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Gas Decarbonisation Pathways for Estonia

Deliverable 2: Baseline Data Collection Report

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**Disclaimer**

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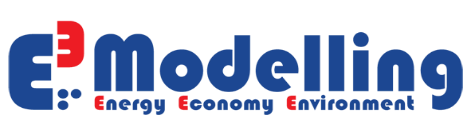
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# Introduction

This report provides an overview of collected data pertaining to the joint gas market in Estonia. The data collected and described will be used in the gas modelling to develop pathways for decarbonising the Baltic RGMC countries (Estonia, Latvia, Lithuania, and Finland) gas supply by 2050, as well as in a socio-economic impact analysis, sensitivity studies, a detailed risk assessment and in the development of policy action plans. This data report is supplemented by a Microsoft Excel data map which contains more detailed data. These data maps provide further documentation and explanations on the data, and indicate which sources were used.

Collected data can be categorised according to the purpose of the data. Many parameters have been collected to establish the baseline (BAU) scenario and 3 decarbonisation scenarios for sustainable gas supply modelling in Deliverable 3. Numerous parameters were required to cover this topic, including data on gas demand in the Baltic-Finnish zone, data on existing cross-border gas grid capacities, traded volumes between RGMC countries, LNG terminals, large storage points, current legislation/regulations for the functioning of the gas sector, EU and country specific policies towards carbon neutrality, technical parameters for alternative gas production technologies, planned pilot projects for gas decarbonisation in the Baltic-Finnish zone, and country specific domestic sustainable gas production and potential.

To collect data that will feed into the socio-economic analysis, many aspects of the Estonian economic system and its anticipated development were investigated, including information on produced goods, and provided services, but also on household incomes and employment parameters. The socio-economic data is not discussed further in this report as detailed data tables are provided separately as a Microsoft Excel data file.

**Chapter 2** of the report gives the summary of the collected data, presented in tabular form. **Chapter 3** of the report presents the summary of relevant data of the last 5 years, describing the current situation of the Estonian joint gas market (Baltic RGMC countries) and an overview of current EU legislation/regulation to decarbonise the gas sector. This is relevant for describing the changes coming for each Estonian market participants and their part in decarbonisation of the gas network. **Chapter 4** of the report gives the trends to 2050 based on existing EU and national level policies with different sector-specific targets. In this section EU targets and country specific NECPs and NDPs are investigated. During the D3 modelling, all these policies and sectoral targets will be considered. **Chapter 5** of the report gives an overview of suitable decarbonised technologies (i.e. in 5 years or more) enabling the Estonian gas network to become carbon neutral with different technologies and its parameters such as cost, TRL, and efficiency. A better understanding of the technology readiness is critical in making good decisions about the inclusion, development and integration of new technologies in complex projects: for these reasons, the Technology Readiness Level (TRL) will be used tool for readiness assessment, also to detail the planned implementation, for technologies related to production, storage, demand/response in the context of the gas market. Also, ongoing and planned pilot projects in the Baltic-Finnish zone geographical and in neighbouring EU countries to decarbonise the gas sector are listed in this chapter. Finally, **Chapter 6** of the report summarises the local potential of biogas/biomethane, hydrogen, and storage options for the Baltic Finnish region based on the inputs provided by the MEAC, in consultation with RGMCG region.

Figure 1- 1 Estonian joint gas market [Source: Conexus Baltic Grid]16

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# Summary of Collected Data

The following table provides an overview of the key data parameters of the gas market in Baltic Finnish region. Throughout the data collection process, data at the highest level of detail possible was always sought after. Open-source data was preferred; however, collecting data from public sources was not always possible. To fill in these data gaps, the ministries and stakeholders were contacted directly. In situations where stakeholders indicated certain data points could not be shared due to sensitivity issues, suitable assumptions have been made. The finalised data map has been sent out to the steering board members after the verification from different stakeholders.

The table presented below shows an overview of the data parameters that will be used in D3 – Pathway Modelling, D4 – Socioeconomic Impact Assessment, D5 – Risk Assessment, D6 – Sensitivity Analysis, and D7 – Action Plan of the study.

Figure 2- 1 Data parameters mapped to relevant deliverables

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Table 2‑1. Map of collected data

| **Parameter** | **Unit** | **Relevant deliverables** | **Geographical coverage** | **Temporal resolution** |
| --- | --- | --- | --- | --- |
| Gas consumption by sector [natural gas, gas alternatives] | TWh | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| Gas produced/processed [natural gas, gas alternatives] | TWh | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| Gas transport of [natural gas, gas alternatives] transported through pipeline linkages connecting each pair of regions | TWh | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| Gas transport- Energy loss, expressed as a fraction of line input or output | % | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| GHG emissions [CO2eq.] for each stage in the gas fuel chain [[Production, processing, transmission and storage, distribution, consumption]] that occurs in the region | CO2eq. | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| Fuel price (fuel consumed to produce gas alternatives) | €/MWh | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| NG import price for gas originating from each different region | €/TWh | D3 | Poland, Russia, Belarus, rest-of-world | Annual |
| ***Statistical data collected for a single year or an annual indicator*** | | | | |
| Sub annual consumption of natural gas, gas alternatives | GWh | D3 | Estonia, Latvia, Lithuania, Finland | Monthly or seasonal |
| Production capacity for natural gas, gas alternatives | GW | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Share of each feedstock consumed to produce gas alternatives | GW | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Conversion efficiency (in energy terms) for converting feedstocks into [gas alternatives] | % | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Sub annual availability of production/processing capacity for natural gas and gas alternatives | GW | D3 | Estonia, Latvia, Lithuania, Finland | Monthly or seasonal |
| Net capacity of all pipeline linkages connecting each pair of regions | GWh/day | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Total capacity of all gas storage facilities when full | TWh | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Liquefaction/regasification installed capacities for natural gas, gas alternatives like syngas, biomethane, and hydrogen | TWh | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Sub-annual availability of liquefaction/regasification capacity for natural gas, gas alternatives like syngas, biomethane, green and blue hydrogen | GWh | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Energy loss or round-trip storage efficiency, expressed as a fraction of energy stored | % | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Conversion efficiency or energy losses for [liquefaction, regasification] of [gas alternatives like syngas, biomethane, and hydrogen]] | % | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Capital cost, annual fixed cost, and maintenance cost per unit of capacity, and variable O&M cost per unit of energy for gas production plant | €/kW, €/kWh | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Capital cost, annual fixed cost, and maintenance cost per unit of capacity, and variable O&M cost per unit of energy for gas transmission pipelines | €/kW, €/kWh | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Capital cost, annual fixed cost, and maintenance cost per unit of capacity, and variable O&M cost per unit of energy for storage facilities (UGS) and LNG plants | €/kW, €/kWh | D3 | Estonia, Latvia, Lithuania, Finland | Most recent data |
| Fuel Characteristics - Net energy density (lower heating value) | GWh/ton | D3 | - | Most recent data |
| ***Data forecasts and estimations collected until 2050*** | | | | |
| Fuel prices (fuel consumed to produce gas alternatives) | €/MWh | D3, D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| All sectors target mixture of [gas alternatives]] in final gas mix consumed | % | D3 | Estonia, Latvia, Lithuania, Finland | 2030/2050 |
| EU ETS prices | €/t | D3, D4, D6 | EU | Annual |
| Cross-border transmission capacities | GWh/d | D3 | Estonia, Latvia, Lithuania, Finland | Annual |
| Electrification rate in NG consumption sectors | % | D3 | Modelled region | Annual |
| ***Socioeconomic parameters for Estonia*** | | | | |
| Gross domestic product and its main components | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Employment levels | Persons | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Employment by skill and economic activity | Persons | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Labour productivity (GDP/employee) | €/person | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Household disposable income | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Household disposable income spent on energy | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Household expenditure by consumption purpose | € (or %) | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Gas costs for households | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Gas costs for commercial consumers | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| NG taxes and levies | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Government taxes and revenues | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Value added | € | D4, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Population trends/forecasts | %, persons | D4, D5, D6 | Estonia, Latvia, Lithuania, Finland | Annual |
| Input Output table |  | | | |

# Historical data and overview of current legislation/regulation and functioning of gas sector

## Historical data

There is no natural gas production in Estonia, Latvia, Lithuania, and Finland. The current gas consumption in the Baltic-Finnish region is mainly dominated by natural gas. Local biogas production is limited and mainly used for electricity production. Some biomethane is produced in Estonia and Finland and is being used as bio-CNG in the transport sector. There is currently no hydrogen use in Estonia and Latvia, but it is being produced and consumed in Finland (in refinery processes) and in Lithuania (in refinery and fertilizer production processes). Current hydrogen production in Finland and Lithuania is based on NG. In Finland only 1% of the total hydrogen produced is electrolytic hydrogen.[[1]](#footnote-2)

Natural gas is either imported in the Baltic-Finnish gas market via pipelines from Russia and Belarus or via LNG terminals. In 2021, 5.02 TWh, 7.78 TWh, 24.27 TWh, and 25.08 TWh natural gas were consumed in Estonia, Latvia, Lithuania, and Finland respectively[[2]](#footnote-3). Country gas mix profiles are presented in the following sections.

###### Estonia

**Natural Gas**

The largest natural gas (NG) consumer in Estonia is the heat production sector (district heating) followed by the industry and buildings sectors (residential, commercial, and public services), and a small amount of electricity is being produced from NG in Estonia, whereas the transport sector has only a small number of gas users. The natural gas consumption profile is shown in **Figure 3‑1**.

Figure 3‑1. Natural gas consumption profile for Estonia[[3]](#footnote-4)

**Biogas/biomethane**

In 2019, Estonia produced about 100 GWh of biogas, from which 38 GWh of electricity was generated. The country’s total biogas production capacity amounts to 25 MW, corresponding to 9.4 MW of installed electricity generation capacity. The first biomethane plant Green Gas OÜ (annual capacity of 5-6 million Nm3) started to produce biomethane from aspen pulp wastewater in the first quarter of 2018. The second biomethane plant Biometaan OÜ (annual capacity of 1.3 million Nm3) produces biomethane from agricultural residues and other feedstocks since June 2018. All the produced biomethane is used in the transport sector. There are 20 bio-CNG filling stations in Estonia; 19 stations offer a blend of bio-CNG and natural gas, while 1 station offers pure bio-CNG. The following **Figure 3‑2** shows the historical production of biogas as per the feedstock used.[[4]](#footnote-5)

Figure 3‑2. Biogas production in Estonia4

**Latvia**

**Natural Gas**

Natural gas consumption in Latvia has increased slightly from 13.13 TWh in 2015 to 14.263 TWh in 2019 and decreased to 7.78 TWh in 2021. The largest NG consumer in Latvia is the electricity generation sector followed by the buildings sector (residential, commercial, and services) and industry, whereas agriculture/forestry and transport only consume small NG volumes (67 GWh and 2.5 GWh in 2019 respectively). While the consumption levels of the buildings and industry sectors remained in 2015-2019 largely at the same level, the gas use for electricity production shows large fluctuations, depending on electricity demand and other supply sources. Sectoral natural gas consumption profile for Latvia (2015-2019) is shown in the **Figure 3‑3**.

Figure 3‑3. Natural gas consumption profile for Latvia[[5]](#footnote-6)

**Biogas/biomethane**

The production of biogas is very limited in Latvia, and there is no biomethane injection into the grid. It is stated in the 2020 report from the Renewable Gas Trade centre in Europe (REGATRACE)[[6]](#footnote-7) that ‘unless the Latvian government drastically changes its legislation and puts in place a legal basis for biomethane production, the Latvian biogas and biomethane sectors will not develop in future. The trajectory of the overall production of biogas production and capacity shows a decrease in numbers in recent years. Legislation on biomethane production has not yet been introduced in Latvia, yet one biogas plant did start producing biomethane for its own needs in 2020’. The historical production of biogas is shown in **Figure 3‑4**.

