ANNEX 2: Common Risk Assessment – Eastern Gas Supply Risk Group – Baltic Sea

Member States

The Baltic Sea Risk Group is composed of: Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxemburg, Netherlands, Slovakia and Sweden.

Gas Storage Capacity in Member States

	Working gas volume in TWh	Share of capacity in risk group in %
AT	97,64	13,36%
BE	9,13	1,25%
CZ	44,67	6,11%
DE	252,40	34,52%
DK	9,85	1,35%
FR	136,35	18,65%
LU	0,00	0,00%
NL	142,41	19,48%
SE	0,10	0,01%
SK	38,55	5,27%
Total	**731,09**	**100,00%**

Source: AGSI+, 16.08.2023

Summary of the Common Risk Assessment

The Baltic Sea Risk Group encompasses a network of interconnected countries that heavily relies on gas imports, specifically on Russian gas via pipelines like North Stream and Yamal pipeline. Despite recent disruptions, such as the damaged North Stream pipeline in 2022, alternative gas imports have managed to persist through other routes. Belgium's gas grid has emerged as a central player for gas transportation across Europe, particularly since the start of the Russian invasion of Ukrainian.

The countries forming this risk group, including Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxembourg, Netherlands, Sweden, and Slovakia, have distinctive gas supply dynamics and interconnections. The declining and uncertain imports of Russian gas have led to the utilization of LNG terminals and the maximization of major interconnectors' capacities to cope with the situation. The evolving gas flow patterns, now focused on flows from west to east due to the reduced Russian gas supply, introduce new supply vulnerabilities, especially for Northern and Eastern European countries. However, a proactive approach involving demand reduction measures has been employed to mitigate future potential risks to supply.

The CRA's core scenario focused on a total discontinuation of Russian gas imports via pipelines, lasting from October 2022 to the end of 2023. This would mean a major reduction in present gas flows of around 83% compared to the average from 2016 to 2021. This chosen scenario holds the most substantial influence on overall risk. While the possibility of other important gas sources halting exists, like Norway, exist, such occurrences were considered implausible due to various reasons. Technical failure rates differ between onshore and offshore pipelines, with Norway's offshore network less likely to experience similar issues. The intricate European gas network further mitigates potential impacts. Given the complexity and minimal impact of alternative scenarios, the CRAs prioritized the full interruption of Russian gas flows as a core scenario, reflecting its notable impact and relative plausibility.

The potential interruption of Russian gas supplies to the EU is viewed as highly severe and probable, prompting a departure from conventional risk assessment practices aligned with Regulation (EU) 2017/1938 on gas supply security. These practices typically involved analysing specific RG events and risks with a restricted geographic focus. However, the risk of significant reductions in gas supply from Russia lead to a broader geographic coverage.

The Joint Research Centre (JRC) conducted extensive modelling simulations for a comprehensive risk scenario about the extended halt of Russian gas deliveries to the EU starting from October 1, 2022. The JRC's analysis encompassed 48 variations, accounting for diverse crisis management strategies, historical gas consumption patterns, different storage management strategies, and capacity maps for interconnection points.

Moreover, the study included a series of sensitivity analyses. First, in response to the proposed Regulation (EU) 2022/1369, which mandates a 15% reduction in gas demand, an additional 36 scenarios were simulated, varying demand reductions from 5% to 15%, with these reductions sustained even after the winter of 2022-2023. Second, beyond disruptions in Russian supply, the report introduced six more risk events relevant to different RGs (Algeria’s total supply disruption, disruption of the Transmed pipeline, total disruption of the Hungary-Romania interconnector, total disruption of the Stenlille gas storage facility, total disruption of Europipe 2 and a two-week cold spell over the entire EU). 72 simulations were carried out to comprehensively evaluate these diverse risk scenarios.

These analyses provide a comprehension of potential risks associated with the halt of Russian gas supplies and other potential threats. Key conclusions from the exercise include the following: A non-cooperative approach, with short-term storage management during winter 2022-2023, leads to 4 bcm of unserved gas on average in the RG, varying from 0 to 10 bcm based on demand scenarios. Relative gas curtailment ranges between 22-46% on average across different countries. The adoption of a cooperative strategy with the same storage management reduces curtailment to 3.2 bcm. For the long-term storage management approach, average curtailment rises to 18 bcm for both cooperative and non-cooperative strategies. However, non-cooperative strategy's peak curtailment reaches nearly 29 bcm, compared to around 22 bcm for the cooperative approach. Countries within the RG experience varying impacts, with Germany, Denmark, Austria, Czech Republic, and Slovakia facing higher curtailment. Peak gas curtailment in Germany reaches around 110 mcm/d in cooperative scenarios, increasing to 208-223 mcm/d under non-cooperative strategies. LNG send-out flows remain at around 30 bcm over winter, with an increase in LNG send-out flow from January 2023 due to new floating LNG terminals. Most RG countries, excluding Luxembourg, have underground gas storage facilities. Short-term storage strategies start with over 90% filling but deplete to 8% by April 2023. Long-term storage management maintains average filling around 35% by April 1, 2023. Cooperation leads to intensive transmission capacity use, with minor effects on curtailment. Sensitivity analysis reveals that a 5% reduction in winter demand mitigates curtailment, while a 15% reduction is needed for long-term security. Lastly, the cold spell emerges as the most impactful risk event, potentially causing unserved gas demand of around 13 bcm over winter. Other risk events have relatively minor effects compared to the baseline scenario.

Description of the System

Belgium

Overview of the pipeline network

Belgium has two different types of gas: H-gas (with high caloric value) and L-gas (with low caloric value). L-gas originates partly from the Groningen field in the Netherlands (Groningen gas) or the artificial transformation of H-gas to L-gas. To be able to import or inject the L-gas into the Belgian L-gas network, the gas needs to have a Wobbe index between 43,9 MJ/m³(n) and 46,89 MJ/m³(n). The Wobbe index for H-gas ranges from 49,13 MJ/m³(n) to 56,81 MJ/m³(n). This lower Wobbe index is compensated through a higher pressure in the public distribution network: average pressure for non-industrial customers in the distribution network is about 25 mbar, while for the H-gas the average pressure is 20 mbar.

Those different characteristics for L- and H-gas lead to two different infrastructure networks and two separate commercial markets in Belgium, one for L-gas and another for H-gas.

The Belgian transmission grid has a high level of interconnectivity with adjacent transmission grids, offering extensive access to Northwest European market areas and production facilities.

Belgium's transmission network has about 4 000 kilometres of pipelines with 17 physical interconnection points and four compression stations. Eight crossborder pipelines connect the Belgian gas market directly to Norway, UK, Germany, the Netherlands, France and Luxembourg. Four compressor stations are located in:

- Weelde: upgraded in 2010 to increase the pressure of low-calorific natural gas in the pipeline from Poppel on the Dutch border to Blaregnies on the French border.
- Winksele: to increase pressure on the North/South axis. The compression station has been upgraded with four new compression units in order to increase pressure on the East/West axis (VTN/ RTR1 and 2).
- Berneau: in 2010-2011 additional compression stations were built on the high calorific gas pipeline from 's Gravenvoeren on the Dutch border to Blaregnies on the French border and to export further on the VTN/RTR pipeline (Zeebrugge-Zelzate/Eynatten).
- Zelzate: on line since the end of 2008 to create additional capacity for the overall rise in demand of the Belgian domestic market and enables larger volumes to be transported to and from the underground storage facility in Loenhout.

The border-to-border gas transmission through Belgium is assured via major two-way high-pressure pipeline systems. The line from Zeebrugge to Blaregnies linking the North Sea and the UK to France (H-gas) is still used mainly for B2B transaction transit. There is a separate pipeline, parallel to the Zeebrugge-Blaregnies pipeline, for domestic transmission in the western part of the country. Presently, all pipelines are meshed in one network and lined up to be used for border-to-border transmission as well as for domestic supply.

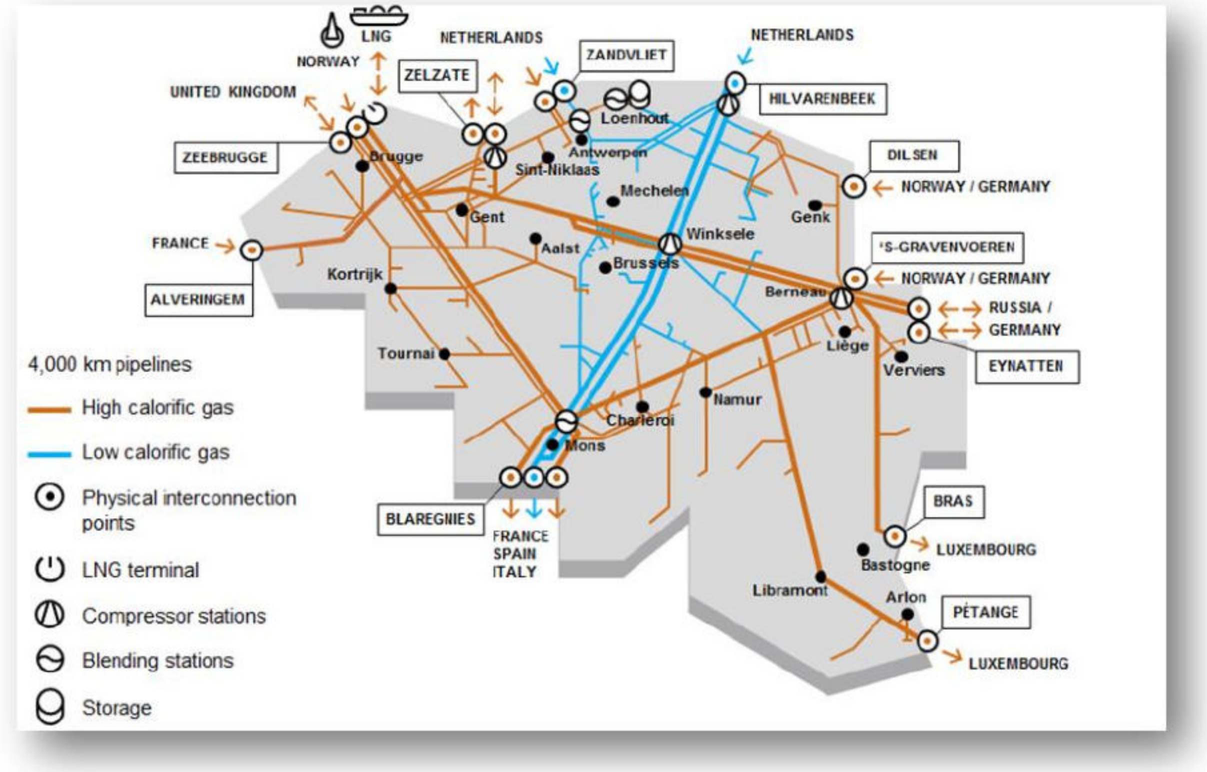


Figure 1: Belgian transmission network operated by Fluxys Belgium

Infrastructure in the L-gas market

The existing infrastructure in the L-gas network consists of:

- a physical entry point at Poppel/Zandvliet L: the corresponding points at the Dutch side of the border (exploited by GTS) are Hilvarenbeek and Zandvliet L. The available capacity at Poppel is 65.52 mcm/d.
- an exit point at Blaregnies: the corresponding entry point in the French network (exploited by GRTgaz) is Taisnières with an entry capacity of 24.96 mcm/d.
- two quality conversion units for H-gas to L-gas in Lillo and Loenhout. Their total production capacity is up to 9 600 mcm/d of L-gas, depending on outside temperatures and other operational constraints. The conversion units at Lillo and Loenhout have been taken out of service since the first of April 2023.

Coming from Poppel, the L-gas is transported over a couple of kilometres to a first compression station, Weelde. From there, it is transported to a second compression station (Winksele) halfway between Poppel and Blaregnies. A second entry point is situated at Zandvliet L. L-gas can be imported through this entry point as long as the pressure in the Dutch gas grid is higher than the pressure in the Belgian network. The quantities taken up at Zandvliet L are derived from the quantities available at Poppel. Entries at Poppel and Zandvliet L must be considered as a cluster.

The Netherlands intended to stop gas extraction in Groningen in 2024. Therefore, conversion of H gas into L gas will ensure that the Netherlands will be able to fulfil their commitments until the end of 2029 (original planning). The chosen approach to tackle this issue in Belgium is to progressively convert the whole L-gas market to H-gas, hence making more sources of gas available to customers currently depending on the supplies from the Netherlands. In 2017, there were about 1.6 million clients connected to the L-gas network. Synergrid (Belgian federation of transport and distribution networks)'s indicative planning for the conversion is ongoing. In June 2018, approximately 50,000 connections have been converted as the first phase of the conversion plan and the entire Belgian natural gas market should be converted to H-gas by the end of 2024 (advanced planning).

However, the transit of L-gas from the Netherlands to France will continue for several years (Fluxys, annual report 2020). The indicative conversion schedule is provided in Figure below.

Interconnections and reverse flow capacity

The VTN-RTR pipeline (H-gas) is bi-directional linking the UK and the Zeebrugge hub with Germany and the Netherlands, the SEGEO pipeline (H-gas) runs from the Dutch border in 's Gravenvoeren to France and the Poppel-Blaregnies pipeline runs from north to south, linking the Netherlands with France (L-gas). In 2010, the Zelzate entry point (physical bi-directional) came into operation following investments in the Dutch grid through which the capacity on the East-West axis increased. The Interconnector is the subsea pipeline which connects the Fluxys Belgium grid to Bacton in the United Kingdom and is an important physical bi-directional link between the UK and continental Europe. Interconnector allows natural gas from the Continent to be shipped to the United Kingdom. Gassco's Zeepipe Terminal (ZPT) connects Norway's Troll and Sleipner offshore gas fields to the Belgium grid via the subsea Zeepipe pipeline.

The table below gives an overview of the technical capacities in forward and reverse flow on each of the interconnection points in Belgium. Capacities also depend on capacities offered by adjacent TSO and could change over time. Belgium benefits from sufficient reverse flow capacity on the following axes: BE-UK, BE-DE, BE-NL. The technical capacity is not a fixed invariable value. An increase of the technical capacity can be allowed by reducing the technical capacity of other interconnection points (resulting in the same network load), by optimizing the steering possibilities or by modifying the network flow scenario's. Published firm capacity can be temporarily higher, based on temperature effect, network load and booked 'restricted' transmission services (wheeling, operational capacity usage commitments (OCUC)).

Although individually available, the capacities on the interconnection points IZT, ZPT, LNG Terminal and ALV are limited in aggregate (as indicated on the Fluxys Belgium data platform).

Table 1: Firm entry and exit capacity offered on the connection points (in mcm/d)

	Connection point	Type	Entry Capacity (2018)	Firm capacity offered 2022 (mcm/d)	
			GWh/d	Entry	Exit
H	IZT	EP	732.24	64.80	78.00
	ZPT	EP	515.28	43.20	0.00
	Zelzate 1	EP	393.24	36.00	24.00
	Eynatten 2	EP	352.56	31.20	24.00
	S Gravenvoeren + Obbicht	EP	352.65	31.20	0.00
	LNG terminal 1	LNG	230.52	22.80	0.00
	LNG terminal 2	LNG	230.52	22.80	0.00
	Dunkerque	EP	218.99	19.38	0.00
	Eynatten 1	EP	203.40	18.00	24.00
	Loenhout Storage	S	169.50	15.00	7.80
	Virtualys (*)	EP	52.21	4.62	66.00
	Zandvliet H	EP	48.82	4.20	0.00
	Zelzate 2	EP		0.00	10.80
L	Poppel/Zandvliet L	EP	642.10	65.52	0.00
	Transfo H à L (**)	EP		9.60	8.64
	Blaregnies L	EP		0.00	24.96

Source: Data compiled based on information of Fluxys

(*) Virtualys is the virtual interconnection point (VIP) comprising of the two physical interconnection points in Blaregnies (H-gas) and Alveringem. Some of the available capacity in Alveringem is used for transborder access to the Dunkerque LNG terminal

(**) Transfo H. L: the entry capacity is on the L-gas side and the exit on the H-gas side. The capacities shown in the table also consider the unit in Loenhout, which is currently mothballed.

Fluxys Belgium’s network still has an interconnection point at Pétange & Bras (connection point Belgium-Luxemburg) but is not commercialized anymore.

No fundamental modification of the infrastructure in terms of interconnections is foreseen for the coming years.

LNG

The Zeebrugge port has an LNG re-gasification terminal (in operation since 1987) with a capacity of 9 bcm per year in five storage tanks. Send out capacity from Zeebrugge LNG facility is 1.9 mcm/h (regasification capacity is 14.2 bcm/y) with a storage capacity of 562.000 m³ LNG. The facility has about 5,5 days of autonomy (storage capacity/ daily regasification capacity).

Currently the terminal has a send-out capacity of up to 12 000 cubic metres of LNG per hour (or 1,7 mcm/h in gas) and can unload 110 LNG cargos per year.

		2022	
Zeebrugge (BE)	Maximum Daily Regasification Capacity [GWh/(	540,9	Source: alsi.gie.eu Period: 1st Jan 2022 to 4th Oct 2022
	Storage Capacity [TWh]	3,77	
	Utilization Rate - Yearly Average [%]	61%	
	Utilization Rate - Daily Peak [%]	97%	
	Utilization Rate - Weekly Peak [%]	83%	
	Access Regime	regulated	

Storage

Belgium has one underground gas storage installation operated by Fluxys Belgium (available for commercial storage of H-gas), which is the aquifer storage in Loenhout, with a useful storage capacity of 770 mcm. Only high calorific gas (H-gas) may be stored in this facility. Short term LNG storage is also available at the Zeebrugge LNG terminal. Part of the stored natural gas is reserved by Fluxys Belgium for operational balancing of the network. The rest of the storage capacity is sold to the market for dealing e.g. with seasonal swings and situations of peak demand.

Although storage plays an essential role in meeting the winter demand at the regional level, even the capacity of the storage could not contribute alone to meet the Belgian domestic peak demand with the national consumption in winter, this facility could help to bridge for a part a cold spell of ca. 10 days.

The Zeebrugge LNG terminal has also a short-term storage capacity available (a working capacity of 2 576 GWh and a peak send out of 515 GWh/day), but the LNG must be sent out almost immediately after cargoes unloading because slots are allocated. Therefore, the LNG storage tanks act more like a very temporary buffer than a storage facility.

The table below gives an overview of the storage capacity of Loenhout and his possible role during the heating season

		2021	2022
BE (Provide National Aggregate Values)	Total Storage Capacity [TWh]	9,00	7,61
	Total Storage Capacity vs Heating Season Demand [%]	7,17%	6,73%

Note: 7.610 TWh as from 29/09/2022 in AGSI (https://agsi.gie.eu/) - redefined from SBU definitions

Domestic production

Belgium has no indigenous fossil gas production. A small amount of colliery gas is however extracted from old coal mines and used for electricity production since 2019 (see below).

In 2021, 2.86 TWh of biogas has been produced in Belgium (the production level is consistently above 2.5 TWh since 2014).

