european network
of transmission system operators
for gas

SoS SIMULATION REPORT
2017

ENTSOG Union-Wide Security of Supply Simulation Report

ENTSOG – A FAIR PARTNER TO ALL!

Union-wide simulation of gas supply and infrastructure disruption scenarios (SoS simulation)

Contents

1. Introduction

Regulation (EU) 2017/1938 of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 ("the Regulation") entered into force on 1 November 2017.

In its Article 7 “Risk assessment”, the Regulation stipulates:
By 1 November 2017, ENTSOG shall carry out a Union-wide simulation of gas supply and infrastructure disruption scenarios. The simulation shall include the identification and assessment of emergency gas supply corridors and shall also identify which Member States can address identified risks, including in relation to LNG. The gas supply and infrastructure disruption scenarios and the methodology for the simulation shall be defined by ENTSOG in cooperation with the GCG. ENTSOG shall ensure an appropriate level of transparency and access to the modelling assumptions used in its scenarios. The Union-wide simulation of gas supply and infrastructure disruption scenarios shall be repeated every four years unless circumstances warrant more frequent updates.

This ENTSOG publication is the first exercise of the above mentioned Union wide simulation. The work for this edition started already before the entry into force of the Regulation in order to comply with the ambitious timeline established therein, also for the subsequent procedures, mainly the common and national Risk Assessments. Thanks to a close cooperation with the European Commission and the Gas Coordination Group the rules and procedures as set up in the Regulation were already followed.

The methodology and assumptions used for the simulation have been defined by ENTSOG in cooperation with the Gas Coordination Group during the meetings and web conference held on 22 March 2017, 23 May 2017 and 28 June 2017.

On 22 March 2017, the Gas Coordination Group was proposed a set of 19 supply and infrastructure disruption scenarios and discussed during that meeting which climatic conditions and which scenarios would be relevant together with their appropriate duration. Members of the Gas Coordination Group were given an additional period of time until April 2017 to further comment on the scenarios and the climatic conditions. Feedback from 21 Member States and 4 organisations was received and led to adapted disruption scenarios that were again discussed with the Gas Coordination Group in a webconference on 23 May 2017. As a result, scenarios including their durations were defined and in some instances, specific demand or production assumptions were agreed, to ensure an increased accuracy in the simulation. Those assumptions are detailed later in this report. It was also decided to delegate the treatment of the scenarios concerning L-gas to the Gas Platform[1].

On 28 June 2017, the methodology and assumptions for the simulations were agreed at the meeting of the Gas Coordination Group.

[1] The Gas Platform is the regional cooperation for gas for Belgium, France, Germany, Luxembourg and the Netherlands. It is an intergovernmental initiative where ministries responsible for energy policy discuss issues related to security of supply and market integration, in close cooperation with the National Regulatory Authorities and Transmission System Operators. Ad hoc, the European Commission or other European authorities participate as observer. The Benelux Secretariat provides support.

The input data for the simulations concerning the gas demand for the different climatic conditions, infrastructure capacities and the estimates for the gas production were submitted by TSOs and Associated Partners and Observers from ENTSOG as part of a specific data collection process in May.

The supply and infrastructure disruption scenarios as well as the methodology and assumptions are further detailed in the next chapters.

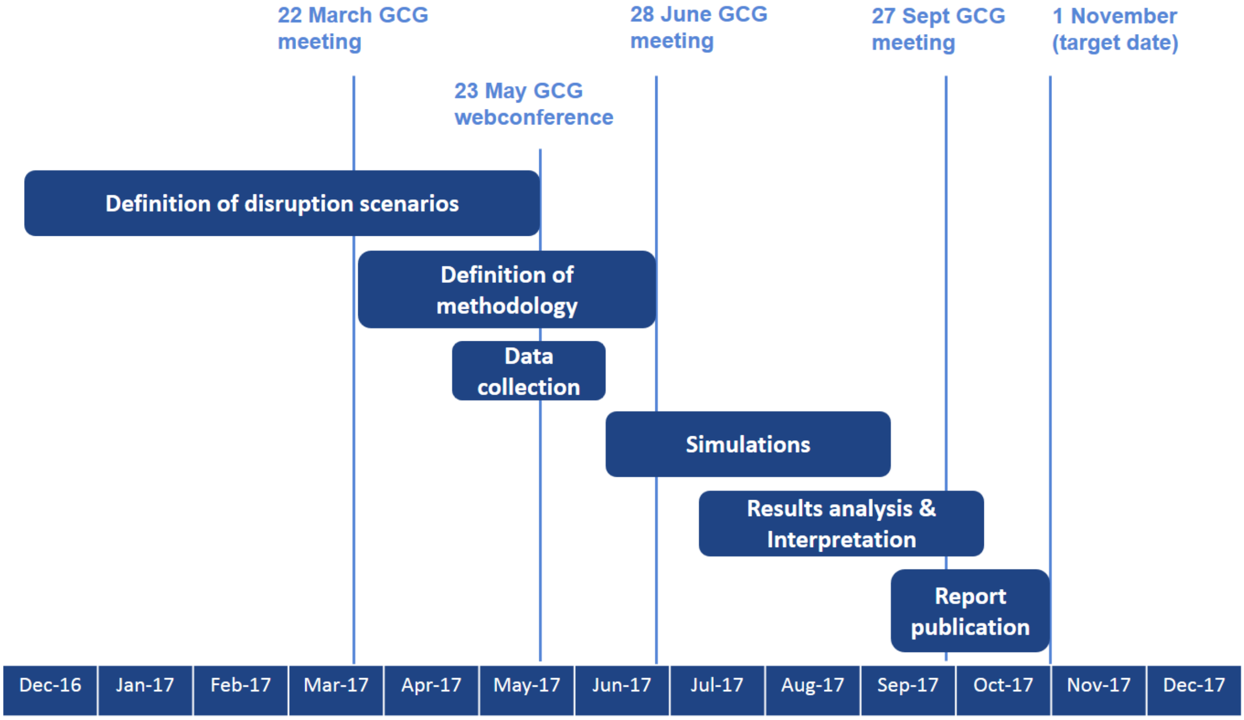


Figure 1: Timeline of Union wide simulation of supply and infrastructure disruption scenarios

2. Supply and infrastructure disruption scenarios

The 19 supply and infrastructure disruption scenarios cover all the Emergency Supply Corridors as well as the 13 different Risk Groups of Member States as defined in the Annex 1 of the Regulation. They are meant to identify which Member States can address identified risks, including in relation to LNG, against the failures of the main gas supply routes or infrastructures.

Among these scenarios, two scenarios are not simulated because no infrastructure exists yet (scenarios 18 and 19). The scenarios regarding Low Calorific gas are defined and treated within the Gas Platform.

	Risk Group	#	Disruption scenario
Eastern gas supply	Ukraine	1	Disruption of all imports via Ukraine
	Belarus	2	Disruption of all imports via Belarus
	Baltic Sea	3	Disruption of one Nord Stream offshore pipeline
		4	Disruption of the onshore receiving facility of Nord Stream (Greifswald station)
	North-Eastern	5	Disruption of all imports to the Baltic states and Finland
	Trans-Balkan	6	Disruption of the largest infrastructure to the Balkan region
North Sea gas supply	Norway	7	Disruption of the largest offshore infrastructure to the UK (Langeled)
		8	Disruption of the largest offshore infrastructure to continental EU (Europipe 2)
		9	Disruption of the largest onshore infrastructure from Norway (Emden station)
	Low calorific gas	10	Disruption of the largest L-gas storage (Gas Platform)
		11	Disruption of the L-gas supply (Gas Platform)[2]
	Denmark	12	Disruption of the largest infrastructure to Denmark (Ellund)
	United Kingdom	13	Disruption of Forties pipeline system
North-African gas supply	Algeria	14	Disruption of the largest offshore infrastructure to Italy (Transmed)
		15	Disruption of the largest offshore infrastructure to Spain (MEG)
		16	Disruption of imports from Algeria, including LNG
	Libya	17	Disruption of all imports from Libya
South-East gas supply	Southern Gas Corridor	18	No existing infrastructure
	Eastern-Mediterranean	19	No existing infrastructure

Table 1: Disruption scenarios

[2] Further scenarios with regard to the L-gas supply will be developed within the framework of the Gas Platform and communicated later.

3. Methodology and assumptions

The methodology and assumptions cover
- Simulation cases along with the corresponding demand assumptions,
- Disruption duration,
- Supply,
- Infrastructure,
- Modelling and results interpretation, and
- Treatment of storages including the initial inventory levels.

The corresponding data is available in the Annexes.

3.1. Simulation cases and demand assumptions

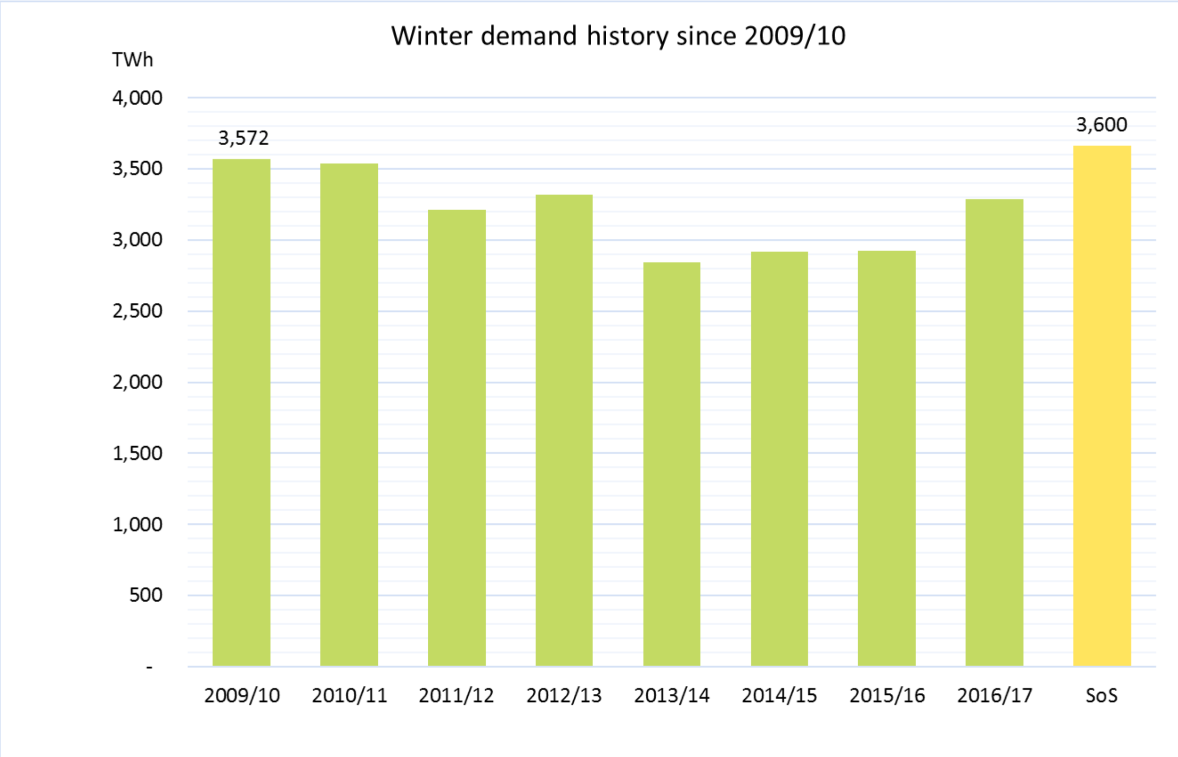
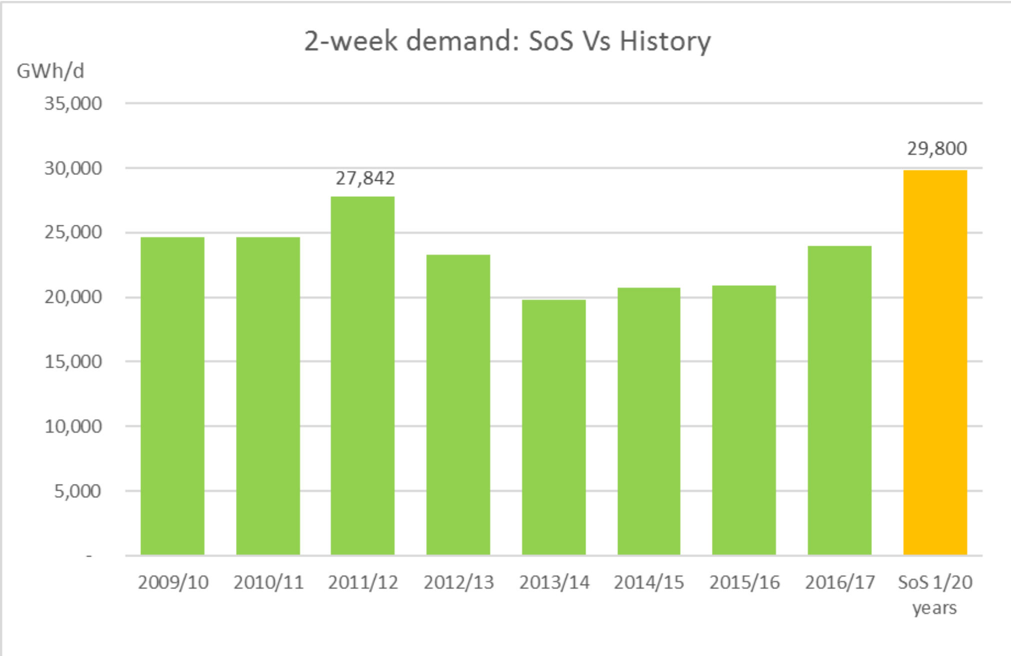


Figure 2: comparison winter demand history and SoS assumptions

For every scenario, 3 different cases are simulated to assess the impact of 3 high demand events:
1. A historical high demand winter[3] – country level maximum since winter 2009/10
2. A period of 2 weeks of exceptionally high demand, occurring with a statistical probability of once in 20 years.
3. One day (Peak Day) of exceptionally high demand, occurring with a statistical probability of once in 20 years – also called Design Case (DC).

