Bcm.

Balticconnector cost includes offshore and onshore connection to the Estonian Transmission System. If LNG was placed in Muuga, then a further investment of € 20 MM would be required compared to Paldiski.

In case of high demand scenario, the LNG should be of 8 Bcm, requiring an upgrade of investments for all the three countries, but with Estonia implying still the minimum investment (Figure 83).

In conclusion, three possible implementation strategies were identified that would benefit the Baltic Region (Figure 84).

A first option is to invest in the GIPL and Intra-Baltic connections, for a total investment of about € 630 MM. Among the major advantages of this options there are:

- Connection to Western Hub;
- Increased attractiveness of Incukalns (access for Poland);
- Diversification targets;
- Baltic countries (i.e. Lithuania and Latvia) could become transit country connecting Europe directly to Russia (without intermediates);
- S-o-S reached with additional investments.

This solution could address a demand up to 5.5 Bcm/y, it would reach a diversification target of 63%, accessing market at Western Hubs prices. The additional investment for reaching security of supply would range from € 60 to € 185 MM. The transmission cost increase would be 0.65 US$/MMbtu.

A second solution comprehends the LNG terminal, the Intra-Baltic connections and the Balticconnector, for a total investment of around € 700 MM. In this case the addressable market is 11 Bcm/y, the access to markets would derive through LNG, therefore benefitting of LNG prices. Regional diversification target would be met for only 33%, while the additional investment for security of supply would cost € 160 MM. Among the major advantages of this option there are:

- Grid Balance;
- Increased attractiveness of Incukalns (access for Finland);
- Finland included in the market;
- S-o-S reached with additional investments.

Last solution comprises all three projects, implying an investment of € 1.25 Bn. The addressable market would be 11 Bcm/y, therefore the same as in the second solution. This time, however access to markets would be granted by LNG and Western hubs prices. Diversification target would be reached for 63%, while the additional investment for reaching security of supply would be limited to € 30 MM. The transmission cost increase would be 0.49US$/MMbtu. The following advantages would be reached:

- Connection to Western Hubs;
- Increase attractiveness of Incukalns (access for Poland and Finland);
- Diversification targets;
- Baltic countries (i.e. Lithuania and Latvia) could become transit country connecting Europe directly to Russia (without intermediates);
- Grid Balance;
- S-o-S reached with limited investments.

Figure 84 –Baltic Infrastructures Strategic Options

	GIPL + Intrabaltic	LNG + Intrabaltic + Balticonnector	All projects
Investment	≈ € 630M	≈ € 700 M	≈ € 1250 M
Additional investment for S-o-S	€ 60-185 M	€ 160 M	€ 30 M
Addressable demand	5.5 bcm/y	11 bcm/y	11 bcm/y
Transmission cost increase	0.65 $/mbtu	0.3 $/mbtu	0.49 $/mbtu
Access to markets	Western hubs price	LNG price	Western hubs and LNG prices
Regional diversification target	63%	33%	63%
Comments	▪ Connection to Western Hub ▪ Increase attractiveness of Incukalns (access for Poland) ▪ Diversification targets ▪ Baltics countries (i.e. Lithuania and Latvia) could become transit country connecting Europe directly to Russia (without intermediates) ▪ Finland is not included in the market ▪ S-o-S reached with additional investments	▪ Grid Balance ▪ Increase attractiveness of Incukalns (access for Finland) ▪ Finland included in the market ▪ S-o-S reached with additional investments	▪ Connection to Western Hub ▪ Increase attractiveness of Incukalns (access for Poland and Finland) ▪ Diversification targets ▪ Baltics countries (i.e. Lithuania and Latvia) could become transit country connecting Europe directly to Russia (without intermediates) ▪ Grid Balance ▪ Finland is included in the market ▪ S-o-S reached with limited investments

Source: Booz & Company Analysis

7. LNG VALUE PROPOSITION ASSESSMENT

7.1. Approach

In the last section of the study, a four steps approach was followed in order to identify the LNG value proposition and suggest alternative strategies to diversify imports.

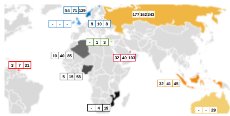
The approach of each step can be summarized as follows (Figure 85):

Figure 85 - Four Steps Approach for the Assessment of LNG Value Proposition

1 Possible evolution of prices

- Estimation of national gas production costs through gas field analysis of main country producer
- Current margins analysis (margins are assumed to be at the same level in the future)

2 Assessment of available gas



- Analysis of available spare capacity through comparison of production volumes and contracted demand for each main country producer
- Assessment of spare liquefaction capacity available

3 Evaluate LNG Value Proposition

- Assessment of the value proposition of the LNG based on the preferred location
- Assessment of diversification based on Russian share over the total gas supply
- Assessment of security based on N-1 rule

4 Alternative supply strategies

- Identification of possible alternative strategy to be implemented to reach Baltics gas diversification and security targets

Step 1: Possible Evolution of Prices. This step included the estimation of gas production though the analysis of main gas producing countries. After, the analysis of current margins was run in order to forecast future gas prices.