Almost 200 biogas production units are active in Belgium, mainly used to power local heat or electricity generation processes. Biogas can also be purified and transformed into biomethane, which can be injected into the natural gas distribution or transmission system. A study conducted by Valbiom has shown that realistically, biomethane could generate 15.6 TWh by 2030, equivalent to around 8% of Belgium's natural gas consumption in 2019.

At the end of 2021, there were 5 injection sites which introduced 86.6 GWh of biomethane into the main gas network. In addition, 51.5 GWh of colliery gas was extracted and used for electricity production in 2021.

		2017	2018	2019	2020	2021	2022
BE Domestic Production	Volume of Production [TWh]	0,00	0,00	0,04	0,06	0,05	
	Volume of Production/Total Annual Demand [%]	0,0%	0,0%	0,0%	0,0%	0,0%	
	Maximal Daily Production Capacity [GWh/d]	not aval.	not aval.	not aval.	not aval.	not aval.	

Main gas consumption figures

The Belgian gas consumption is divided between H-gas or high calorific gas and L-gas or low calorific gas. In 2021, the total measured gas demand of the Belgian end consumers amounted to 196.0 TWh (or 18.4 bcm) , of which 153.3 TWh was H-gas (78% of total demand) and 42.6 TWh was L-gas (22% of total demand).

The L-gas demand in Belgium has a different behaviour than the H-gas demand due to the type of consumers that are connected to the two networks. A large majority of the L-gas consumption is attributed to the public distribution (which includes residential, commercial, services, agriculture and small industrial clients), while the remaining feeds large industrial consumers directly connected to the transmission network. There are no power plants on the L-gas transport network.

Gas demand by sector

Figure 2 shows the total consumption in 2021, as well as the breakdown of the H-gas and L-gas consumption, for energy (transformation and energy sectors), industry (including non-energy use), and other (residential, commercial, services, agriculture and transport).

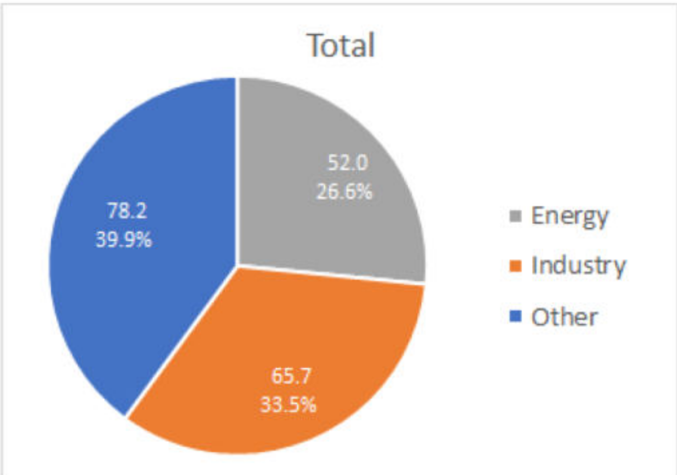


Figure 2: Natural gas consumption in TWh for 2021

Source: FPS Economy based on internal official data (Eurostat definitions) and on TSO/DSO data for H-gas/L-gas distinction

The above figures demonstrate the dominance of the “other” sector (residential, commercial, services, agriculture and transport) in Belgium. In 2021, 40% of the natural gas consumption in

Belgium was used by the “other” sector, 34% by the industry and 27% by the energy sector. L gas is only used by the "other” sector (84%) and the industry (16%). H-gas is used by all three sectors, namely the “other” sector (28%), industry (38%) and the energy sector (34%).

Evolution of the yearly gas demand

Figure 3 and Figure 4 show the evolution of the total gas consumption in Belgium for the period 2012-2021 (in TWh/year). Figure 3 also shows the breakdown of the H-gas and L-gas consumption, while Figure 4 shows the breakdown of the energy, industry and “other” sectors.

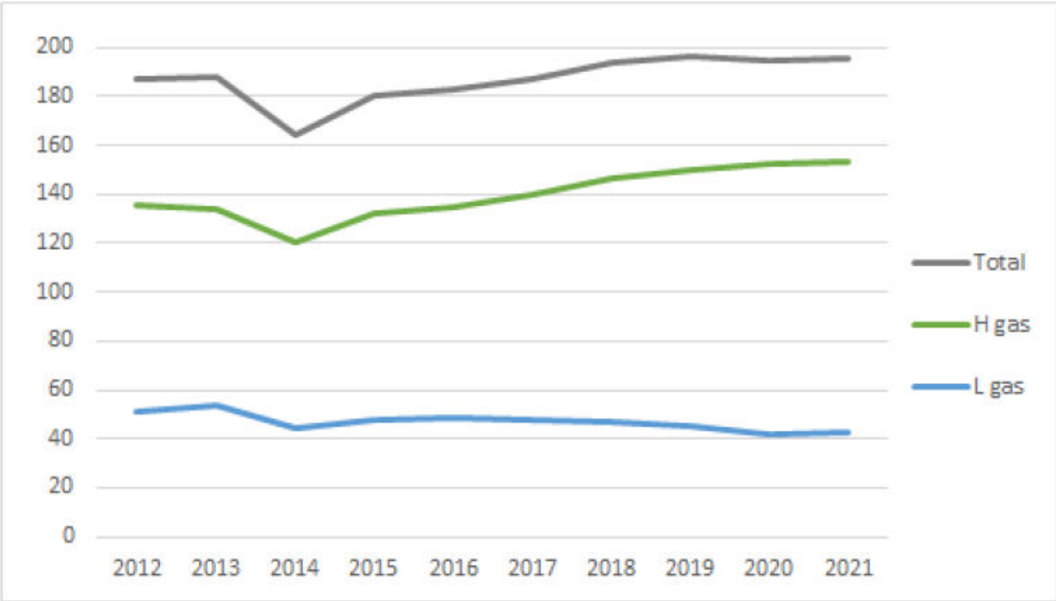


Figure 3: Measured yearly consumption in TWh (2012-2021), total, and L and H separately

Source: FPS Economy based on internal official data (Eurostat definitions) and on TSO/DSO data for H-gas/L-gas distinction

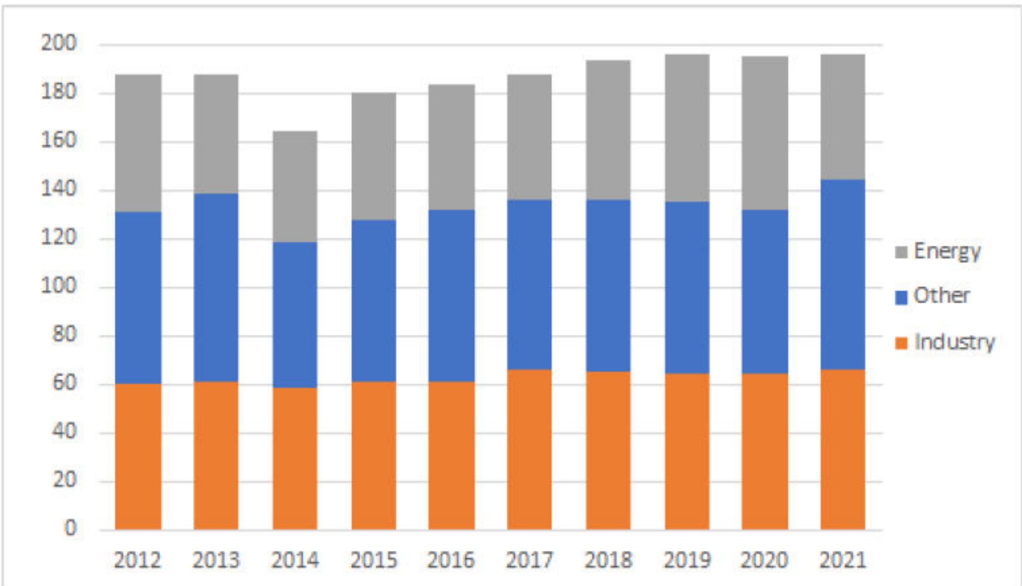


Figure 4: Measured yearly consumption in TWh (2012-2021), by sector

Source: FPS Economy based on internal official data (Eurostat definitions)

A significant part of the gas consumption in the “other” sector is used for space heating, therefore it is sensitive to the outside temperature. The number of equivalent degree-days as well as the pattern of the degree days over the year have a significant influence. Figure 4 shows that the “other” consumption decreased in 2014 and 2020, which were warmer years, and was highest in 2013 and 2021, both colder years. This link between degree-days and consumption is most noticeable in the residential sector, but also to a lesser extent in the commercial and services sectors. Until 2016, this link could also be seen in the agricultural sector, but this consumption has been steadily increasing since.

Industry consumption is less influenced by the outside temperature. The consumption of the industry was relatively stable in the period of 2012-2016, with an average consumption of 60 TWh/year. In 2017, the consumption increased to 65 TWh/year and has remained around this level since (s. Figure 4).

As already mentioned, primary gas demand is also expected to grow in medium and long term. The government’s forecasts project a strong growth of gas consumption in power generation because the new capacities that need to be built (particularly to replace a significant portion of the nuclear generation capacity to be phased-out) will probably be mainly gas-fired. An increase in intermittent renewables-based power generation could also increase demand for gas to fuel back-up facilities. Growth in gas demand is also expected in the residential sector because households continue to move away from gasoil towards natural gas for heating.

The role of gas in the electricity production

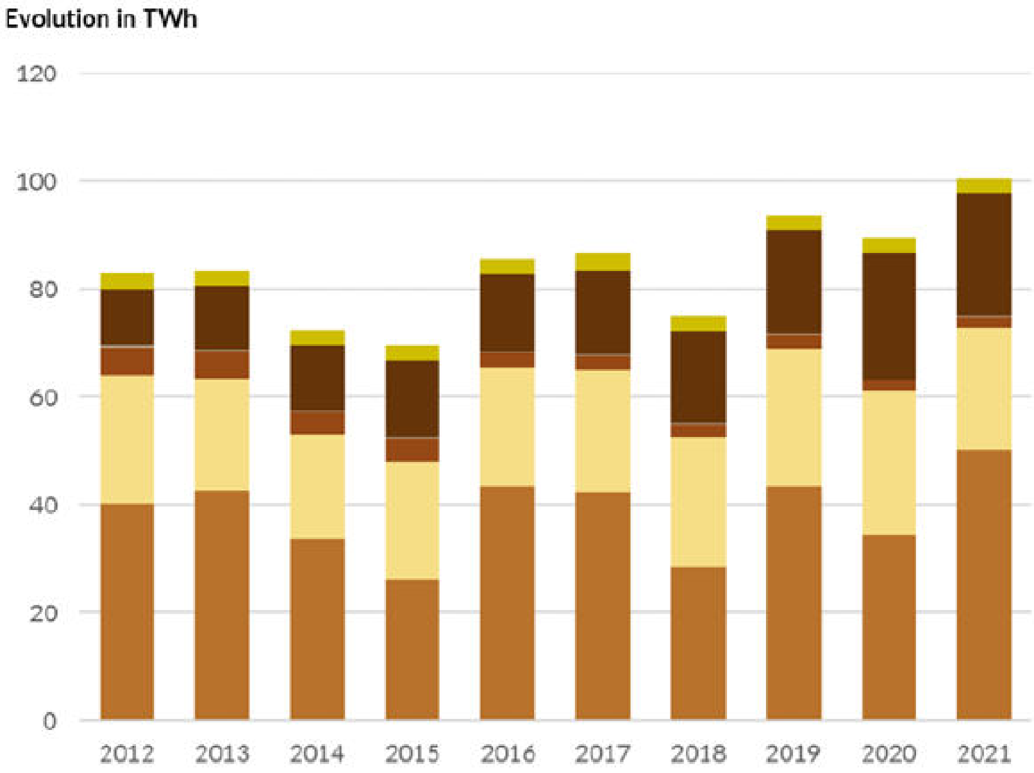
Yearly Electricity generation

In 2021, gross electricity production in Belgium was 100,5 TWh. During the last decade, the largest increase of electricity production can be found in renewable energy, where electricity production increased by 116.0% or 12.2 TWh compared to 2012. The use of oil products and solid fossil fuels strongly decreased (respectively -45.8% and -62.9% over the last decade), mainly in favour of renewable energy. The last power plant running on solid fossil fuels closed in 2016. The electricity still produced today from this group of fuels comes from gases released during the manufacturing process in the steel industry and from small multi-fuel cogeneration plants.

Table 2: Gross Electricity Production in 2021

Electricity		TWh
Nuclear		50.3
Natural gas		22.5
Solid fossil fuels and manufactured gases		2.0
Oil products		0.2
Renewable energy		22.7
Other sources*		2.7
Total		**100.5**

*Other sources include pumped hydro, heat recovery, non-renewable waste and other.



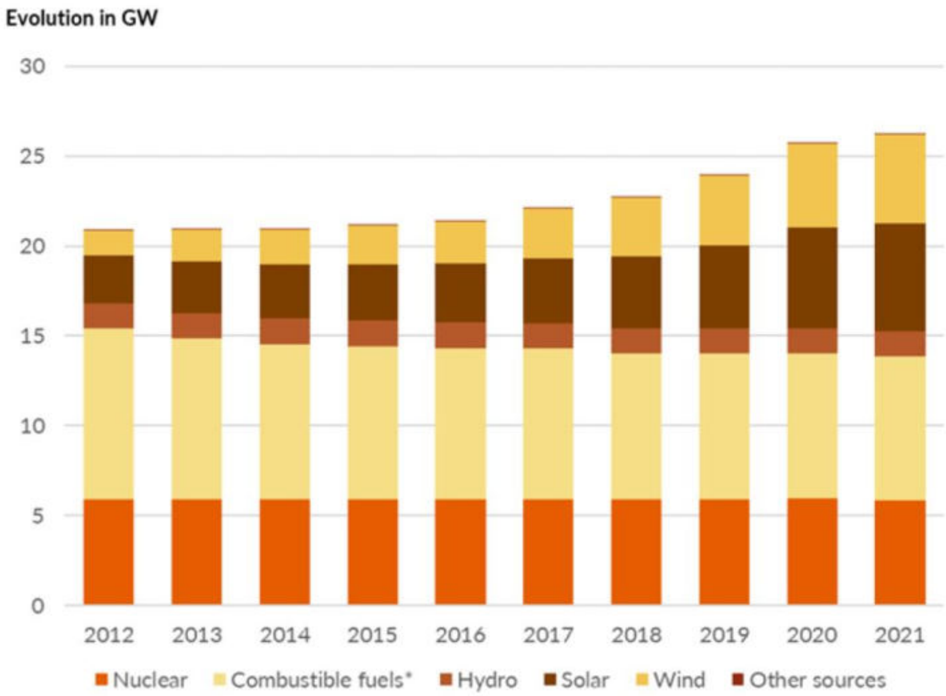
Flexibility is provided mainly by gas-fired power plants (60% of the flexible production capacity), cogenerations (CHP) and the hydropower pumping station (the largest one in Coo offers 1MWe capacity for 6 hours). Turbojets are almost negligible (0.8% of flexibility capacity).

In 2021, the volumes of gas consumed by Belgium for producing electricity (alone and also together with heat) were 4.09 bcm (43.5 TWh), excluding Blast Furnaces, and the percentage of these volumes with respect to total gas consumption was 22%. The total quantities of electricity produced with natural gas amounted to 22.5 TWh, which represented 22.4% of the entire national electricity production.

Electricity production in Belgium is currently generated by a diversified mix of energy sources. In recent years, the share of natural gas used for power and heat generation (i.e. the transformation sector for statisticians) was between 24% and 27% of the total natural gas available on the Belgian market. Gas power plants were considered to be the residual category of power plants and were the last in line of the merit order. However, the (partial) nuclear phase out will result in a larger share of power produced by gas power plants and no longer be considered as a residual category but as a structural component of the Belgian electricity mix. Note that in 2021, 53% of the power production based on gas has been done with cogeneration units.

Installed capacity

Power capacity installed in Belgium increased from 20.8 GW in 2012 to 26.2 GW in 2021. Conventional thermal installations (thermal excluding nuclear) decreased by 1.5 GW, while renewable electricity production capacities, mainly solar energy and wind energy, increased considerably to represent 11 GW or 41.8% of the total installed electricity capacity.



*Combustible fuels include solid fossil fuels, oil products, natural gas, renewable fuels and waste (solid and liquid biomass, biogas, and renewable and non-renewable waste).

Figure 5: Installed Electricity Generation Capacity in 2021

Table 3: The role of gas in the electricity production

		2017	2018	2019	2020	2021	2022
BE Electricity Generation	Gas-Fired Generating Capacity - Total [MWe](1)	6464	6534	6642	6799	7282	6729
	Gas-Fired Generating Capacity - Percentage of Total Generating Capacity	31,3%	30,7%	29,6%	28,3%	28,3%	26,4%
	Cogeneration Capacity - Total [MWe](3)	2322	2306	2432	2423		
	Cogeneration Capacity - Percentage of Total Generating Capacity [%]	11,2%	10,8%	10,8%	10,1%		
	Total Electricity Production [GWh] (4)	86616	75037	93640	89389	100142	
	Percentage of electricity produced from gas [%] (5)	26,7%	32,2%	27,4%	30,1%		
	Percentage of gas used for power generation [%] (6)	24,7%	25,2%	25,5%	26,9%	22,1%	

Table 4:The role of gas in the electricity production

NOTES
(1) Based on ENTSOE transparency platform
(2) Based on ENTSOE transparency platform
(3) EUROSTAT dataset Maximum gross electricity capacity in CHP mode
(4) Gross electricity production EUROSTAT
(5) EUROSTAT dataset Production of electricity and derived heat by type of fuel [NRG_BAL_PEH], in particular to the Gross electricity production using natural gas
(6) EUROSTAT [NRG_CB_GAS], Transformation input - electricity and heat generation - to the sum of the quantities of electricity only and combined heat and power for both main activity producer and auto-producer.

Monthly gas demand & seasonality

The monthly demand pattern is quite stable across the different years. We also see that the global gas demand is strongly linked to the outside temperature. Belgian gas consumption shows a strong seasonal pattern (Figure 6). The average gas demand in July and August is mostly independent on the outside temperature and consists mainly of the gas demand from the industrial and energy sectors. Gas use in the winter months can exceed 25.000 GWh/month.