The high demand cases are meant to capture the capability of the gas system to cope with the most challenging demand situation (Peak Day / Design Case) and a long high-demand period (2-week high demand). 2-Week and Peak Day simulations consider the beginning of the winter follows a historical high demand reflected in the storage levels and LNG import flows (see also chapter 3.6).

[3] Winter: period from 1 October to 31 March, covering the six months in between with 182 days in total.



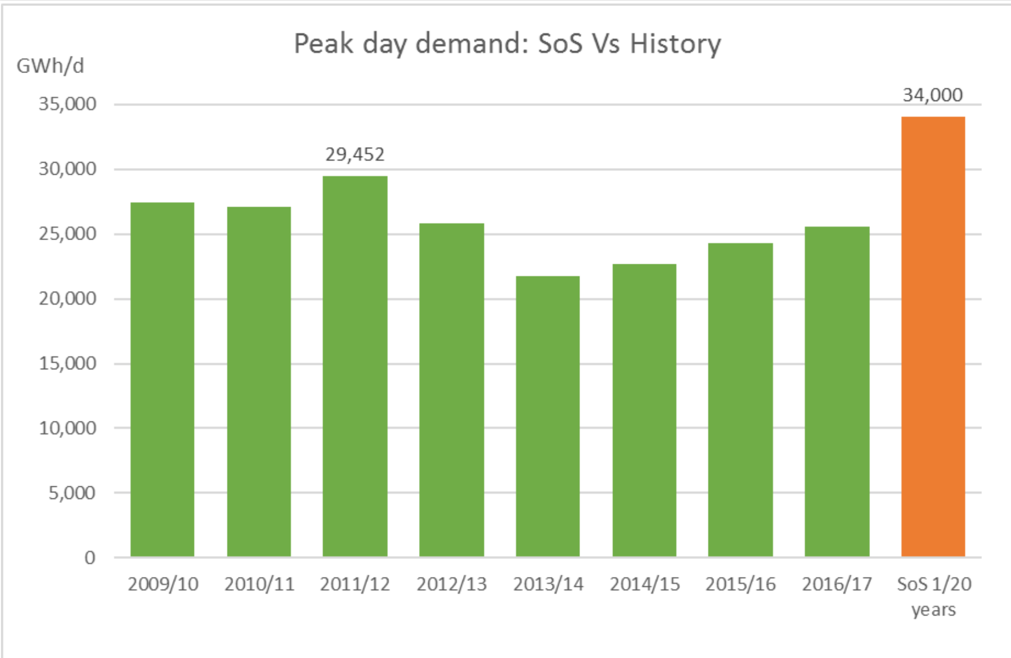


Figure 3: comparison 2-week and Peak Day demand history and SoS assumptions

In specific countries, due to the structural decrease of the gas demand over the last years the application of historical demand figures for the whole winter simulation would not be appropriate.
This applies to Denmark, Finland, Lithuania and Sweden. Instead of the highest winter demand since 2009/10, a best estimate of the current winter demand has been considered for Denmark and Sweden. For Finland, the highest demand of the last five winters is considered, and for Lithuania the highest demand of the last two winters is used in the simulations.

The sum of the winter demand of the EU countries in this assessment is 2.5% above the demand that has materialised simultaneously across the EU since 2009/10. This deviation is derived from the fact that the historical highest winter demand did not occur simultaneously in every European country. For the 2-week and peak day demand cases, the 1-in-20 years approach leads to the sum of the 2-week demand being 7% and the one for the Peak day 15% above the simultaneous demand that could be observed since 2009/10.

3.2. Exports

In addition to the demand within the EU member states as shown in figures 2 and 3, the demand of non-EU countries that are only supplied via the European gas infrastructure (BA, CH, MK, RS), the exports to Ukraine (based on the last two winters), and the transits towards Kaliningrad and Turkey (based on the last 5 winters) have been considered in the simulations. The transits to Turkey are not maintained in the scenarios 1 and 6, the transits to Kaliningrad are not maintained in the scenarios 2 and 5.

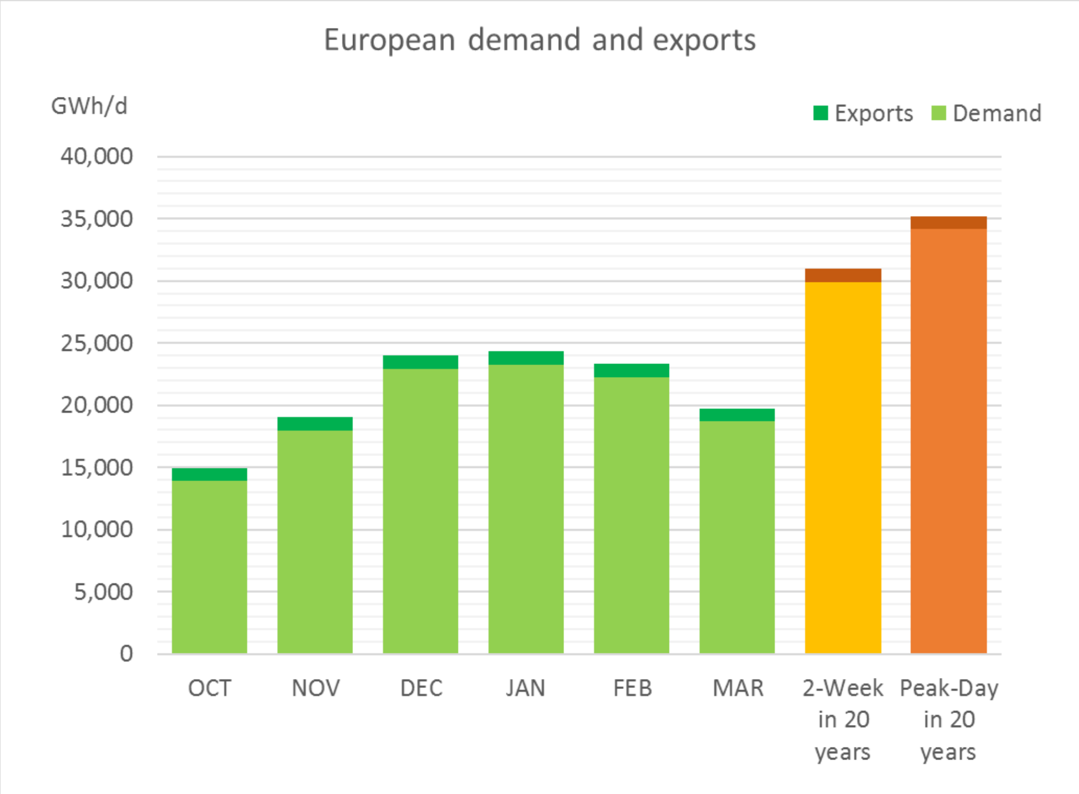


Figure 4: Monthly, 2-Week and Peak Day EU demand and exports from EU

In general, exports to non-EU countries represent around 5% of the EU winter demand and, in particular, Ukrainian exports in the simulations represent around 2% of the EU winter demand.

3.3. Demand and disruptions timelines

The disruption periods are defined to assess the impact of the various scenarios along with a low initial storage level during these exceptionally high demand events. They are not defined based on their probability of occurrence. Therefore, the 2-month disruptions are simulated during January and February and the 2-Week disruptions from 15 February to 28 February.

Regarding the 2-Week and Peak Day simulations, storage levels and LNG import flows considered on 15 February are resulting from the whole winter simulation (see also chapter 3.6 for further information).

Simulation case	**Historical high demand winter**	**2-week in 20 years**	**Peak day in 20 years**
Simulation period	From 1 October to 31 March	From 15 February to 28 February	On 15 February
Gas demand	Highest winter demand since 2009/10 (at country level and then aggregated for EU)	Exceptionally high demand, occurring with a statistical probability of once in 20 years.	Exceptionally high demand, occurring with a statistical probability of once in 20 years.

Table 2: Simulation cases timeframes

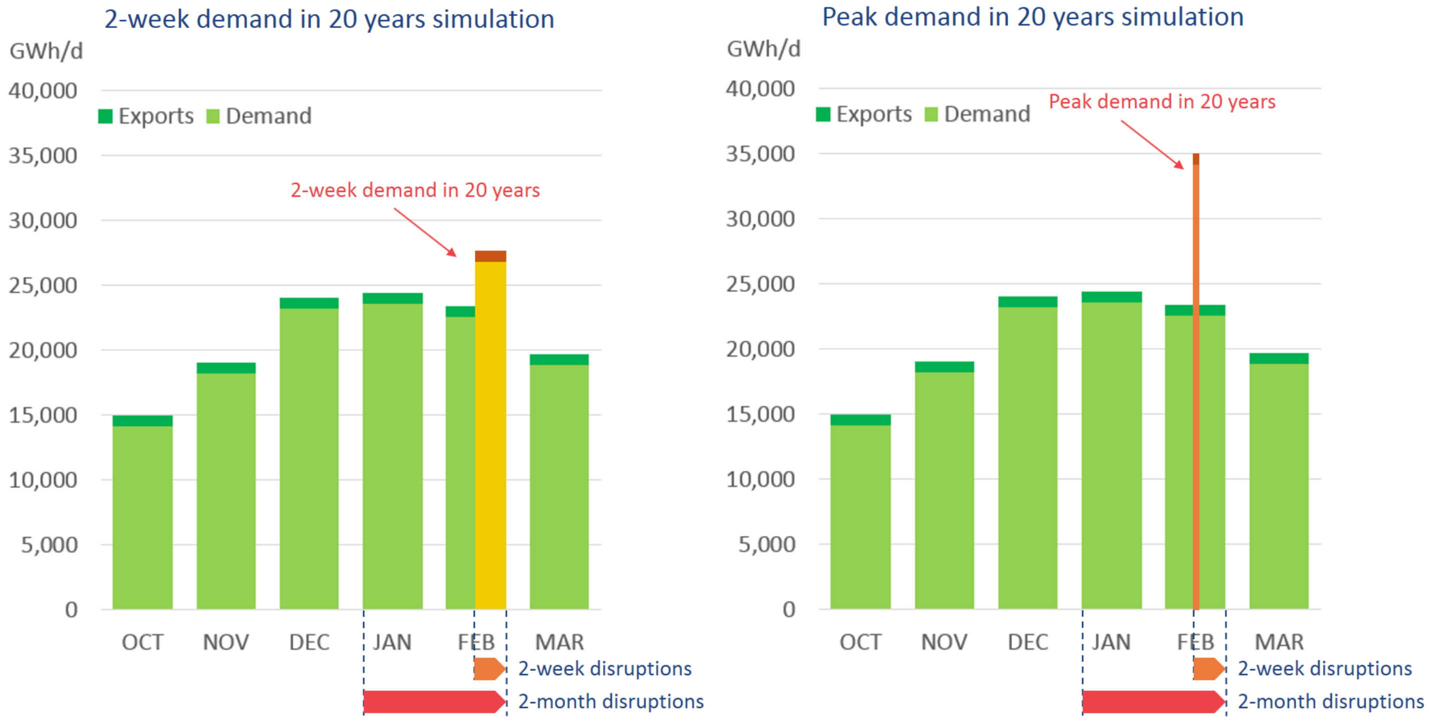


Figure 5: Demand assumption and disruption timeframes

Specificity of scenario 16 - Algerian disruption:

Disruption scenario #16 considers the disruptions of the imports from Algeria via both pipelines and LNG cargos. However, different supply assumptions are made regarding pipelines, that cannot physically be rerouted, and LNG, to consider that additional cargos can come from different suppliers. Therefore, it is assumed that a period of 3 weeks starting from 1 January is necessary to attract more LNG cargos to substitute the Algerian LNG (see figure 6).

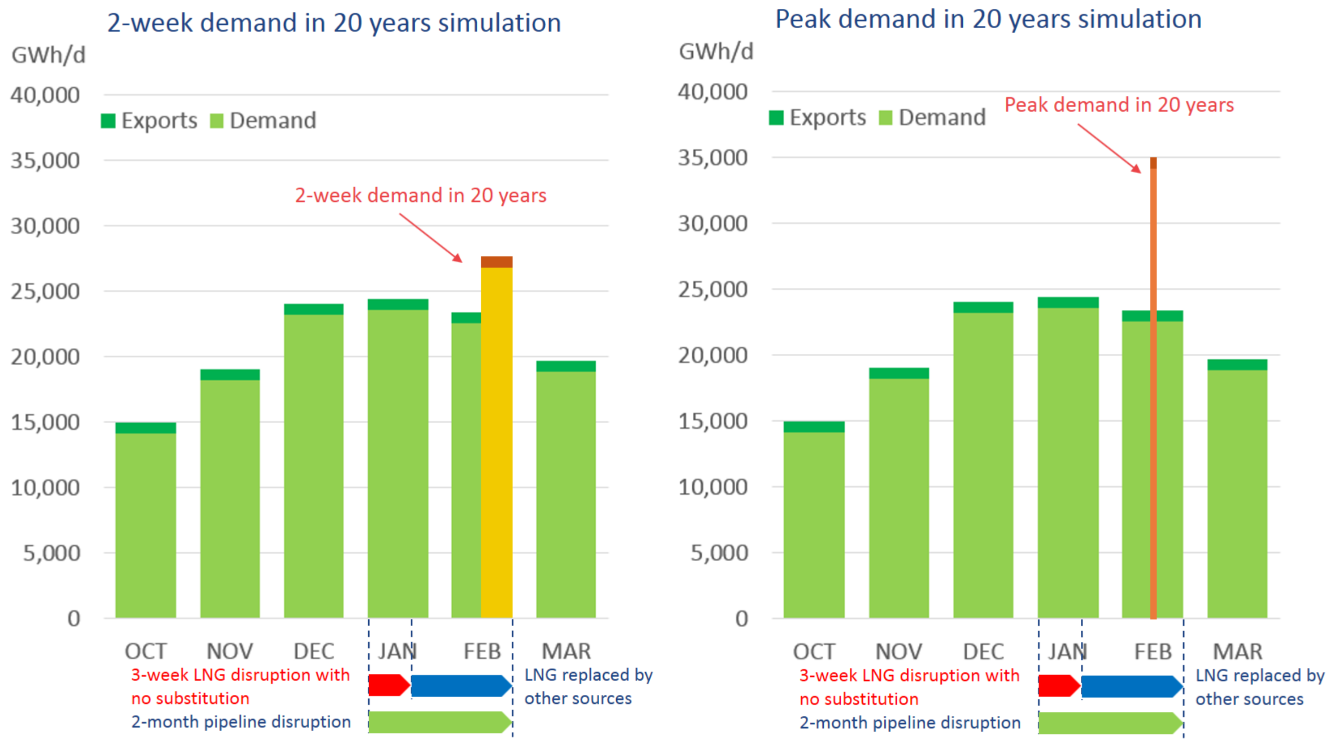


Figure 6: Demand assumption and disruption timeframes for scenario 16

3.4. Supply

Figure 7 shows historical supply since winter 2009/10 for pipeline and LNG imports.