Step 2: Assessment of Available Gas. In this step, it was analysed the available gas supply spare capacity through the comparison of production volume and contracted demand for each main country producer. Besides, it was also analysed the available spare liquefaction capacity. The result of this step was a shortlist of possible exporters that could supply the Baltic States.

Step 3: Evaluation of LNG Value Proposition. Based on preferred location, it was assessed the value proposition of the LNG in terms of the benefits it will bring to the Baltic area. Moreover, diversification and security of supply were tested.

Step 4: Alternative supply strategies. The study was run in order to identify the possible alternative strategies that could grant the Baltic States those benefits of a LNG terminal.

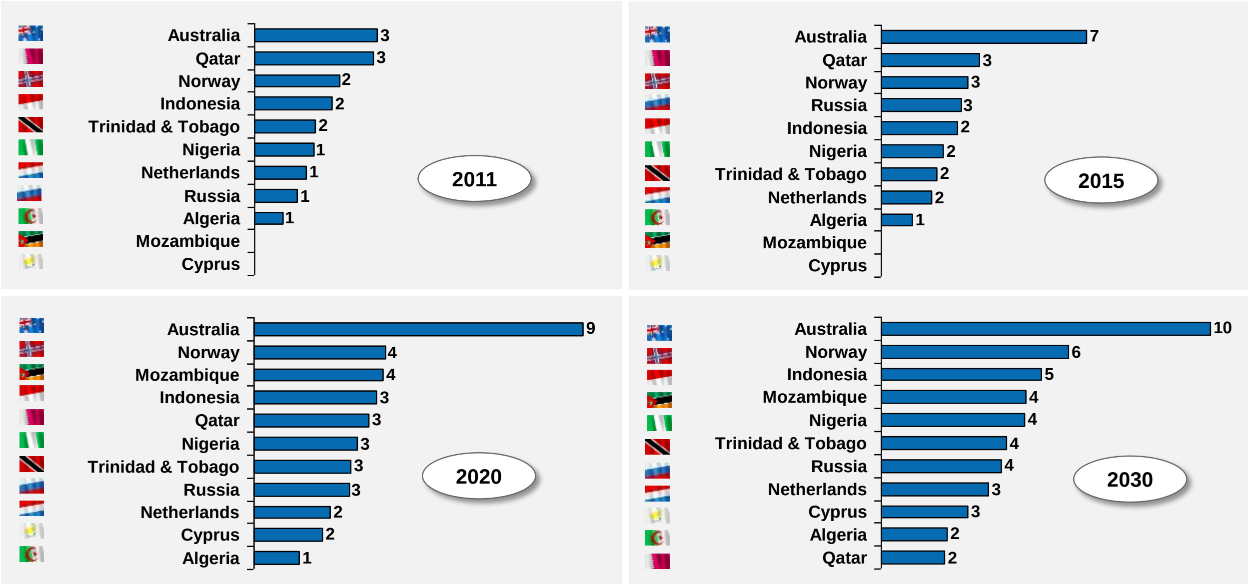
7.2. Analysis

Step 1 - Possible Evolution of Prices

In order to assess the convenience of LNG over gas via pipe, it was first forecasted the most likely evolution of gas production costs of major exporting countries, as the production cost is part of the final price that a country pays for purchasing its gas.

The results of the analysis are shown in the figure below (Figure 86).

Figure 86 - Production Costs per Unit by Country ($/MMbtu; 2011 – 2015 – 2020 – 2030)