Figure 3‑4. Biogas production in Latvia4

##### Lithuania

**Natural Gas**

Natural gas consumption in Lithuania has decreased from 26.3 TWh in 2015 to 24.27 TWh in 2021. The largest NG consumer in Lithuania is the non-energy sector (used as feedstock for fertilizer production and in refinery processes) followed by the electricity production, energy use in industry, and buildings sector (residential, commercial, and services), whereas agriculture/forestry and transport only use small volumes (267 GWh and 341 GWh in 2019 respectively). Sectoral natural gas consumption profile (2015-2019) is shown in the **Figure 3‑5**.

Figure 3‑5. Natural gas consumption profile for Lithuania5

**Biogas/biomethane**

The biogas production was 390 GWh in 2019.4 Till 2020, biomethane was in Lithuania not used as biofuel for transportation. Currently there is no biomethane injection in the natural gas network. There are at present no restrictions or specific standards for injecting biomethane into the natural gas network, but if biomethane would be injected into the grid, it must be made compatible with the natural gas quality specifications.

**Hydrogen**

Currently, hydrogen is produced in Lithuania for use as feedstock to produce fertilizers and in an oil refinery. Small quantities of hydrogen are produced for blending with natural gas to fuel natural gas-powered public buses. Hydrogen is in general produced from fossil fuel (Steam Methane Reform) without carbon capture[[7]](#footnote-8). Achema is the largest hydrogen producer in the Baltic States; it uses it as feedstock to produce fertilizers. Achema has two steam methane reforming (SMR) facilities and produced 5.9 TWh of hydrogen in 20206. The other major hydrogen producer is Orlen Lietuva, which operates an advanced and the only oil refinery in the Baltic States. It has two units for hydrogen production.

##### Finland

**Natural Gas**

Natural gas consumption in Finland has decreased from 28.9 TWh in 2015 to 25.076 TWh in 2021. The largest NG consumer in Finland is the electricity production sector followed by industry, whereas the non-energy sector (refinery), agriculture/forestry, buildings, and transport only consume very small NG volumes (771 GWh, 13 GWh, 695 GWh, and 232 GWh in 2019 respectively). Sectoral natural gas consumption profile for Finland (2015-2019) is shown in the **Figure 3‑6**.

Figure 3‑6. Natural gas consumption profile for Finland5

**Biogas/biomethane**

Biogas is in Finland currently used in CHPs. In 2019, Finland produced 474 GWh of biogas, from which 180 GWh of electricity was generated. Finland’s total biogas production capacity was 97 MW in 2019, corresponding to 37 MW of installed electricity generation capacity. In 2019, 156 GWh biomethane was produced in Finland, and 10% of it was injected into the gas grid4. The following **Figure 3‑7** depicts the historical production of biogas per feedstock.

Figure 3‑7. Biogas production in Finland4,9

**Hydrogen**

The total dedicated hydrogen production in Finland is estimated at 140000 - 150000 t/a (4.7–5.0 TWh), of which 99 % is produced from fossil fuels (from NG via either steam reforming (SMR) or partial oxidation of solid fossil fuels) and only <1 % is produced via water electrolysis using electricity. Annual NG sourced hydrogen production (via SMR) is presented in **Figure 3‑8**. In addition, 22000 - 24 000 t/a (730–800 GWh) of by-product hydrogen is generated via sodium chloride electrolysis. In Finland, approximately 88% of the produced hydrogen is used in refinery processes including biofuel production. The remainder is used in the chemical industry and mining sector. By-product hydrogen from NaCl electrolysis is mostly used to generate process steam, district heat, and to a lesser extent also electricity (via Rankine cycle) at the chlorate and chlor-alkali plant[[8]](#footnote-9).

Figure 3‑8. NG sourced hydrogen production trend in Finland[[9]](#footnote-10)

**Country figures for biogas and biomethane production**

An overview of the biogas and biomethane production of the four countries (Estonia, Latvia, Lithuania, Finland) is shown in the following **Figure 3‑9.** The biogas and biomethane production data for 2020-2021 is not yet available for Lithuania so it is assumed as constant from 2019 to 2021.

Figure 3‑9. Biogas production in the Baltic-Finnish region[[10]](#footnote-11)

Latvia and Lithuania don’t have any biomethane production yet, but they have plans to produce biomethane and inject it in the transmission grid. The annual biomethane production data for Finland and Estonia is presented in the following figure. The biomethane production in Estonia in the years 2020 and 2021 is 98 GWh and 154 GWh respectively[[11]](#footnote-12).

Figure 3‑10. Biomethane production in Estonia and Finland4

## Natural gas network Infrastructure and flows

Russia was historically the main natural gas supplier to the Baltic and Finnish region. This dependency slightly decreased as of 2017, when the Klaipėda LNG terminal was commissioned and started importing NG for injection into the grid and the Inčukalns underground gas storage (UGS) in Latvia. Till 2019, the gas system of the Baltic countries was not connected with Finland but in January 2020, the Balticonnector came into operation and enabled natural gas trade from/to Finland through the Estonian joint gas network. Since May 2022, Lithuania is connected to Poland's gas network which further reduces its gas import dependency from Russia. Beforehand, the gas pipeline network of the Baltic countries and Finland was not connected to the European NG grid. Due to the current geopolitical situation, the countries in the Baltic-Finnish region intend to drastically reduce (and eventually stop) their gas imports from Russia. As a first step, Lithuania, Estonia and Finland stopped its gas import from Russia from April/May 2022. Latvia planning also planned to stop the gas import from Russia by end of 2022. The following map shows the gas interconnection points in the Baltic/Finnish joint gas market.

Figure 3‑11. Baltic and Finnish Natural Gas Pipeline Connection Points

Map

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**Estonia**

Elering AS is the sole gas transmission system operator (TSO). It owns and operates a network of 10 gas pipelines (977.4 km, 43 of which are transit pipelines), 3 gas metering stations, and 36 gas distribution stations. The Estonian gas transmission system is connected with Russia and Latvia through three interconnectors. The Izborsk–Inčukalns and Pskov–Riga pipelines are parallel pipelines in Southeast Estonia and used primarily for transporting gas between Russia and Latvia but also to supply the Misso GDS located in Estonia. These parallel pipeline sections are not connected to the rest of the Estonian transmission network. Gaasivõrgud, a subsidiary of Eesti Gaas, is the major distribution system operator (DSO) in Estonia. It operates the 1486 km long distribution network owned by Eesti Gaas under a commercial leasing contract. There are 23 other small companies operating 648 km of natural gas distribution networks[[12]](#footnote-13).

The maximum technical capacity of the Estonian interconnection points is shown in **Table 3‑1**. The Karksi, and Balticonnector points allow bidirectional flows; the gas is being imported and exported through the following interconnection points.

Table 3‑1. Technical capacity of gas connection points in Estonia12

| **Interconnector** | **Maximum technical capacity** |
| --- | --- |
| Latvia-Estonia (Karksi, Bi-directional) | 7 mcm/d (73.5 GWh/d) |
| Russia-Estonia (Värska) | 4 mcm/d (42.0 GWh/d) |
| Russia-Estonia (Narva) | 3 mcm/d (31.5 GWh/d) |
| Finland-Estonia (Balticconnector, Bi-directional) | 7.7 mcm/d (81.2 GWh/d) |

The historical gas flows at the different interconnection points are shown in the following figure. The gas flows highly fluctuate throughout the year depending on fluctuating market demand and trade.

Figure 3‑12. NG flows in interconnection points of Estonia[[13]](#footnote-14)

**Latvia**

Latvia has a total of 1200 km of transmission pipelines, including 3 cross-border connection points, two with Estonia (Karksi-Murati) and one with Lithuania (Kiemenia). JSC Conexus Baltic Grid is the only TSO in Latvia. The recent improvements of the interconnection infrastructure enabled the increase of natural gas flows to the volumes required in the single Baltic natural gas market and enable traders/suppliers active in Estonian or Finland to also use the Incukalns underground gas storage (IUGS) in Latvia12.

The maximum technical capacity of the Latvian interconnection points is shown in the following table. The Karksi, and Lithuanian connection points allow bidirectional flows; natural gas is being imported and exported through the following interconnection points.

Table 3‑2. Technical capacity of Latvian gas connection points12

| **Interconnector** | **Maximum Technical capacity** |
| --- | --- |
| Latvia-Estonia (Karksi, Bi- directional) | 73.5 GWh/d |
| Lithuania - Latvia (Kiemenai) | 67.6 GWh/d |
| Latvia - Lithuania (Kiemenai) | 65.1 GWh/d |

The historical gas flows at the different interconnection points are shown in **Figure 3‑13**. The gas flow fluctuates based on the market demand fluctuations and trade opportunities. The different gas import and export flows are presented in the following figure which includes the injected and withdrawn gas volume in IUGS. The complete data is available only from 2018.

Figure 3‑13. NG volume flows in interconnection points of Latvia[[14]](#footnote-15)

**Lithuania**

Lithuania has 2100 km of transmission pipelines, including 3 interconnection points, one with Belarus (Kotlovka), a bidirectional connector with Latvia (Kiemenia), and an interconnection point with Kaliningrad (Šakiai). Since 5 May 2022, Lithuania and Poland gas pipelines are connected via the 508 km long Gas Interconnection Lithuania–Poland (GIPL) pipeline[[15]](#footnote-16). Since then, gas is flowing between Poland and the Baltic gas network. Ab Amber Grid is the only TSO in Lithuania. The planned increase of the Latvia-Lithuania interconnection capacity will enable the exchange of greater volumes of natural gas between Latvia and Lithuania, which is especially important to establish a fully integrated single Baltic natural gas market. The interconnection capacity is expected to increase to 125 GWh/d when the project is completed, which is scheduled in 2023[[16]](#footnote-17).

The maximum technical capacity of the Lithuanian interconnection points is shown in the following table. The Latvian and Polish interconnectors allow bidirectional flows; the gas is imported and exported through the following interconnection points.

Table 3‑3. Technical capacity of Lithuanian gas interconnection points12

| **Interconnector** | **Maximum Technical capacity** |
| --- | --- |
| Lithuania - Latvia (Kiemenai) | 67.6 GWh/d |
| Latvia - Lithuania (Kiemenai) | 65.1 GWh/d |
| Poland - Lithuania (GIPL) | 2.6 GWh/h, 22.5 TWh/a |
| Lithuania - Poland (GIPL) | 2.4 GWh/h, 21 TWh/a |

The historical gas flows at each interconnection point are shown in the following **Figure 3‑14**. The gas flow fluctuates based on the market demand and trade opportunities. The different gas import and export flows are presented in the following figure which includes the gas infeed from the Klaipeda LNG terminal.

Figure 3‑14. NG volume flows in the interconnection points in Lithuania[[17]](#footnote-18)

**Finland**

Finland has a total of 1300 km of gas transmission pipelines. Gasgrid Finland Oy is the only gas TSO in Finland. Finland has one interconnection point with Russia (Imatra), through which gas is imported. The Finnish gas transmission network is also connected to Estonia via the Balticonnector, which is 152 km long and allows bidirectional flows. In Finland, there are three compressor stations (Imatra, Kouvola, and Mäntsäla) with a total capacity of 64 MW. The following table presents the maximum technical capacity of the interconnector for cross-border gas trade16.