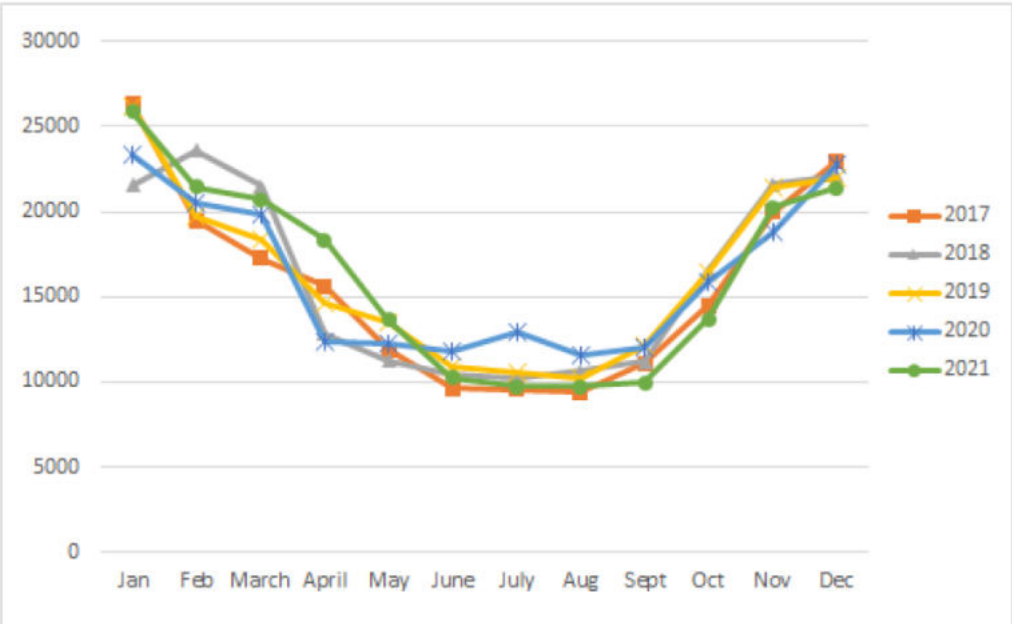


Figure 6: Total monthly consumption in GWh (2017-2021)

Source: FPS Economy based on internal official data (Eurostat definitions)

The consumption during a cold month (January is typically the coldest of the year) can be more than 200% than that of a summer month. This leads to widely different possible demand situations in any given incident scenario that has to be evaluated in the context of this Risk Assessment. The preferable and more conservative approach is of course to consider the worst-case scenarios, with a peak consumption over the specified period. The shorter this period is, the greater the difference between the associated peak consumption and the average consumption is – see next paragraph.

Czech Republic

The gas network of the Czech Republic consists of an interconnected set of equipment for the production, transport, distribution and storage of gas, including a system of control and signaling technology and equipment for transfer of information for the activities of computer technology and information systems used to operate these devices.

The gas system of the Czech Republic consists of:

- Transit pipelines of the transmission system: total length of 2 637 km, DN 800 - DN 1 400, nominal pressures 6,1 MPa; 7,35 MPa; 8,4 MPa.
- Domestic gas pipelines of the transmission system: total length of 1 181 km, pipelines DN 80 to DN 700, nominal pressures 4 MPa; 5,35 MPa and 6,1 MPa;
- Compression stations on the transmission system: Breclav, Veselí nad Lužnicí, Kralice nad Oslavou Otvice and Kourim;
- Border transfer stations on the transmission system: Lanžhot (CZ), Hora Svaté Kateriny (CZ), Brandov (CZ), Waidhaus (SRN), Olbernhau (SRN), Mokrý Háj (SR) and Cieszyn (PL);
- Transmission stations between transit and domestic transmission systems: Hrušky, Uhercice, Olešná, Limuzy, Hospozín and Veselí nad Lužnicí.
- GasNet, EGD and PPD distribution pipeline systems: pipelines DN 25 to DN 700, nominal pressures from 2,5 MPa to 4 MPa, with a total length of approximately 73.4 thousand km (with connections).
- Underground storages:
- RWE Gas Storage - Tvrdonice, Dolní Dunajovice, Štramberk, Lobodice, Tranovice, Háje;
- MND Energy Storage - Uhrice, Uhrice South;
- Moravia Gas Storage - Damborice;
- SPP Storage - Dolní Bojanovice (so far connected only with the transport system of the Slovak Republic)

- Border transfer points in distribution systems: Vejprty - Bärenstein, Aš - Selb, Alzbetin - Eisenstein, Hevlin - Laa an der Thaya, Úvalno - Branice, Zlaté Hory - Glucholazy, Hrádek nad Nisou - Zittau.

NET4GAS, s.r.o. (hereinafter also “NET4GAS”) is the transmission system operator in the Czech Republic. The company holds an exclusive gas Transmission System Operator (hereinafter also TSO) license in the Czech Republic and ensures gas transmission across and inside the Czech Republic.

The transport system is defined according to the Energy Act as a mutually connected set of high-pressure gas pipelines and compressor stations and related technological objects, including a system of control and signaling technology and information transmission equipment for computer and information systems activities connected to gas systems abroad, the gas shipment license holder. The transport system is established and operated in the public interest.

Description of the Transmission System Operated by NET4GAS

The company NET4GAS operates pipelines for international transit and national transport with a total length of approximately 3 973 km, with nominal diameters ranging from DN 50 to DN 1400 and nominal pressures ranging from 4.0 to 8.5 MPa.

The transmission system shows four main branches. The northern branch runs from Brandov / Hora Svaté Kateriny to Lanžhot, the southern branch from Rozvadov to Lanžhot, the western branch connects the northern and southern branches in the west and in the southeast the Moravian branch makes the Moravian area accessible for gas as well as connects the Czech gas transmission system to Poland. The northern, southern and western branches are interconnected at the key junction points Malešovice, Hospozín, Jirkov, Primda and Rozvadov.

In border transfer stations (BTS), where the NET4GAS' system is connected to the transmission systems of operators in neighboring countries, there is transferred gas and measured its volume, quality and energy content. Namely, on the Czech-Slovak border, it is BTS Lanžhot (located on the Czech side of the border), on the Czech-Saxon border, these are BTS Brandov, Hora Svaté Kateriny (located on the Czech side) and BTS Deutschneudorf and Olbernhau (located on the German side), on the Czech-Bavarian border it is BTS Waidhaus (on the German side) and on the Czech-Polish border it is BTS Cieszyn[1] (on the Polish side).

The gas pipeline "VTL DN 1400 - HPS Brandov - Rozvadov" ("Gazelle") starts at the interconnection point Brandov and ends at the German border station Waidhaus, where the exit point is located and where the Gazelle connects to the German transmission system. The Gazelle pipeline is owned by BRAWA, a.s., which is a legal entity distinct from the Czech gas transmission system operator. NET4GAS operates the Gazela gas pipeline on the basis of a lease agreement. The Gazelle pipeline is technically connected to the Czech transmission sytem in Brandov, Jirkov, Svinomazy and Primda for emergency situations. The interconnection pipeline is exempt from the obligation to allow third parties access under the terms of the Energy Act.

The required gas pressure in the pipelines operated by NET4GAS is provided through five compressor stations (CS), which are located on the northern branch at Kralice nad Oslavou, Kourim and at Otvice and on the southern branch at Veselí nad Lužnicí and Breclav. All compressor stations except CS Otvice can operate in bi-directional mode. The total installed output power of the compressors of the stations is 281 MW of the mechanical power.

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[1] The gas flow at BTS Cieszyn is one-way only in a direction from the Czech Republic to Poland, even though the BTS has been built as bidirectional. The reason for this is a considerably lower gas pressure for reverse flow on Polish side (1.7 MPa) compared to the pressure ratios in the Czech transmission system in this region (6.1 MPa). NET4GAS, based on a decision of the Ministry of Industry and Trade dated 6 October 2017, was exempted from the obligation to allow bi-directional capacity at the cross-border point Cieszyn, for the high-pressure gas pipeline DN 500, PN 63 STORK I. This exemption expires on 31st December 2022, in June 2022 NET4GAS and GAZ-SYSTEM submitted a new request for an exemption for a period of one year (until December 31, 2023) to create space for discussion with the state administration to find a suitable solution to ensure alternative gas supplies to the Czech Republic from diversified sources.

Table 4: Total installed power at the compressor stations

Compressor Station	Břeclav	Kouřim	Kralice nad Oslavou	Otvice	Veselí nad Lužnicí
Number of turbine units and their individual output power	9 x 6 MW	5 x 6 MW	5 x 6 MW	3 x 8 MW	6 x 6 MW
	1 x 16 MW	2 x 13 MW	2 x 13 MW		
	1 x 15 MW	1 x 12 MW	1 x 12 MW		
Installed CS power	85 MW	68 MW	68 MW	24 MW	36 MW
Total installed power for transmission	281 MW				

In the Czech Republic, the gas is further transported through the transmission system to distribution systems, directly connected customers and gas storages. 8 gas storage facilities are connected to the transmission system. Gas supplies are provided by 100 transfer stations (including border transfer stations) where commercial gas quantity measurement is installed. The gas quality is measured at 31 node points of the system by gas chromatographs.

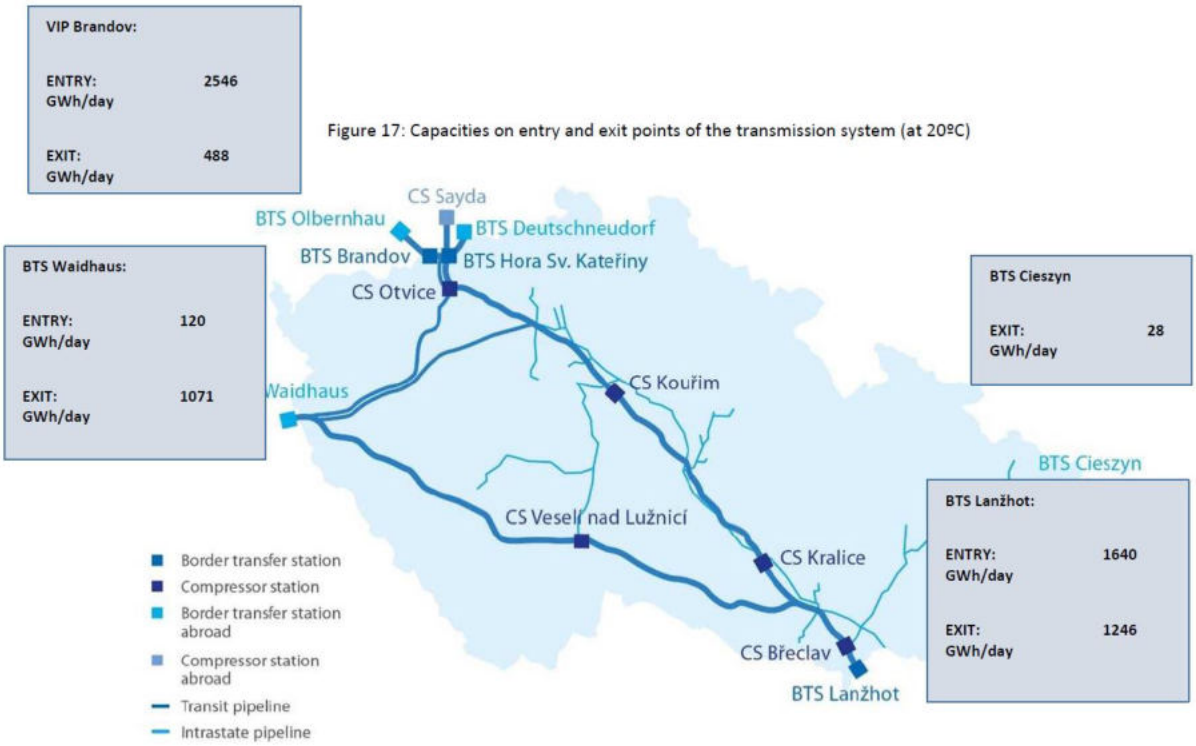

Figure 7: Capacities on entry and exit points of the transmission system (at 20ºC)

The normal operating mode does not allow reverse flow from Poland to the Czech Republic, but under pressure adjustments on both the Polish and Czech side it is possible to supply about 1.0 million Nm3 / day.

Transmission system technology allows bidirectional gas flow at all border stations and allows gas to be transported from east to west, but also from west to east. At the Cieszyn border station, the possibility of bi-directional flow of gas in crisis situations is ensured by reducing the pressure in the NET4GAS transmission system.

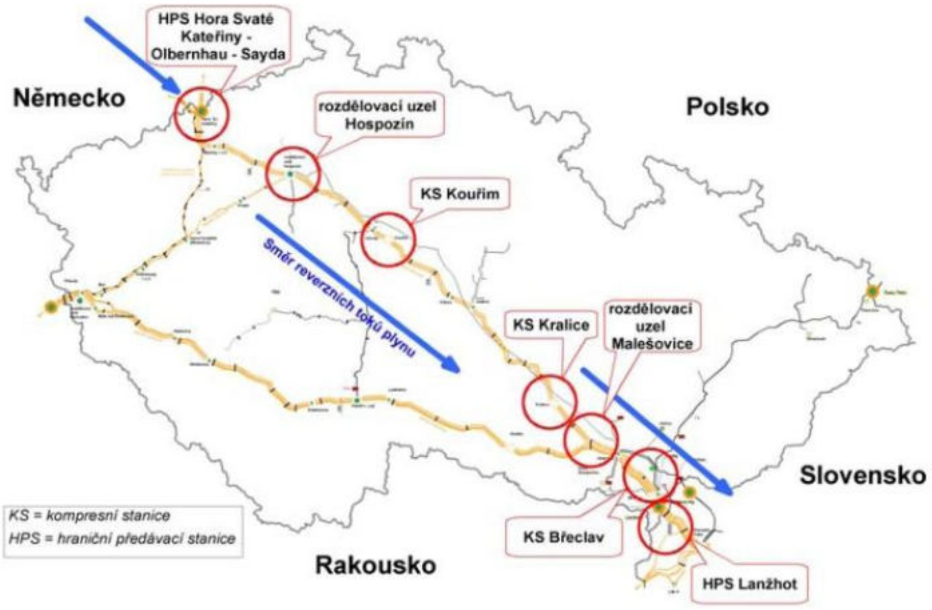

Figure 8: Current reverse gas flows in the transmission system

HPS-border transfer station, KS-compressor station

The distribution system is defined according to the Energy Act as a mutually interconnected set of high-pressure, medium-pressure and low-pressure gas pipelines, gas pipelines owned by the distribution system operator and related technological objects including the control and signaling technology and information transfer facilities for computing and information systems is not directly connected to compressor stations and where the gas distribution license holder holds the gas distribution; the distribution system is established and operated in the public interest.

The total storage capacity of underground gas storage facilities in the Czech Republic for year 2022 is 4.104 billion m3, without the Dolní Bojanovice gas storage (for the Slovak transmission system only) of 3.452 billion m3, representing about 40% of the annual gas consumption in the Czech Republic.

UGS owned by RWE Gas Storage CZ, s.r.o.:

PZP Háje, PZP Tranovice, PZP Štramberk, PZP Lobodice, PZP Dolní Dunajovice, PZP Tvrdonice

UGS owned by MND Energy Storage, a.s.:

PZP Uhrice, PZP Uhrice Jih

UGS owned by Moravia Gas Storage, a.s.:

PZP Damborice

UGS owned by SPP Storage, s.r.o.:

Dolni Bojanovice - up to now connected only to the gas system of the Slovak Republic.

Figure 9: Underground gas storages

Table 5: Storage capacity of the individual UGS

UGS / OWNER	**Storage capacity (mil. m3)**	Maximum daily withdrawal (mil. Nm³/day)	Maximum daily injection (mil. Nm³/day)
UGS Dolní Dunajovice / RWE GS	905	23	15
UGS Tvrdonice / RWE GS	555	9	8
UGS Háje / RWE GS	75	6	6
UGS Lobodice / RWE GS	177	5	3,6
UGS Štramberk / RWE GS	470	7	3,8
UGS Třanovice / RWE GS	530	8	3,2
The group of these six underground gas storages is operated as a single virtual storage.	**TOTAL** 2 712	**TOTAL** 58	**TOTAL** 39,6
UGS Dambořice / Moravia GS	420	8	4,5
UGS Uhřice / MND Energy Storage	320	10	6,4

Natural gas is taken over and transferred at the entry and exit from the Czech Republic, ie. measured in volume and quality at the border transfer stations (BTS) between the Czech Republic and Slovakia: Lanžhot and Lanžhot - Mokrý Háj, between the Czech Republic and Germany: at Hora Svaté Kateřiny - KS Sayda, Brandov - KS Olbernhau, KS Waidhaus and between the Czech Republic and Poland at the Cieszyn transfer station.

Denmark

The Danish gas system consists of gas production facilities and pipelines in the Danish part of the North Sea, a transmission system, where gas is transported across the country, and a distribution system, where gas is delivered to the gas customers. Moreover, the gas system consists of a gas treatment facility (Jutland), underground storage facilities (Zealand aquifer and North Jutland salt caverns) and compressor stations (Jutland and South Zealand). The compressor station in Jutland supports the transport of gas from Germany to Denmark; the compressor station in South Zealand supports the gas transit from Norway to Poland.

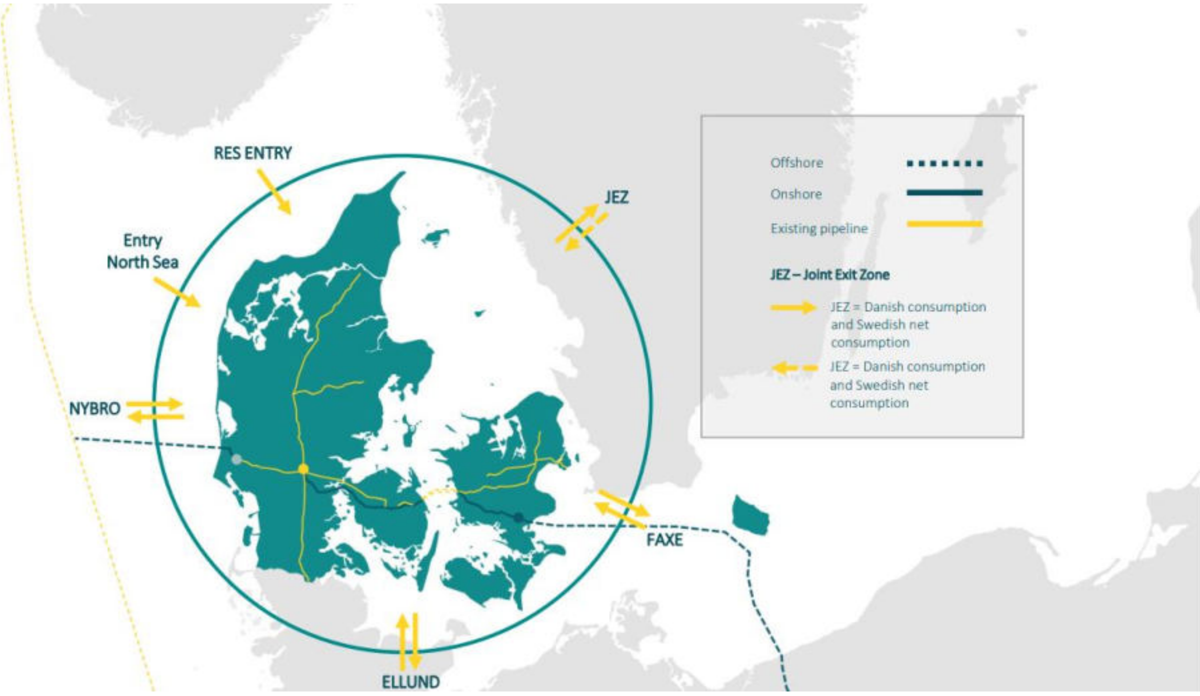

Figure 10: The Danish gas system and market model

Source: Energinet

The Danish gas transmission system is based on a simple entry-exit model, which allows market players to commercially move gas in and out of Denmark. The gas system has several entry/exit points where gas can be supplied either as import or export:

- Danish North Sea gas (Nybro Entry)
- German gas import and export (Ellund Entry/Exit)
- Gas transit from Norway (North Sea Entry)
- Gas transit to Poland (Faxe Entry/Exit)
- Joint Exit Zone[2]
- RES Entry

[2] Single exit zone for delivery of gas to Danish and Swedish customers.