Source: Booz & Company Analysis

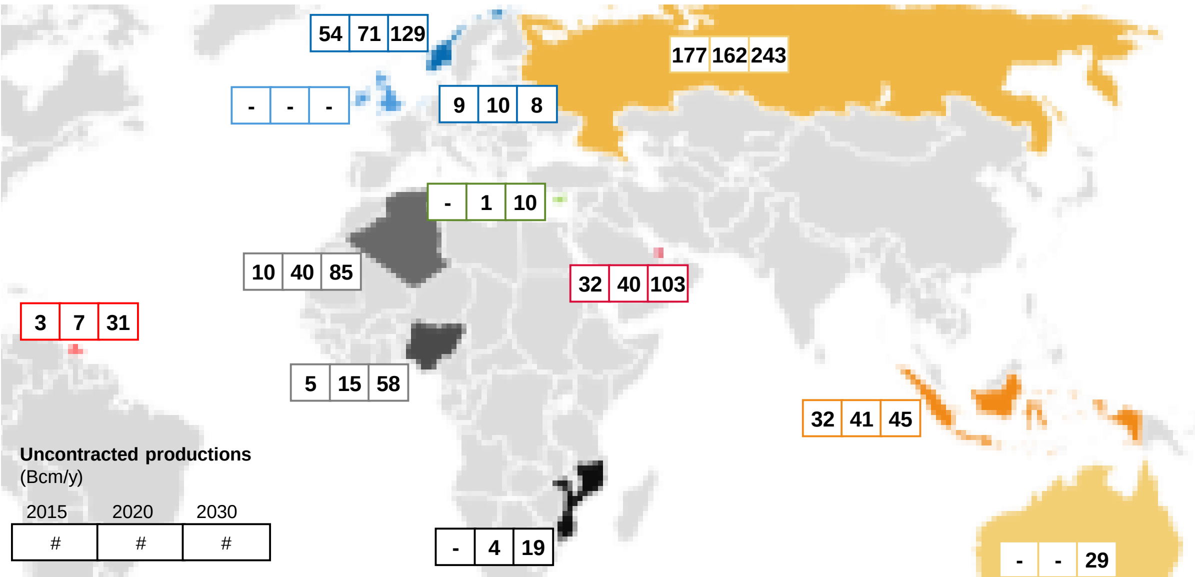
There is a change from current to future production costs scenario: Australia will experience a rise in its costs over next 20 years as prices will more than triple. This is mainly due to the morphology of Australian territory, which present many extraction sites located far way one from each other and with a size that does not allow considerable economies of scale. Overall, production costs rise for all countries, except for Qatar, which only produces LNG and will benefit from past explorations. Finally, Mozambique and Cyprus would play a relevant role thanks to the discovery of new extraction sites.

Step 2 - Assessment of Available Gas

The aim of this second step was to identify potential gas exporters that could supply the Baltic States in the future. In order to do so, it was first considered the un-contracted production of major gas exporters in the world. Each exporter has a certain amount gas produced and depending on the existing contracts with importer countries, some of this production is not contracted. This un-contracted gas might either be allocated (sold to importing countries that did not fully contracted their demand) or left spare.

As of 2012, the following map shows the future un-contracted supply of gas (Figure 87).

Figure 87 - World Un-contracted Production (Bcm/y)

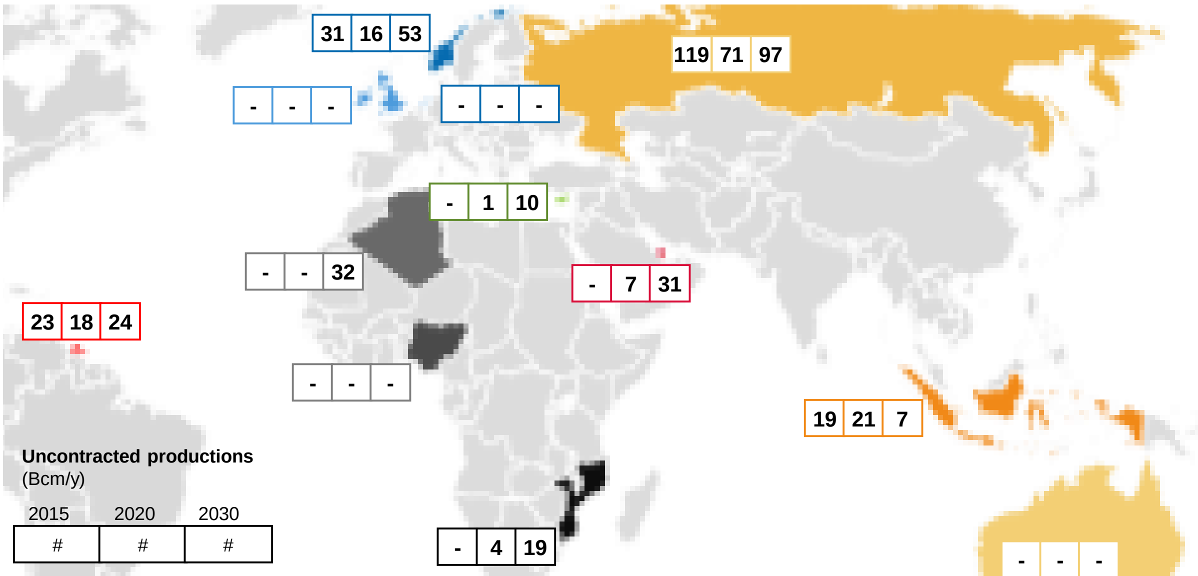


Source: Booz & Company Gas Model Analysis

However, not all the un-contracted supply should be considered available for exportation. Algeria, for example, has contracts with Eni/Sonatrach (16 Bcm) and with Spain (23 Bcm) that will expire respectively in 2019 and between 2015 and 2030. These contracts are most likely to be renewed, and therefore there will unlikely be spare capacity from Algeria. A similar situation can be observed for Australia: its 30 Bcm contract with Japan is expected to be renewed. Production in Netherlands is expected to decrease and will be mainly used to fulfil internal demand. Different scenario is forecasted for Nigeria and Indonesia. In Nigeria gas production is expected to boost, while in Indonesia no major contracts are expected to be in place in the future, however, 50% of production will fulfil national demand.