In 2021, Finland used around 28 TWh of pipeline gas, out of which the Balticonnector accounted for roughly 6.2 TWh. Currently Finland is building a new LNG terminal (Hamina), upon completion, this terminal can import up to 3 TWh of natural gas. The maximum technical capacity of the Balticconnector is shown in the following table.

Table 3‑4. Technical capacity of Finland gas interconnection point9

|  |  |
| --- | --- |
| **Interconnector** | **Maximum Technical capacity** |
| Balticconnector (Finland-Estonia) | 7.7 mcm/d (81.2 GWh/d) |

The historical gas flows via the Balticonnector are shown in **Figure 3‑15**.

Figure 3‑15. NG volume flow in interconnection points of Finland13

## LNG terminal and Underground storage

Natural gas is for short-term flexibility needs stored at LNG terminals while underground storage capacities (depleted oil and gas reservoirs, salt caverns, etc.) are used to provide seasonal flexibility and hence contribute to gas supply security. This section describes the current situation; new development projects are presented in the chapter 6 (local potentials).

**Estonia**

Estonia has no LNG terminal and no underground storage facilities.

**Latvia**

Inčukalns underground gas storage (IUGS) in Latvia is the only functional large-scale storage facility in the Baltic countries; it is the 3rd largest UGS in Europe and ensures the security of gas supply at regional level. Conexus Baltic Grid is next to its role as TSO also operating the IUGS. During the summer season, when the gas consumption level is several times lower than in the winter, natural gas is pumped into the storage site, so that in the heating season it can be supplied to consumers in Latvia, Estonia, north-west Russia and (in smaller amounts) Lithuania. Inčukalns UGS has a storage capacity of 4.47 billion cubic meters, from which 2.32 billion cubic meters (24.2 TWh) are active storage quantities or constantly pumped natural gas.[[18]](#footnote-19) Historically, the region has been dependent solely on natural gas supplies from Russia. When the Klaipeda LNG terminal in Lithuania was commissioned in 2014, it created an alternative route for Latvia to reduce the gas import from Russia. In 2017, natural gas imported via the Klaipeda LNG was for the first time injected into the IUGS16. The active gas storage volumes were constantly changing over the last five years, as shown in **Figure 3‑16**.

Currently, Latvia doesn’t have any LNG terminal.

Figure 3‑16. Active gas storage in Inčukalns underground gas storage (IUGS)14

**Lithuania**

The Klaipeda LNG terminal, operated by AB Klapėdos nafta, is the only LNG terminal in the Baltic region. It is owned by the Lithuanian state and a private shareholder. An almost 18 km long pipeline connects the LNG terminal with the natural gas transmission lines of Amber Grid AB. The LNG terminal was commissioned in 2014 and consists of a floating storage and regasification unit (FSRU) with a total technical capacity of 10.25 mcm/d and an operational LNG storage capacity of 170000 m3 (about 1.2 TWh). **Figure 3‑17** presents the LNG regasification and reloading handling volumes since 2017.

Figure 3‑17. Gas handling data for Klaipeda LNG terminal (regasification and reloading)[[19]](#footnote-20)

**Finland**

Finland has 2 LNG terminals located in the northern part of the country; they are not connected to the national NG grid but directly supply gas to mainly industrial sites9. These terminals will not be included in the modelling, because they are not connected with the transmission grid9. The terminals are operated by the Finnish state-owned energy company Gasum Oy. Finland doesn’t have any underground gas storage.

## Main EU legislation, policies and strategies affecting the Baltic/Finnish gas sector

The EU has published several legislative documents, policies and strategies that should enable the decarbonisation of the gas sector, including by facilitating and accelerating the deployment of biomethane and hydrogen as part of the decarbonization options. Recent initiatives for revised directives and policies such as the new energy and climate targets for 2030, the EU commitment for a fully decarbonised energy supply by 2050, the recast gas directive and regulation, the renewable energy directive, the energy efficiency directive, and the EU hydrogen strategy will have a major impact on the gas sector. Moreover, due to the Russian invasion in Ukraine, natural gas imports from Russia will have to be reduced more rapidly and drastically. To this end, REPower EU extensively addresses the role of LNG imports and gas storage as well as alternative gas supply sources and routes, next to the increased deployment of hydrogen and biomethane. Some major political initiatives at EU level are summarised in **Table 3‑5** and other recent revisions or additions to EU legislation are briefly described below. Also, there is a range of incentives in place to encourage the production and/or use of renewable and decarbonised gases, but they differ greatly between Member States, and few of them address grid connection and access[[20]](#footnote-21).

Table 3‑5. Overview of policies

| **Policy** | **Overview** |
| --- | --- |
| **Repower EU****[[21]](#footnote-22)** | -Increase the stored gas volumes before winter 2022; Existing gas infrastructures in the EU territory should be filled up to at least 90% before 1 October.  -Phasing out our dependence on fossil fuels from Russia should be done well before 2030, with two pillars:  **-Diversifying gas supplies**, via higher LNG imports and pipeline imports from non-Russian suppliers, and higher levels of biomethane and hydrogen.  **-Reducing faster our dependence on fossil fuels** at the level of buildings, transport and the industry, and at the level of the power system by boosting energy efficiency gains, increasing the share of renewable and addressing infrastructure bottlenecks. |
| **Gas directive26** | -Regulators must verify that the network and connection's technical design and operating rules, including safety, are properly defined.  -Promoting the integration of large- and small-scale renewable gas generation, both in transmission and distribution networks, in accordance with energy policy, including by removing barriers to additional capacity.  -Regulators’ duties include establishing norms and conditions for network connection and access, as well as ensuring that there are no cross-subsidies.  -Regional cooperation between regulators for operation, network codes and congestion. |
| **Recast Renewable Energy Directive**[[22]](#footnote-23) | -Provisions for the access to and operation of gas networks with gases from renewable sources.  -Biomethane is included in the definition of biogas as ‘gaseous fuels produced from biomasses.  -Extension of guarantees of origin to all renewable gases, including hydrogen.  -Increase in biomethane consumption. |
| **EU Hydrogen strategy[[23]](#footnote-24)** | -The share of hydrogen in Europe’s energy mix is projected to grow from the current share (less than 2%) to 13-14% by 2050.  -Repurposing or reusing parts of existing natural gas infrastructure, helping to avoid stranded assets in the future and to provide an opportunity for a cost-effective energy transition in combination with newly built hydrogen pipelines.  -An incentivising, supportive policy framework needs to enable renewable and, in a transitional period, low-carbon hydrogen to contribute to decarbonisation at the lowest possible cost.  -Hydrogen can decarbonise mainly the difficult to electrify energy uses in industry and (heavy-duty) transport sectors. |

The proposed EU Hydrogen and decarbonised gases market package,[[24]](#footnote-25) which is not yet formally adopted by the European council and parliament, includes measures to stimulate the deployment of renewable and low carbon gases. To this end, hydrogen-based infrastructure will progressively complement the natural gas infrastructure and fossil gas use will progressively be replaced by renewable electricity, hydrogen (or its derivates) and biogas/biomethane. The current regulatory framework for gaseous energy carriers does not address the deployment of hydrogen as a specific energy carrier via dedicated hydrogen networks. There are at present no rules at the EU level on regulated tariff-based investments in hydrogen networks, or on the ownership and operation of dedicated hydrogen networks, and on the third party access to pipelines. In addition, harmonized rules on (pure) hydrogen quality do not yet exist. Consequently, barriers exist to the development of a cost-effective, cross-border hydrogen infrastructure and a competitive hydrogen market, a prerequisite for the uptake of hydrogen production and consumption.

Some of the important changes introduced in the **Recast EU directive and regulations on gas**is that the scope is now enlarged to also incorporate renewable gases and hydrogen as key components of the future EU gas market. The draft legislation foresees that tariff discounts of 75 % can be applied to facilitate access of hydrogen and renewable gases to the gas grid (a discount of 100 % would apply for the first year after the recast EU Gas Regulation takes effect). New rules are proposed requiring firm network capacity for hydrogen and renewable gases, hydrogen blending with other gases (including an obligation for TSOs to accept a hydrogen content of up to 5 % in interconnectors from 1 October 2025), and cross-border coordination on gas quality (assisted by an ENTSOG monitoring report on gas quality every two years). These new firm capacity requirements will apply to both TSOs and DSOs. A legal framework for cross-border EU hydrogen networks is developed, including the establishment of network codes[[25]](#footnote-26).

The **Energy Efficiency Directive ('EED')** and the related Energy Performance of Buildings Directive ('EPBD') including the proposals for their amendment, interact with the present initiative as they affect the level and structure of gas demand. Energy efficiency measures can substantially reduce gas demand while alleviating energy poverty and reducing consumer vulnerability. As gaseous fuels are currently dominating the European heating and cooling supply, as well as the transport sector and the cogeneration plants, their efficient use and substitution where appropriate (e.g., electrification of transport and heating) stay at the core of the energy efficiency measures. The Gas Directive and the Gas Regulation are coherent with the energy efficiency first principle: an open and competitive EU market with prices that reflect energy carriers’ production costs, carbon costs, and external costs and benefits would efficiently provide clean and safe hydrogen to end users who value it most[[26]](#footnote-27).

The revised Trans-European networks in energy (**TEN-E) Regulation** was proposed by the Commission in December 2020, and adopted as a delegated regulation since April 2022, aims to better support the modernisation of Europe's cross-border energy infrastructure for the European Green Deal26. While No oil projects were submitted for the Project of Common Interest list, the future natural gas infrastructure projects would no longer be eligible as projects of common interest (PCI) and therefore unable to secure Connecting Europe Facility (CEF) funding. It means that natural gas infrastructure projects are excluded from the scope of the revised TEN-E Regulation except for H2 blending into existing natural gas pipelines and storage during a transitional period that will end in 2029. Smart gas grid investments (new PCI category) would be promoted to facilitate integration of clean gases (like biogas and renewable hydrogen) into existing natural (methane) gas networks.[[27]](#footnote-28) Moreover, the REPowerEU set the stage for all the interconnectors to be compatible for transferring hydrogen in the future aiming at hydrogen infrastructures expansion across the Union.

In 2021, the European Union imported an average of over 380 million cubic metres (mcm) per day of gas by pipeline from Russia, or around 140 billion cubic metres (bcm) for the year as a whole. Next to the imports via pipelines, around 15 bcm was delivered in the form of liquefied natural gas (LNG). The total 155 bcm imported from Russia accounted for around 45% of the EU’s gas imports in 2021 and almost 40% of its total gas consumption. Progress towards net carbon zero ambitions in Europe will bring down gas use and imports over time, but the today’s energy crisis raises specific questions about the imports from Russia and the measures that policy makers and market operators/consumers can take to lower them.28 The IEA28 analysis proposes a series of immediate actions (presented below) that could be taken to reduce reliance on Russian gas, while enhancing the near-term resilience of the EU gas network and minimising the hardships for vulnerable consumers.

**A 10 Point plan to reduce the European union’s reliance on Russia’s natural gas****[[28]](#footnote-29)**

**Action 1** – No new gas supply contracts with Russia.**Impact:** Taking advantage of expiring long-term contracts with Russia will reduce the contractual minimum take-or-pay levels for Russian imports and enable greater diversity of supply.

**Action 2** – Replace Russian supplies with gas from alternative sources.

**Impact:** Around 30 bcm in additional gas supply from non-Russian sources.

**Action 3** – Introduce minimum gas storage obligations to enhance market resilience.

**Impact:**Enhances the resilience of the gas system, although higher injection requirements to refill storage in 2022 will add to gas demand and prop up gas prices.