The maximum supply potentials of the different sources providing gas to EU via pipeline (Algeria, Libya, Norway, Russia) are based on a 5 years history.

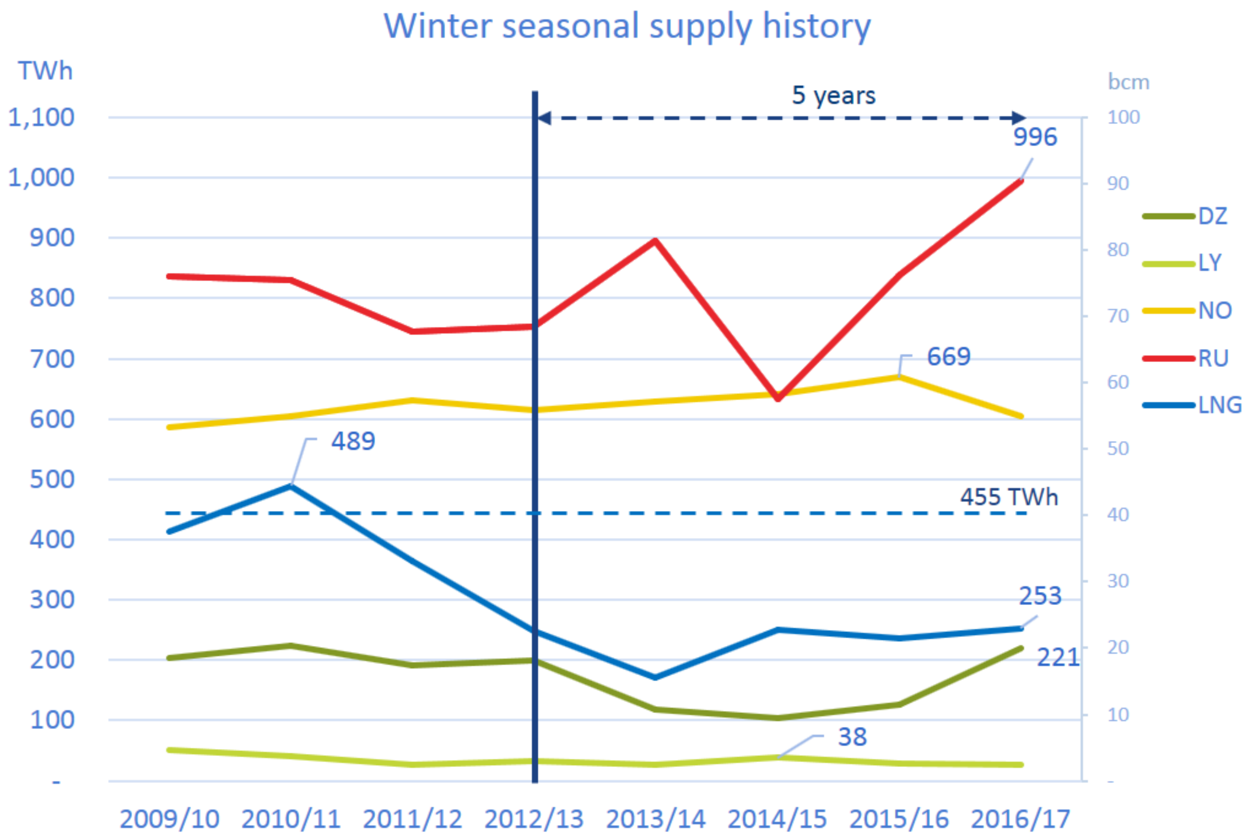


Figure 7: Winter supply limitation

Supply limitations are set for different time scales (winter season, monthly and daily) so that the maximum flow of each source cannot exceed reasonable levels based on historical observations.

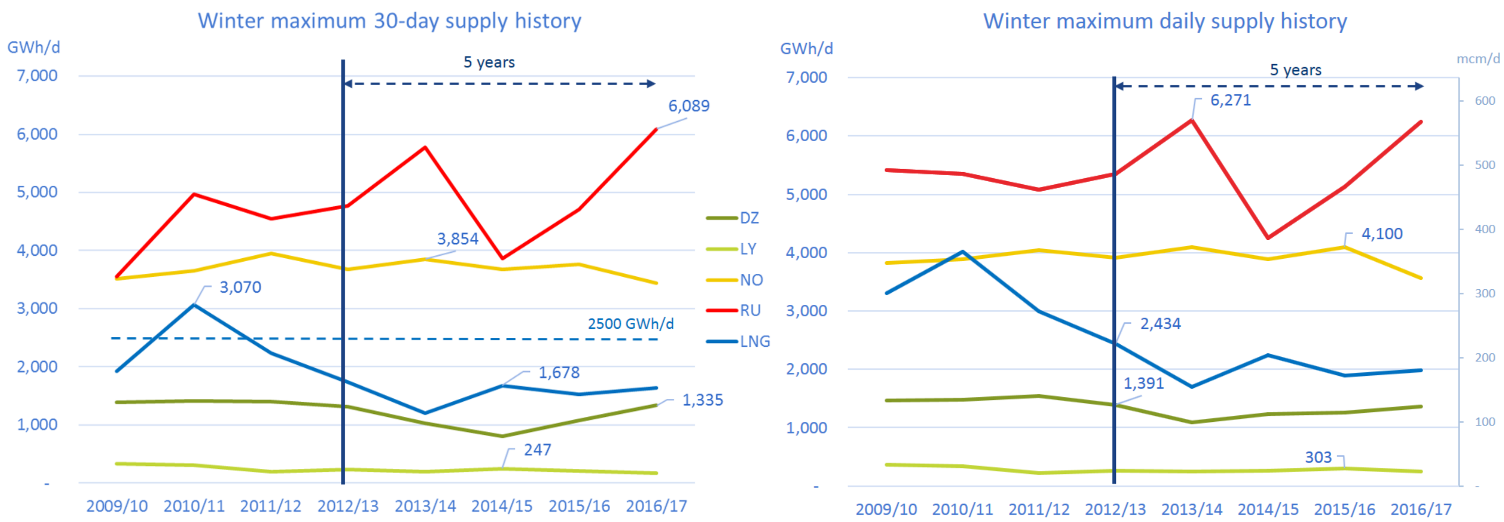


Figure 8: 30-day and daily supply limitation

Example with Norwegian imports:
Over the whole simulated winter, gas imports from Norway do not exceed 669 TWh and for each month, the average import flows do not exceed 3,854 GWh/d.
However, during some days, import flows go up to the daily limit – 4,100 GWh/d –the monthly average flow remaining below the 3,854 GWh/d, and the winter average flows remain below 3,675 GWh/d.

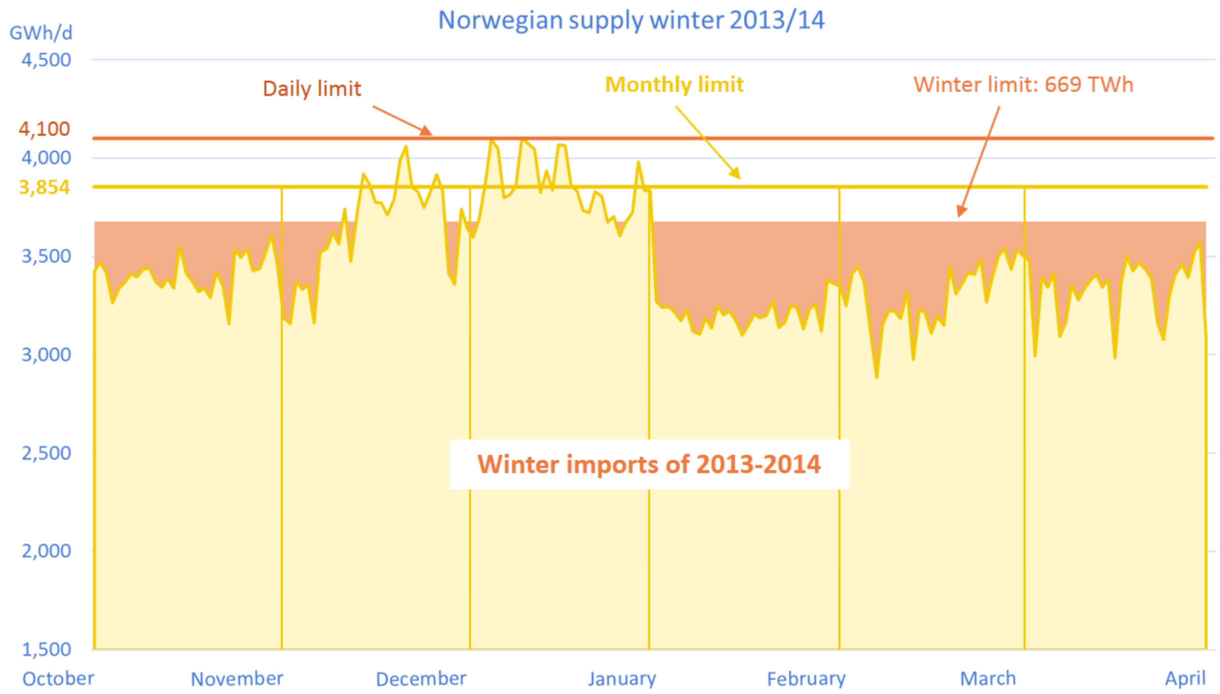


Figure 9: Winter supply history and modelling assumptions

LNG specificity:
Import flows and storage use are driven by the demand: the higher the demand the higher the import flows and the storage withdrawal. However, supply flexibilities are based on historical flows that were observed over the last 5 years (from winter 2012/2013) and highest demand was observed prior to this period. For this reason, the LNG supply records over the last 5 years do not reflect this supply/demand interaction appropriately.
Therefore, to ensure a sufficient level of supply for meeting the high winter demand, the LNG supply limitation for the simulations is set at 2,500 GWh/d to match the historical European flows driven by the highest demand of winter 2009/10 and 2010/11 for those countries with high LNG imports. It should be noted that the monthly limitation of 2,500 GWh/d matches the winter limitation of 455 TWh.

During the Peak Day, the LNG supply is allowed to go up to the total send-out capacities of the terminals (6,082 GWh/d).

LNG flows during the first week of the 2-Week simulations (15 to 21 February):
For the first week of the 2-Week simulation, the model considers the LNG flows resulting from the whole winter simulation.

Algerian LNG specificity in scenario 16:
For scenario #16 (disruption of all Algerian imports), the model considers that the flows to the different LNG terminals are reduced by the share of Algerian LNG in their LNG mix in 2016.

Share of Algeria in LNG supply mix			
Belgium	0%	Netherlands	0%
Finland	0%	Poland	0%
France	67%	Portugal	12%
Greece	100%	Spain	21%
Italy	3%	Sweden	0%
Lithuania	0%	UK	2%

Table 3: Share of Algerian LNG in the LNG mix per country in 2016 – Source GIIGNL

<u>EU Production:</u>
The EU production levels are based on best forecast for the winter 2017-18.

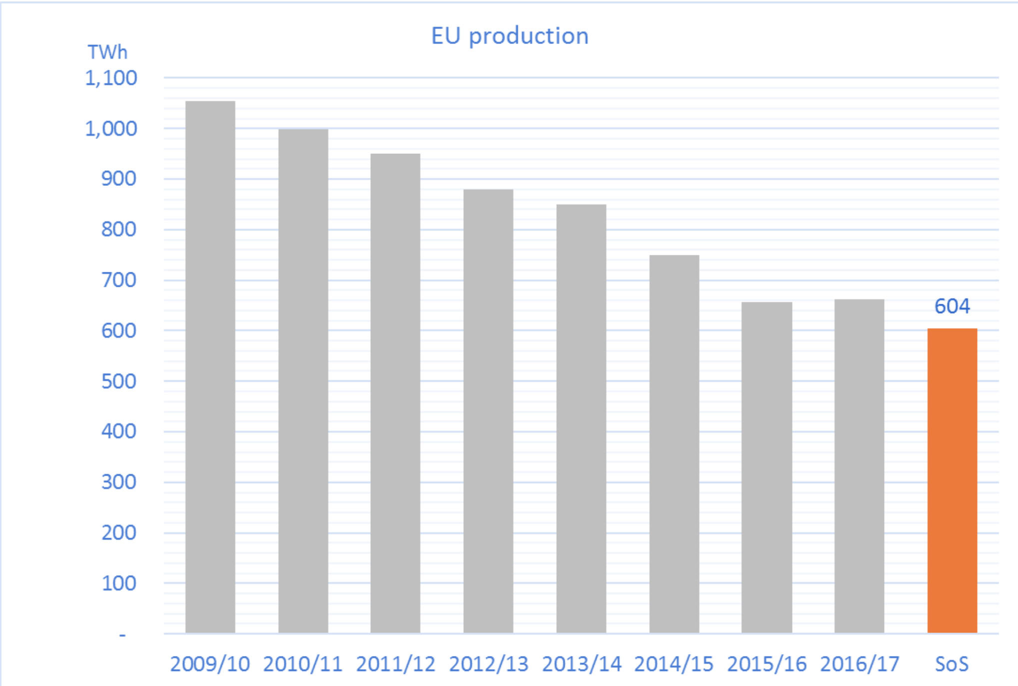


Figure 10: EU production history and SoS assumption

The EU Production level considered in the simulations is 40% below the EU Production that was observed during the high demand winter of 2009/10.