Therefore, the below map was defined to highlights the world unfulfilled gas production (Figure 88). The map shows that at current market conditions, there could be spare gas production to supply Baltic countries.

Figure 88 - World Unfulfilled Production (Bcm/y)



Source: Booz & Company Gas Model Analysis

However, unfulfilled production would not grant gas supply. A second issue to be addressed was the actual liquefaction capacity of those countries that will have an unfulfilled spare demand: the availability of spare gas would be subjected to the possibility to liquefy the gas at extraction sites and transport it to importing country. Through the Booz & Company Global Gas Model it was assessed which countries will have liquefaction capacity in the future, assuming that liquefaction capacities will remain the same as those of today.

The table below shows that only Russia and Norway would be capable of liquefy the spare gas in 2030 (Figure 89). However, considering that one of the goals of this study was to find alternatives to Russian supply, Norway remains the sole alternative gas exporter of LNG.

Figure 89 - Spare Liquefaction Capacity (Bcm; %; 2015; 2020; 2030)

Norway	**6**	**12**	**12**
Algeria	**54**	**54**	**54**
Trinidad Tobago	**22**	**29**	**29**
Qatar	**135**	**135**	**135**
Russia		**46**	**54**
Indonesia	**29**	**33**	**33**

Norway	0%	0%	73%
Algeria	0%	0%	0%
Trinidad Tobago	0%	0%	0%
Qatar	0%	0%	0%
Russia		32%	92%
Indonesia	0%	0%	0%

>70% 70%-30% <30%

Source: Booz & Company Gas Model Analysis

However, upcoming gas producers such as Cyprus and Mozambique could represent an alternative to Norwegian gas (see figure below), if new investments in liquefaction capacities will be implemented (as of today, none of the two countries have liquefaction capacity). Otherwise, LNG from Norway might be the only alternative to Russian gas and it will be likely supplied at market high end LNG price due to increasing production costs (Figure 90).

Figure 90 – Spare Production, Production Costs and LNG Availability in 2030

	Spare Production (Bcm at 2030)	Production Cost ($/MBTU at 2030)	LNG Availability (Bcm at 2030)
Algeria	32	2,0	-
Australia	-	9,9	-
Cyprus	10	2,6	10
Indonesia	7	4,8	-
Mozambique	19	4,4	19
Netherland	-	3,2	-
Nigeria	-	4,3	-
Norway	53	5,6	9
Russia	97	1,9	49
Qatar	31	3,6	-
Trinidad & Tobago	24	3,8	-

Source: Booz & Company Gas Model Analysis

Step 3 –LNG Value Proposition

Third steep assessed the value proposition of the LNG terminal in terms of the following objectives:

- **Supply Security:** proposed Baltic pipelines infrastructures alone do not fully allow all Baltic countries to meet the N-1 rule. However, locating the LNG terminal in Estonia and investing on interconnections would meet the target;
- **Supply Diversification:** although a 4 Bcm terminal could be sufficient, together with the GIPL pipe, to limit the relevance of Russian gas, the alternative LNG sources are not competitive with pipe gas prices;
- **Russian Gas Pipe Price Cap:** the diversification opportunity offered by the LNG terminal would put a cap on Russian gas piped price, given different sourcing options;
- **Demand Modulation and Peak Demand Coverage:** A 4 Bcm LNG terminal would be the optimal size (built through a ramp up) to meet Baltic current limited gas demand and to exploit the likely increase in future demand through scalability of the investment. Additionally, it would be big enough to have sufficient storage to grant supply in case of high peak demand.

Overall, the LNG terminal could be a cap to Russian gas prices and act as a strategic source to cover peak demand.

Step 4 –Alternative Supply Strategies

The fourth step can be divided in three different but interconnected sections:

Section A - Identification Alternative Sourcing Strategies: this section aimed to identify the alternative entry points to Baltic countries in order to diversify the market, as well as sourcing points.

Section B - Assessment of the European Infrastructure Network: this section implied the study of the European infrastructure network and its connection to entry points in Baltic area. It also included an assessment of the European infrastructure network utilization rate that may impact supply to Baltic countries.