**Action 4** – Accelerate the deployment of new wind and solar projects.

**Impact:** An additional 35 TWh of generation from new renewable projects over the next year, over and above the already anticipated growth from these sources, bringing down gas use by 6 bcm.

**Action 5** - Maximise generation from existing dispatchable low emission sources: bioenergy and nuclear.

**Impact:**An additional 70 TWh of power generation from existing dispatchable low emissions sources, reducing gas use for electricity by 13 bcm.

**Action 6** - Enact short-term measures to shelter vulnerable electricity consumers from high prices.

**Impact:**Brings down energy bills for consumers even when natural gas prices remain high, making available up to EUR 200 billion to cushion impacts on vulnerable groups.

**Action 7** - Speed up the replacement of gas boilers with heat pumps.

**Impact:** Reduces gas use for heating by an additional 2 bcm in one year.

**Action 8** - Accelerate energy efficiency improvements in buildings and industry.

**Impact:** Reduces gas consumption for heat by close to an additional 2 bcm within a year, lowering energy bills, enhancing comfort, and boosting industrial competitiveness.

**Action 9** - Encourage a temporary thermostat adjustment by consumers.

**Impact:** Turning down the thermostat for buildings’ heating by just 1°C would reduce gas demand by some 10 bcm a year.

**Action 10** - Step up efforts to diversify and decarbonise sources of power system flexibility.

**Impact:** A major near-term push on innovation can, over time, loosen the strong links between natural gas supply and Europe’s electricity security. Real-time electricity price signals can unlock more flexible demand, in turn reducing expensive and gas-intensive peak supply needs.

## EU and national gas quality standards

The transport, distribution and supply of methane via the public network is subject to gas quality standards and specifications. However, the current technical requirements may hinder the injection of renewable and low-carbon gases into the existing methane grid. The current technical specifications are mainly based on non-binding CEN standards at the European level, and divergences in national specifications or actual quality levels may hinder cross-border flows. As some types of renewable and decarbonised gases do not meet the technical requirements for methane, their injection into the existing methane grid is hindered or constrained.

**Biogas** does not comply with the technical gas quality specifications of gas TSOs/DSOs and hence cannot be injected as such. The chemical composition of raw biogas includes 50%-75% methane (CH4), 25%-50% carbon dioxide (CO2); the rest is composed of water vapour (H2O), and traces of oxygen (O2), nitrogen (N2) and hydrogen sulphide (H2S). Most often it is locally used for combined heat and power production (CHP)[[29]](#footnote-30). To allow injection of biogas into the natural gas grid or to use it as a vehicle fuel, it must be upgraded to **biomethane** which means that carbon dioxide is removed whereas the share of methane is increased to usually above 96% so that it meets the quality standards for natural gas. Biomethane can have different properties depending on the feedstock or upgrading process used, such as the Wobbe index and the proportion of components like sulphur or oxygen, but these variations are in general manageable. Similar to biomethane, **synthetic methane** has also chemical and physical properties that are comparable to natural gas (methane content >90%) and can hence be injected into the gas grid without major constraints. Estonia has specific gas quality standards for biomethane injection in its transmission and distribution grid. The oxygen content of biomethane at the point where biomethane is injected into the transmission and distribution network should be less than or equal to 0.5 mole percent[[30]](#footnote-31).

**Hydrogen** has however different chemical and physical properties. This has an impact on its integration into the methane grid because not all gas infrastructure components and end-user equipment can handle blended gases[[31]](#footnote-32). Hydrogen has unique qualities, such as a lower specific energy content than natural gas, which reduces the calorific value of the gas mixture and the methane number (essential for gas engines) and might impact combustion properties[[32]](#footnote-33). Market segmentation and trade restrictions might result from differences in gas quality criteria between Member States. Constraints may occur, particularly from high-blending-rate regions to low-blending-rate regions. Cross-border gas flows are managed in a well-coordinated manner. Depending on the injection rates of hydrogen, this would require system-wide adaptations to ensure the proper operation of the entire methane gas system, as well as gas quality management that considers the potential negative effects of gas quality fluctuations on system operation and end-use equipment. This requires extensive coordination at the EU, regional, and bilateral levels, as well as among the various players along the value chain (gas producers, TSOs, DSOs, LSOs, NRAs, equipment suppliers and consumers, etc.).

Existing natural gas networks can safely transport small amounts of hydrogen. There are no specific rules or specifications in the Baltic-Finnish region regarding hydrogen injection and blending with natural gas. To facilitate the uptake of renewable hydrogen, developing a regulatory and technical framework that enables hydrogen blending as a means for decarbonizing gas supply, might be an appropriate policy measure for the Baltic-Finnish region. Tests have revealed that existing industrial equipment can handle up to 3% Vol hydrogen. The technically acceptable hydrogen concentration can reach up to 25%, depending on the end-user equipment and natural gas composition. However, for such high hydrogen volume concentrations, using dedicated transport/distribution infrastructure would be more appropriate from an economic perspective.32

Having the right regulatory framework in place for renewable and decarbonized gases’ network connection and access is an important step towards ensuring that they can contribute efficiently to the future energy mix. As per Article 20 of the recast Renewable Energy Directive, network operators must establish enabling technical criteria for the integration of renewable gases (i.e., network connection rules including gas quality, odorization, and pressure requirements). These regulations should, ideally, clarify possible ownership and operation of network injection facilities that provide compression, mixing (if necessary), and metering functions (e.g., producer or network operator ownership and/or control). Article 20 of the REDII requires network operators to publish connection tariffs for renewable gases. These tariffs have an impact on the business case of renewable gases’ projects. At present the Baltic countries and Finland do not provide specific incentives for the injection of hydrogen/biomethane into the natural gas network (e.g., obligation to connect, priority access, favourable connection tariffs). Such enabling regulation is for biomethane injection in place in several other EU Member States (e.g., France, Belgium) following policy priorities and/or according to system benefits provided by biomethane[[33]](#footnote-34).

# Trends to 2050 based on existing policies and forecast

## European trends and policies

The European Union has set an ambitious goal to be the first climate neutral continent by 2050. To achieve this, the EU Member States and the European Parliament have agreed, in the European Climate Law, to reduce greenhouse gas emissions by at least 55% by 2030. The following proposed initiatives are strongly linked and complementary to the legislative proposals brought forward in the context of the fit-for-55 package to implement the European green deal.

The revised Renewable Energy Directive (‘RED II’) is the main EU instrument aiming at promoting the deployment of energy from renewable sources, including renewable gases, and their integration in the energy system and market. Its proposed amendment increases the 2030 target for renewable sources in the EU’s energy mix to 40% and promotes the uptake of renewable fuels, such as renewable hydrogen in industry and transport, with specific additional targets. In relation to this initiative, the RED II defines renewable hydrogen as ‘renewable fuels of non-biological origin’ and ‘biomass fuels’ that can reduce the 70% greenhouse gas emission compared to fossil fuels. (50% of total hydrogen consumption for energy and feedstock purposes in industry by 2030 and 2.6% of the energy supplied to the transport sector)22.

The Climate Target Plan Impact Assessment indicates that the share of gaseous fuels in total EU energy consumption in 2050 would be about 20%24. And the updated REPower EUplan mentions thatto reduce the Russian gas imports, LNG imports should be increased, biomethane production should be boosted to 35bcm by 2030 and hydrogen production and imports to 20mt by 2030, deployment of wind energy and solar PV should be substantially accelerated allowing to save 3bcm of gas, and additional capacities of 80GW should be built by 2030 to accommodate for higher production of renewable hydrogen in EU. In the residential sector, the large-scale deployment of heat pumps (30 million new installations by 2030) could save 35 bcm of gas in 203021. According to the recital to the recast EU gas directive, hydrogen is expected to be utilized in energy intensive industries and heavy-duty transport sectors and developing a dedicated hydrogen infrastructure is necessary to release the full potential of this energy carrier in specific end-use applications.

According to the Long-Term Strategy scenario 1.5TECH, electricity would account for about half of EU final energy demand in 2050 (versus 22% in 2015), while hydrogen would account for 10% (approximately 800 TWh), e-gas 7%, and biomass (including biogas and biomethane) 14%, while natural gas would be the sole fossil fuel left, with a share limited to 2% of total final demand25.

## Baltic and Finnish national energy and climate targets

The National Energy and Climate plans (NECP) and National Development Plans (NDP) of Estonia, Latvia, Lithuania and Finland for 2030 provide the targets for the share of renewable energy in final energy consumption, as shown in the following figure. To meet the targets and specifically to reduce the natural gas consumption, specific measures for the deployment of renewable/low carbon gases in specific sectors are provided with the relevant plans and policy measures. Not all four countries have specific targets for renewable fuels for each sector; the most relevant information is summarised in the following table.

Figure 4‑1. National targets for RES share (%) in Final Energy Consumption by 2030

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The NECPs and NDPs are detailed and strategic frameworks that help public and private operators for planning their investment and operational decisions. The plans provide indications of the impacts of the different considered policies and measures on the energy and climate objectives, including the greenhouse gas emissions reduction. The following table provides an overview of the specific targets of the four countries.

Table 4‑1. National energy and climate targets mentioned in NECPs or NDPs

| **Country** | **Targets from NECP or NDPs** |
| --- | --- |
| **Estonia**[[34]](#footnote-35) | - **Overall RES target**: share of renewable energy in total final consumption must be 42% - 50% (around 32 TWh) by 2030.  **- Transport:** 14% of renewables in final energy consumption by 2030 and 340 GWh of biomethane and 395 GWh 2nd generation biofuels by 2030. Fuel consumption of vehicles in 2030 should not exceed the 2012 level (8.3 TWh).  **- Electricity production:** By 2030, the share of renewables must be 40% of gross final consumption and domestic primary energy consumption should be 10% lower than 2012 level.  **- Gas supply:** The share of the largest supply source and largest gas supplier in Estonia’s gas market should not exceed 70% and 32% respectively. |
| **Latvia**[[35]](#footnote-36) | - **Overall RES target**: RES share in final energy consumption must be at least 45 % by 2030.  - **Biomethane** production will be stimulated (biogas upgrading)  **- Heating:** RES share in the heating sector is at least 57.5% in 2030.  **- Transport:** 14% of RES in final energy consumption plus advanced biofuels to be 3.5% of RES in 2030. Biogas use in the transport sector is 0.62 PJ by 2030. Consumption of alternative fuels (CNG, LNG, biofuel, biogas, and electricity) in road transport is increasing and amounts to 4.4 PJ in 2030. It corresponds to about 11.8 % of the total consumption in the transport sector.  **- Electricity Production:** Share of electricity produced from RES in total final energy consumption should reach 47.5% in 2027 compared to 39.02% in 2017. |
| **Lithuania**[[36]](#footnote-37) | - **Overall RES target**: RES share in gross final energy consumption must be at least 45% by 2030.  **- Buildings:** By 2030, the **s**hare of RES in H&C should be 67.2% and 90% in district heating.  **- Transport:** RES share in final energy consumption in transport sector must be 15% by 2030 and 50% by 2050. Use of biomethane gas in the transport sector should reach 81.5 ktoe by 2030.  **- Electricity Production:** RES share in final energy consumption in electricity sector should reach 45% by 2030 and 100% by 2050.Biofuel power plants between 47.5 and 50.1 ktoe and biogas plants 10.9 ktoe by 2030. |
| **Finland**[[37]](#footnote-38) | - **Overall RES target**: RES share target is 51% for the year 2030.  **- Agriculture:** The use of forest chips and pulpwood for electricity and heat production is 29-34 TWh and for making biofuels is 7-19 TWh by 2030.  **- Heating:** RES share must by 2030 reach 61% of gross final energy consumption. Heating energy use is 54 TWh for 2030 except saunas. Total GHG emissions reduction would be 62% in 2030.  **- Transport:** By 2030, the number of electric cars should be at least 250,000 next to minimum 50,000 gas-powered cars. Share of biofuel in all transport fuels consumed in Finland should be 30%.  **- Electricity Production:** RES share of53% of gross final energy consumption by 2030. |

Additional relevant information is hereafter summarised, based on the National Energy and Climate plans and National development plans.