Danish production:
According to the Danish Energy Agency the production at the Tyra gas field is expected to be shut completely down from December 2019 and to come on stream again from March 2022. It is a complicated project so there might be some uncertainty about the final timetable including the resumption of the full production at the Tyra gas field. More information about the project and when the production will shut down is expected at the end of 2017.

The Danish gas fields are scattered around to main areas where two pipelines are evacuating the gas production from the North Sea to Denmark (Tyra-Nybro and Syd Arne-Nybro). Gas can also be transported between the two areas in the North Sea. Furthermore, there is a pipeline connection to the NOGAT pipeline on the continental shelf of the Netherlands which brings gas on shore to the Netherlands.

The Tyra gas field is the largest producing Danish gas field and the main supplies to Denmark come from Tyra. At the same time gas from the surrounding gas fields cannot be evacuated to Denmark during the renovation period. This gas will be exported to the Netherlands. During the renovation of Tyra no gas will be evacuated through the Tyra-Nybro pipeline. During the renovation of Tyra there will be very limited supplies to Denmark from the North Sea from the Syd Arne-Nybro pipeline.

Therefore, the following supplies from the Danish North Sea are expected:

Expected Sale gas BCM Nm^3 from the Danish North Sea

	DK or NL[1]	DK	NL
2017	3.80		
2018	3.53		
2019 (January-November)	2.71		
2019 (December)		0.02	0.08
2020		0.24	0.80
2021		0.20	0.70
2022 (January-February)		0.08	0.03
2022 (March-December)		2.28	

Table 4: Danish production (source ENS)

In the simulations, this production was represented by 6.6 GWh/d for Denmark plus 23 GWh/d for the Netherlands. Consequently, the amount of production for Denmark in these simulations is only around 5% of the one used for ENTSOG's Winter Supply Outlook 2016/17.

Dutch production:
The maximum allowed production level of the Groningen field (starting gas year 2018) will be 21.6 bcm (with allowance for 5.4 bcm of additional production in a cold year if necessary).

Underground Gas Storages:
In winter, the supply flexibility in the European gas system is largely ensured by the gas storages, they are essential assets to cope with the high demand variation during the winter season.
The capability of the gas system to cope with the winter demand variation depends on storage filling levels at the beginning of the winter, and is reported every year by ENTSOG in its Winter Supply Outlook.
For this Security of Supply simulation, storage filling levels are considered at the lowest level in the last 5 years history: 82.0% on 1 October. For further information, see Annex IV.

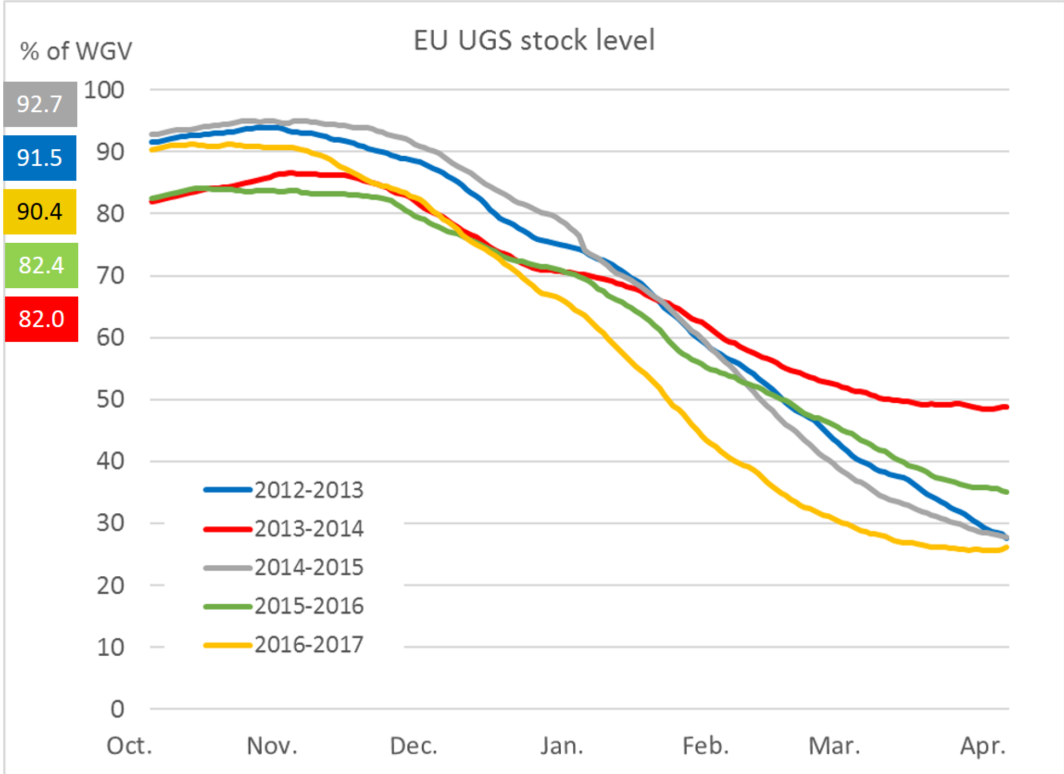


Figure 11: EU production history and SoS assumption (Source: AGSI+)

ENTSOG models the variation of the withdrawal capacities with the filling level the storages based on figures provided by the Storage Systems Operators via GSE (available in Annex IV).

Storage levels at the beginning of the 2-Week and Peak Day simulations (15 February):
The model considers the storage levels resulting from the whole winter simulations on 15 February as an input for 2-Week and Peak Day simulations.

UK specificity
Centrica's Rough storage in the UK has announced its closure. There is the plan to withdraw the remaining gas in the storage over the next 3-5 years. When the input data for the simulations for this report were fixed details regarding the related timeline and the structure were not available. Due to these uncertainties, this potentially temporarily additional gas source was left out of the simulations.
In September 2017, the UK's Oil & Gas Authority approved Centrica Storages' application to produce 869 mcm of gas from the reservoir[4]. These volumes would not change significantly the outcomes of the simulation.

LV specificity
The simulation considers the latest development regarding the low filling level of Latvian storage in 2017.

NL specificity
The simulation considers the reduction of the Working Gas Volume of the Norg storage that has been decided during summer 2017.

[4] Link to Platts article : https://www.platts.com/latest-news/natural-gas/london/withdrawal-works-at-uks-rough-gas-storage-extended-21115344

LNG terminals tank flexibility:

LNG stocked in the tanks fluctuates within a normal operating range of LNG in the tanks following normal operation. Besides, there is a minimum amount of LNG that must be kept in the tanks for a safe operation. However, in case of high demand events such as cold spells or peak demand days, this minimum amount can be lowered and part of the tanks are therefore used as a buffer volume, waiting for more LNG carriers to unload.

ENTSOG models this tank flexibility based on figures provided by the LSOs via GLE (available in Annex V).

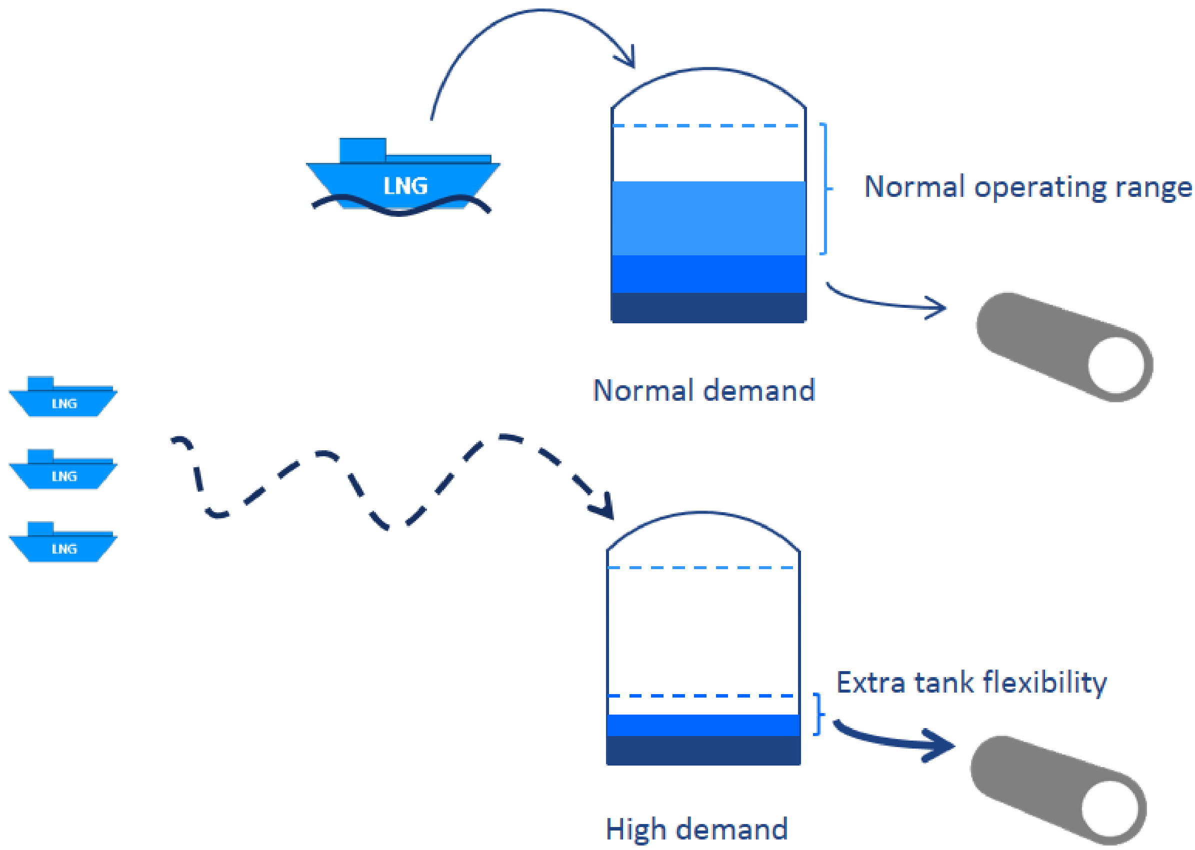
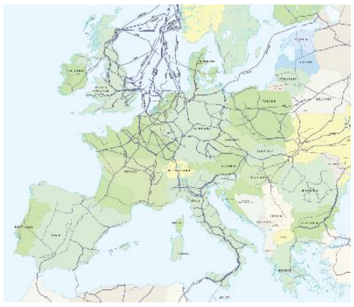


Illustration 1: LNG tank flexibility

3.5. Infrastructure

The simulations consider the existing European gas infrastructure as of 1 October 2017[5].



ENTSOG modelling tool (NeMo) builds on TSO expertise and hydraulic modelling of national infrastructure to model the European infrastructure with the most relevant accuracy. This enables the national assessment of relevant risks affecting the security of gas supply to benefit from the Union wide simulation of supply and infrastructure disruption scenarios and further extend the local assessment with a higher granularity. Capacities used in the simulation can be found in annex I.