Section C - Assessment of required Baltic States Infrastructures development: last section's goal was to identify the required infrastructure network development in the Baltic region that would be necessary to achieve diversification targets set by the presence of LNG in case alternative investments will be implemented. This last section involved also related costs assessment.

A detailed description of each section is provided below.

<u>Section A - Identification Alternative Sourcing Strategies.</u>

As can be seen from figure below, the main alternative strategy to LNG terminal that would enable the Baltic countries to diversify gas supply should be based on the boosting of the Poland – Lithuania interconnection capacity.

The Western and southern Europe infrastructure network would play a critical role in the Baltic countries diversification strategy (Figure 91). Moreover, Poland may lend gas from several sources (both Pipe and LNG):

A. Worldwide LNG from Swinoujscie Terminal in Poland;

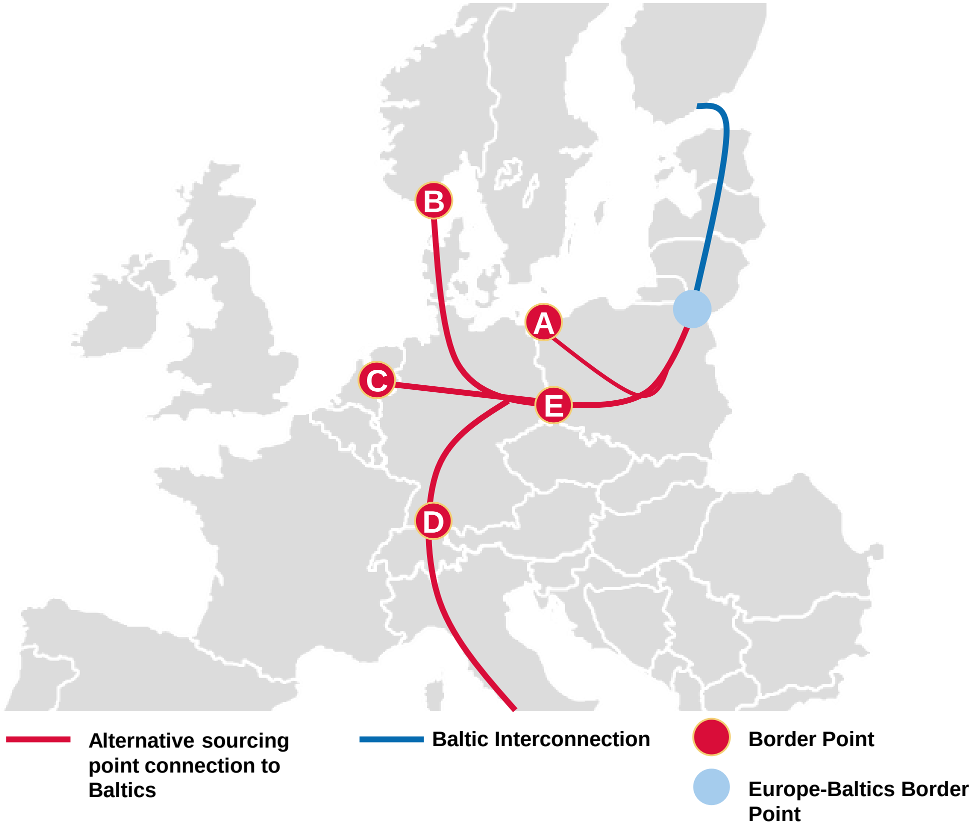
B. Norway gas pipe through Germany;

C. Worldwide LNG from Gate Terminal in Netherlands;

D. African and Caspian gas pipe trough Italy and Transitgas RF ;

E. Germany-Poland connection, currently planned, is essential to enable Baltic region diversification (it could also be a reverse flow, if viable).

Figure 91 - Alternative Routes for Gas Reaching Baltic Region



Source: Booz & Company Gas Model Analysis

Section B - Assessment of the European Infrastructure Network.

The second section looked at European infrastructures in terms of possible bottlenecks that might occur when gas is transported to Baltic area.

The figure below shows possible infrastructure utilization rates for each of the pipeline considered (Figure 92).