**Estonia** has set the target of producing 380 GWh per year of biomethane by 2030; the majority (340 GWh) would be used in the transport sector34. Recent studies on the hydrogen potential and hydrogen roadmap consultations in Estonia could be used to set a national target, but up to now targets for hydrogen deployment have not yet been published by the state government.

**Latvia** foresees to take regulatory measures to increase biomethane usage in transport. There are in Latvia not yet specific targets regarding hydrogen production and use35.

In **Lithuania**, biogas production facilities are at present intended for electricity and heat production, and to maximize the potential use of biogas, re-orientation of biogas use for electricity and heat production towards biogas treatment and upgrade to biomethane for injection into the natural gas networks will be proposed. Such a measure would allow the fastest possible deployment of the biomass potential using existing infrastructure and the expected emergence of biomethane gas on the Lithuanian market in 2022. The Lithuanian government foresees the biomethane production to reach 1 TWh by 2030 with the help of shifting the existing biogas production subsidies to biomethane production. There is no specific information available on the expected (or targeted) hydrogen production volumes in Lithuania. The Alternative Fuels Law was adopted by the Lithuanian Parliament in March 2021. Lithuania considers that there is a (big) potential for biomethane and hydrogen gas use in the transport sector, and projects that the alternative fuels (biomethane, hydrogen and syngas) could account for at least 5% of final energy consumption in the transport sector by 2030[[38]](#footnote-39).

**Finland** is stimulating the use of biogas in road transport, electricity and heat production and agriculture sectors by 203037. It is estimated that the techno-economical biogas production potential is about 11 TWh, and the theoretical production potential is up to 25 TWh. By 2030 the biogas production would be about 4 TWh[[39]](#footnote-40). SSAB (Swedish steel company) has communicated its plan to replace its blast furnaces in Rahe Steel mill with electric arc furnaces (H2-DRI) by 2030. The Finnish industry could consider a similar initiative. The industrial hydrogen consumption in Finland is estimated in the national hydrogen roadmap at 180000 t/a (6 TWh) by 2030 (mainly due to the increased industrial activity) and 310000 t/a (10.33 TWh) from 2030 onwards (with the replacement of blast furnaces in the steel industry). Finland has also the intention to start power-to-X projects well before 2030. This could also enhance Finland’s hydrogen consumption levels in the future. The increased consumption levels with new industrial activity prospects will most probably be met by green hydrogen. But within the Finnish hydrogen roadmap, there are no clear targets on the replacement of the current SMR based fossil hydrogen[[40]](#footnote-41).

# Local potential for renewable gas production

## Technical potential of biogas/biomethane in the Baltic-Finnish region

The term technical potential assumes that all bioenergy which are not fully used today is available for biogas/biomethane production in the future, considering all relevant regulatory limitations especially about food security priorities. There is a lack of detailed, bottom-up technical potential data by EU Member State and by feedstock and most studies only present data at the EU27 level (as a whole). In 2017 CE Delft conducted an analysis on the technical potential of biomethane for each Member State[[41]](#footnote-42). Also, GreenGasGrids and BIOSURF projects have published extensive analyses for a significant number of Member States, but not all Member States were included in the scope[[42]](#footnote-43). Scarlat, N. et al. 2018[[43]](#footnote-44) conducted a detailed study per country for manure, which represents a modest contribution to the technical potential.

The historical data for Estonia shows a slight annual increase in biogas production. The regulatory framework and schemes are supportive for biogas/biomethane production in Estonia. In Latvia, the overall biogas production and capacity show a decrease in recent years.

Currently, Lithuania is utilizing its biogas to produce electricity and heat. Latvia has not yet introduced any legislation on biomethane production; one biogas plant did start producing biomethane for its own needs in 2020. In Lithuania, there is currently no biomethane use as biofuel for transportation. There are no restrictions and standards for blending biomethane with natural gas. If biomethane is injected into the grid, it must be compliant with the gas quality requirements. It is expected that the first biomethane plant with 12 GWh annual production (potentially 41 GWh from 2023) will be connected to the Lithuanian gas network in 2022. Lithuania has foreseen to introduce regulatory measures to increase biomethane usage in transport. The biogas/biomethane potential would allow to substitute a large part of the current fossil gas consumption.

The available studies have estimated the Baltic states and Finland’s biomethane potential differently. The numbers presented in these studies are the authors' estimates based on available literature sources and do not necessarily reflect the individual member state's points of view. A comparison of the biomethane potential in Estonia, Latvia, Lithuania, and Finland is presented in Table 5‑1. The realistic potential is mentioned in the column named ‘value considered’ and is validated by the steering board and the stakeholders.

Table 5‑1 Biomethane potential in the Baltic-Finnish region

| **Country** | **Source 1**[[44]](#footnote-45) **(TWh)** | **Source 2**[[45]](#footnote-46) **(TWh)** | **Source 3****[[46]](#footnote-47) (TWh)** | **Value considered 46(TWh)** | **Country’s baseline gas demand projection by 2050** | **Comments on the selected values** |
| --- | --- | --- | --- | --- | --- | --- |
| **Estonia** | 7 – 8 | 2.9 | 4.7**[[47]](#footnote-48)** | 2.4 | 3.909 | A 50% of the maximum available value is considered to be more realistic. |
| **Lithuania** | 16 | 6 | - | 8 | 24.294 |
| **Latvia** | 12 | 6 | 2.7**[[48]](#footnote-49)** | 2.7 | 5.929 | Based on the inputs received from ministry representatives, the number presents considered to be more realistic. |
| **Finland** | 56 | 43 | ∼11**[[49]](#footnote-50)** | 11 | 19 |

## Renewable hydrogen potential in the Baltic-Finnish region

The Baltic states are likely to adopt in the near future national hydrogen strategies to enable wider use of hydrogen in transport and other high-potential sectors[[50]](#footnote-51). It is reported[[51]](#footnote-52) that Estonia, Latvia, Lithuania, and Finland, are resources rich with high infrastructure potential of hydrogen.

The Baltic States and Finland have substantial technical renewable electricity potential. As hydrogen is expected to be mainly produced by water electrolysis using electricity, the renewable electricity potential is deemed a relevant basis for the green hydrogen production potential in each country. The following table shows the technically realisable renewable electricity potential per country. Two information sources have been used: the report commissioned by the European Commission on the impact of biomethane and hydrogen potential on trans-European infrastructure44 and the 2021 report on the European Hydrogen Backbone (EHB)[[52]](#footnote-53). For Latvia and Lithuania, it is assumed that 50% of the technically realisable renewable electricity potential can be considered as economically realisable potential. For Finland, 70% of the technically realisable renewable electricity potential is assumed as economically realisable, considering Finland’s current electricity consumption level. For Estonia, the renewable electricity production potential is taken from the recent study ‘Transitioning to a climate-neutral electricity generation in Estonia, 2022’[[53]](#footnote-54) which provides the most accurate and recent estimates.

Table 5‑2 Renewable electricity potential in the Baltic-Finnish region

| Countries | DG Energy, EU Commission44(TWh) | EHB (TWh)52 | Assumed range of economically realisable potential (TWh) | Assumed value of economically realisable potential (TWh) |
| --- | --- | --- | --- | --- |
| **Estonia** | 81 | 87 | 26.453 | 26.4 |
| **Latvia** | 216 | 141 | 70.5 - 108 | 89.25 |
| **Lithuania** | 270 | 217 | 135 - 108.5 | 121.75 |
| **Finland** | 243 | 281 | 170.1 – 196.7 | 183.4 |

As a simplified approach, it is assumed that the remaining renewable energy potential after satisfying the country's final electricity demand would be available for green hydrogen production. The following figures present the final electricity demand, the economically realisable renewable electricity potential, and the resulting green hydrogen production potential.

Figure 5‑1 Hydrogen production potential in Estonia [Source: Calculations based on DG REFORM53]

Figure 5‑2 Hydrogen production potential in Latvia [Source: DG Energy 202044, EHB 2021 52]

Figure 5‑3 Hydrogen production potential in Lithuania [Source: DG Energy 202044, EHB 2021 52]

Figure 5‑4 Hydrogen production potential in Finland[Source: DG Energy 202044, EHB 2021 52]

# Renewable gas decarbonisation technologies: An overview of the gas value chain

This section focuses on the technical aspects of the value chain of renewable gases. The domestic renewable gas production, gas storage options, adaptability of the gas supply infrastructure and the end-use equipment to natural gas/hydrogen or dedicated hydrogen use are discussed in the different sections of this chapter. An overview of the renewable gas value chain is presented in the Figure 6‑1.

Figure 6‑1. Overview of the value chain of the renewable gas value chain

Diagram

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Source: Author’s own representation of the processes

## Renewable gas production technologies

Figure 6‑2 presents a side-by-side comparison of hydrogen production, biomethane production, and synthetic natural gas (SNG) production processes. The energy value of the produced hydrogen and SNG is compared against the input electricity. Biomethane production is also explained in Figure 6‑2, starting from feedstock (biomass) to biogas conversion and then to the biogas upgradation.

Figure 6‑2. A holistic comparison of the gas production technologies

Diagram

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Source: Own representation of the processes. Technical parameters are taken from: ENTEC 202263, IEA 201957, SGC 2012 [[54]](#footnote-55)

The comparison of the market and cost maturity levels for the different gas production technologies is discussed in the Table 6‑1.

Table 6‑1. Maturity overview of the gas renewable gas production technologies

| Technology | TRL[[55]](#footnote-56) | Market maturity | Cost Maturity |
| --- | --- | --- | --- |
| Electrolyser | 957 | Two commercial forms of electrolyser are Alkaline electrolyser and Polymer electrolytic membrane (PEM). They are already being deployed for (renewable) hydrogen production worldwide. | The cost of electrolyser is a relevant part of the renewable hydrogen production cost. Electrolyser technology is subject to cost reduction with the improved and new low-cost material use.  The presented investment cost trend by 2050 in Table 6‑2 is for the PEM electrolyser technology which is already at market maturity and the costs will decrease with the new and cheap material use in electrolyser stack. |
| Anaerobic digester | 960 | Anaerobic digestion technology is in operation at large scale worldwide. There are new and innovative versions of anaerobic digesters also near to market maturity (e.g., Auto-generative High-Pressure Digestion – APHD is at TRL 8) | Anaerobic digesters (AD) are market mature and a possible capital cost decrease in traditional AD is not foreseen. It is possible that in future different new versions of AD will be available on market, but investment cost and the future cost decrease in the AD technology are unknown. |
| SNG plant | 8-964 | The methanation technology (transforming H2 into CH4) is available but not yet proven for large scale applications. Although the technology is still in demonstration phase, the fixed-bed reactor has a high readiness level of TRL 8/9 | Different options of SNG production reactors have different investment costs and hence different cost learning curves. The presented investment cost trend by 2050 in Table 6‑4 is for the chemical catalytic reactor technology which is near market maturity. |

##### Renewable hydrogen production via electrolysis

Hydrogen is one of the most abundant elements on the earth, mostly chemically bounded in hydrocarbons and water. The electrochemical splitting of water in electrolysers is a clean and efficient process to generate hydrogen and oxygen. Given the steadily increasing supply of electricity from intermittent renewable energy sources, power-to-hydrogen can contribute to ensuring a reliable electricity supply and enable long-term or seasonal storage in future energy systems. PEM water electrolysis, which uses a **proton exchange membrane (PEM)**, is well suited for combination with renewable energy sources. Currently, when compared to the other processes, this process offers good efficiency (still need to be improved in the future) values at high current densities and can be operated at high pressure and very dynamically in a wide operating window, i.e., also under partial-load conditions. PEM is a mature technology (TRL 9).[[56]](#footnote-57) The following table presents the typical characteristics of a PEM electrolyser stack.