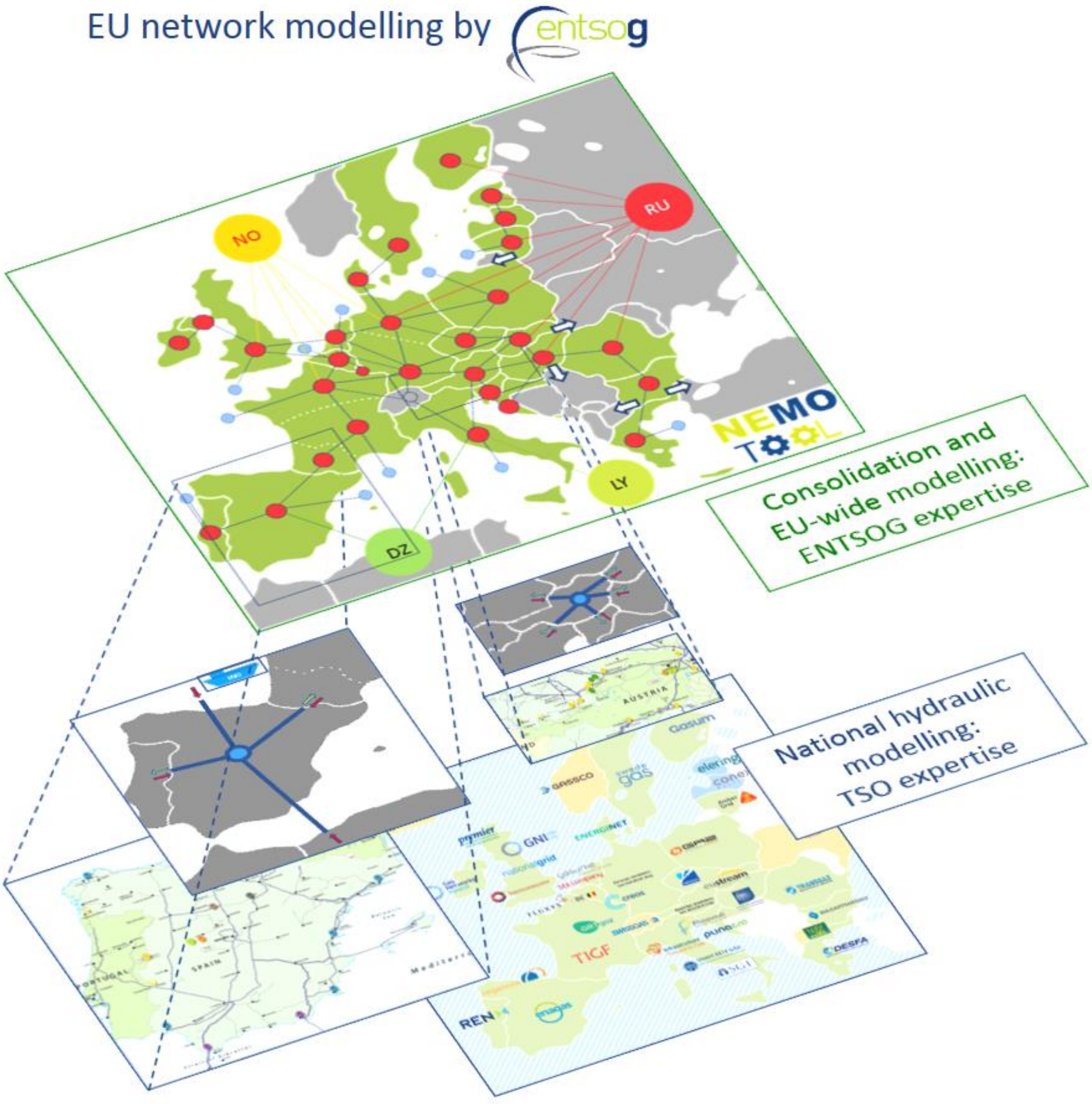


Illustration 2: NeMo tool simplistic overview

[5]On 27 September 2017, Fluxys announced capacity restrictions on TENP pipeline until 31 March 2019. This recent information, at the time of writing this report, is not considered in the Union-wide SoS simulation.

3.6. Modelling results interpretation

The simulations identify situations where a country can receive help from its neighbouring countries in order to avoid demand curtailment, and the infrastructure limitations. An infrastructure limitation can be observed when the technical capacities on the direct and indirect routes between countries are completely used so that no further flows to the country with the higher risk for demand curtailment are possible.

Demand-side response and demand-side measures are not simulated so that the results can be interpreted and compared to the reference scenario without pre-empting any reaction or possible solution to the identified situations.

Storage use:

Simulations of the whole winter assesses the capability and the flexibility of the gas system to cope with a high demand winter. Therefore, the model prepares for this high demand level by injecting in the UGS as long as the import flows allow for it.

High demand cases (2-Week and Peak Day) consider the storage levels at the start of the events resulting from the whole winter simulation.

Demand curtailment allocation

Whenever a simulation result indicates possible demand curtailment, the actual allocation of this curtailed demand between the countries depends on several factors amongst which the cooperation of member states and contractual arrangements are most relevant. In some instances, infrastructure limitations can limit the cooperation possibility. Consequently, in order not to pre-empt on any possibility, the assessment presents two different allocations for non-infrastructure related curtailment that are not meant to reflect demand segmentation or protected demand:

- Unified allocation: All member States within the risk group cooperate by avoiding a demand curtailment to the extent possible by transporting other supply – including LNG from tanks and ships, pipeline supply, indigenous production and storage withdrawal – and furthermore by sharing the curtailment equally in such a way that they try to reach the same curtailment rate.
- Distance-based allocation: All member States within the risk group cooperate by avoiding a demand curtailment to the extent possible by transporting other supply – including LNG from tanks and ships, pipeline supply, indigenous production and storage withdrawal – and leave the demand curtailment occurring in the countries that are close to where the supply and infrastructure disruption occurs.

The allocation of the demand curtailment within the member states can be further investigated as part of the national and regional risk assessments.

Comparison with reference case

For the purpose of giving more insight to the flows during the disruptions scenarios, a reference case without disruption has been defined (scenario 0).

The comparison of the scenarios results with the reference case is described in the results analysis and gives more information on the reaction to the disruption scenarios. Such reaction can either be a market reaction or an active steering of the market participants that could derive from applying appropriate measures within the regulatory framework. Changes in the flows are one possible reaction and other reactions could be further investigated in the preventive action plans.

Units

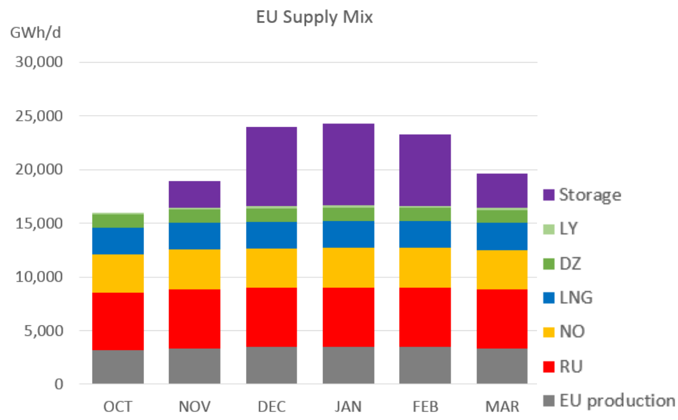
All the data used in the simulation are expressed in energy (TWh or GWh). For better readability of the results analysis, ENTSOG present the results in both energy and volumes.
ENTSOG derives volumes from energy by applying a single conversion factor of 11 kWh/m^3.

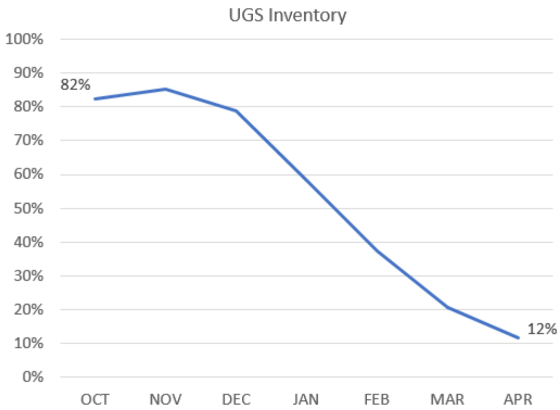
4. Results analysis

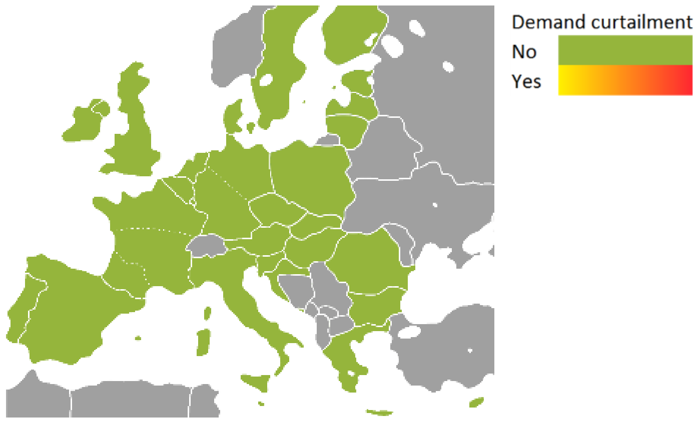
Reference Scenario	Reference case	
Risk group:	Not applicable	
Scenario duration:	No disruption	

Simulation results

Whole winter







Supply

Storages: filling level ends around 13% on 31 March at EU level. In general, gas is still injected in the storages in October and withdrawal is observed in all countries from November to March. The behaviour between the countries varies following the different demand evolution with the UK and Sweden showing a high withdrawal rate already in January and other countries like Austria, Bulgaria, Czech Republic, Denmark, NCG/Germany, Italy, the Netherlands and Romania that show still fill levels above 35% for the beginning of February.

Pipeline and LNG supplies: Supplies can be imported up to the maximum defined supply potentials. **This implies that there is no import flexibility left is case of a disruption event**.

DZ	LNG	LY	NO	RU	EU production
1,214 GWh/d	2,500 GWh/d	208 GWh/d	3,677 GWh/d	5,473 GWh/d	3,388 GWh/d
110 mcm/d	227 mcm/d	19 mcm/d	334 mcm/d	498 mcm/d	308 mcm/d

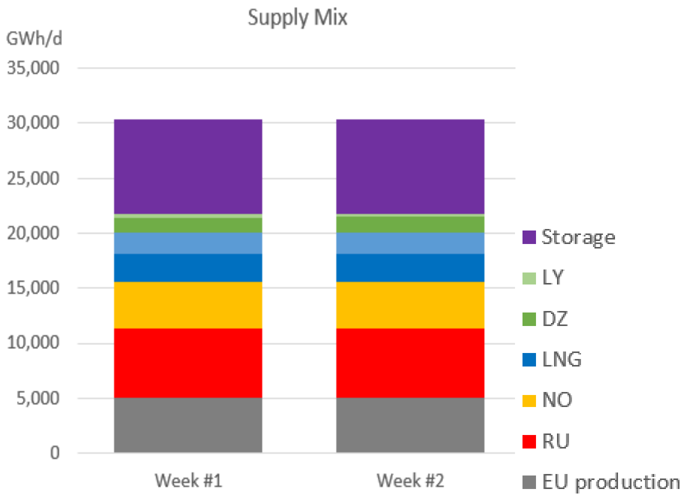
Demand

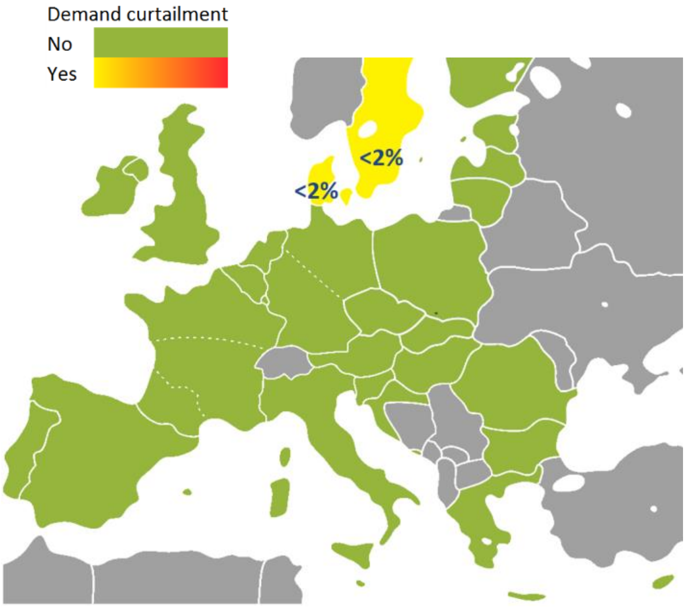
No country is exposed to demand curtailment.

Exports to Ukraine (UA) and transits to Turkey and Kaliningrad can be maintained.

Reference Scenario Reference case

2-week / 20 years – simulated from 15 to 28 February





Supply

Storages: used at their maximum withdrawal capacities in AT, BG, ES, HR, DK, RO, SK. In other countries, still additional usage possible.

Pipeline and LNG supplies: used at their maximum potential.

DZ	LNG	LY	NO	RU	EU production
1,391 GWh/d	2,500 GWh/d	303 GWh/d	4,100 GWh/d	6,238 GWh/d	5, 062 GWh/d
126 mcm/d	227 mcm/d	28 mcm/d	373 mcm/d	567 mcm/d	460 mcm/d

LNG tanks: In total LNG tanks can provide up to 28.3 TWh of flexibility that can be used within the limits of the capacities from the individual LNG terminals (around 6 TWh/d).

Demand

Infrastructure limitations: DK and SE are exposed to less than 2% demand curtailment.

Reduced production for DK, storage withdrawal low due to low fill level (33%) and capacity from DE fully used (100 GWh/d from DEg).

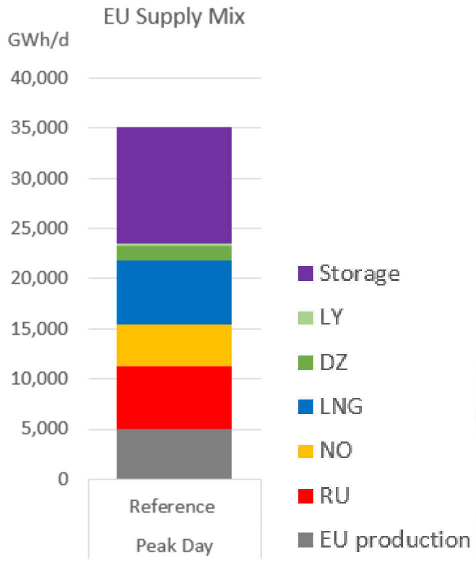
Context: The simulation results in the reference case show that Denmark and Sweden will experience demand curtailment even in the 2-week case and design case. This result is based on the supply situation with no supply from off-shore production Tyra and the current firm entry capacity from Germany (Ellund). The supply capacity is compared with the 2017/2018 prognoses for the consumption in Denmark.
It must be noticed on the supply side that OGE offers additional extra firm exit capacity at Ellund towards Denmark from January 2019 and that the Danish biogas production on the gas-grid is not taken into account. Furthermore, the consumption in Denmark is expected to be lower in the tight period during Tyra-renovation in December 2019 to March 2022. Please note that these remarks would mitigate the tight supply situation for DK and SE, especially during the Tyra renovation.