Ellund and Faxe are constructed with options for physical reverse flow. Furthermore, there are virtual transfer points for gas traded within the system (bilateral contracts or gas exchange) and for upgraded biomethane (RES[3]-entry).

The Danish gas distribution system distributes the gas via 18.000 km gas pipes. Evida, owned by the Danish state, is the sole distribution company. Evida is responsible for maintaining the regional and local gas distribution system, which transports gas to the consumers. The gas distribution system is originally designed to receive natural gas from the transmission system, though the development of increasing production of biomethane in Denmark have resulted in, that biomethane plants delivers local produced gas directly to the distribution system.

Renewable Energy Sources (RES) - Biomethane

Since 2005 the consumption of natural gas in Denmark has been decreasing. The Danish Energy Agency projects the production and consumption of biomethane phasing out natural gas consumption for household and district heating, while converting the industry to consume more biomethane to reduce emissions from the use of coal and oil.

The amount of biomethane in the Danish system along with the future projections until year 2035 is shown below.

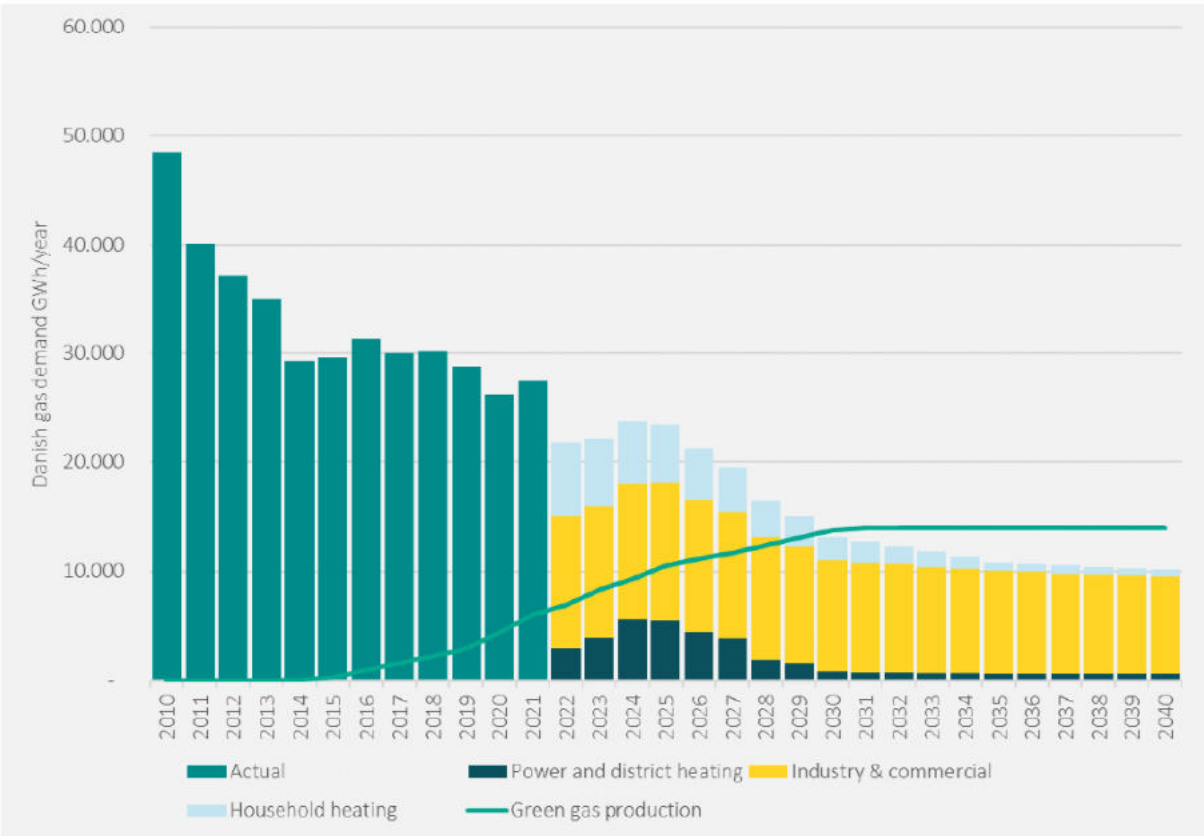

Figure 11: Historic and projected development in Danish consumption of natural gas and production of biomethane

Source: Energinet based on AF 22-data from the Danish Energy Agency

[3] Renewable Energy Source i.e., biomethane.

The amount of biomethane is expected to significantly grow over the coming years. The current projection indicates that 100% of the gas consumption in Denmark will be covered by biomethane in app. 2029. By September 2022 app. 30 % of the Danish gas supply is covered by biomethane.

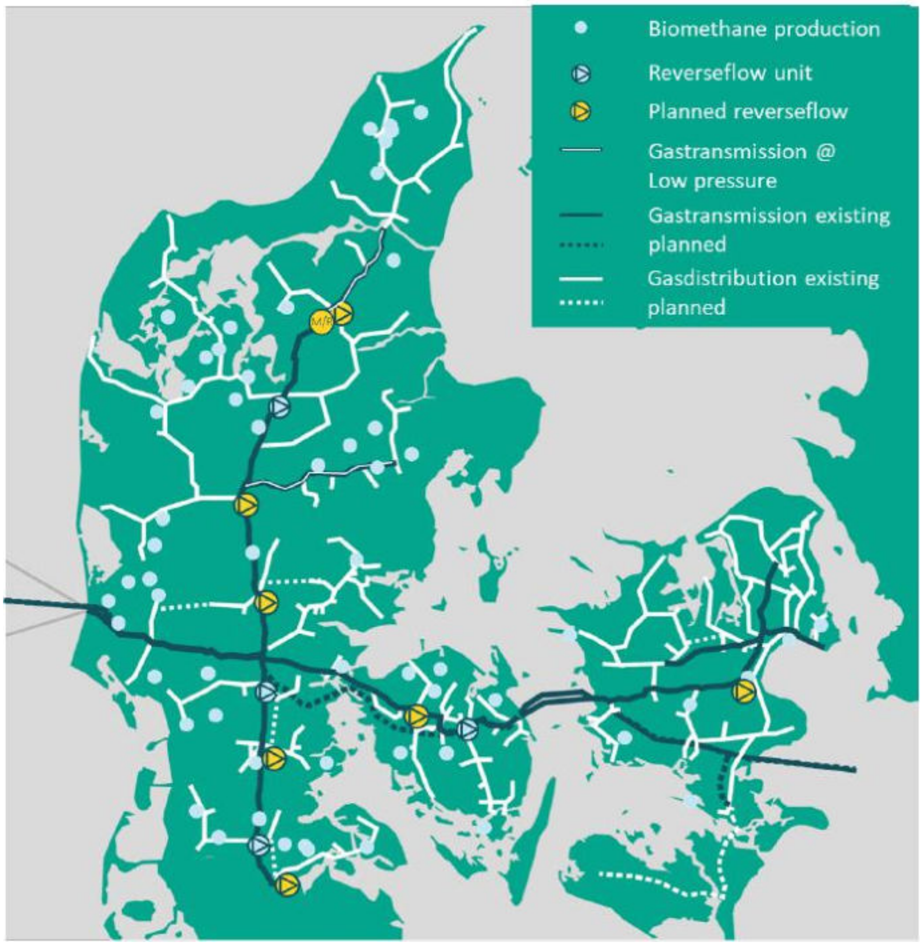

Figure 12: The Danish gas system including biomethane plants connected to the gas system (2021)

Source: Energinet

The biomethane production in Denmark is a significant contributor to the security of supply both in relation to the increasing share of the total gas consumption and in relation to the location of the biomethane plants. Biomethane contributes to a more decentralized and dispersed gas supply to the Danish gas customers. Decentralization of gas supply will, to a certain extent, help protect consumers in the event of supply shortages of natural gas, as they do not become dependent only on the primary sources of supply from the Danish North Sea and import from Germany and Norway, respectively.

Biomethane produced in Denmark may contain a higher concentration of oxygen if comparing with neighboring countries, Germany, Sweden, and Poland. The large quantities of biomethane fed back from the distribution grid to the transmission grid, pose challenges in relation to gas export from Denmark.

The measures put in place to handle the concentration of oxygen is by sectioning the system and mixing the gas within the system, respectively. The gas system is sectioned to ensure gas with a low concentration of oxygen from the North Sea can be sent to Germany, without being mixed with biomethane. In practice, this means that one of the transmission lines to Germany is kept free from biomethane. For the same reason this means that biomethane is not supplied to the western transmission grid in Denmark.

North Sea entry (gas from Norway) will flow all year round, with the exemption for short periods due to planned maintenance and be a supplement to mix the gas to lower concentration levels of oxygen.

The instability in Europe due to the Russian invasion of Ukraine contributes to the acceleration of biomethane production in Denmark. The current system capacity cannot fully accommodate for the increased biomethane production. To ensure the full potential from biomethane to benefit the security of supply in Denmark, a lot of ongoing collaboration happens across the system to investigate market- as well as finding sustainable technical solutions to handle these challenges.

Main gas consumption figures

According to Statistics Denmark[4] the total energy consumption in 2021 in Denmark was 686 petajoules, equivalent to 19 bcm natural gas, distributed across several energy sources, such as oil products, renewable energy, and natural gas. The consumption of gas transported in pipes was 86 petajoules, which corresponds to around 13 percent of the total energy consumption. In 2021, the share of natural gas in Denmark's energy consumption was at the lowest level measured over the past 30 years.

Table 6: Gas consumption figures by year (bcm/year)[5]. Source: Danish Energy Agency

	2018	2019	2020	2021
Natural gas incl. biomethane	2,50	2,44	2,31	2,46

Table 7: Gas consumption figures by year (bcm/year)[6]. Source: Danish Energy Agency

Biomethane[7]	*0,18*	*0,25*	*0,40*	*0,54*

Gas is consumed by different sectors in Denmark: Households, industry (including service industries), district heating and electricity generation. Furthermore, gas is consumed in oil and gas production in the Danish North Sea. In 2021, the total gas consumption including the gas used for production in the North Sea was 2,81 bcm. The natural gas consumption in Denmark, excluding oil and gas production, in 2021 was 2,46 bcm. After having declined for many years, the Danish annual gas consumption has been relatively stable in the last years, and at the same time, with steadily growing amounts of biomethane entering the gas system. The amendment to the Regulation on coordinated demand-reduction measures[8] sets out requirements to Member States to voluntarily

[4] www.statistikbanken.dk
[5] Gas consumption in oil and gas production is not included.
[6] Gas consumption in oil and gas production is not included.
[7] The share of Biomethane is included in the natural gas figures.
[8] REGULATION (EU) 2022/1369 of 5 August 2022 concerning coordinated demand reduction measures for gas.

or mandatory in the case of a Union Alert to reduce gas by at least 15% in the period from 1 August 2022 to 31 March 2023 compared to the average gas consumption in the same period the five consecutive years.

In the past year, consumption in Denmark has decreased 10-20% as a reaction to the high gas prices and the security of supply situation. The reduction of consumption of natural gas alone (without offshore and biomethane) was 61 % in the months August – October 2022. Consumption reached a level corresponding to the needed demand-reduction already in the reference period 2021-2022, and during 2022 a further decrease in consumption has been observed.

The gas consumption divided by sectors is shown below.

Table 8: Gas consumption and utilization figures by sector (bcm/year (percent)). Source: Danish Energy Agency

	2018	2019	2020	2021
Households	0,64 (26%)	0,64 (27%)	0,61 (29%)	0,60 (27%)
Industry	0,99 (40%)	0,96 (41%)	0,95 (45%)	1,09 (48%)
District heating	0,34 (14%)	0,27 (11%)	0,25 (12%)	0,31 (14%)
Electricity generation	0,49 (20%)	0,49 (21%)	0,28 (13%)	0,22 (10%)

Approximately 75% of the annual gas consumption is consumed by protected customers (of which approx. 33% are solidarity-protected) while the remaining 25% of the annual gas consumption is delivered to unprotected customers.

Table 9: Peak demand (mcm/day). Source: Energinet

	2018	2019	2020	2021
Denmark	17.0	14.5	11.8	17.1
Sweden	5.6	4.0	3.1	5.1

Table 10: Entry/Exit point's technical capacity (mcm/y). Source: Energinet

	2018	2019	2020	2021
Nybro Entry	11.945	11.945	11.978	11.945
Ellund Entry	5.575	5.575	5.618	6.468
Ellund Exit	9.706	9.706	9.706	9.706
Joint Exit Zone	9.399	9.399	9.425	9.399

The technical capacity at North Sea Entry will be 27 mcm/d, corresponding to 10 bcm/y.

Table 11: Entry/Exit point's commercial capacity (mcm/y). Source: Energinet

	2018	2019	2020	2021
Nybro Entry	3.957	2.471	93	68
Ellund Entry	2.338	2.627	3.120	3.146
Ellund Exit	712	282	33	129
Joint Exit Zone	2.526	3.627	3.258	3.895

Table 12: Entry/Exit point's volume flow (mcm/y). Source: Energinet

	2018	2019	2020	2021
Nybro Entry	3.500	2.325	77	44
Ellund Entry	242	936	2.373	2.300
Ellund Exit	654	269	21	78
Joint Exit Zone	2.326	2.389	2.164	2.287

Table 13: Entry/Exit point's commercial utilization rates. Source: Energinet

	2018	2019	2020	2021
Nybro Entry	88%	94%	83%	65%
Ellund Entry	10%	36%	76%	73%
Ellund Exit	92%	95%	65%	60%
Joint Exit Zone	92%	66%	66%	59%

Table 14: Entry/Exit point's technical utilization rates. Source: Energinet

	2018	2019	2020	2021
Nybro Entry	29%	19%	1%	0%
Ellund Entry	4%	17%	42%	36%
Ellund Exit	7%	3%	0%	1%
Joint Exit Zone	25%	25%	23%	24%

The low values for Nybro Entry and Ellund Exit in the period from 2020 are due to the shutdown of the Tyra Complex during the reconstruction period from ultimo 2019. Similarly, the increase in values for Ellund Entry, during the reconstruction period, are due to the increase in import gas from Germany.

Key infrastructure relevant for the security of gas supply

The gas transmission infrastructure in Denmark is robust and has a high level of reliability, because of the high monitoring and maintenance standards in Energinet. The high level of monitoring includes onshore and offshore constructions, and both observed and potential damages are repaired immediately. Energinet continuously provides information to external parties on planned repairs and maintenance activities on the gas transmission infrastructure. If there are activities that affect the transport capacity, the affected transport customers will be notified directly via ENTSOG Transparency Platform.

Construction work in the vicinity of Energinet's gas pipelines is carefully monitored and controlled by Energinet's inhouse surveyors. In Denmark, the Danish Register of Underground Cable Owners (LER) is available to seek information on underground cables, to ensure construction work can be performed safe and without posing unnecessary damages to the pipelines. The purpose of LER is to proactively prevent accidental damages to underground cables, lower administration costs in the contracting sector and to increase the security of supply.[9]

The onshore transmission pipelines are in total approx. 1100 km. All transmission pipelines are buried underground and marked above ground with marking poles to prevent unintended influence from excavation works etc. The offshore transmission pipelines connect Jutland, Funen,

[9] The Danish Register of Underground Cable Owners (LER) (www.ler.dk)

and Zealand. These pipelines are buried in the seabed and protected by rock-dumping. All pipelines are inspected/surveyed at regular interval to ensure a high level of integrity. All pipelines in Denmark are constructed, manufactured, maintained, and operated as per requirements in the Guide for Gas Transmission and Distribution Piping Systems.[10]

Approx. every 10-20 km along the transmission pipeline there are remotely operated line-valve stations. These stations can isolate parts of the pipeline as well as function as pressure relieve, should there be a need, e.g., in case of a rupture.

The transmission pipelines are supplied with several measuring and regulator stations. Among other functions these stations ensure pressure alignment between the transmission system and distribution system.

Reverse flow stations are installed at the transmission system's Metering and Regulating stations, where reverse flow from distribution to transmission system is needed. The reverse flow stations are designed with compressor units, metering unit, deodorization unit and gas quality measuring unit.

The compressor stations ensure an acceptable pressure level in the gas transmission system. The compressors are necessary to maintain the transport capacities in the gas system especially during periods with high demand.

The annual gas production historically exceeded the annual Danish and Swedish consumption, and is expected to exceed consumption again in 2024. During the period November 2019 – ultimo 2023 the Tyra complex in the Danish North Sea is out for reconstruction. Due to COVID-19 the reconstruction period is prolonged until the winter period 2023/2024.

The Danish production of natural gas in the North Sea is either exported directly to the Netherlands or, when the Tyra complex is fully functioning, transported to Denmark where it is consumed by Danish customers, stored in storages, and exported to Sweden and Germany. The commercial withdrawal capacity from the storage facilities is 185 GWh/d. If the gas storage inventory level is at least 25 %, the Danish consumption can be covered by storage withdrawal and biogas production for consumption corresponding to daily average temperatures down to –4°C.

The Danish gas production is an important part of the Danish and Swedish gas market since it covers the gas demand most of the year. Denmark and Sweden were until 2011 fully dependent on gas supplied from the Danish North Sea, but investments in the Danish gas system have enabled import of large amounts of gas from Germany (Ellund Entry). This has made the Danish and Swedish gas market less dependent on the Danish gas production, but instead created dependence on imported gas.

[10] Published by the American Gas Association

Table 15: Gas import sources per country of origin (bcm). Source: Danish Energy Agency

	2018	2019[11]	2020	2021
Germany	0,09	0,94	2,53	2,37
Norway	0,27	0,14	0	0

The Danish gas production has decreased significantly since its peak period (9-10 bcm annually in 2005-2007).

From October 2022, the Baltic Pipe has been in operation. The Baltic Pipe will allow transport of gas from Norway to the Danish and Polish markets, as well as to customers in neighboring countries in the Baltic Region and Eastern Europe. At the same time, the Baltic Pipe enables the supply of gas from Poland to the Danish market, which will contribute to the security of supply in Denmark and Sweden as more supply points are introduced to the Danish Gas system. With the new connections in Nybro and Everdrup, new supply points are added in both eastern and western part of the system.

The Danish gas storages are located in Ll. Torup, in North Jutland, and in Stenlille, in Zealand (see map below). The underground gas storage facilities are usually filled up during the summer when gas consumption is low. When it gets colder and consumption exceeds the daily gas deliveries from the Danish North Sea, the deliveries are expected to be supplemented by gas from the storage facilities. In addition to seasonal leveling, gas trading may influence gas export and import and affect gas flows to the storage facilities. The storage facilities are also used for emergency supply. The injection and withdrawal capacities of the Zealand aquifer and North Jutland salt caverns storage facilities are shown before.