Figure 92 - European Infrastructure Utilization Rates (%, 2015 – 2030)

	From:	To:	2015	2020	2025	2030	Border Capacity: Bcm/y[1]
A	Poland (Swinoujscie LNG)		0%	0%	31%	31%	4
B	Norway	Germany	77%	83%	100%	14%	36
C	Netherlands	Germany	49%	45%	26%	26%	51
C	Netherlands (Gate LNG)		0%	0%	0%	0%	10
C	Belgium	Germany	0%	0%	0%	0%	7
C	Belgium (Zeebrugge LNG)		65%	45%	45%	3%	7
D	Switzerland	Germany	0%	68%	17%	0%	14
D	Algeria	Italy	100%	100%	100%	100%	30
D	Libya	Italy	97%	100%	100%	100%	10
D	Greece	Italy		70%	0%	38%	9
D	Turkey	Greece		77%	9%	100%	10
E	Germany	Poland	50%	50%	38%	33%	8

Utilization Rate:

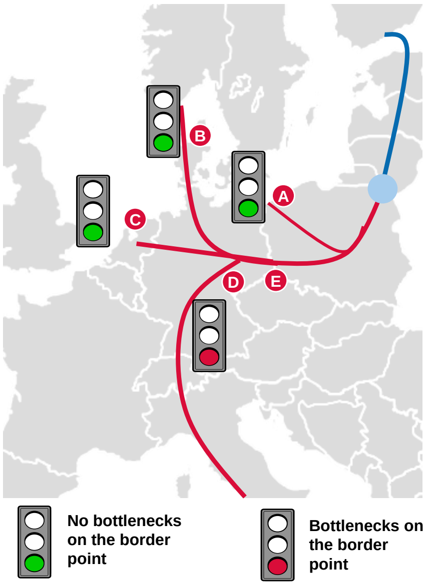
0% – 20% | 20% – 60% | 60% – 100%

Source: Booz & Company Gas Model Analysis

In Poland and in Norway, LNG might be available due to low utilization rates. There might not be bottlenecks on Western European infrastructure network. Besides, more pipe gas and LNG could get into Germany from Belgium and The Netherlands. On the other side, Italy might be capped both from Africa (Algeria and Libya) and from Southern Eastern Europe (Greece); therefore no spare capacity might be left to transport gas to Central Europe. Finally, Germany – Poland pipeline could have a spare capacity to bring gas from Europe to Baltic countries.

The figure below summarizes bottlenecks in alternative sourcing (Figure 93).

Figure 93 - Map of Possible Bottleneck



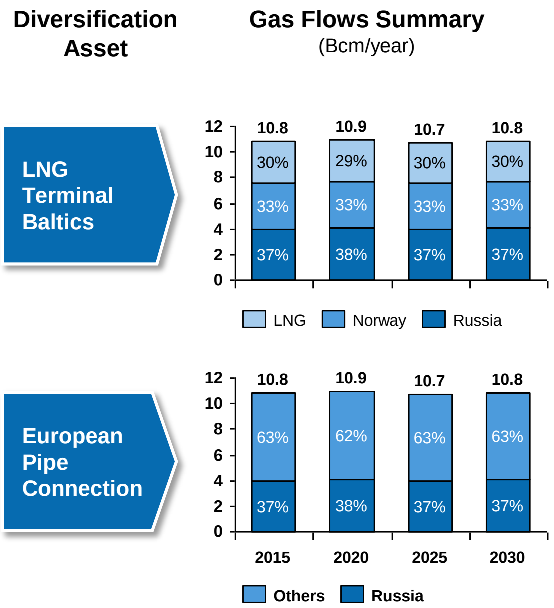
Source: Booz & Company Gas Model Analysis

Section C - Assessment of required Baltic Infrastructures development

In the last section, it was assessed which would be the required investment in case an alternative strategy other than the LNG terminal would be chosen. The analysis was run both for the base case and the high case demand scenarios. The diversification target level was set as that reached by locating the LNG terminal in Estonia (previously chosen as the most convenient location).

The following figure represents the output of the analysis for the base case demand scenario (Figure 94).

Figure 94 - Base Case Demand Scenario: Required Investments



Infrastructure developments required

Border Point (From - To)	Capacity (Bcm/year)[1] Actual	Required
Germany - Poland	10	
Poland - Lithuania	4.5	
Lithuania – Latvia	4.0	
Latvia – Estonia	3.3	
Estonia - Finland	2.4	

Border Point (From - To)	Capacity (Bcm/year)[1] Actual	Required
Germany - Poland	10	+4
Poland - Lithuania	4.5	+4
Lithuania – Latvia	2.2	+2.8
Latvia – Estonia	3.3	
Estonia - Finland	2.4	

10.8 Bcm/y

Source: Booz & Company Gas Model Analysis

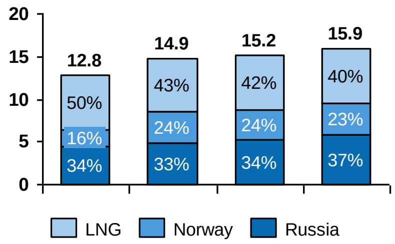
In the upper side of the figure, the LNG effects and requirement on the area are shown: Russia would have a share of 37% in 2030 on the overall gas supply in the area. No further investments on the Intra-Baltic infrastructure would be necessary. In the lower part of the figure, it is shown what would be the required investment in case piped gas would supply the Baltic countries, assuming a target diversification identical to that of LNG. Overall, in the base case demand scenario minor further infrastructure developments would be necessary to achieve diversification targets. Three pipeline routes (specifically the Germany-Poland, the Poland-Lithuania and the Lithuania- Latvia) will require boosting of capacity for a total of 9 Bcm/y. Assuming a cost of 0.03 €/ Scm^3 the expected monetary investment will be € 320 MM.