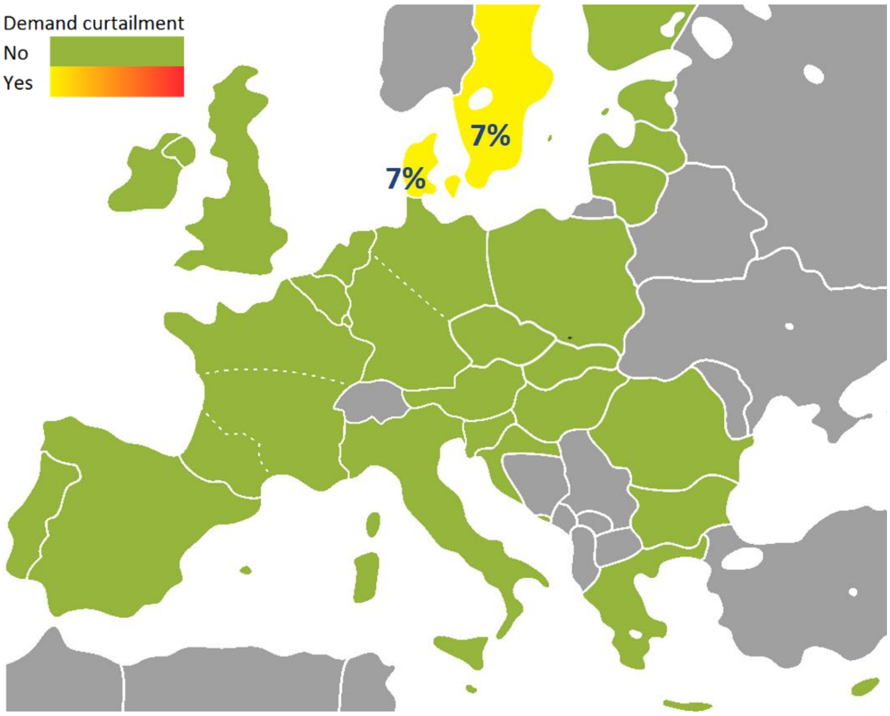
Further sensitivity analysis is ongoing to assess the situation from December 2019 on.

Exports to UA and transits to Turkey and Kaliningrad can be maintained.

Reference Scenario	Reference case

Peak day / 20 years – simulated on 15 February





Supply

<u>Storages:</u> used at their maximum withdrawal capacities in AT, BE, BG, CZ, DK, FR, HR, HU, LV, NL, RO, SE.

<u>Pipeline and LNG supplies:</u>

The pipeline and LNG supplies are completely used up to the defined volumes:

DZ	LNG	LY	NO	RU	EU production
1,391 GWh/d	6,082 GWh/d	303 GWh/d	4,100 GWh/d	6,238 GWh/d	5,062 GWh/d
126 mcm/d	553 mcm/d	28 mcm/d	373 mcm/d	567 mcm/d	460 mcm/d

Demand

<u>Infrastructure limitations:</u> DK and SE are exposed to 7% demand curtailment.

Reduced production for DK, storage withdrawal low due to low fill level (33%) and capacity from DE fully used (100 GWh/d from DEg)

Context: The simulation results in the reference case show that Denmark and Sweden will experience demand curtailment even in the 2-week case and design case. This result is based on the supply situation with no supply from off-shore production Tyra and the current firm entry capacity from Germany (Ellund). The supply capacity is compared with the 2017/2018 prognoses for the consumption in Denmark.
It must be noticed on the supply side that OGE offers additional extra firm exit capacity at Ellund towards Denmark from January 2019 and that the Danish biogas production on the gas-grid is not taken into account. Furthermore, the consumption in Denmark is expected to be lower in the tight period during Tyra-renovation in December 2019 to March 2022. Please note that these remarks would mitigate the tight supply situation for DK and SE, especially during the Tyra renovation.

Further sensitivity analysis is ongoing to assess the situation from December 2019 on.

Exports to UA and transits to Turkey and Kaliningrad can be maintained.

Scenario #1 - Disruption of all imports to EU via Ukraine

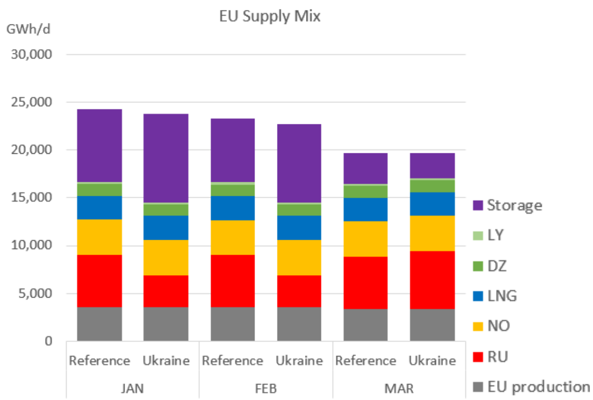
Risk group: Eastern gas supply – Ukraine

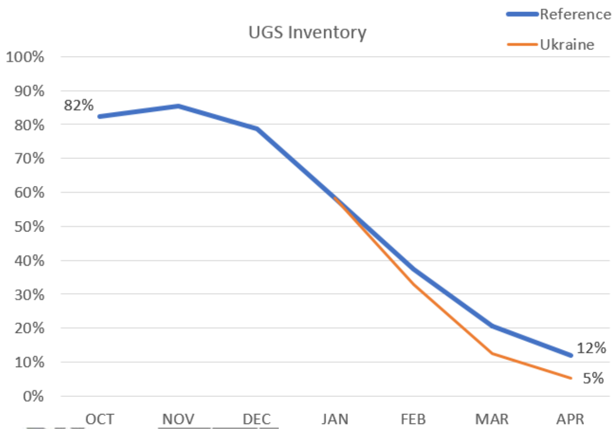
Austria, Bulgaria, Croatia, Czech Republic, Germany, Greece, Hungary, Italy, Luxembourg, Poland, Romania, Slovenia, Slovakia

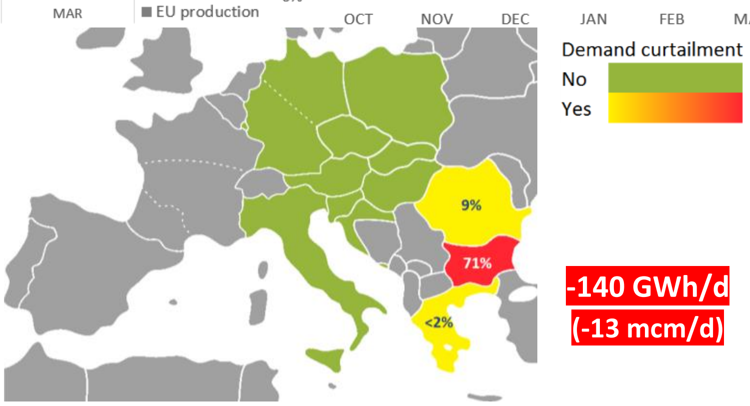
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Storages: Higher use of storages in January and February (around +100 TWh).

Pipeline and LNG supplies: The flows of Russian gas are increased via Belarus and Nord Stream. These two transit routes are used up to the technical maximum. The overall flows of Russian gas are reduced to around 3,400 GWh/d (~60% of Reference case) which is limited by the capacities of the transit via Belarus and the Nord Stream (both routes are used to the technical maximum) and the imports to the Baltic States and Finland (flows are following the requirement from the gas demand). The imports from other sources cannot be increased as already used to their maximum due to the demand situation.

Demand

EU: demand curtailment for BG and RO due to infrastructure limitations.

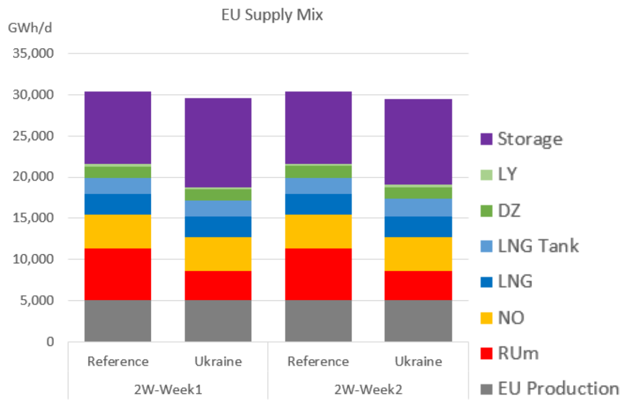
Infrastructure limitations:

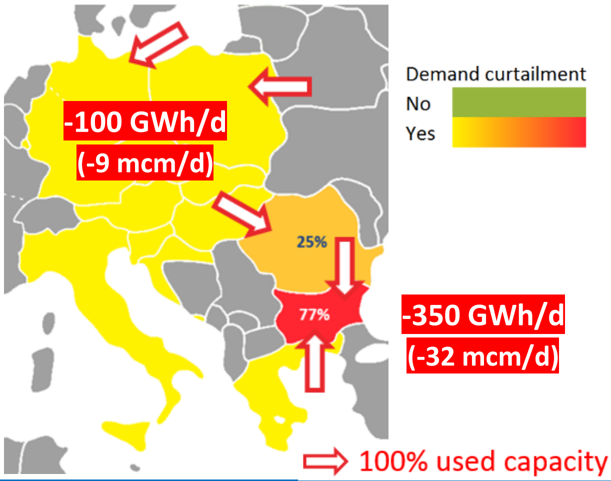
Exposition to demand curtailment in BG (71%), RO (9% in February only) and GR (2% in February only) due to infrastructure limitations: capacities towards BG are fully used in January and February, and capacities from HU to RO fully used in February.

No neighbouring country can help mitigating the situation as the curtailment is infrastructure related.

Scenario #1 - Disruption of all imports to EU via Ukraine

2-week / 20 years – simulated from 15 to 28 February





Supply

Storages: used at their maximum withdrawal capacities.

Pipeline and LNG supplies: The overall flows of Russian gas are reduced to around 3,600 GWh/d (~60% of Reference case) which is limited by the capacities of the transit via Belarus and the Nord Stream (both routes are used to the technical maximum) and the imports to the Baltic States and Finland (flows are following the requirement from the gas demand).

LNG tanks: necessary to provide extra LNG capacity during both weeks.

Demand

Infrastructure limitations:

Capacities towards BG, from HU to RO, from SI to HR (2nd week) and AT to HU (2nd week) are fully used.

EU-wide:

For each day of the 2 weeks EU is missing 450 GWh/d, among which:

- 350 GWh/d cannot be mitigated because of infrastructure limitations.
- 100 GWh/d can be allocated to helping countries representing less than 1% of their demand.

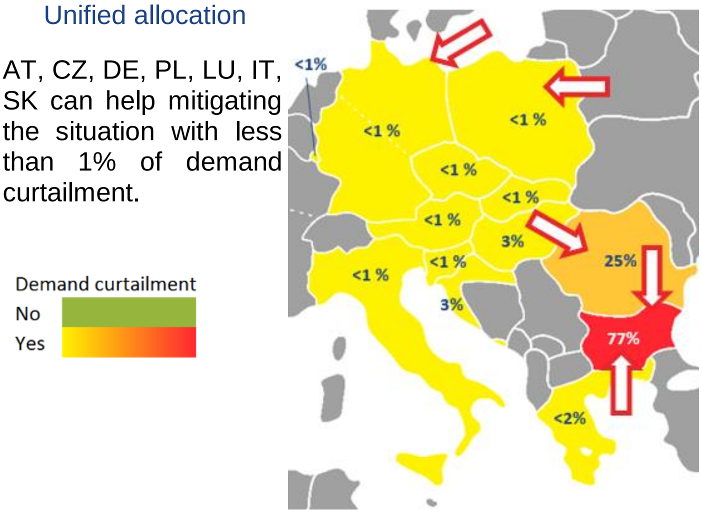
Within the risk group:

Risk group demand	Demand curtailment week 1	Demand curtailment week 2
13,300 GWh/d	350 GWh/d	450 GWh/d

Possible curtailment allocation for the 2nd week:

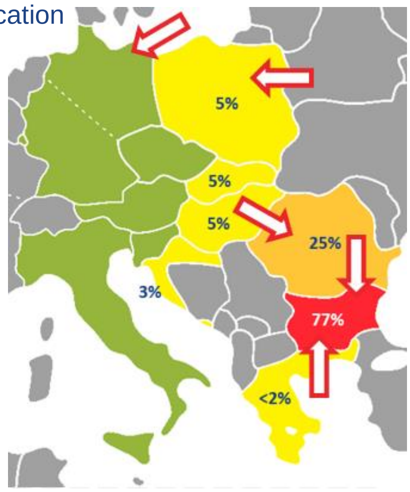
Unified allocation

AT, CZ, DE, PL, LU, IT, SK can help mitigating the situation with less than 1% of demand curtailment.



Distance-based allocation

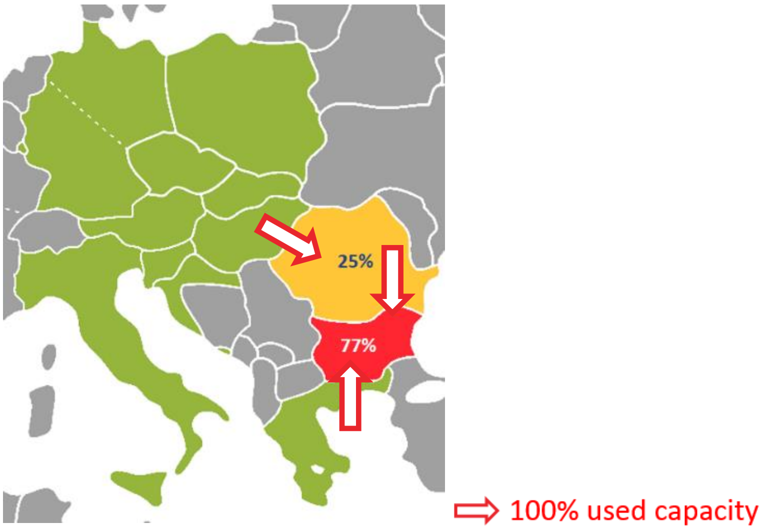
PL, SK and HU could face demand curtailment around 5%.