Table 16: Injection/Withdrawal capacity (mcm/day). Source: Energinet

	Injection	**Withdrawal**
Zealand aquifier	4,8	8,2
North Jutland salt caverns	3,6	8,0

The storage capacity is dimensioned conservatively in relation to the “normal” pressure in the gas transmission system. When the pressure occasionally increases, it is possible to inject more gas into the storage facilities than the specified injection capacities given in Table 16. The commercial withdrawal capacities of the Zealand aquifer and North Jutland salt caverns are today at 8,2 mcm/d and 8,0 mcm/day, irrespective of whether the storage levels are 100% (full storage level) or 30% (end of season level). The total storage capacity varies, but is currently app. 9,9 TWh WGV (Working gas Volume).

The storage facilities provide security of supply to the Danish gas customers. In the event the supply to the Danish market from external sources is reduced, the storage facilities and bio-methane production can partly or fully maintain the gas supply, depending on the offtake and the storage inventory gas level. Energinet buys emergency storage to ensure sufficient inventory gas inventory level during the winter. Emergency storage concists of emergency gas, owned by

[11] The Tyra Complex shut down for reconstruction in November 2019. Since then all gas import comes from Germany via Ellund Entry (with small amounts of gas from the South Arne field to Nybro Entry).

Energinet and individual filling requirements, where storage customers are paid to store gas during winter and Energinet has an option given by the contract to purchase the gas from the storage customer.

During the storage year 2022-2023, 75% of the injection capacity is available when the gas storage facility is filled up to 95%. All injection capacity is available when the storage filling is below 95%. Withdrawal restrictions are imposed when filling levels go below 20% (close to the System Operator emergency volume). Thus at 20% filling level, 85% of the withdrawal capacity is available, at 15% filling level, 75% of the withdrawal capacity is available and so forth.[12]

The role of gas in electricity production

Table 17: Electricity production by source. Source: Energinet's environmental declaration for electricity, 2021

Wind	41,8%
Biofuel (mainly biomass)	18,6%
Hydro	11,7%
Coal	10,8%
Natural gas	5,2%
Waste	4,6%
Solar	3,9%
Nuclear	2,3%
Oil	0,8%
Lignite	0,4%

The electricity production in Denmark comes from many sources. Energinet's environmental declaration for electricity production shows that gas constitutes 5,2% of the energy used to produce the electricity consumed in Denmark. The largest share of Danish electricity production is made up from wind (41,8%) and biofuel (18,6%). From an electrical point of view, Denmark is strongly connected to the neighboring countries and the consumption is not covered by Danish electricity production alone[13].

In relation to security of supply, power plants that use only gas constitute 26% of the total thermal production capacity. In addition to the gas-fired power plants, there are a few power plants that can use gas together with other fuels, e.g., biomass or waste. All gas-fired power plants can produce both electricity and heat.

In addition to the phasing out of thermal electricity production, there are several climate benefits to phasing out oil and natural gas in district heating. Although the risk of less power adequacy are increased, and the so called "brown outs" could be a possibility in an energy crisis, power shortages in Denmark are relatively rare. The lack of power has not yet led to interruptions in Denmark or neighboring countries electrically connected to Denmark[14], but the risk has increased and the focus on demand reduction has been maintained to mitigate this.

[12] Please visit the Gas Storage Denmark webpage to see the latest figures; http://www.gasstorage.dk.

[13] Source: Miljøredegørelse 2021, Energinet (https://energinet.dk/El/Gron-el/Deklarationer).

[14] Source: Analysis prerequisites 2021, Danish Energy Agency (https://ens.dk/service/fremskrivninger-analyser-mod-eller/analyseforudsaetninger-til-energinet).

France

Gas consumption

Consumption in the French gas market is around 490 TWh/year. Gas represents a much smaller share (15%) of total primary energy consumption than the EU average (23%). Natural gas is primarily used for heating in the residential and industrial sectors. Power generation from natural gas is limited.

Due to the important share of heating in gas use, there is a strong link between climate and demand for gas. Thus demand is highly modulated during the year. Average consumption increases almost fivefold between August (530 GWh/d) and February (2 370 GWh/d). Considering a cold spell with an occurrence of once every fifty years, daily peak demand is 4 300 GWh/d.

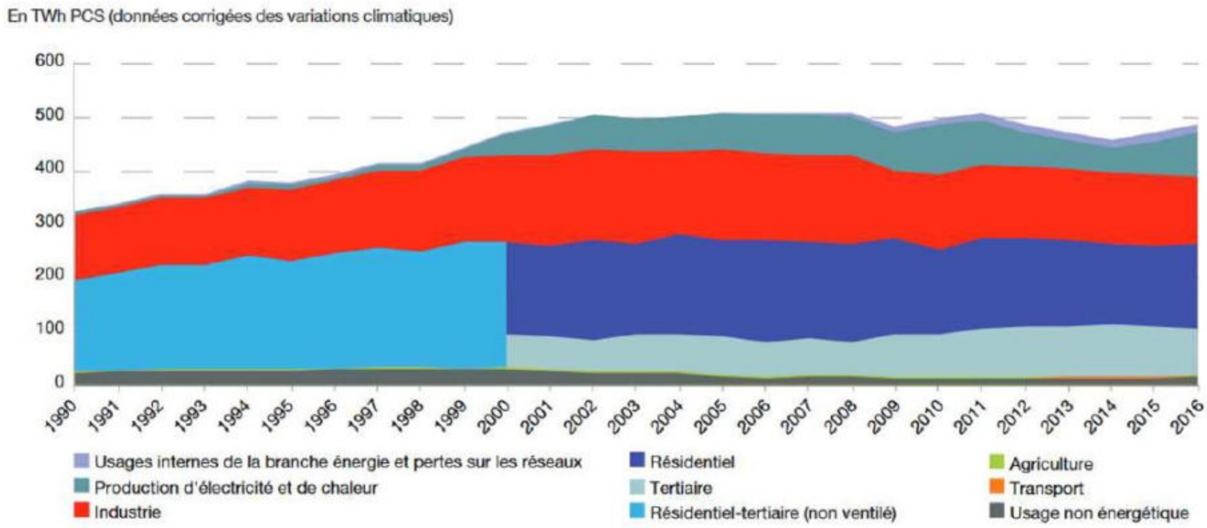

Figure 13: Gas consumption by sectors[15]

Since 2003, a slight decrease in gas demand has been observed. In the residential sector, energy efficiency efforts combined with the stagnation in the number of customers led to a decline in demand. Conversely, industrial demand has remained stable with an increase in fuel conversion (from heavy fuel oil) and increasing demand in the commercial and service sectors.

For the coming years, the drivers of the natural gas demand evolution are:

- The effectiveness of energy efficiency measures, which should result in lower demand in the residential and tertiary sectors;
- The economic situation and the competitiveness of natural gas compared to other fuels, which will determine the use of gas by the industry;
- The potential development of gas demand in new sectors such as power generation and mobility.

[15] Sources: enquête annuelle sur les statistiques gaziéres (SDES), enquête annuelle sur la production d'électricité (SDES), enquête annuelle sur les consommations d'énergie dans l'industrie (Insee).

Gas system

The gas system in France is composed of:

- 12 500 km of transmission network operated by two TSOs (GRTgaz and TIGF).
- 7 major interconnection points (2285 GWh/d of technical entry capacity)
- LNG terminal (1 330 GWh/d of technical entry capacity)
- 12 storages sites in operation (2 400 GWh/d of withdrawal capacity).
- The daily import capacity on the French territory amounts to around 3 600 GWh/d, 65% of which is pipeline gas and 35% LNG.

Figure 14: Map of Gas infrastructure in France

The French gas system has eight major interconnection points.

Table 18: Interconnection points in France

Interconnection point	From/to	Capacity (GWh/d) Entry	Capacity (GWh/d) Exit	Flows 2016	Flows 2017
Dunkerque	***Norway***	***570***	-	***500***	***525***
Alveringem	***Belgium***	-	***270***	***0***	***8***
Taisnières B	***Belgium***	***230***	-	***135***	***122***
Taisnières H	***Belgium***	***640***	-	***367***	***351***
Obergailbach	***Germany***	***570***	-	***240***	***229***
Oltingue	***Switzerland***	-	***223***	***-37***	***-81***
Jura	***Switzerland***	-	***37***	***-6***	***-6***
Pirineos	***Spain***	***225***	***170***	***-84***	***-118***
		2 235	***700***		

France has 15 gas storage facilities. Storengy operates 100 TWh of storage capacity, or around three-quarters of the country's total. TIGF operates two aquifers with a total capacity of 32 TWh or 20% of the gas storage.

Since 2012, three storage facilities (Trois-Fontaines, Soings-en-Sologne and Saint-Clair-sur-Epte) have been mothballed, reflecting worsening economics for storage operators.

Table 19: Gas storage capacities in France

Storage	Working gas [TWh]	Maximal daily withdrawal capacity for 45% filling level [GWh/d]
Beynes	5.5	125
Céré-la-Ronde	6.5	105
Cerville-Velaine	7.3	70
Chemery	42.4	420
Etrez	7.9	360
Germigny-Sous-Coulomb	9.4	60
Gournay (gaz B)	13.4	245
Lussagneet / Izaute	32.6	544
Monasque	3.3	170
Saint-Illiers-la-Ville	7.8	1 335
Tersanne	1.8	140
Total	**137.9**	**3 574**

France has four operating LNG terminals. The country's total regasification capacity stands at around 35 bcm/y. Since 2011, the utilization of the French LNG infrastructure has been low (25% in 2017) because of the significant fall in Europe's gas demand and the diversion of LNG cargoes to higher-priced markets in Asia (re-export).

The facilities at Fos-Tonkin, Fos-Cavaou and Montoir-de-Bretagne follow a regulated third-party access (TPA) regime and tariffs for capacity used at these facilities are set in a fashion similar to that for network tariffs.

Dunkirk LNG terminal was granted full exemption from third-party access (TPA) and tariff regulation. These exemptions apply to all the capacity of the terminal for a period of 20 years from the date of commissioning (2016). Exemptions were granted by the European Commission under the European Directive 2009/73/EC Article 36.

Table 20: Capacities of LNG terminals in France

LNG Terminal	State	Startup	Capacity [GWh/d]	Capacity [Bcm/y]	Storage capacity (LNG m³)	Max capacity of LNG cargoes (m³ GNL)
Dunkerque	Exemption	2016	350	13.0	570 000	266 000
Montoir	Exemption	1980	400	10.0	360 000	266 000
Fos Tonkin	Exemption	1972	410	3.0	80 000	75 000
Fos Cavaou	Exemption	2010		8.3	330 000	266 000
			1 160	**34.3**	**1 340 000**	

Gas supply

French natural gas security of supply relies on a gas system with numerous entry points that allows diversified imports and extensive gas storage facilities.

French supply is based on diversified imports. Norway, Russia, the Netherlands and Algeria are the major suppliers with a 43%, 21%, 11% and 10% share of imports, respectively. Norway is the only supplier representing more than 20% of total imports.

Gas supply sources

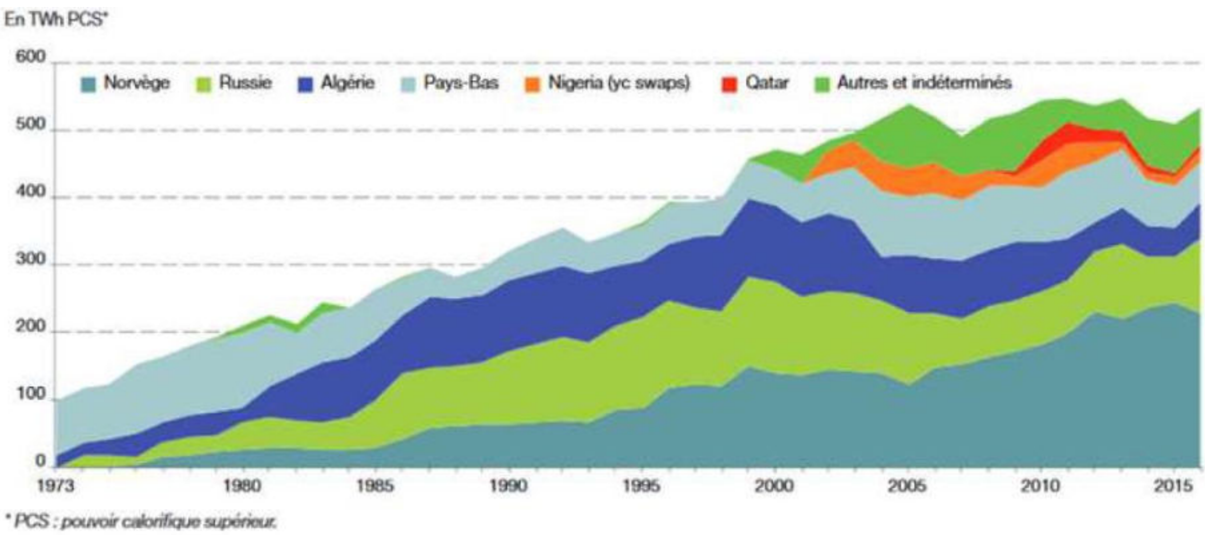

Figure 15: Gas supply sources[16]

In 2017, 80% of imports were made by pipeline and 20% by LNG terminal. In addition to pipeline imports (55%) and LNG terminal dispatch (15%), storage covers an average of 30% of winter

[16] Source: calculs SDES, enquête annuelle et mensuelle sur la statistique gaziére.

demand. During peak demand, or supply issues, the role of storage is even more important. It reached 55% on a daily basis during a cold spell in February 2012.

French gas production represents a small share of gas consumption. In 2016, 0.2 TWh were produced accounting for 0.04% of French gas consumption.

Since 2012, biogas can be injected into the gas network. Volumes are very limited but grow every year (0.4 TWh in 2017). There is strong potential for production based on agricultural waste. The TECV Act set an objective of 10% of renewable gas in gas consumption for 2030. Several measures have been taken to support biogas production.

Germany

With the Russian war of aggression on Ukraine and its aftermath, the general energy economy framework conditions for Germany and Europe are changing. The supply of Russian natural gas was secure for decades. The new circumstances require reduced dependency on Russian energy sources, especially natural gas. This can be accomplished by increasing the diversification of gas supply sources and replacing Russian natural gas, for example with liquefied natural gas (LNG). Another forward-looking approach would be to switch from natural gas to green, carbon-neutral gases such as hydrogen as quickly as possible. These developments have a significant impact on the framework conditions for gas, as the load flows are changing significantly. The precise impact is currently under investigation, final answers are not concluded yet.

Role of German network development plan

In principle, necessary investment projects are identified as part of a network development plan by the transmission system operators. In order to ensure the rapid integration of LNG facilities in view of the current geopolitical situation, the transmission system operators, in consultation with the Federal Network Agency, have identified particularly time-critical measures, the implementation of which should begin before the network development plan is confirmed.

One focus of these expansion measures to provide capacity is the high capacity requirement for the transport of LNG volumes expected at the FSRUs and later stationary LNG terminals. A challenging factor here is that the gas coming from Norway is injected "close" to the LNG sites on the North Sea in terms of network technology. As a result, the pipeline gas coming from Norway is "in competition" in terms of transport with the gas volumes fed in from the North Sea LNG sites for existing transport capacities.

In parallel with the implementation of the expansion measures already initiated, the regular process cycle of the Gas Network Development Plan 2022-2032 is currently underway, in which the necessary investment requirements for the next ten years are determined in their entirety.

In response to the changed supply situation, the Federal Network Agency has instructed the transmission system operators in the current process cycle to expand the gas transmission system development plan to include variants in which Russian import volumes are fully substituted and any long-term decline in demand for natural gas is taken into account. The substitution concerns both the capacities earmarked for supplying Germany and those earmarked for transits. An adequate supply of transport capacities to neighbouring countries, especially in the direction of south-eastern Europe, must be ensured. To balance the Russian gas volumes, injection capacities from German LNG plants as well as at Western European border crossing points are to be assumed.

According to the current status, the result of the flow-based calculations to determine the necessary network expansion measures should be available in January 2023 and consulted with the market.

Against the background of the current geopolitical situation and its impact on the supply situation with natural gas and the current efforts to reduce Germany's dependence on Russian gas supplies, the expansion of the LNG infrastructure in Germany represents a central building block.

For this reason, the development of this LNG infrastructure is being driven forward at full speed by the authorities and market players. In addition to the five Floating Storage and Regasification Units (FSRUs) currently chartered by the federal government, which will be deployed in the short term - the first two federal FSRUs (RWE, Uniper) are scheduled to go into operation as early as winter 2022/2023 - there are other private-sector project sponsors planning both land-based and floating terminals (FSRUs). Possible locations are currently under discussion, including e.g. the sites in Wilhelmshaven, Brunsbüttel, Stade, and Lubmin.

Russia

Since the gas flows of last 20 percent via Nord Stream 1 have not been resumed by Gazprom on 02.09.22 and also via Poland no transport volumes are used for imports, a supply via other alternative routes from Russia is carried out. Import volumes at the Waidhaus cross-border point, via which volumes could normally also be imported from Russia via Ukraine transit, are currently only taking place due to relocations in accordance with TSO agreements. Consequently, Germany currently no longer receives any pipeline gas from Russia. Nevertheless, the Ukraine transit continues to take place in a narrow band between 300 and 400 GWh/day and is obviously used to supply the Eastern European countries. This benefits Germany in that these countries do not receive additional gas volumes from the transit country Germany.

Since July, gas volumes have been exported to Eastern Europe via Waidhaus for the first time. In July these exports amounted to 0.2 TWh/month, in August and September they increased to 0.8 TWh/month.

Norway, Belgium, Netherlands, Denmark

Gas imports from the North-West region are taking place at a very high level.

France

Since 13.10.22, 100 GWh/h are marketed in flow direction from FR to DE via “Medelsheim”. Currently, these are also used to a high degree.

Luxembourg

The interconnection with Luxembourg only allows mono-directional flows. Exports to Luxembourg via the IP Remich were very low during the last years and close to zero since the summer of 2022.

Poland

In mid-March, except for minor exceptions, the last gas imports from Russia via the "Yamal" pipeline to Germany via Poland were recorded. At the relevant cross border point Mallnow, larger gas volumes were also exported. At the peak, exports amounted to over 6 TWh/month in May. Most recently, it was just under 3 TWh/month in August. These volumes were partly used directly by Poland for storage, partly they are used in Eastern European countries for the same purpose or consumption. This includes Ukraine, according to the TSOs.

Switzerland, Austria

Exports to Switzerland have increased year-over-year through August from 21 to 29 TWh/month. Italy in particular has probably used these volumes for storage to a greater extent. However, from March onwards, the flow direction at Wallbach keeps changing, so that new peaks are also imported via Wallbach from France and Italy to Germany. Compared to other typical import cross border points, however, the volumes are still low at 0.5 to 0.9 TWh/month.