The figure below, instead, summarizes the results obtained considering a high case demand scenario (Figure 95).

Figure 95 - High Case Demand Scenario: Required Investments

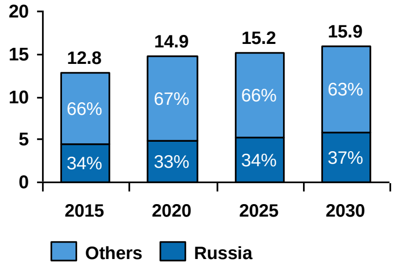
Diversification Asset | **Gas Flows Summary** (Bcm/year) | **Infrastructure developments required**

LNG Terminal Baltics



Border Point (From - To)	Capacity (Bcm/year)[1] Actual	Capacity (Bcm/year)[1] Required
Germany - Poland	10	
Poland - Lithuania	4.5	
Lithuania – Latvia	2.2	
Latvia – Estonia	3.3	
Estonia - Finland	2.4	

European Pipe Connection



Border Point (From - To)	Actual	Required
Germany - Poland	10	+8
Poland - Lithuania	4.5	+8
Lithuania – Latvia	2.2	+6.3
Latvia – Estonia	3.3	+2.4
Estonia - Finland	2.4	

24.7 Bcm/y

Source: Booz & Company Gas Model Analysis

In the upper side of the figure, the LNG effects and requirement on the area are shown: Russia would have a share of 37% in 2030 on the overall gas supply in the area. No further investments on the Intra-Baltic infrastructure would be necessary. In case of high demand scenario higher infra-structure developments, in addition to the proposed projects, would be necessary to achieve diversification targets reached with an LNG terminal, the total further investment required would be 23 Bcm/y, totalling € 740 MM (assuming a cost of 0.03 €/Scm^3).

Alternative Supply Strategies Summary

Overall, the alternative strategy to a LNG terminal in Baltic region would necessary require a connection to Europe by pipeline. An effective alternative strategy would bring similar contribution to Baltic area than a LNG terminal. This has been assessed on supply diversification because supply security would not be reached with a LNG either.

Poland-Lithuania connection would be the only likely solution to avoid further dependence on Russia.

With competitive LNG prices, the Poland-Lithuania connection may be sufficient, exploiting LNG from Swinoujscie regasification facility. Otherwise pipe gas would be more convenient and improvements on German-Poland connection would be necessary to bring additional gas to the region. The European pipe connection would require at least € 300 MM to finance further network improvements to those already under evaluation (Balticconnector, GIPL, and Intra-Baltic Connections).

Although the boost on the European network may require a lower investment than a new LNG terminal and the LNG sourcing could not be competitive to pipe gas, the terminal located either in Latvia or Estonia would be the unique opportunity to have a third entry point in the region. Baltic infrastructure would be effectively exploited and diversifications target would be reached.

8. ADDENDUM: ASSESSMENT OF LNG TERMINAL IN FINLAND

As requested by DG ENER during the BEMIP High Level Group meeting held in Brussels on September 11th, Booz & Company has conducted a high level strategic assessment of Finland as possible location for the Baltic LNG Terminal.

This assessment complements the finding proposed in this report and it has been conducting assuming as possible Finnish regasification terminal the FinGulf project as proposed for PCI candidate (project code G41).

The FinGulf LNG Terminal would fit within the strategic goal set by the European Commission to improve both S-o-S and diversification in the Baltic region. It would bring the same benefits of a LNG terminal located in Estonia, both in terms of supply diversification and security of supply. Furthermore a LNG terminal in Finland has the advantage to be closer to the centre of biggest gas consumer in the region, namely Finland (Figure 96).