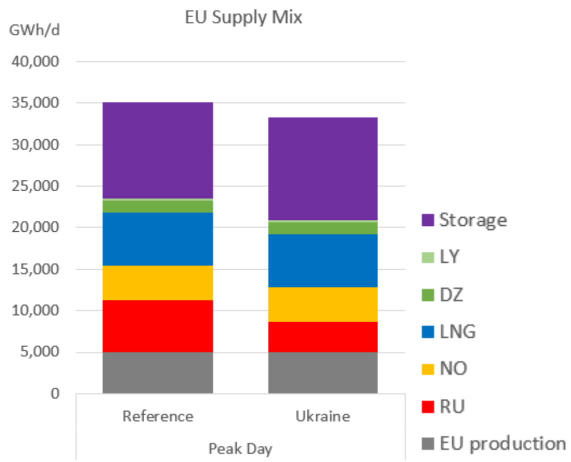
Scenario #1 - Disruption of all imports to EU via Ukraine

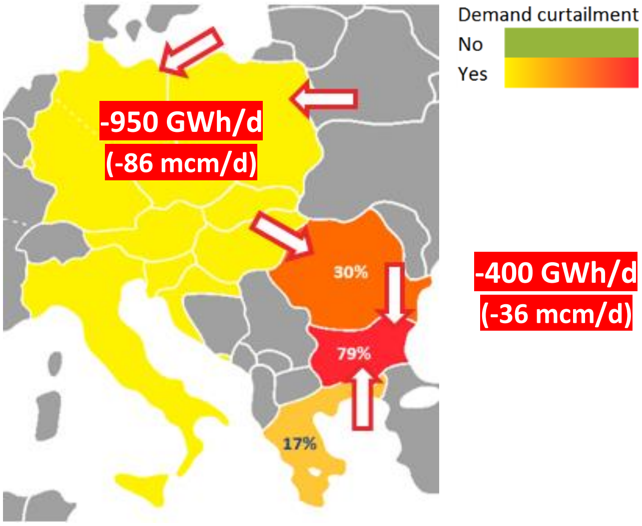
Situation considering restriction in exports to UA

In case of exports to UA restricted from their reference value of 416 GWh/d (38 mcm/d) down to 300 GWh/d (27 mcm/d) and below, countries of the risk group are not exposed to demand curtailment except BG and RO that cannot be helped further because of infrastructure limitations.



Peak day / 20 years – simulated on 15 February





Supply

Storages: used at their maximum withdrawal capacities in AT, BE (H), BG, CZ, DE, DK, ES, FR, HR, HU, IT, LV, NL, PL, RO, SE, SK, UK.

Pipeline and LNG supplies: The overall flows of Russian gas are reduced to around 3,600 GWh/d (~60% of Reference case) which is limited by the capacities of the transit via Belarus and the Nord Stream (both routes are used to the technical maximum) and the imports to the Baltic States and Finland (flows are following the requirement from the gas demand).

Scenario #1 - Disruption of all imports to EU via Ukraine

Demand

Infrastructure limitations: BG, GR, RO face infrastructure limitations for the Peak day. Capacities towards BG and from HU to RO are fully used.

EU-wide: EU is missing 1,350 GWh/d among which:

- 400 GWh/d cannot be mitigated because of infrastructure limitations.
- 950 GWh/d can be allocated to helping countries.

Exports to UA can be maintained.

Within the risk group:

Risk group demand 14,200 GWh/d.

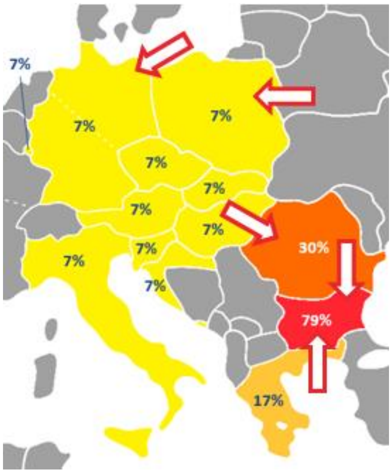
⇨ 100% used capacity

Demand curtailment: No / Yes

Possible curtailment allocation for the Peak Day:

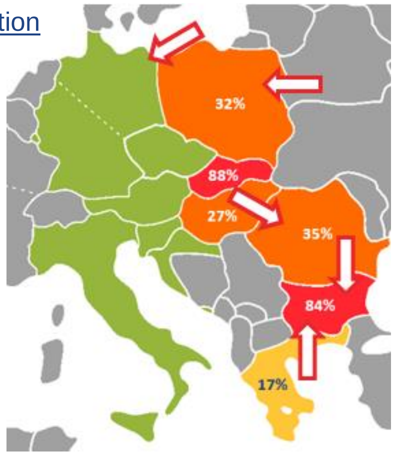
Unified allocation

All countries within the risk group can help mitigating the situation by sharing 7% of demand curtailment.



Distance-based allocation

HU and PL are exposed to higher demand curtailment. SK could face demand curtailments above 50%.

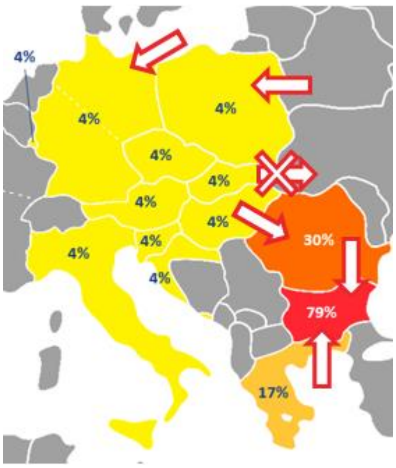


Situation considering no of exports to UA

Even in case all the exports to UA would cease, infrastructure limitations remain and BG, GR and RO are exposed to the same risk of demand curtailment. The other countries of the risk group are exposed to a demand curtailment of 335 GWh/d with no infrastructure limitation. Therefore, different demand curtailment allocations are possible:

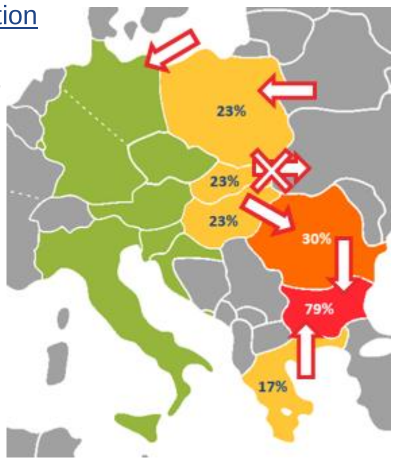
Unified allocation

All countries within the risk group can help mitigating the situation by sharing 4% of demand curtailment.



Distance-based allocation

HU, PL and SK are exposed to higher demand curtailment.



Results analysis

Ukraine supply route is significant for ensuring demand coverage under cold demand situations.

Infrastructure limitations further expose South-Eastern Europe to demand curtailment risk.

Scenario #2 - Disruption of all imports to EU via Belarus

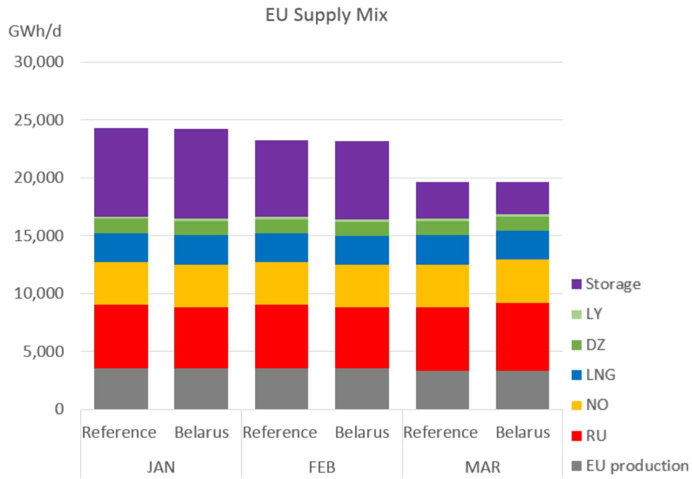
Risk group: Eastern gas supply – Belarus

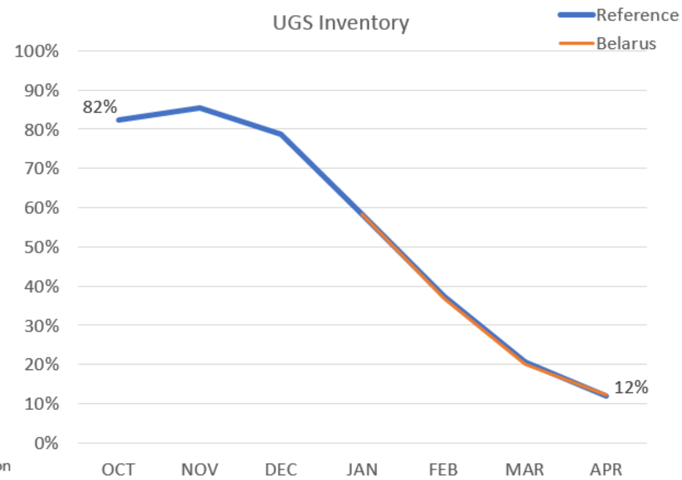
Czech Republic, Belgium, Estonia, Germany, Latvia, Lithuania, Luxembourg, Netherlands, Poland, Slovakia

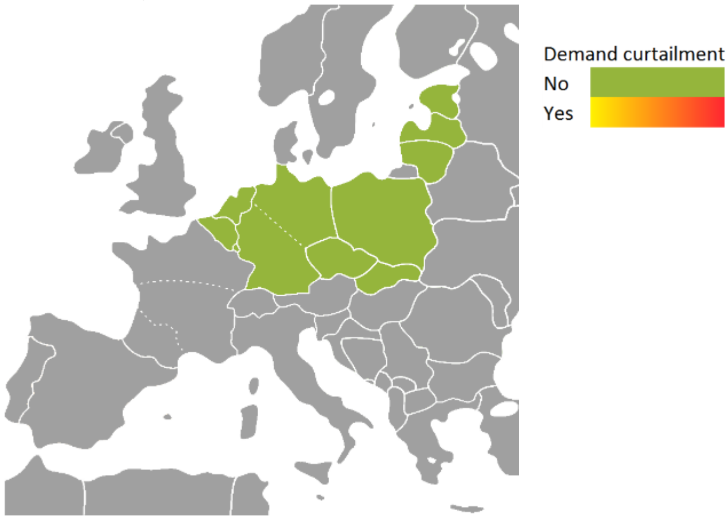
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Storages: similar usage.

Pipeline and LNG supplies: LNG flows to Poland and Lithuania. Gas is flowing from Germany to Poland via all connections, transport direction changes. A further increase of these flows would still be possible.

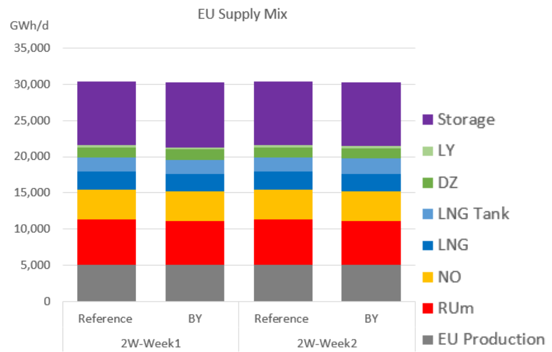
The overall flows of Russian gas stays on a similar level, transit via Ukraine and Nord Stream are increased. Nord Stream and Ukrainian transits to both Poland and Slovakia are used completely while there is still more capacity available towards Hungary and Romania.

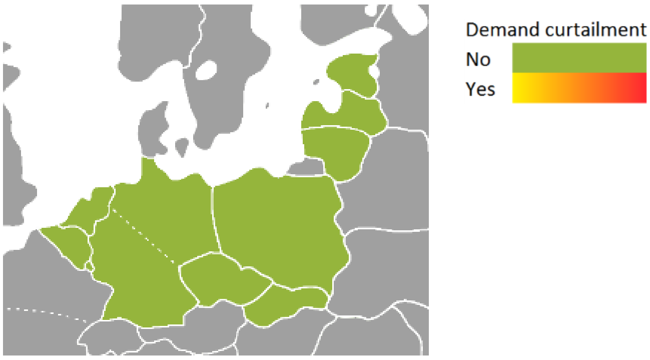
Demand

No demand curtailment.

Scenario #2 - Disruption of all imports to EU via Belarus

2-week / 20 years – simulated from 15 to 28 February





Supply

Storages: Higher storage withdrawal rate in Poland.

Pipeline and LNG supplies: Increased flows from CZ to PL up to maximum capacity. Flow from Germany to Poland completely used reverting the flow direction from the reference case.

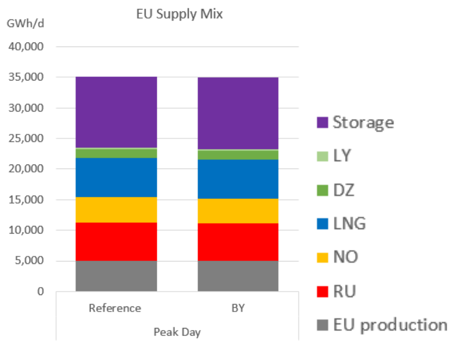
The overall flows of Russian gas are slightly reduced to around 6,000 GWh/d (~96% of Reference case), the transit via Ukraine and the Nord Stream are increased. The Nord Stream and the Ukrainian transits to Hungary, Poland, Romania and Slovakia are used completely.