Until August, 44 TWh were exported from Germany to Austria via the Oberkappel cross border point, more than 4 times as much as in the previous year. However, volumes are comparable to 2020, with volumes via the smaller Überackern cross border point also increasing significantly to 17 TWh year to date (2021: 10 TWh; 2020: 9 TWh). The import volumes from Austria are negligible.

General information on the German infrastructure

Germany has an extensive transmission system. The network of the transmission system operators (TSOs) is about 38 000 km long, has more than 110 compressor stations and is connected to the systems of neighbouring countries via a large number (>25) of cross-border interconnection points. The German gas transmission system is divided into an H-gas area and an L-gas area.

The import of large volumes plays an important role in the north-west of Germany. In the past, equally large volumes also entered the area via the pipeline networks from an eastern and northeastern direction, so the principal flow of gas was from the northeast to the south-west. This is to be expected to change and changed already significantly from a predominantly east to west flow into a west to the east flow as described above

There are further import points for the western transmission system around Aachen, allowing gas to be transported to Germany from the Netherlands/Belgium via Eynatten/Raeren, and Bocholtz. Eynatten/Raeren can also be used as an export point.

In the southern part there are significant import points on the borders of the Czech Republic and Austria. The major export points are on the borders to France, Switzerland and Austria. The transmission system is thus used for both transit and supply services.

The eastern part of the supply area covers Mecklenburg-Western Pomerania, Brandenburg, Saxony-Anhalt, Saxony, Thuringia and Berlin. Gas for this part used come from import points in the east via Poland, in the northeast via the Baltic Sea and in the south from the Czech Republic. Now these areas are supplied through western routes due to the disruption of Russian gas. Some of the gas needed is fed in from the west of Germany.

In the following figure the size and the spread of the German H-Gas network is shown. The H-Gas network covers the entire territory from the North to the South and from the West to the East.

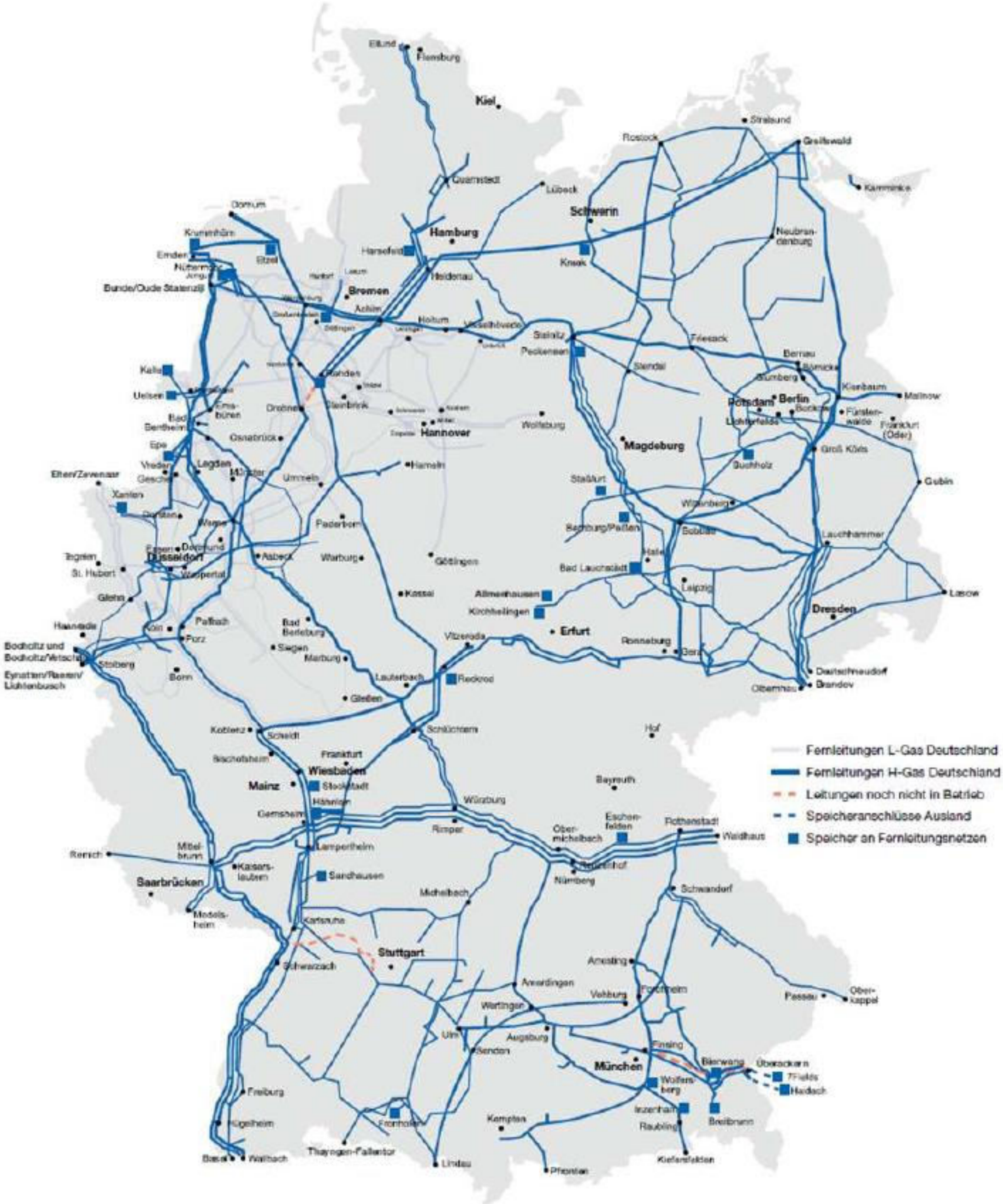

Figure 16: H-Gas transmission network

Parallel and partly overlapping to the H-Gas network in the following figure the size and the location of the L-Gas network is displayed. The L-Gas network concentrates in the northwestern part of the German territory.

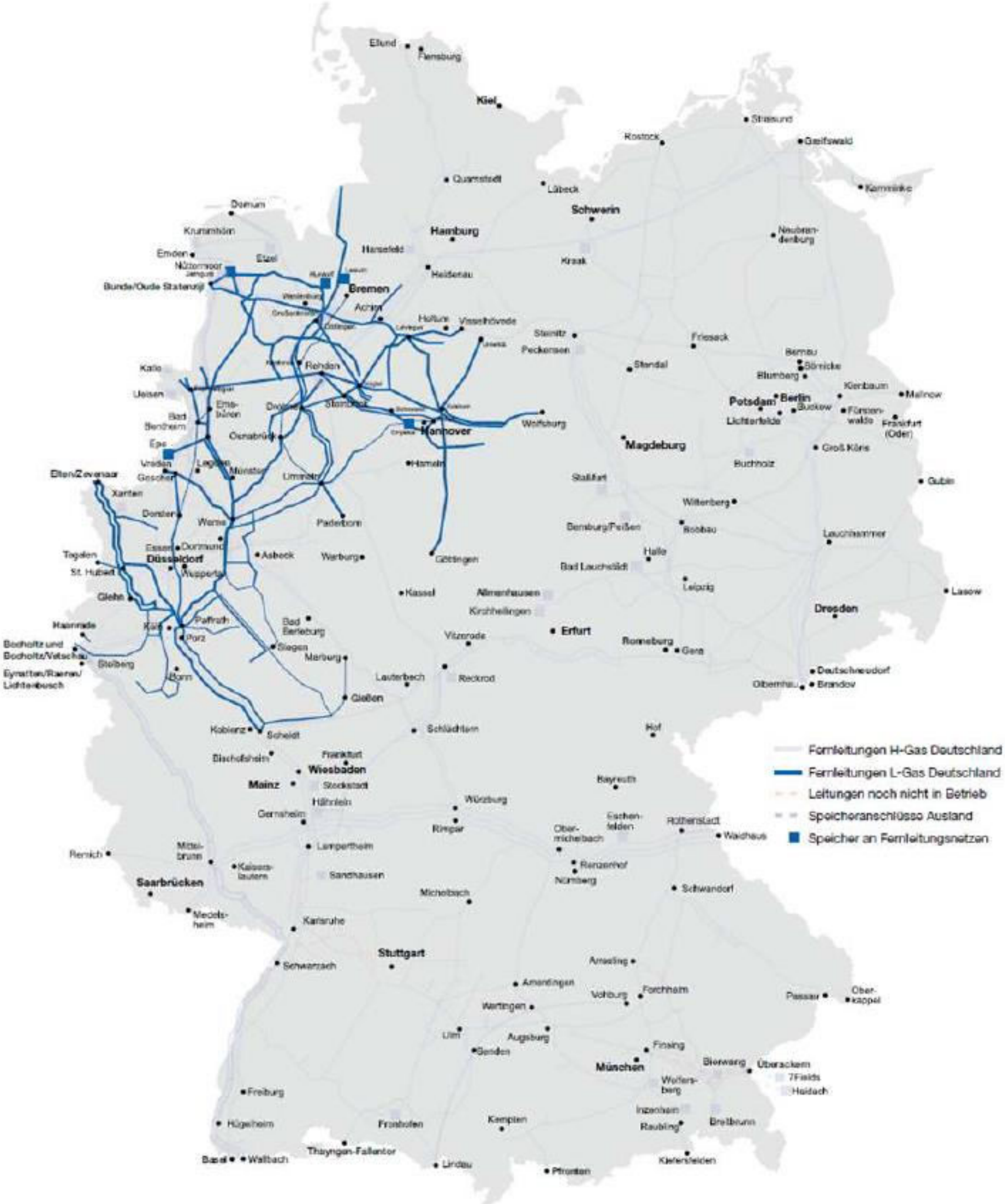

Figure 17: L-Gas transmission network

Historically, the L-gas networks in the north grew up around the existing reserves, i.e. the large areas around the Elbe/Weser and Weser/Ems in Germany and the Groningen gas field in the Netherlands, from which gas is imported via the Oude Statenzijl station. These are still the only sources today. Storage facilities to allow resources to be structured and cover peak loads are located in Nüttermoor, Huntorf, Lesum and Empelde. The network is designed to be supplied from the abovementioned reserves and offers only limited flexibility.

The L-gas network in the west primarily supplies final consumers across the network levels. The high proportion of household customers makes gas sales heavily dependent on temperature. Situations that put the system under strain occur not just under normal circumstances but also in intermediate or weak load situations when there is a lot of flexibility on the entry side. The system is supplied partly by imports from the Netherlands and partly by volumes from German production through the northern subsystem. Storage facilities to allow resources to be structured and cover peaks are located in Epe.

In view of the reductions in German L-gas production and L-gas imports from the Netherlands, the relevant companies are already taking action to prevent any decline in the availability of L-gas negatively affecting security of supply. German L-gas producers, the network operators affected and storage system operators have set up a joint working group to develop a plan for the coordinated conversion from L-gas to H-gas. The companies involved are drafting a conversion plan that will include a schedule for converting the supply areas affected from L-gas to H-gas.

Gas storage facilities

Some 34 underground storage facilities are operated in Germany now, but because some of them are used by more than one operator, 50 facilities are marketed. The maximum usable working gas volume in these underground storage facilities amounts to some 274.72 TWh, giving Germany the largest storage capacity in the European Union.

Of the total usable working gas volume, 136.1 TWh are accounted for by cavern and 117.01 TWh by pore storage facilities (rest 21.71 TWh). Reflecting the structure of the German natural gas market, the majority of the storage facilities are used for the storage of H-gas (251.86 TWh for H-gas compared to 22.87 TWh for L-gas).

The storage facilities are located across nearly the whole of Germany, although for geological reasons there are regional clusters in the north-west and southeast.

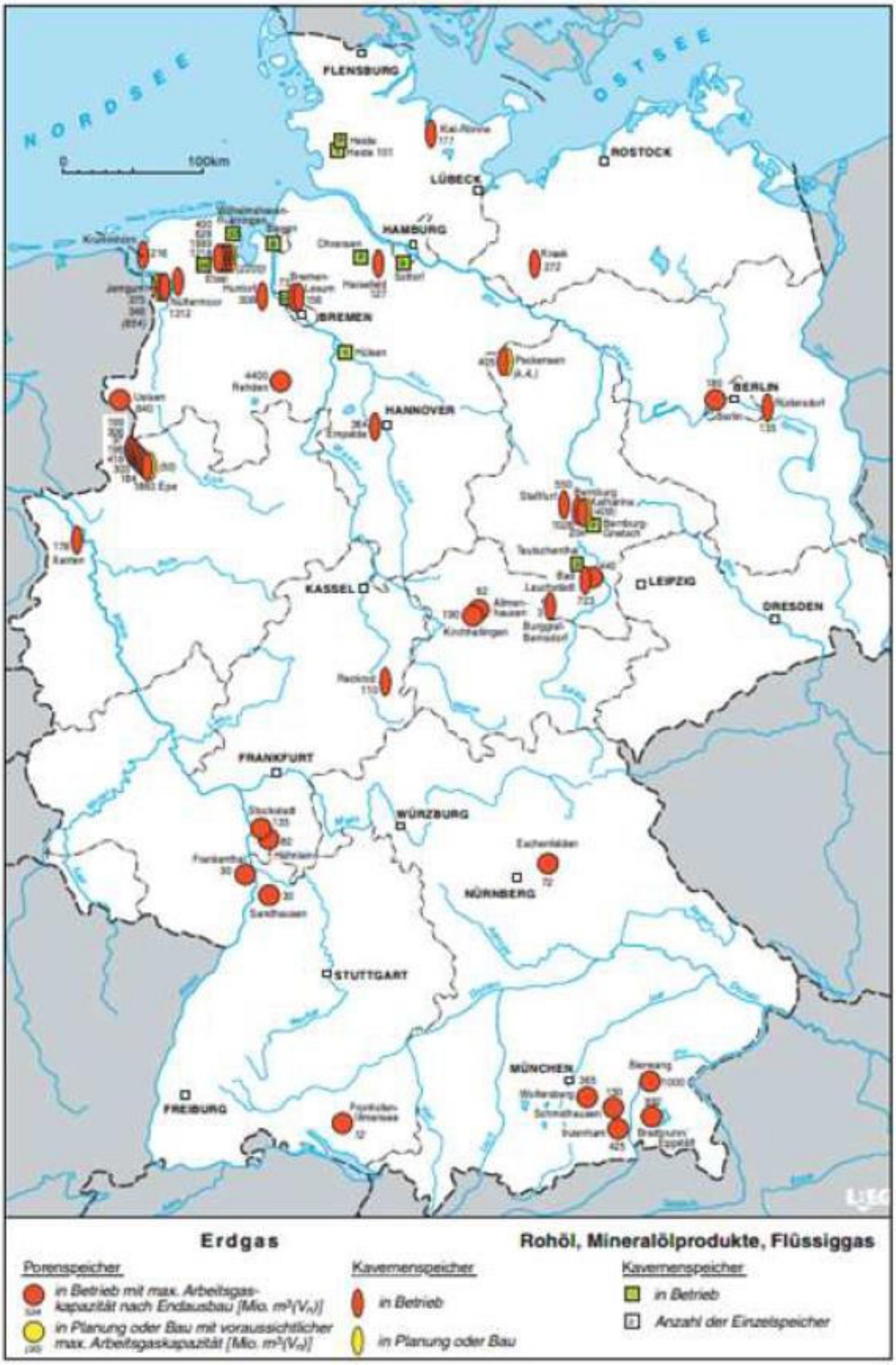

Figure 18: Map of German natural gas underground storage facilities

Luxembourg

Luxembourgian natural gas transmission system

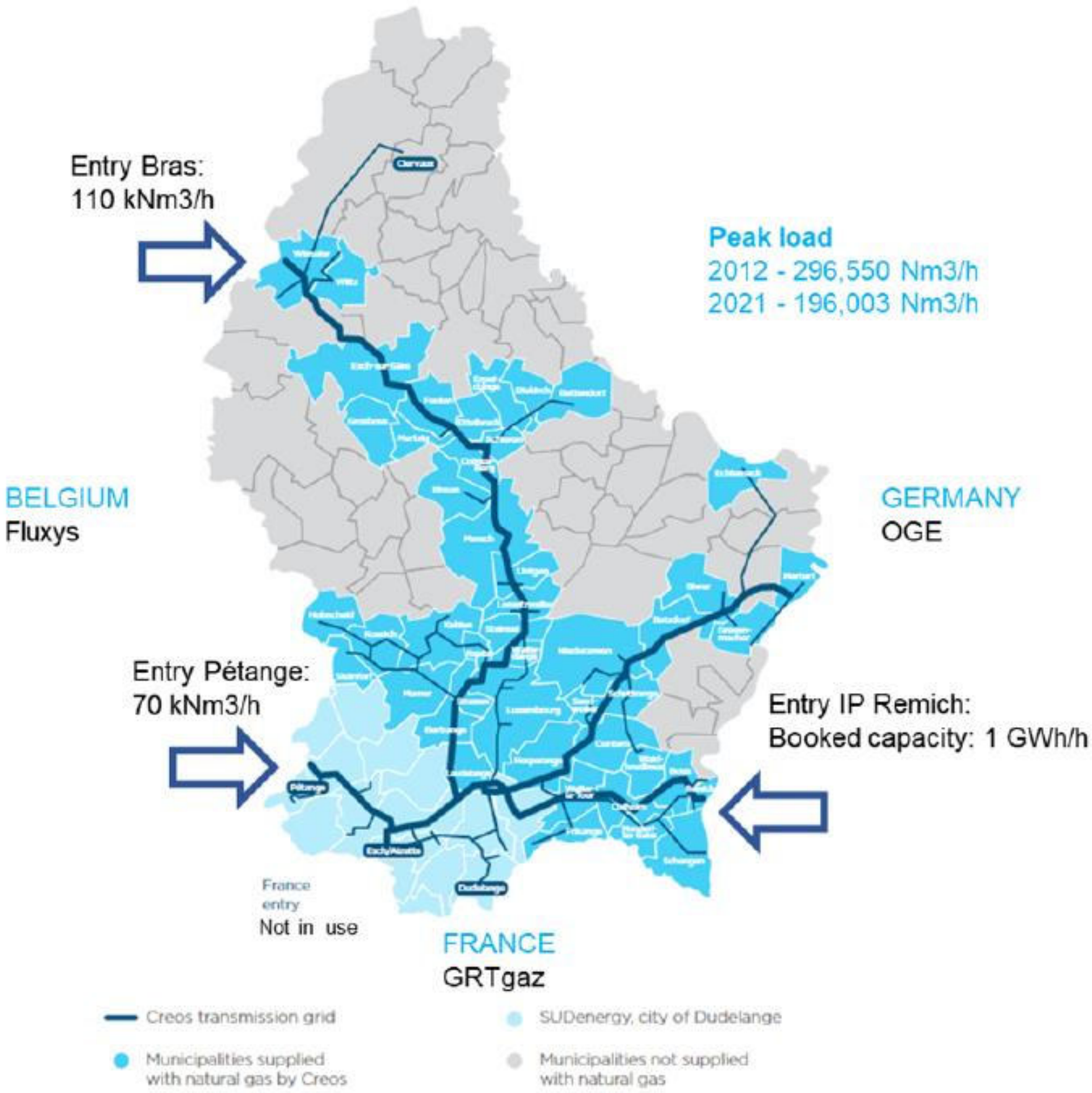

Figure 19: Natural gas transmission system of Luxembourg

The natural gas transmission system of Luxembourg comprises 277.2 km of PN 67.5 high pressure pipeline (DN500/DN400). The transmission gas infrastructure is owned and operated by Creos Luxembourg. The gas supply of Luxembourg is ensured mainly by three physical entry points, two from Belgium and one from Germany. The two entry points with Belgium ensure a total capacity of 180 000 Nm3/h. The booked capacity at the German interconnection point (IP) Remich is 1 GWh/h.