Table 6‑2. Characteristics of a PEM electrolyser stack

| PEM Electrolysis | Current | 2030 | 2050 |
| --- | --- | --- | --- |
| **CAPEX [€/kW]** | 949.44 | 427.25 | 284.83 |
| **OPEX [€/(kW\*a)] (1.5% of CAPEX)** | 14.24 | 6.41 | 4.27 |
| **Efficiency (%)** | 60 | 68 | 74 |
| **Stack lifetime [h]** | 90,000 | 90,000 | 150,000 |

Source: The Future of Hydrogen [IEA 2019][[57]](#footnote-58), Global Hydrogen Review [IEA 2021][[58]](#footnote-59), 1 USD = 0.95 EUR

##### Biogas/biomethane production

Biogas or biomethane is another possible sustainable alternative to natural gas. Biomethane production is a two-step process. The **first step** is to produce biogas, for which a range of bio-feedstocks (food crops, bio/food-waste, bi-product of energy crops, sewage water, animal manure etc.) can be used via different **biogas production technologies** (non-specific digestion, mono-digestion, co-digestion, and sewage sludge digestion). The **second step** is the upgrading of the produced biogas to biomethane, which involves the removal of CO2 by using one of the process technologies (pressure swing adsorption, membrane separation, amine scrubber, or water scrubber). This step is required to reach the similar methane content as natural gas so that it can be injected into the natural gas grid or can be compressed for use in the transport sector as bio-CNG.[[59]](#footnote-60)

Biogas/biomethane production is a well proven and a mature industrial scale process (**TRL 9**)[[60]](#footnote-61), but its potential development is limited by the availability of biomass resources (**see section 5.1**), by the implementation of more strict sustainability criteria under the Renewable Energy Directive (RED II), and by competing biomass uses for food, feed, and feedstock production.[[61]](#footnote-62)

The following table presents the investment and operational costs (CAPEX & OPEX) of a biogas plant and a set of biogas upgradation technologies. Anaerobic digesters (AD) are market mature and a possible capital cost decrease in traditional AD is not foreseen. **It is possible that in future different new versions of AD will be available on the market, but with the current knowledge the investment cost and the future cost curve for the new versions are unknown.**

Table 6‑3. Biogas/biomethane plant investment and operational costs

|  |  |  |
| --- | --- | --- |
| Biogas/biomethane\* | CAPEX [€/kW] | OPEX [% of CAPEX/y] |
| **Biogas plant (Anaerobic Digester)** | 170 | 4 % |
| **Biogas upgradation (Pressurised water scrubber)** | 113 |
| **Biogas upgradation (pressure swing adsorption)** | 127 |
| **Biogas upgradation (membrane separation)** | 123 |
| **Biogas upgradation (Amine scrubber)** | 128 |

**\***Biogas upgradation: CO2 & other impurities removal from the biogas to convert it to biomethane, Source: BIOSURF 2016[[62]](#footnote-63)

##### Synthetic methane

Synthetic methane production from hydrogen is an advanced technology but still in the demonstration phase. As a gas, synthetic methane can be further processed into liquefied methane, for transport via trucks, or it can be fed in into the natural gas grid to substitute grey methane. It can also be used as fuel (e.g., for transport purposes) or in the production industry as feedstock. The methanation technology (transforming H2 into CH4) is available but not yet proven for large scale applications. Although the technology is still in the demonstration phase, a fixed-bed reactor has a high readiness level of **TRL 8/9**[[63]](#footnote-64),[[64]](#footnote-65). The following process assumptions are considered:

* Methanation efficiency: 77% – 80%
* CO2 demand for methanation: 2.8 kg CO2/kg methane

Methanation plant investment and operational costs are presented in Table 6‑4.

Table 6‑4. SNG plant Investment and operational costs

|  |  |  |  |
| --- | --- | --- | --- |
| Methanation (SNG) | Current | 2030 | 2050 |
| **CAPEX [€/kW]** | 600 | 562 | 324 |
| **OPEX [% of CAPEX /y]** | 4% | 4% | 4% |

Source: Taltech 2020[[65]](#footnote-66), ENTEC 202263, PtX Atlas - Fraunhofer IEE[[66]](#footnote-67)

CO2 is an integral part of SNG production, and the CO2 capture costs can affect the levelized cost of the produced SNG. Table 6‑5 presents the CO2 capture cost from different sources. Since CO2 is co-produced in biogas upgradation plants, the CO2 capture cost is not considered additionally, as CO2 already must be separated to produce biomethane from biogas The CO2 capture costs by different sources are presented in the Table 6‑5.

Table 6‑5. Levelized cost of CO2 capture by sector [Source: Adaptation of IEA source[[67]](#footnote-68)]

|  |  |
| --- | --- |
| CO2 input for SNG\* | Euro/ton |
| Co-produced CO2 from biomethane plants[[68]](#footnote-69) | 0 |
| Direct Air capture | 133 – 339 |
| Power generation | 49.5 - 99 |
| Hydrogen (SMR) | 49.5 - 79 |

Considering the energy value loss (see Figure 6‑2) to convert renewable electricity to hydrogen and then into synthetic methane, and the related investment and operational costs, this technical solution is not considered as an optimal choice from an energy and economic perspective. The main advantage is however that synthetic methane has similar characteristics as natural gas and can hence be used in existing transport/distribution infrastructure and end-user appliances without any technical changes.

**The largest methanation plant in operation in the world (as of October 2016) is a catalytic methanation plant located in Werlte, Lower Saxony, Germany**. The plant was constructed by Etogas (formerly called Solarfuel) for the German car manufacturer Audi, in collaboration with the research institutions Fraunhofer IWES and ZSW and the energy company EWE. The plant is a hybrid methane production plant as it produces biomethane from biogas (with amine scrubbing) and the captured CO2 from biogas upgradation unit reacts with the renewable hydrogen (from an alkaline electrolyser) to produce the second methane stream. The produced synthetic methane is then injected into the natural gas grid.[[69]](#footnote-70)

Figure 6‑20. Schematic of the system layout of the biogas methanation facility in Werlte, Germany. Source: [Future Gas 2017]69

Diagram

Description automatically generated

## Storage of renewable gases

The choice of the most appropriate gas storage option is contingent on the application. Key metrics to investigate are energy density (e.g., kWh per mass and per volume), energy capacity (energy that can be stored per unit of technology, e.g., MWh per tank), maximum cycling rate (in MW) and investment and operational costs (storage usually includes pre-processing such as compression and liquefaction). Further requirements could include safety, efficiency, space requirements and availability. Storage options can be segregated based on the surface and subsurface storage options and can be further divided on the storage phase (gas/liquid). Additionally, storage time (seasonal, monthly, daily/hourly), is another parameter to take into consideration while evaluating and planning storage options. The following figure shows the storage technology segregation based on the above defined parameters.

Figure 6‑21. Gas storage options

Diagram

Description automatically generated

The storage scale, storage duration and technology readiness level are discussed in the following table. Compression, liquefaction, and hydrogen derivatives present short- to medium-term storage options used to have storage capacity during some hours up to a few days, whereas salt caverns present the gas storage option for medium- to long-term storage (weeks – months - seasonal). Only porous reservoir storage (depleted gas fields or aquifers) presents the large enough capacities which can serve for seasonal gas storage facilities. Some types of existing natural gas storage sites (in particular salt caverns) are also considered suitable for later repurposing for hydrogen storage. Field tests are ongoing at the initiative of ENTSOG and some of its gas TSO members.

Table 6‑6. Gas storage technologies

| Storage Technology | Storage scale | Storage duration | TRL\* | Comments |
| --- | --- | --- | --- | --- |
| Compressed gas (CNG, Bio-CNG, CGH2) | Small-scale to medium-scale storage | Short to medium (hours, days) | 9 | The most used gas storage type but offers low energy density and hence requires large storage volumes |
| Liquefaction (LNG, Bio-LNG, LH2) | Small-scale to medium-scale storage | Short to medium (hours, days) | 9 | Largely deployed capacities across EU: 8.5-9.1 mil. m3 exists in EU (173 (bcm(N) / year) regasification capacity) |
| Liquid derivatives of Hydrogen – PtG (ammonia, methanol) | Small-scale to medium-scale storage | Short to medium (hours, days) | 9 | PtG is a mature storage option for hydrogen which allows then the use of these derivatives (ammonia, methanol) in transport or industry or can be dehydrogenated to recover the stored hydrogen |
| Liquid derivatives of Hydrogen (LOHC) | Medium-scale storage | Short to medium (hours, days) | 9 | After hydrogenation, the LOHC can be treated same as diesel. It can potentially be stored in large diesel storage tanks without requiring any major modification to the existing storage facility. |
| Salt caverns (hydrogen storage) | Large-scale storage | Medium-term storage (weeks, months) | 6-9 | Fast cycle operation storage service is yet to be demonstrated, hence TRL is lower than 7. TRL = 9 for security of supply services where continuous supply is required. |
| Porous reservoirs (NG, Biomethane, H2) | Large-scale storage | Seasonal | 9,  2-3 | Porous UGS (NG) reservoirs exists EU wide. Biomethane acceptance in UGS facilities has been tested by Marcogaz recently (in 2022) and the results presented the oxygen levels implications on the storage facility. It was concluded that biomethane can be injected in UGS facilities as an exchange gas equivalent to natural gas provided that the NG standards are met. But these reservoirs have not been tested yet with pure hydrogen. Early-stage pilot testing with natural gas and H2 mixture has been performed in Austria, hence the TRL 2-3. |

Source: Hydrogenious[[70]](#footnote-71), ENTEC 202263, Marcogaz 2022[[71]](#footnote-72)

Gas storage in pressurized tanks is the most common option for surface gas storage technologies. Compressed hydrogen gas storage in tanks is currently among the most expensive storage options but tanks can be operated at high cycling rate, and this can help amortize the high investment cost. The investment and operational costs of the compressed gas storage tanks for hydrogen and methane is given in the Table 6‑7.

Table 6‑7. Compressed gas storage investment costs

|  |  |  |  |
| --- | --- | --- | --- |
| Compressed H2 storage | | | |
|  | Current | 2030 | 2050 |
| **CAPEX (€/MWhH2)** | 33330 | 18001 | 14100 |
| **OPEX [% of CAPEX /y]** | 2% | 2% | 1.5% |
| **Compressed methane storage** | | | |
|  | Current | 2030 | 2050 |
| **CAPEX (€/MWhH2)** | 10780 | 7898 | 5015 |
| **OPEX [% of CAPEX /y]** | 2% | 2% | 1% |

Source: Store & GO[[72]](#footnote-73), ENTEC 202263, PtX Atlas - Fraunhofer IEE66

Liquid natural gas (LNG) is regasified again before injecting it into the NG grid. Liquified bio-methane or synthetic methane can be imported/exported (and temporally stored) through existing LNG terminals, can be regasified and be injected into the NG grid, or can be utilised directly in (heavy duty) transport. LNG has a low overall energy efficiency due to losses during the liquefaction, storage/transport, and regasification phase (Table 6‑8).