Figure 96 - Investments required for Supply security (N-1 rule) and supply diversification

	Network Upgrades for Supply Diversification[1]				Network Upgrades for Security of Supply[1]			
	Base Case		High Case		Base Case		High Case	
LNG Location	Capacity (Bcm/y)	Cost (€ Mln)	Capacity (Bcm/y)	Cost (€ Mln)	Capacity (Bcm/y)	Cost (€ Mln)	Capacity (Bcm/y)	Cost (€ Mln)
ESTONIA	-	-	-	-	1.5	30[2]	2.1	30[2]
LATVIA	-	-	2.1	60	2.4	60[3]-185	5.2	120[3]-245
LITHUANIA	2.8	80	9.0	270	0.9	30[3]-155	3.1	90[3]-215
FINLAND	-	-	-	-	1.5	30[2]	2.1	30[2]

Source: Booz & Company analysis; Booz & Company Gas Model

The project sponsors propose either a FSRU technology with an overall cost of about € 300 MM or a land based Onshore Terminal (about € 400 MM). Given the scalability required to serve the Baltic region in the high case regional demand, the onshore solution of 4 Bcm/year of capacity has been retained for the current analysis.

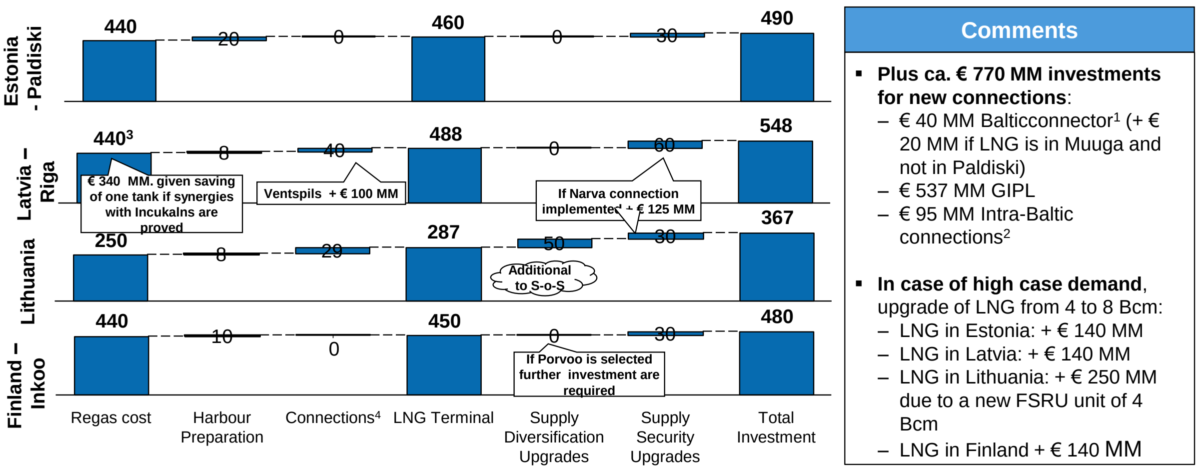
The Balticconnector would be connected to the FinGulf LNG terminal and will land in Estonia at Paldiski as it is currently the only viable solution analysed through a feasibility study. The port fitting costs have been assumed with an average of € 10 MM of investment, while European pipe enhancements investment cost have been used as benchmark for the connectivity estimations.

The LNG terminal in Finland would improve the S-o-S of Finland and through Balticconnector also Estonia will largely cover the internal peak demand (limited investments would be still required to grant Lithuania S-o-S as well). Supply diversification in the region is granted transferring up to 2 Bcm/y to Estonia, Latvia and possibly Lithuania without any further investment than those already presented in the case the LNG were located in Estonia (Figure 97).

The FinGulf LNG project currently identifies either Inkoo (port 60 Km East from Helsinki) or Porvoo (50 Km West from Helsinki) as possible locations for the terminal. Main characteristics of the selected locations:

- Inkoo project, as currently proposed, has daily capacity of 19.2 Mcm/d. The location lies at 20 Km of distance from Finland transmission network. Inkoo port is kept open by the icebreakers of the Finnish Maritime Administration in wintertime. The ice conditions are favourable during normal winters, as the channel is ice free almost always.
- Porvoo capacity would be limited to 9 Mcm/d. The location is 5 Km distant from Finland transmission network

Figure 97 – Analysis of Required Investment for LNG - Base Case (€ MM)



Source: Booz & Company Analysis

In summary, the FinGulf LNG project brings all benefit included in the Estonian solution and allows further closeness to the biggest consumption centre (Figure 98).

Figure 98 – Assessment of Strategic Decision

	Estonia	Latvia	Lithuania	Finland
Country Demand	< 1 Bcm	2 Bcm	3 Bcm	5 Bcm
Additional capacity required for Regional Supply Security (Bcm/year)	1.5 – 2.1	2.4 – 5.2	0.9 – 3.1	1.5 – 2.1
Supply Diversification	Granted	Base Case: winter flows are not optimized High Case: requires investments	Requires investments in base and high cases	Granted
Ice Free Port	Manageable	YES (Ventspills) NO (Riga)	YES	Manageable

Source: Booz & Company Analysis