A minimum of 90 000 Nm3/h is necessary to fulfil the N-1 obligation.

The total capacity of the transmission system amounts to 330 000 Nm3/h.

The transmission system transports natural gas to 62 pressure-reduction substations (distribution system and customers). No transit flows are currently possible due to operational constraints and gas odorization at the German and Belgian border. No infeed or storage entities are connected to the transmission system.

The main peak load registered in the last ten years dated from 2012 and amounts to 296 550 Nm3/h. However due to the decommissioning in July 2016 of a CCGT gas power plant with a capacity of 375 MWel, the peak load decreased significantly to 196 003 Nm3/h in 2021.

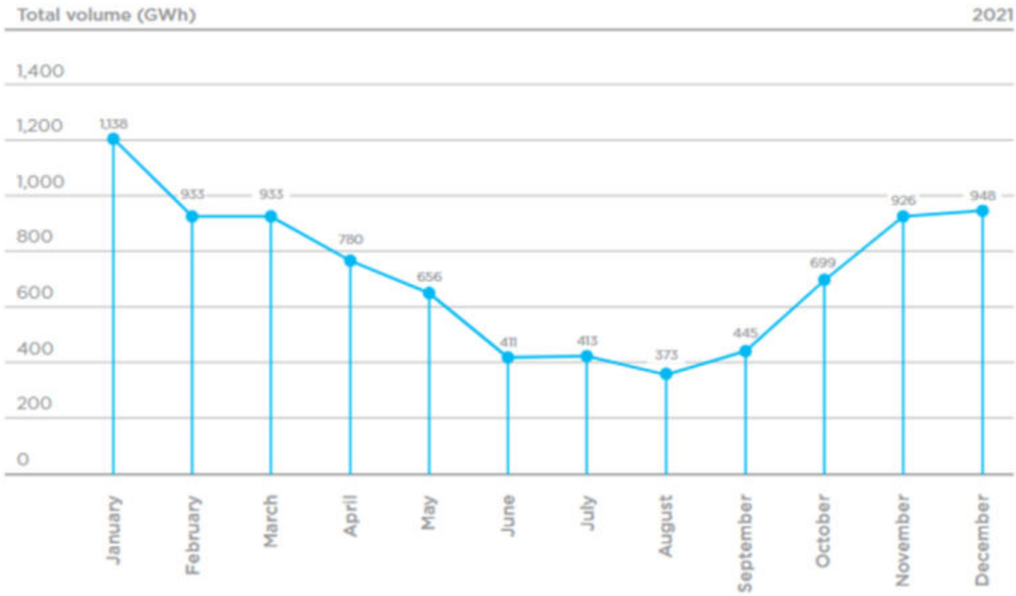

Figure 20: Monthly demand in Luxembourg

Since 2016 the two TSOs Fluxys Belgium and Creos Luxembourg have launched the first cross border market integration. With the removal of the Bras/Pétange interconnection point from the commercial offer, grid users will no longer have to reserve capacity at that point (which disappeared from the commercial offer) to transmit gas between Belgium and Luxembourg. The commitment to increase firm capacity from 110000 Nm3/h at 27 bar up to 180 000 Nm3/h at 40 bar in Bras and at 32 bar in Pétange is part of the integration project and insures significantly the security of supply for Luxembourg.

Due to the market integration and the shutdown of the CCGT in Luxembourg, more gas volumes are currently delivered from Belgium to Luxembourg than from Germany.

In 2021 79% of the flows were delivered from the Belgium entry points.

Table 21: Breakdown of flows on Luxembourg's interconnection points

			2021	2020	Variation
Remich	German network	(GWh)	1,780	1,773	+0.4%
Bras	Belgian network	(GWh)	6,277	5,122	+22.5%
Pétange	Belgian network	(GWh)	598	1,133	-47.2%
Total		(GWh)	8,655	8,028	+7.8%

Netherlands

In the Netherlands the national transmission system for gas is owned and operated by the Dutch Transmission System Operator (TSO) for gas, Gasunie Transport Services (GTS). This transmission system consists of one network for low calorific gas or Groningen gas (L-gas or G-gas) and one network for high calorific gas (H-gas). The two networks are interconnected through the conversion facilities of GTS. These facilities make it possible to convert H-gas into L-gas by adding nitrogen, while H-gas can also be injected into the L-gas system up to the upper Wobbe limit of L-gas.

In the Netherlands H-gas is used by large industries and most of the gas fired power plants. L-gas or G-gas is used by all other gas consumers, including households. Next to the national transmission system for L-gas there are multiple regional distribution systems for L-gas. There is no regional distribution system for H-gas.

Both H-gas and L-gas are exported. H-gas is exported to Belgium, Germany and the United Kingdom, L-gas is exported to Belgium (and via Belgium to France) and Germany. There is no import of L-gas or G-gas as this quality of gas is only produced in the Netherlands (and to a very limited extent in Germany). H-gas is imported via Belgium, Germany and the United Kingdom and as LNG. In the Netherlands there is local production of L-gas or G-gas (only on shore) and H-gas (on shore and off shore).

Change in direction of gas flows

The decrease of Russian gas supply has caused a reversal of international gas flows. As a result, gas flows are increasingly running from west to east and from south to north across Europe. This also encompasses additional gas flows from the UK via the BBL interconnector and via Zelzate towards the Netherlands. These developments have brought a spike in demand for capacity in Germany.

Transport via the Nordstream 1 had been in decline since the invasion of Ukraine, and has ceased since September 2022.

Drop in demand

High energy prices have caused a drop in volume demand. GTS transported 389 TWh of natural gas in the first half of 2022, which is 15% less than the 459 TWh transported in the first half of 2021. Exit transport in the H-gas network and the G-gas network to industries, power stations, and regional transmission system operators was down by approximately 24% in total. Transport volumes were low because of the higher-than-normal temperatures, the high gas prices, and the conversion of the G-gas market outside the Netherlands. The drop in demand on the consumer side is not reflected in transport figures on a one-on-one basis because transport volumes to storage facilities and exports to Germany were up. Exports to Germany peaked in the second half of 2022.

Extra LNG capacity

The Dutch government in cooperation with Gasunie has taken measures to enhance security of supply for the coming years. This has resulted in an increase of the national LNG import capacity from 12 to 24 BCM annually. This was achieved by developing a new floating LNG terminal in the Eemshaven area, the EemsEnergyTerminal, which consists of two Floating Storage Regasification Units. The capacity of the terminal is 8 BCM per year. EemsEnergyTerminal has been operational since 15 September 2022 and is expecting to be operating at full capacity by late November or early December 2022.

The capacity of GATE LNG terminal was increased from 12 to 16 BCM.

Security of supply and filling levels of storages

In July 2022, Gasunie Transport Services analysed that no gas shortages need to occur in the Netherlands if Russian gas in Europe were to be completely eliminated for a year. In that case, however, a number of preconditions must be met. Due to the high filling level of the gas storages (at present moment than 91%), the doubling of the LNG import capacity via the Eemshaven and Rotterdam, the full utilization of the import connections with the UK and Belgium and the significant demand reduction as a result of the high prices, the preconditions for this scenario are currently met. In the figure below, a historical overview of the filling level of storages in the Netherlands at November 1st is displayed.

Table 22: Historical overview of the filling level of storages in the Netherlands at November 1st Source: AGSI-GIE

AGSI-GIE (in TWh)											
Storages Netherlands	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas in Storage (1 nov)	102,6453	102,5678	102,0451	140,287	134,106	126,3731	126,4177	134,6527	125,754	90,0658	127,5577
Full (%)	98,29	97,64	97,15	92,98	94,88	95,83	95,87	95,03	86,62	61,84	91,81

However, measures are needed that ensure a structural improvement of the supply/demand balance in the Dutch market area for the winter of the year 2023/2024. This requires both a structural increase in supply and a structural and significant reduction in demand, possibly in combination with network optimisations.

Configuration of regional grids

In the Netherlands there is a total of 135,000 km of gas pipelines.[17] At the time of writing there were 6 Local Distribution Companies for gas in the Netherlands. On the map below the service areas of the different distribution companies for L-gas are indicated.

Of the 135,000 km, 11,000 km is high pressure pipelines, operated by GTS. The high-pressure gas network is shown on the map below. The Dutch high-pressure network is directly connected to Belgium, Germany, Norway and the United Kingdom. Through over 1,000 gas custody transfer stations gas is distributed to the Dutch domestic market to for example large industries, power plants and to local distribution companies.

[17] Netbeheer Nederland, http://www.netbeheernederland.nl/branchegegevens/infrastructuur/

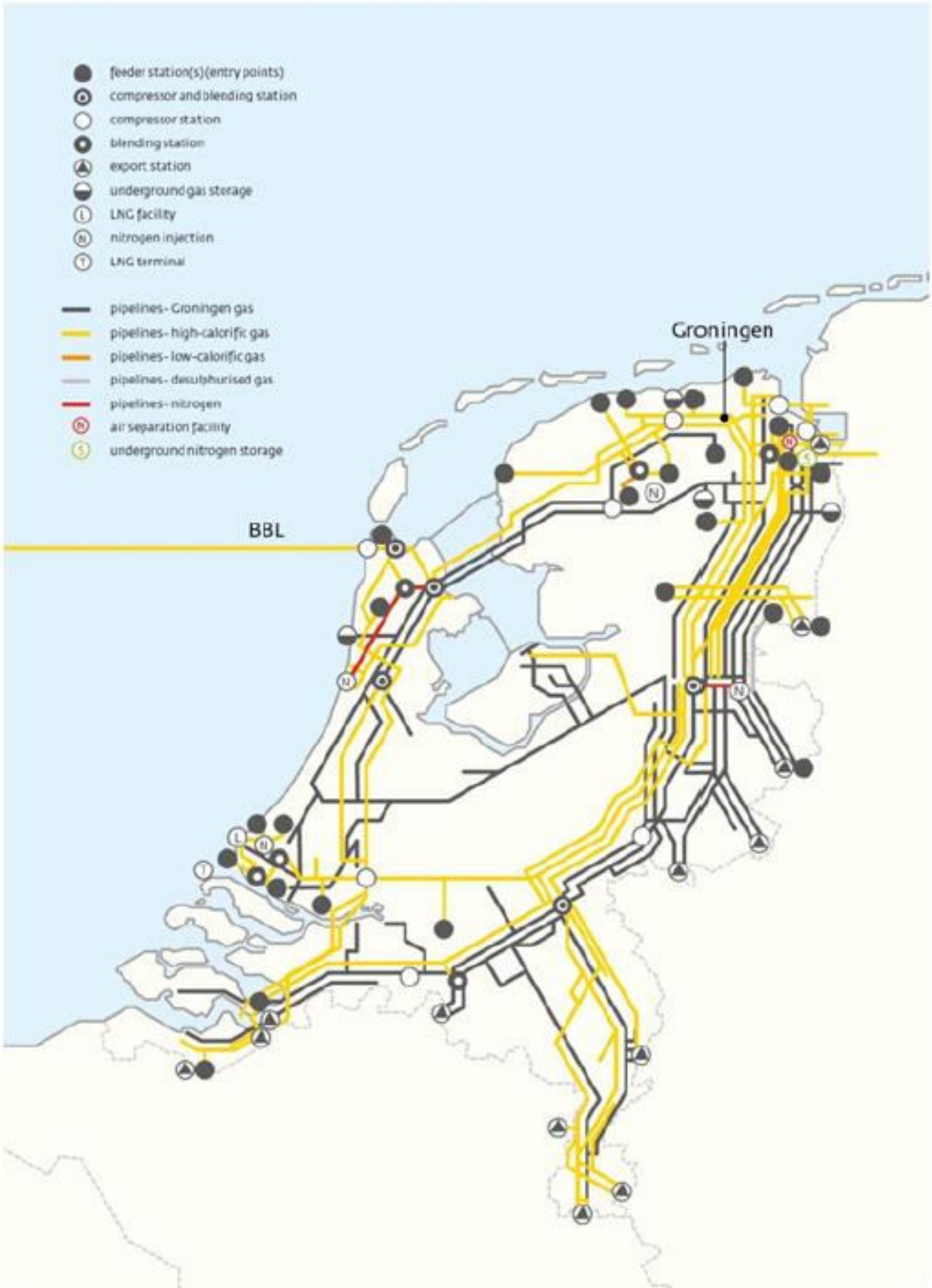

Figure 21: Overview of the Dutch Gas Transport network

Dutch gas market size

A good illustration of the size of the Dutch gas demand is the fact that peak demand for gas is almost 10 times the size of peak demand for electricity. The Dutch network of gas pipelines, storage facilities and an LNG terminal can supply 10 times as much energy to the domestic market as compared to the existing Dutch electricity grid. This is illustrated by the figure below, where the gas demand is compared to the electricity demand.

In 2021 GTS transported about 841 TWh. This means that the average Dutch annual gas consumption of 379 TWh is less than half of the total volume of gas that annually is transported through the country. This is due to export of indigenous gas and the role of the Netherlands as a transit country. Depending on climatic conditions, the share of L-gas in the domestic gas demand varies from year to year. In 2021, the L-gas demand was 233 TWh, roughly 61% of the total gas demand.

Table 23: Historic L-gas demand in the Netherlands. Source: GTS

	2019		2020		2021	
	Yearly	Peak	Yearly	Peak	Yearly	Peak
	TWh	GWh/d	TWh	GWh/d	TWh	GWh/d
Build environment	108	2238	100	2262	113	2225
Industry and power generation	123	829	118	796	120	836
Total	231	3067	218	3058	233	3061

While on average national demand slightly decreases, domestic production has been in strong decline. As a result more volumes had to be imported. Infrastructure has been and will be adjusted to facilitate this. In recent years, NL became a net importer of gas although it is expected that the Netherlands will continue to export L-gas until 2029/2030.[18]

Sources of gas

Gas flows through the Netherlands

The sources of the gas that flows through the Netherlands are indigenous production, LNG, Norwegian gas and Russian gas. The figures below show the gas flow from and to neighboring countries and the yearly utilization rates of the infrastructure that were observed in 2021.

Table 24: Actual cross-border flows in 2021 Source: GTS[19]

Actual cross-border flows in TWh in 2021				
		L	H	Total
Belgium				
	To Belgium	85	44	129
	From Belgium	0	68	68
Germany				
	To Germany	140	55	195
	From Germany	0	88	88
Norway				
	To Norway	0	0	0
	From Norway	0	216	216
United Kingdom				
	To the UK	0	26	26
	From the UK	0	10	10

[18] GTS Draft Investment plan 2022-2032, page 47.

[19] The actual flows do not include the flows related to cross-border connections to German storages.

Gas production in the Netherlands

In 1959 one of the world's largest gas fields was discovered in the Netherlands, the Groningen gas field, located in Groningen province in the north eastern part of the Netherlands. The Groningen gas field is owned and operated by the Nederlandse Aardolie Maatschappij BV (NAM), a joint venture between Royal Dutch Shell and ExxonMobil with each company owning a 50% share. The Groningen field produces gas of so-called G-gas quality.

The Groningen field has been producing natural gas for more than 60 years. It had an estimated total production volume of 2,800 BCM of which ~77% is produced. However, due to the earthquakes originating from the gas production and their impact on buildings and society, the government decided to diminish the production from the Groningen field year on year with the goal to end the production from the Groningen field as soon as possible, while ensuring security of supply.[20]

To achieve this goal, measures were taken. Some of them are already executed, like enabling the gas storage Norg to be filled with pseudo G-gas, exporting pseudo G-gas via Oude Statenzijl to Germany and GTS buying extra nitrogen to extend the efficiency of existing nitrogen conversion facility Wieringermeer. Some of the measures are still work in progress, such as the realisation of the new nitrogen plant Zuidbroek II. This plant is expected to be operational in early 2023.

Furthermore, a number of large industrial customers will be converted from L-gas to H-gas.

The current market demand for all these L-gas consuming countries is shown in the overview below. The Netherlands is the largest consumer and main supplier of L-gas in the region. Germany, the second largest market, does also have L-gas production but this is insufficient to meet total domestic demand. L-gas demand in Belgium and France is entirely supplied by import from the Netherlands.

Table 25: L-gas consumption in the L-gas consuming countries in gas year 2020/2021. Source: Task Force Monitoring L-Gas Market Conversion Winter Report 2022

Country	Netherlands	Germany	Belgium	France
L-gas consumption	235.9	143.3	44.6	39.2

The total L-gas supply is decreasing due to political decisions of the Dutch government aimed at minimizing Groningen production (in order to reduce earthquakes both in frequency as well as magnitude) and due to a natural decrease of production from the small fields. It has become clear that the current L-gas market demand cannot be sustained. Other sources of gas will, in due course, replace the L-gas sources gradually in the coming years. Also, measures are in place to diminish the dependence on L-gas and convert L-gas demand to H-gas.

[20] Kamerstuk 33529-457, d.d. 29 maart 2018.

In the Netherlands, 9 large industrial customers will be connected to the H-gas transport network instead of the G-gas network, as required by legislation adopted in June 2020. Investments have been made in a new nitrogen facility which will be able to provide the market with a yearly estimated production of 10 BCM of pseudo L-gas.

Germany, Belgium and France have agreed to diminish their dependence on L-gas. Projects to convert their domestic L-gas markets to H-gas have started a number of years ago and are expected to take several years before full completion: all (household and industry) appliances have to be checked and adapted to a different gas quality range and changes have to be made to the infrastructure.[21] However, the conversion projects in Germany, Belgium and France have already resulted in a decrease of L-gas demand the last couple of years, and will continue to do so in the future. The conversion of the L-gas markets into H-gas markets will be the result of on-going intensive interaction between governments, TSOs and suppliers.

The ENTSOG TYNDP currently does not model the conversion of L-gas markets because the future need for L-gas substitution is neither a matter of resilience of the system nor can L-gas be imported from somewhere else, which is the core focus of the TYNDP. However, the topic of L-gas is considered highly relevant for the North West region, therefore will be explored in the Gas Regional Investment Plan (GRIP NW) 2022.

Possibilities to accelerate the market conversion in Germany, Belgium and France are also investigated. By gas year 2029/30, imports of L-gas will be reduced to nearly zero. Notably, the optimization of the conversion planning in Belgium is expected to allow for higher conversions in the gas years 2022/23 and 2023/24, indicating a potential reduction of Belgium's L-gas imports from the Netherlands to 0 by gas year 2024/25 instead of gas year 2029/30.[22]

In the meantime, the production from the Groningen field will never be more than is required from a security of supply perspective. This means that the blending stations of GTS will produce baseload and the Groningen field with the other sources (storages) will cover the rest of the demand of the market. The baseload-level of blending stations rose from 85% of blending stations Ommen and Wieringermeer in 2017 to 100% in 2021, with the additional baseload installation Zuidbroek II ready in the beginning of 2023.