Table 6‑8. LNG round losses (10-day transport basis)

|  |  |  |  |
| --- | --- | --- | --- |
|  | Liquification | Transport/Storage | Regasification |
| Round trip LNG losses | 15% | 1.5% | 2% |

Source: Pospíšil et al. 2019[[73]](#footnote-74)

The investment and operational costs of an LNG liquefaction plant are presented in Table 6‑9.

Table 6‑9. NG Liquefaction plant investment cost

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  |  | Current | 2030 | 2050 |
| **Liquefaction (LNG)** | **CAPEX [€/tonLNG\*y]** | 1035 | 660 | 500 |
| **OPEX [% of CAPEX /y]** | 2.5% | 2.5% | 2.5% |

Source: Oxford 2018[[74]](#footnote-75), ENTEC 202263, PtX Atlas - Fraunhofer IEE66

To achieve high storage energy density, hydrogen can be liquified (LH2) and stored in special insulated, cryogenic tanks, which maintain the gas condition (-253°C) and reduce evaporation losses. Stationary tanks consist of an outer and an inner tank, high quality insulation and pressure relief valves to compensate for evaporation losses. LH2 is lost during storage and handling operations through the following stages:

* Pump operation (loading and unloading) of LH2 leads to 0.6% average loss due to boil-off63
* Boil-off for stationary LH2 storage (located at terminal, import and export) reaches 0.1%/d (1% loss for a 10 day hold up at the LH2 terminal)57

The investment and operational costs of a LH2 plant (liquefaction, regasification) are presented in the following table.

Table 6‑10. Hydrogen liquefaction plant investment and operational costs

|  | |  | Current | 2030 | 2050 |
| --- | --- | --- | --- | --- | --- |
| **Liquefaction (LH2)** | **CAPEX [€/tonH2\*y]** | | 5108 | 4450 | 3500 |
| **OPEX [% of CAPEX /y]** | | 4% | 4% | 4% |
| **Liquid hydrogen evaporation (Regasification)** | **CAPEX [€/ton H2\*y]** | | 16 | 13 | 8 |
| **OPEX [% of CAPEX /y]** | | 3% | 3% | 3% |

Source: Harvard 2022[[75]](#footnote-76), ENTEC 202263, PtX Atlas - Fraunhofer IEE66, Reuß et al. 2017[[76]](#footnote-77)

### Gas storage potential of the Baltic-Finnish zone

The current and announced short-term storage facilities (mainly at LNG terminals) in the Baltic-Finnish countries can as such be used for bio-LNG and could, after significant infrastructure modifications, also be used as storage facilities for LH2 and hydrogen derivatives.

The Baltic-Finnish region has only one underground gas storage facility which is situated in Latvia (Inčukalns UGS) and is operated by the national TSO Conexus Baltic Grid.[[77]](#footnote-78) This storage facility is classified as a porous underground gas storage facility; it consists of a layer of porous sandstone, which has good storage properties, and which is coated with gas-tight rock layers. These geological structures are situated at an optimal level of 700-800 meters deep, allowing safe and cost-efficient storage of gas.[[78]](#footnote-79)

The Gas Infrastructure Europe’s 2021 report[[79]](#footnote-80) discusses the feasibility and readiness of European underground gas storage sites to store hydrogen. The report concludes that there is no salt cavern or depleted gas field potential in Estonia and Finland that could be utilized for natural gas/hydrogen storage. Caglayan et al.[[80]](#footnote-81) also reported the EU wide salt cavern storage potential and concluded that there is no suitable salt cavern underground storage potential in the Baltic-Finnish region.

Inčukalns UGS is the only functional gas storage facility in the Baltic countries, which ensures the stability of the regional NG gas supply and has not been tested with any hydrogen blends till now. But there is an early planning phase for a potential R&D Project in Inčukalns UGS as hydrogen seasonal storage with a capacity of at least one TWh[[81]](#footnote-82).

Biomethane acceptance in UGS facilities has been tested by Marcogaz recently (in 2022) and the results presented the oxygen levels implications on the storage facility. Marcogaz concluded that biomethane can be injected in UGS facilities as an exchange gas equivalent to natural gas provided that the NG standards are met. But the methane gas reservoirs have not been tested yet with pure hydrogen. Early-stage pilot testing with natural gas and H2 admixture has been performed in Austria, hence the concept entails a TRL of 2-3 but can be a potentially mature option after further field tests in the near future34,38.

Table 6‑11. Gas storage technology feasibility/potential by member state in the Baltic-Finnish zone

| Country | Storage type feasibility | | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| Compressed gas (CNG, Bio-CNG, CGH2) | Liquefaction (LNG, Bio-LNG, LH2) | Liquid derivatives of Hydrogen – PtG (ammonia, methanol) | Liquid derivatives of Hydrogen (LOHC) | Salt caverns (hydrogen storage) | Porous reservoirs (NG, Biomethane, H2) |
| **Estonia** | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Close with solid fill | Close with solid fill |
| **Latvia** | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Close with solid fill | Checkmark with solid fill |
| **Lithuania** | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Close with solid fill | Close with solid fill |
| **Finland** | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Checkmark with solid fill | Close with solid fill | Close with solid fill |

Source: Own analysis based on the information provided in the previous paragraphs

### LNG terminals design to import renewable and decarbonised gases

The feasibility and associated costs of converting LNG terminals to handle liquefied renewable and low-carbon gases is a critical subject in determining LNG terminals’ potential role in decarbonization. With some modifications, biomethane and hydrogen may be stored and transported using LNG facilities. As the characteristics of biomethane and synthetic methane are similar to those of natural gas, it can be ensured that they meet the gas quality criteria, and upgrades to LNG terminals[[82]](#footnote-83) would hence not be required. Shippers may need administrative procedures to monitor guarantees of origin/sustainability certificates and ensure that the gas satisfies the technical criteria, but no new investments or O&M are required[[83]](#footnote-84).

In the case of hydrogen, due to technical differences between methane and hydrogen (such as hydrogen's lower boiling temperature than methane), existing LNG infrastructure cannot be used as is and must be modified. Moreover, as hydrogen has a lower energy density than LNG (at pressures between 350 and 700 bar), shipping costs are expected to be substantially higher. As the costs of adjusting the liquefaction, transport, storage, and regasification phases would be relatively high, importing hydrogen via LNG terminals could be difficult. Another option for importing hydrogen from non-EU production facilities is to convert hydrogen to ammonia or methanol and transport these energy vectors using LNG ships and terminals: their boiling temperatures, -33°C and 65°C, respectively at atmospheric pressure are much higher than those of H2 and CH4, the liquefaction, transport, storage, and regasification stages can be carried out at higher temperatures or lower pressures, and the associated costs are lower for  ammonia and methanol than for hydrogen. As a result, synthesizing methanol and ammonia makes the transport and import processes easier and more economic than importing hydrogen.  However, additional energy is required to obtain the hydrogen back from these carriers, if the goal is not to use the methanol or ammonia as such[[84]](#footnote-85).

## Gas blending effect on gas supply infrastructure and on the end-use equipment

##### Potential impacts of biomethane injection into the NG grid

Biomethane has a lower Wobbe index (WI) and calorific value than most EU and notably non-EU natural gas sources[[85]](#footnote-86). Furthermore, given the various biomass feedstocks and manufacturing procedures, the Wobbe index of biomethane can be intrinsically variable. Gas quality fluctuations can also occur due to demand fluctuations and varying biomethane injection rates (biomethane production does not display substantial seasonality on a system level, although there can be daily and intra-day fluctuations). The impact of biomethane on the average gas WI or calorific value is not significant at low blending rates, but the situation may alter when biomethane injection increases. At high biomethane blending rates, the gas's lower and fluctuating calorific value could cause metering and billing problems, as flow meters may wrongly estimate the users’ effective energy use. Second, increased biomethane blending rates can lead to higher concentrations of specific components, which could harm the gas network infrastructure or end-users’ equipment.

Injecting biomethane into distribution grids could be done at lower pressures, requiring a smaller compressor (if one is required at the biogas upgrading plant's outlet) and cheaper operating costs (notably for electricity). However, if high volumes are injected at distribution level, investments in compressors may be needed to allow flows to the transmission level. On the other hand, Injection at the transmission level, requires the construction of grid-connection pipelines that must operate at higher pressures (as gas compression typically occurs at the biogas upgrading site), and the reduction of gas pressure for injection from transmission to distribution grid results in losses due to the need for pre-heating when decompressing the gas. The increasing injection of biomethane of varying quality may also require efficient cross-border flow management. Biomethane can for instance be naturally high in sulphur. Sulphur is usually removed with oxygen, resulting in a high oxygen concentration in the gas.

Blending biomethane with natural gas must respect the gas quality standards and considered the interconnected regional gas system, any national plan for biomethane injection must respect the common standards. Each country of the Baltic-Finnish region has the ambition to increase the biogas/biomethane production for direct consumption in the transport or power sector but no clear targets of biomethane blending into the natural gas grid have been published. Currently in Estonia, around 70% - 75% of the biomethane production is injected into the distribution grid and 25% - 30% is locally used, as the concerned plants don’t have a grid connection[[86]](#footnote-87). The Estonian TSO stated that the biomethane quality is adequate to be injected into the natural gas transmission system, but that compressors would be needed to enable reverse flows from distribution to transmission networks. Otherwise, injection would only be possible to the extent that the biomethane production would not exceed the distribution grid consumption. According to the EBA report 2020, Finland is injecting 10% of its produced biomethane in the natural gas grid. There is no restriction for biomethane blending in Lithuania but currently the overall production is very low.

##### Limitations to hydrogen blending in natural gas networks

The implications of hydrogen admixture are numerous. Some components of the transmission or distribution infrastructure can be extremely sensitive to gas quality fluctuations to accept high hydrogen admixture rates due to the ease with which point-to-point supply/demand connections can be controlled. Although hydrogen can be blended with natural gas, the chemical and physical properties of hydrogen-blended natural gas differ significantly from those of pure natural gas. If hydrogen blending in gas grids exceeds certain thresholds, it will necessitate significant investments to upgrade existing grid infrastructure (distribution and transmission pipelines, gas metering and monitoring) as well as end-user equipment (power plants, gas engines, residential appliances, and industrial equipment) to make them methane/hydrogen blending ready.