In addition to the Groningen field, the Netherlands has been dedicated since the 1970s to extract gas from smaller fields, the so-called small fields policy. Since then, over 495 small gas fields have already been discovered in the Netherlands, of which 221 are producing at the time of writing.[23]

The figure below shows the expected long term domestic gas production, originating from the small fields and the Groningen field.

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[21] For details on the current state of the conversion project in the countries Germany, Belgium and France, see the latest report of the Task Force Monitoring L-gas Market Conversion.

[22] ENTSOG L-gas market conversion review – Winter Report 2022, p.3.

[23] https://www.nlog.nl/sites/default/files/2021 08/jaarverslag_2020_delfstoffen_en_aardwarmte_in_nederland_30082021_0.pdf

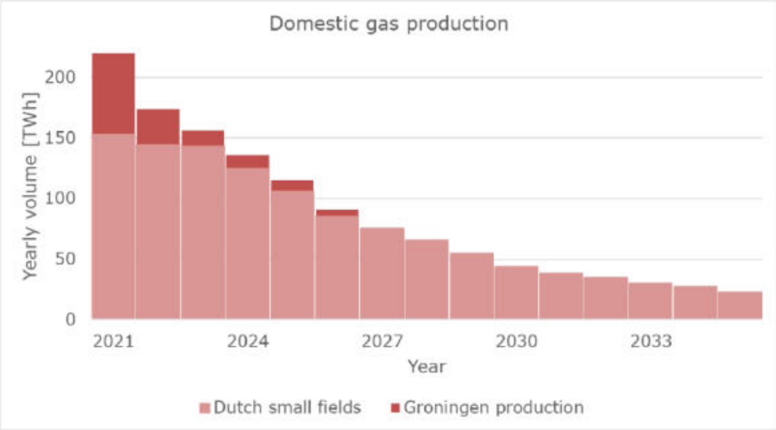

Figure 22: Estimated production of Dutch small fields and the Groningen field

Gas storage in the Netherlands

Indigenous gas production plays an important role in compensating for fluctuations in North West European market demand. The decline in gas production in North West Europe is causing a decrease in the availability of this natural flexibility. Storage facilities are playing an increasingly greater part in order to compensate for this declining production flexibility. To this end, it is important to make a distinction between storage facilities that can provide supplies for summer-winter variations and those that can absorb relatively short peaks in the gas demand. Depleted gas fields (DGF) are extremely suitable for absorbing seasonal fluctuations or to satisfy peak demand. Salt caverns are often used for shorter peaks, but can, when having a large storage volume, also be used to balance out seasonal supply and demand.

The following figure lists the storages in the Netherlands. The storage operators provided the 100% data publicly to GIE and the 30% data to GTS.[24]

Table 26: Storage facilities in the Netherlands. Source: https://agsi.gie.eu/#/ (Norg, Alkmaar and EnergyStock store G-gas, the other storages store H-gas)

Facility/ Location	Type	Operator	Working gas TWh	Withdrawal 100% GWh/day	Withdrawal 30% GWh/day	Injection GWh/day
EnergyStock	SC	EnergyStock BV	3,657740	449	449	322,4
Grijpskerk[25]	DGF	NAM	27,6667	719,3	609	172,9
Norg	DGF	NAM	59.3385	802	703	281,4[26]

[24] Public storage data can be found at https://agsi.gie.eu/#/

[25] The Dutch Ministry of Economic Affairs has decided on April 1, 2022 to convert the storage from a high-calorific storage to a low-calorific storage.

[26] Since storage Norg is filled with pseudo G-gas and this gas cannot be transported via the Groningen production system, this is the injection capacity of Norg at the connection point with the GTS-network.

Alkmaar	DGF	TAQA Energy BV	5	357	357	40.6
Bergermeer	DGF	TAQA Energy BV	48,1515	527	353	450.3

Besides access to storages located on Dutch territory, the Dutch gas network has access to German storage facilities. The figure below shows the capacities at Interconnection Points connecting these storages and the GTS grid.

Table 27: Capacities at Interconnection Points connecting German storages to the GTS grid. Source: GTS

Location	NWP	Entry capacity (GW)	Exit capacity (GW)
Cluster Enschede/Epe storages	Cluster	13,1	7,0
Cluster Oude Statenzijl storages (H)	Cluster	35,0	24,6

LNG in the Netherlands

On the Maasvlakte in Rotterdam, Gate terminal has built the first H-gas LNG import terminal in the Netherlands which is operational since 2011. The terminal currently has a throughput capacity of 12 bcm per annum and consists of three storage tanks, two jetties and a process area where the LNG is being regassified. Annual throughput capacity has been increased from 12 to 16 bcm in the summer of 2022, and could potentially be further increased in the future.

The Gate terminal dovetails with Dutch and European energy policies, built on the pillars of strategic diversification of LNG supplies, sustainability, safety and environmental awareness. The initiators and partners in Gate terminal are N.V. Nederlandse Gasunie and Koninklijke Vopak N.V. Gate terminal is an important factor in importing gas from other countries and sources into Europe. It increases the security of supplies and enables new players to enter the European gas market. Moreover, the terminal's direct connection to the national natural gas transmission network supports the Netherlands' position as a major European hub for gas trade and distribution.

In response to gas supply insecurities and a desire to be less dependent on Russian gas, Gasunie has developed a new floating LNG terminal in the Eemshaven area, called the EemsEnergyTerminal. The capacity of the terminal is 8 BCM per annum. The terminal has been operational since 15 September 2022 and is expecting to be operating at full capacity by late November or early December 2022.

Slovakia

Transmission network is defined by the relevant legislation as: "the network of compressor stations and the network foremost of high-pressure gas pipelines that are interconnected and which serve primarily for transporting gas in the defined territory, excluding the upstream network, storage and high-pressure gas pipelines that serve primarily for transporting gas to part of the defined territory".

In the field of gas transmission one company is active in Slovakia - Eustream - which is the operator of the national transmission network. Based on the decision of the Government of the Slovak Republic from 28 November 2012 it was determined that unbundling required by European legislation will be carried out by using the model of an independent transmission operator (ITO).

In 2016 the total gas transmission amounted to 60.6 bcm. Due to the amount of transported gas Eustream remains one of the most important TSOs based on the volume of gas transported within the EU.

The transmission network is made up of parallel pipes DN 1 200 and DN 1400 in four to five lines, the total length of the gas transmission network is almost 2 270 km. Four compressor stations are part of the transmission network – Velké Kapušany, Jablonov nad Turnou, Velké Zlievce and Ivanka pri Nitre – which provide a pressure differential needed for the flow of gas with a total output of 600 MW. They are situated at a distance of about 110 km apart. The total transmission capacity of the network is more than 90 bcm per year. Natural gas from the transmission network in the defined territory passes through intrastate stations into the distribution networks and is transported to the final customers.

Figure 23: Transmission system of eustream[27]

[27] Source: eustream, a.s.

On 30 November 2011 implementing measures were completed that allow reverse flow within the transmission network in Slovakia. In this mode it is possible to transport in the west – east direction the amount of gas that is higher than the highest consumption in Slovakia in the winter months. This project was funded under Regulation (EC) No 663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Community financial assistance to projects in the field of energy (hereinafter "Regulation No 663/2009").

Slovakia interconnection with neighbouring countries on the level of transmission networks currently exists with Austria [border point Baumgarten], Czech Republic [border point Lanžhot], Hungary [border point Velké Zlievce] and Ukraine [border point Velké Kapušany and border point Budince].

Interconnection with the Czech Republic since 2009 and with Austria since 2010 have been prepared so that it will be possible in a crisis situation (emergency level respectively) to ensure a physical reverse flow of gas to Slovakia.

Technical firm capacity at interconnection points of transmission system with systems of neighbouring countries

Table 28: Cross border points in Slovakia[28]

Border point	Exit firm capacity (GWh/day)	Entry firm capacity (GWh/day)
Veľké Kapušany [SK/UA]	0	2028.0
Budince [SK/UA]	280.8	176.8
Baumgarten [AT/SK]	1570.4	247.5
Lanžhot [CZ/SK]	400.4	696.8
Veľké Zlievce [SK/HU]	126.9	0

The distribution system is defined by the legislation as: the gas distribution equipment within part of the defined territory, including high-pressure gas pipelines that serve primarily for the transportation of gas to part of the defined territory, except for gas pipelines that are part of other networks".

Over 40 companies are active in the field of gas distribution in Slovakia. SPP - distribúcia, a.s. is the largest operator with nationwide coverage to more than 1.5 million connected customers (including more than 1.4 million household customers). The distribution system of SPP - distribúcia, a.s. is made up of about 33 000 km of gas pipelines, its total distribution capacity is nearly 10 bcm per year. Slovakia is one of the most gasified EU countries.

Distribution system of SPP

[28] Source: eustream, a.s., data

Figure 24: Distribution system of SPP[29]

Slovakia has in its territory several geological formations which are suitable for the construction of underground gas storage facilities. Currently there are two companies active on the market that are storage system operators - NAFTA a.s., Bratislava and POZAGAS a.s., Malacky. Total storage capacity in Slovakia is 3.35 bcm, which represents more than 65% of total consumption. The facilities are located in the southwestern part of the country near the border with Austria and the Czech Republic.

The storage facility at Dolní Bojanovice located in the Czech Republic is used solely for the Slovak market. It is operated by SPP Storage, s.r.o., Praha, Czech Republic and its storage capacity is 0.57 bcm. The facility is directly connected to the Slovak gas network and is used by SPP - distribúcia, a.s. primarily to ensure the balancing of the distribution system and losses in the distribution system as well as to ensure security of supply standard for household gas customers.

Table 29: Figures of unterground storage in Slovakia. Source: storage systems operators Note: All Figures at 101.325 kPa and 15°C.

Underground storage facility/region	*Operator*	*Working gas volume (storage capacity) (bcm)*	*Maximum firm withdrawal capacity (mcm/day)*	*Maximum firm injection capacity (mcm/day)*
Láb 1,2,3 a 5	NAFTA a.s., Bratislava	2.70	38.25	31.9
Láb 4	POZAGAS a.s., Malacky	0.65	6.85	6.85
Total SK		3.35	45.1	38.75
Dolní Bojanovice (CZ)	SPP Storage, s.r.o., Praha	0.57	8.8	8.8
Total CZ		0.57	8.8	8.8
Total (SK+CZ)		**3.92**	**53.9**	**47.55**

[29] Source: SPP – distribúcia, a.s.

Sweden

There is no extraction of natural gas in Sweden and the entire volume of consumed natural gas is imported from Denmark via pipeline. The Swedish transmission system for natural gas begins in Dragør in Denmark, crosses the Öresund strait via the Öresund pipeline to Klagshamn south of Malmö, from where the trunk pipeline heads northward to Stenungsund. The technical capacity of the Öresund trunk line is 8.6 mcm/d and the technical capacity of the entry point of Dragør (in Denmark) is 8.6 mcm/d. The natural gas network consists of approximately 620 km of transmission lines and roughly 2 700 km of distribution lines. Branch pipes lead off from the trunk pipeline to various consumption areas.

Swedish gas mainly comes from the Tyra gas fields in Denmark which is closed for maintenance until 2024. During the reconstruction of Tyra the Swedish market has been completely dependent on natural gas from Germany via Ellund. This causes increased vulnerability of the Swedish natural gas supply as there is no secondary pipeline route option during this time.

Sweden has a biogas production and small volumes of biogas with a quality equal to natural gas is injected into the distribution systems. The total production of biogas in Sweden is around 2 TWh per year. The produced biogas is mainly consumed in transportation where over half is used. Sweden is also a world leader in liquefied biogas technology (LBG), although this is still represented by very low figures of production in pilot plants.

The gas flow in the Öresund pipeline is one-way from Denmark to Sweden. Today it is not technically possible to reverse the flow so that gas flows from Sweden to Denmark. Sweden has no natural gas production or any significant gas storage, nor is biogas production significant, although biogas production will gradually increase according to decisions and plans.

Sweden has an exemption from the N-1 infrastructure criteria in the regulation as well as the criteria for reverse flows. The western Swedish natural gas system is exclusively connected to the Danish natural gas system.

Furthermore, Sweden has been granted an exemption from the criteria for reverse flows as Sweden does not have any natural gas production or any significant storage, nor is the internal/domestic biogas production significant in volume although production is gradually increasing. This means that Sweden cannot contribute to the security of supply in the Danish or European gas system, therefore, there is no need for establishing reverse flows between Sweden and Denmark.

Figure 25: The Swedish gas system

Gas consumption

The Swedish natural gas market is relatively small when compared to other European markets. In 2020 the total Swedish natural gas demand was about 11.3 TWh. Industry is the biggest consumer of natural gas and consumed 36 percent of the total in 2020. The power sector consumed 6 percent, 13 percent was consumed in the commercial and residential sector, 3,5 percent in transportation and 41,5 percent was used for non-energy purposes. The power generated by natural gas amounted to 0.7 percent of Sweden's total electricity generated in 2020.

Approximately 9-10 TWh natural gas is imported from Denmark via pipeline on a yearly basis. In addition, approximately 0.5 TWh/year of indigenous biogas production is fed into the natural gas grid.

The maximum demand for gas in Sweden is estimated to be 7,2 MNm3/day on a cold winter day (-15 degree Celsius). Furthermore, the maximum demand for a month is estimated to be 124 MNm3. Gas demand in summer is significantly lower than winter demand. According to Article 6 in the regulation 2017/1938, Sweden is required to guarantee their protected customers gas for at least 30 days during a period with exceptionally high demand. Demand from protected costumers amounts to approximately 3 percent of the total gas consumption. The demand from the protected costumers is estimated to increase by 40 percent from its average demand during winter (0 Degrees Celsius) and amount to 3.9 MNm3 in total during one month with exceptionally high demand. Sweden is able to meet its requirement to provide its protected consumers with gas even in peak demand periods.

Infrastructure standard

N-1 formula

According to the Regulation[30], “the N – 1 formula describes the ability of the technical capacity of the gas infrastructure to satisfy total gas demand in the calculated area in the event of disruption of the single largest gas infrastructure during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years.”

The result of the N-1 formula should yield at least 100%, indicating the technical capacity of the remaining gas infrastructure is at least equal to the total daily gas demand of the risk group Baltic Sea area during a day of exceptionally high gas demand which might occur once every 20 years. Initially, the disruption of gas supply represented by total loss of Russian gas flows into the regional gas system is considered.

The N – 1 formula with market-based demand-side measures:

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

Where:

Dmax The total daily gas demand of the calculated area during a day of exceptionally high gas demand (20 year incidence)

EPm Total technical capacity of all entry points that can supply the calculated area, excluding production, storage and LNG facilities

Pm Maximum technical production capacity that can supply the calculated area

Sm Maximum technical withdrawal capacity from storage facilities in the calculated area

LNGm Maximum technical send-out capacity at all LNG facilities in the calculated area

Im Technical capacity of the single largest infrastructure with the highest capacity to supply the calculated area

Deff The part of Dmax that in the case of a disruption of gas supply can be sufficiently and timely covered with market-based demand-side measures.

The single largest infrastructure

N-1 calculations are completed for the 2022, 2022-09, No Russian (NR) 2022 and NR 2022-09 gas scenarios. For the 2022 and 2022-09 scenarios, the disruption of critical infrastructure is presumed as the loss of Russian gas flows into the RG Baltic Sea system. In the NR 2022 and NR 2022-09 scenarios, the largest Interconnection Points (IPs) carrying mostly Russian Gas and no longer providing physical flow (Greifswald, Kondratki, Tieterowka and Wysokoje) are not considered and their capacities removed from the calculations. The IP Velké Kapušany (UA-SK) still show some flows and is included. Following the exclusion of these capacities, the IP Velké Kapušany (UA-SK) becomes the largest capacity infrastructure. Accordingly, NR 2022 and NR 2022-09 assume disruption of the IP Velké Kapušany for computation of the N-1 formula.

Calculation of regional N-1 for risk group Baltic Sea

Data for all listed relevant parameters has been collected and categorized by the coordinator of the Risk Group Baltic Sea and the JRC, for the calculation of the technical capacity of the gas

[30] Annex II Calculation of the N – 1 formula

infrastructure to satisfy total gas demand through the N-1 formula. An example of this calculation is shown below for the 2022 scenario.

$$\mathrm{N}-1[\%]=\frac{(8869.4\ +746.8\ +14574.39+2504.78-1913.6)\frac{GWh}{d}}{14066.2\frac{GWh}{d}}\cdot 100=176.2\%$$

A full overview of the determined N-1 and collected relevant data is shown below.

Tabelle 30: Demand and capacities

Parameter	2022	2022-09	NR 2022	NR 2022-09
D_{max} [GWh/d]	14066,20	14066,20	14066,20	14066,20
EP_m [GWh/d]	8869,40	8659,30	6783,10	6636,40
P_m [GWh/d]	746,80	746,80	746,80	746,80
S_m [GWh/d]	14574,39	14574,39	14574,39	14574,39
LNG_m [GWh/d]	2504,78	2504,78	2504,78	2504,78
I_m [GWh/d]	1913,6	1913,6	1913,6	1913,6
N-1 [%]	176,2%	174,7%	161,3%	160,3%

Furthermore, the IP Wilhelmshaven LNG terminal must be considered in the event of the project providing additional capacity for the RG Baltic Sea system. The resulting changes in N-1 calculations are presented in Tabelle 31 below.

Tabelle 31: Demand and capacities with Wilhelmshaven

Parameter	2022	2022-09	NR 2022	NR 2022-09
D_{max} [GWh/d]	14066,20	14066,20	14066,20	14066,20
EP_m [GWh/d]	8869,40	8659,30	6783,10	6636,40
P_m [GWh/d]	746,80	746,80	746,80	746,80
S_m [GWh/d]	14574,39	14574,39	14574,39	14574,39
LNG_m [GWh/d]	2864,17	2864,17	2864,17	2864,17
I_m [GWh/d]	1913,60	1913,60	1913,60	1913,60
N-1 [%]	178,7%	177,2%	163,9%	162,9%

These calculations of the regional N-1 formula for the calculated area in the RG Baltic Sea show that N-1 > 100% by a significant margin for all scenarios considered. Therefore, the calculated regional area complies with article 5 (infrastructure standard) of the regulation in all relevant 2022 scenarios.

Bi-directional capacity

Bi-directional capacity is established between allinterconnection points in RG Baltic Sea which do not have an exemption.

Notable exemptions in accordance to article 5(4a) due to connections to production facilities such as LNG facilities and to distribution networks include IPs; Dornum / NETRA (NO.DE), Dunkerque (NO.FR), Emden (EPT1) (NO.DE), Emden (EPT1) (NO.NL), Greifswald (RU.DE), North Sea Entry (NO.DK), Zeebrugge / IZT (BE.UK/IUK), Zeebrugge / IZT (UK/IUK.BE), Zeebrugge / ZPT (NO.BE).