The Table 6‑12 shows the maximum tolerated hydrogen blending percentages (vol.%) in the NG transmission infrastructure, storage, distribution pipelines and end user appliances/equipment. **These maximum blending limits are determined by Marcogaz[[87]](#footnote-88) and do not necessarily represent the specific hydrogen blending limits of the gas network and end-use applications in the countries of the Baltic-Finnish zone.**

Table 6‑12. Overview of available test results and regulatory limits for hydrogen admixture into existing NG infrastructure and end-use equipment [Source: Marcogaz][[88]](#footnote-89)

|  |  |
| --- | --- |
|  | **Hydrogen blending levels\*** |
| **Transmission lines (> 16 bar)** | **Steel transmission pipeline:** Up to 10% (allowance can be up to 100% after modifications to the infrastructure depending on the case-by-case basis)  **Compressor:** Up to 5% |
| **Gas storage** | **Cavern storage:** Up to 100%  **Porous storage:** Under study, but learnings from depleted fields can be utilised |
| **Grid metering and pressure regulation** | **Gas meters:** Up to 10% without modifications  **Valves:** Up to 10% – 60% (up to 10% without technical modifications) |
| **Distribution**  **(< 16 bar)** | **Steel transmission pipeline:** Up to 10% (allowance can be up to 100% after modifications to the infrastructure depending on the case-by-case basis) |
| **End-use equipment** | **Gas turbine:** Up to 1% without modifications  **Gas engine:** Up to 10% without modifications  **Residential appliances (without modifications):**   * NG fuelled FC heating appliances: Up to 10% * Gas cooker/burner: Up to 10% * Condensing boiler: Up to 10%   **Mobility (CNG vehicle):** Up to 5%  **Industrial equipment:**   * Feedstock: Up to 2% with some use case base modifications * Steam boiler: Up to 5% without modifications * Industrial thermal processes (uncontrolled): Up to 5% without modifications * Industrial thermal processes (uncontrolled): Up to 5% without modifications |

Studies on the feasibility of hydrogen blending in the natural gas grid in the Baltic region have been undertaken. Based on a study conducted by the Riga Technical University, feasible hydrogen blending levels in the Estonian, Latvian, and Lithuanian NG grids could range between 5 and 23% (vol.%). As a precondition to any gas blending percentage, it is of utmost importance to evaluate the readiness of the gas grid components and end consumers’ equipment in the concerned countries. The feasibility and safety of hydrogen blending levels above 5 %mol can only be confirmed, after a thorough analysis of the possible review of the minimum requirements for the quality of the grid gas and an evaluation of the associated risks (primarily related to specific gravity)[[89]](#footnote-90).

In 2020, the Estonian TSO Elering AS has commissioned a study**90** (undertaken by TALTECH University) to investigate the impacts of hydrogen and synthetic gas on transmission pipelines and end-user equipment. As the different categories of consumers have different end-use limitations, a uniform high level blending percentage for all end-users can give rise to problems, in this case, certain level of end user limitations for H2 blending is considered. The key findings of the study on the maximum allowable limit of hydrogen admixture in the NG grid for various types of end-users are presented in **Table 6‑13**. The values presented in the following table may differ from the actual limitations in the Estonian gas grids or end consumer devices, resulting in possible safety concerns for end-users.

Table 6‑13. Hydrogen blending allowable limits for end-users and NG infrastructure[[90]](#footnote-91)

|  |  |
| --- | --- |
| Limiting factors, components/elements | Permissible concentration |
| CNG transport | up to 2 %mol |
| Gas turbines | up to 2 %mol |
| Sensitive to the quality of natural gas as a raw material industrial consumer | case-by-case, as a rule  up to 2 %mol |
| Compressors (natural gas transmission network) | up to 5 %mol |
| Density of hydrogen/ natural gas mixture compliance | up to 5 %mol |
| FID and DIAL type natural gas detection equipment | do not detect hydrogen or behave incorrectly |
| Pigging station | no information available |
| Natural gas cast iron pipeline | no information |

The current maximum possible hydrogen blending levels in NG grid in the Baltic-Finnish zone are presented in the following table.

Table 6‑14. Maximum hydrogen blending level accepted by the national network operator

|  |  |
| --- | --- |
| Country | Maximum blending level in vol% |
| Estonia13 | 0.1 |
| Latvia33 | 1.54 |
| Lithuania33 | 1.95 |
| Finland[[91]](#footnote-92) | 1 |

Currently Finland has set the maximum hydrogen percentage at 1% in both TSO and DSO levels.

**Information from TSOs regarding possible developments of hydrogen blending in the Baltic states**

Currently, there are no determined hydrogen blending targets for Estonia. The blending percentage will amongst others depend on the EU regulation and policy. The Baltic-Finnish TSOs are jointly planning to conduct a technical study to evaluate the necessary modifications and costs to make the NG transmission system suitable to transport 2%, 5% (EU Commission proposal for October 2025), 10%, and 20% of hydrogen volume blending. This study started in September 2022. Also, the TSOs are part of the European hydrogen backbone (EHB) initiative to assess the possibilities of developing a pan EU dedicated hydrogen transmission infrastructure. According to the Lithuanian TSO (Amber grid), regional market operators are currently analysing the acceptable hydrogen blending levels into the natural gas system; the first blending % will likely be available regionally after 2024 and domestically after 2025, starting at 2% hydrogen, up to a maximum of 10 %, or, more realistically, at 5 %. An optimistic target for both biomethane and hydrogen would account for about 5 % by 2030. Up to 5 % hydrogen blending in the Lithuanian natural gas grid is possible with minor modifications in the infrastructure. Currently, a new study is carried out by Amber Grid, which analyses the modernization of the existing natural gas system and its individual components (valves, pipelines, distribution stations, etc.) that could be used for hydrogen with a particular interest in the technologies used for their modernization (e.g., internal coating of pipelines, etc.). The hydrogen roadmap for Lithuania is also in the last steps of finalization. According to the Latvian NECP, Latvia plans to retrofit its gas infrastructure to improve its pipelines standards, and this creates a possibility to assess and to adapt the natural gas infrastructure enabling it for hydrogen transportation. In Baltic-Finnish region, there is no specific targets for hydrogen blending in the natural gas grid in the near future which has been published.

# Relevant pilot projects

Table 7‑1. List of relevant pilot projects for the renewable gas value chain [ENTSOG H2-Project Visualization tool][[92]](#footnote-93)

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Nr. | Type | Project name | Country | Timeline | Project maturity | Scope and goal | Suitability or applicability in 3B+F region |
| **1** | H2 production | H2 at Riga Wind farm | Estonia | 2020-NA | Project (Pilot) | The aim is to identify the most suitable solution for hydrogen production with the lowest environmental impact, even if hydrogen production could only be implemented at a later stage of the project, due to technological or investment barriers. | Can be taken as a working example for establishing hydrogen production hubs |
| **2** | Integrated H2 project (production and use) | H2 NODES | Estonia | 2016-NA | Project | H2Nodes investigates planning and realising a chain of hydrogen refuelling stations (HRS) and boosting demand for fuel cell electric vehicles (FCEVs) along the North Sea - Baltic core network corridor. | Can be taken as a example of dedicated hydrogen production for transport sector |
| **3** | H2 production | Power to Gas Production with infrastructure building/enhancement | Latvia | NA-NA | Project | Power to Gas technology will be used and generated hydrogen as also potentially synthetic hydrocarbon will be injected into existing gas transmission grid with possible utilization of existing or creation of new aquifer gas storage. The first steps of the demonstration project will be feasibility study on the best location and technology as well the impact of hydrogen on aquifer storages. Option of production of the synthetic methane capturing CO2 from industrial site also will be considered. | It is an example to initiate the power-to-gas projects (renewable hydrogen and SNG) and to test their feasibility for gas blending (in the NG infrastructure) and to test hydrogen injection in underground storages points in 3B+F region |
| **4** | Integrated H2 project (production, transport, use) | Hydrogen injection into the gas network in Lithuania (power-to-gas) | Lithuania | 2022-2024 | Project (Pilot) | Hydrogen mixing in gas networks, investigating mixture effects in transport infrastructure and consumers devices. | This pilot project can be taken as an example to initiate the practical testing of gas infrastructure with different hydrogen blends in the member states in the 3B+F region |
| **5** | H2 production | OYSTER | Denmark | 2021-2024 | Project (Pilot) | The OYSTER project will lead to the development and demonstration of a marinized electrolyser designed for integration with offshore wind turbines. Preparation for further offshore testing of wind-hydrogen systems will be undertaken, and results from the studies will be disseminated in a targeted way to help advance the sector and prepare the market for deployment at scale | Can be taken as a working example for establishing offshore hydrogen production hubs in 3B+F region |
| **6** | H2 production/SNG Production | P2G Augsburg project | Germany | 2018-NA | Project (Pilot) | Installation of a decentralized power-to-gas system in a residential complex in Augsburg. Renewable electricity not consumed directly, it is used to generate hydrogen in an electrolyser and converted into synthetic natural gas using carbon dioxide. Synthetic gas in this way can be used to generate heat in a CHP plant and condensing boiler. | It is a working example of SNG production for power sector. This can be taken as a reference for SNG to be included in the gas sector mix in 3B+F region |
| **7** | H2 production/consumption | H2 production projects | Italy | 2022-2023 | Project (Pilot) | The companies are studying two pilot projects aiming at supplying green hydrogen to qualified Eni refineries. The two pilot projects will involve electrolysers of around 10 MW each and are expected to start generating green hydrogen by 2022-2023. | This pilot project is an example of renewable hydrogen inclusion in refineries to decarbonize and reduce the fossil hydrogen use. This pilot project can be taken as an example to initiate the renewable hydrogen deployment for refineries in Lithuania and Finland. |
| **8** | H2 production/consumption | REFHYNE | Germany | 2018-2022 | Project | The REFHYNE project will install and operate a 10MW electrolyser from ITM Power at a large refinery in Rhineland, Germany, which is operated by Shell Deutschland Oils. The electrolyser will provide bulk quantities of hydrogen to the refinery’s hydrogen pipeline system (currently supplied by two steam methane reformers). The electrolyser will be operated in a highly responsive mode, helping to balance the refinery’s internal electricity grid and also selling Primary Control Reserve service to the German Transmission System Operators. | This pilot project is an example of renewable hydrogen inclusion in refineries to decarbonize and reduce the fossil hydrogen use. This pilot project can be taken as an example to initiate the renewable hydrogen deployment for refineries in Lithuania and Finland. |
| **10** | H2 blending | Energy Storage – Hydrogen injected into the Gas Grid via electrolysis field test | Denmark | 2017-2019 | Project (R&D) | How implement H2NG blend in already existing MR stations for transmission and distribution. The project has demonstrated transportation of up to 15% hydrogen in natural gas in a closed-loop high-pressure system, consisting of components and infrastructure from both the transmission and distribution grids. The test has shown that there is no increased leakage of hydrogen from the system compared to natural gas and that the tested components from the gas system are capable of handling hydrogen in the tested concentrations without major modifications. | This R&D project example can be taken as a guide to start testing the hydrogen blends in NG infrastructure in 3B+F zone |
| **11** | H2 blending | Hydrogen injection into the gas network in Lithuania (power-to-gas) | Lithuania | 2022-2024 | Project (Pilot) | Hydrogen mixing in gas networks, investigating mixture effects in transport infrastructure and consumers devices. | This R&D project example can be taken as a guide to start testing the hydrogen blends in NG infrastructure and to find out the tolerable H2 mix in the end use equipments in each country in Baltic-Finnish zone. |
| **12** | H2 blending/deblending | FenHYx2 | France | 2021-2025 | Project (R&D) | Optimise separation systems on the network for different use-cases. Bench test and demonstrator to de-blend H2GN to protect sensitive clients and/or to purify H2 (also potentially in case of repurposed pipes) | This is research project example to show the deblending of the H2 based blended flows for the sensitive consumers |
| **13** | Adaptation of end consumer application | H2 Ready Central Heating Burner | Netherlands | 2018-2020 | Project (R&D) | Developing a H₂ Burner System as a Retrofit. The goal is to develop a burner system that can replace the current natural gas burner. This means that future boilers for hydrogen can be produced. However, already installed boilers can also be converted with a retrofit. | This project can be taken as a R&D initiative in 3B+F region to put force in developing local end use equipment retrofitting technology and skills |
| **16** | SNG production |  | Poland | NA - 2020 | Project (Pilot) | The installation was built by TAURON Wytwarzanie S.A. at the Łaziska Power Plant in Poland. After the commissioning, the Institute for Chemical Processing of Coal (IChPW) was responsible for conducting research. | It is an example to initiate the power-to-gas projects (SNG production) in 3B+F region |

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