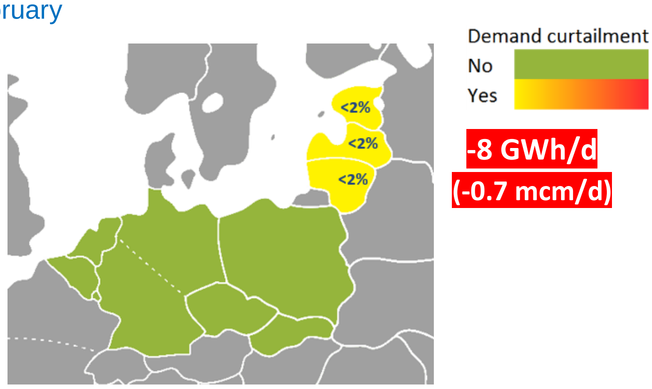
LNG tanks: Additional LNG flows from the tanks and cargos to LT and PL up to the maximum capacity.

Demand

No demand curtailment.

Peak day / 20 years – simulated on 15 February





Supply

Storages: The lower storage levels in LV allow only for a reduced withdrawal rate.

Pipeline and LNG supplies: No change for LNG. Flow from Germany to Poland completely used reverting the flow direction from the reference case.

The overall flows of Russian gas are slightly reduced to around 6,000 GWh/d (~97% of Reference case), the transit via Ukraine and the Nord Stream are increased. The Nord Stream and the Ukrainian transits to Hungary, Poland, Romania and Slovakia are used completely.

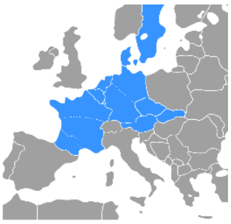
Demand

EU: 2% in the Baltic states (EE, LT, LV) demand curtailment due to infrastructure limitations (no connection to other countries).

No neighbouring country can help further mitigating the situation as the curtailment is infrastructure related.

Scenario #3 - Disruption of one offshore pipeline of Nord Stream

50% of Nord Stream capacity



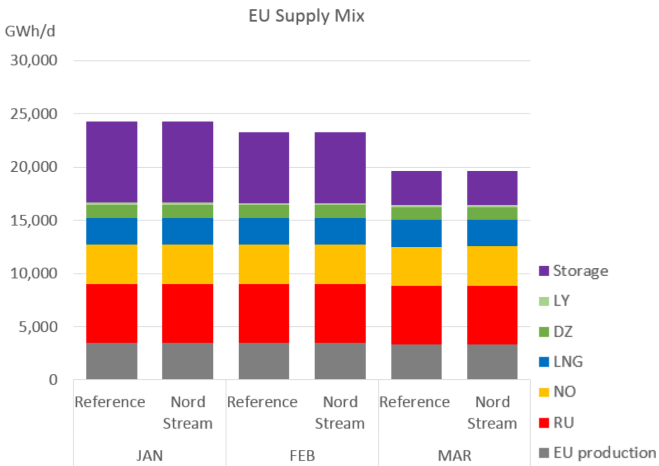
Risk group: Eastern gas supply - Baltic sea

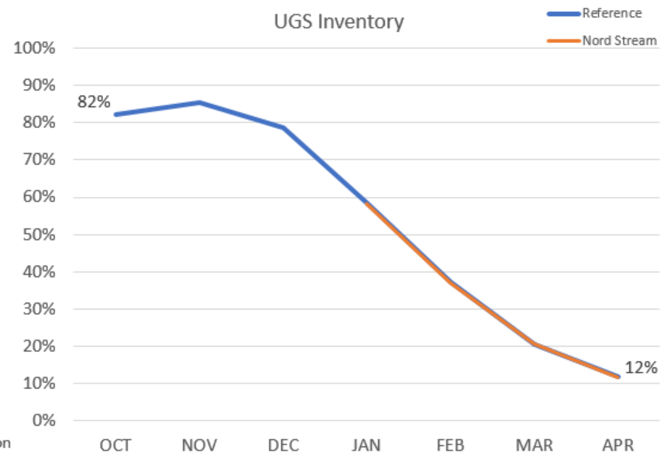
Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxembourg, Netherlands, Slovakia, Sweden

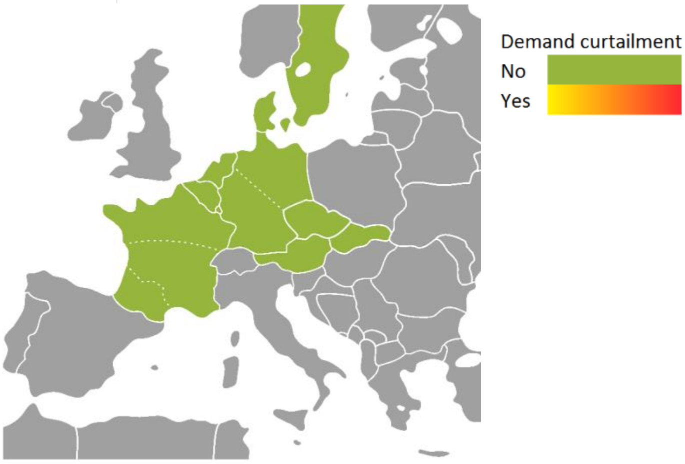
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Storages: additional withdrawal (including DK).

Pipeline and LNG supplies: Increase of Russian supply via BY and UA. The overall supply from Russia stays on a similar level.
Additional capacities to GASPOOL market area in DE are still available from BE, CZ, NL and PL.

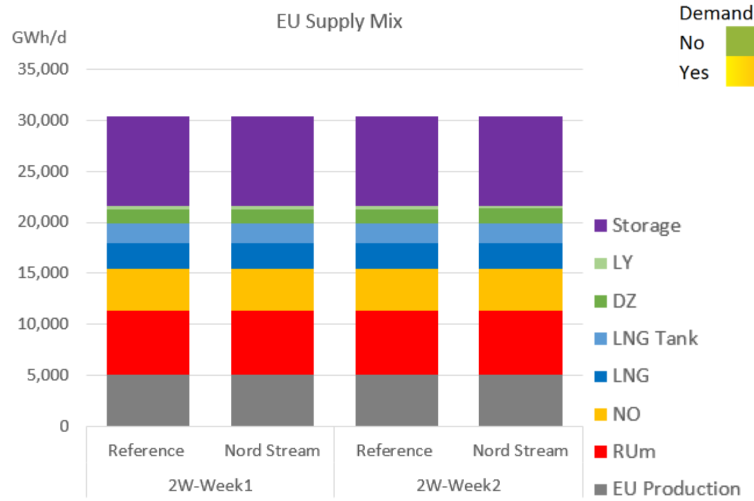
Demand

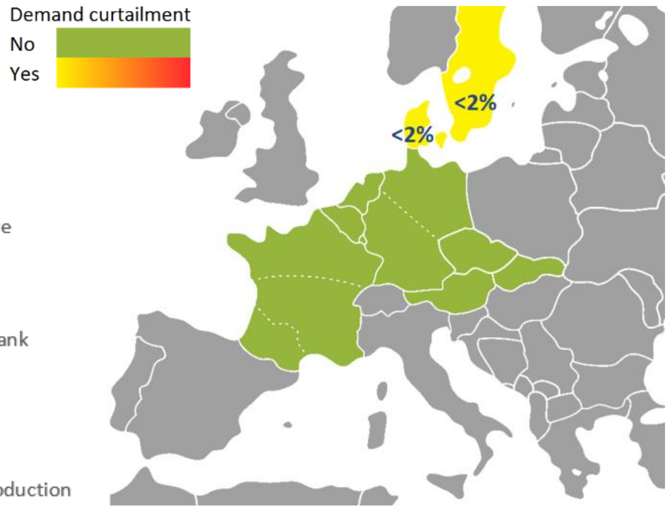
No demand curtailment.

Scenario #3 - Disruption of one offshore pipeline of Nord Stream

50% of Nord Stream capacity

2-week / 20 years – simulated from 15 to 28 February





Supply

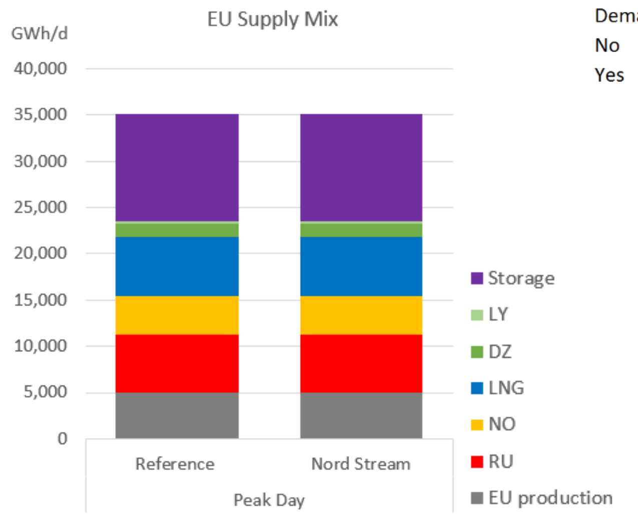
Storages: similar usage as the reference scenario.

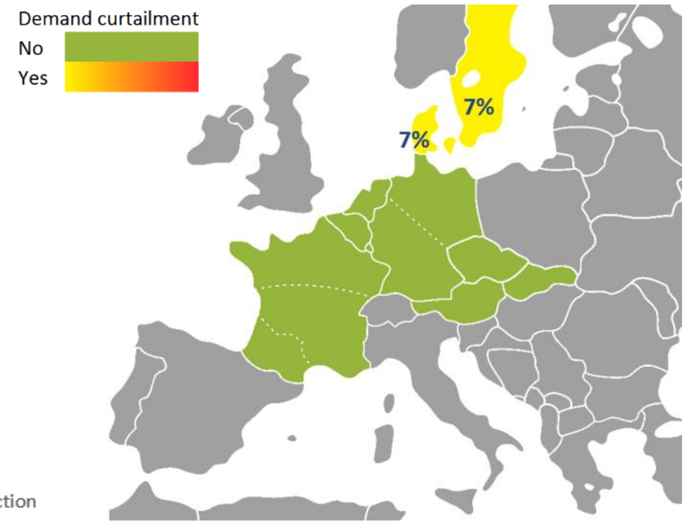
Pipeline and LNG supplies: Increase of Russian supply via BY and UA. Still more flow from CZ and PL to DE possible.

Demand

No additional demand curtailment (DK and SE are exposed to less than 2% demand curtailment in the reference case).

Peak day / 20 years – simulated on 15 February





Supply

Storages: similar usage as the reference scenario.

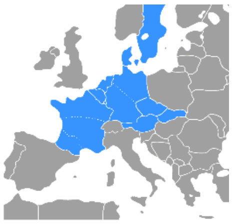
Pipeline and LNG supplies: Increase of Russian gas via BY and UA. Yamal route to Germany used to maximum. Additional capacities to GASPOOL market area in DE still available from BE, CZ and NL.

Demand

No additional demand curtailment (DK and SE are exposed to 7% demand curtailment in the reference case).

Scenario #4 - Disruption of the onshore receiving facility of Nord Stream (Greifswald station)

Risk group: Eastern gas supply – Baltic Sea

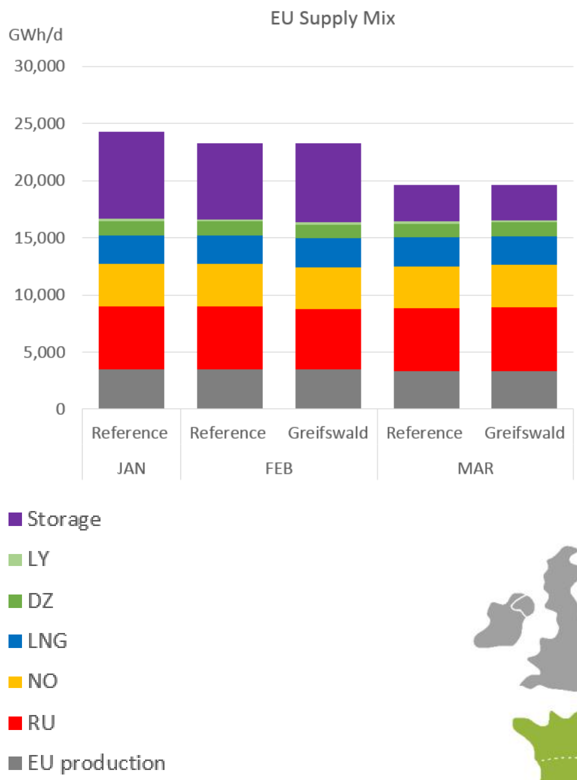


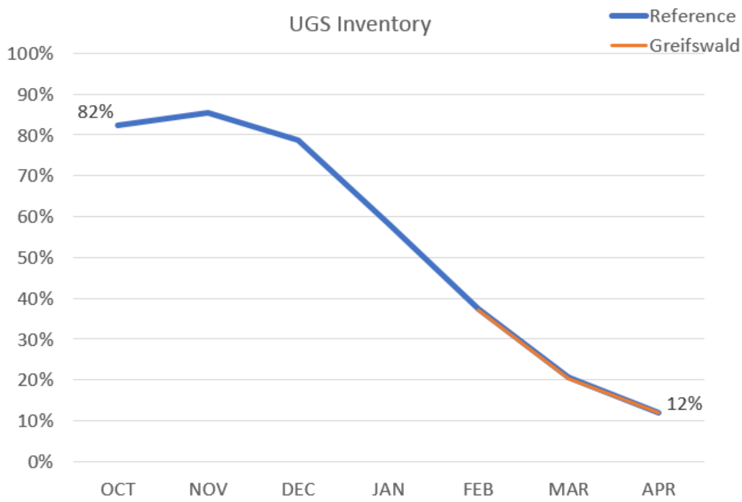
Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxembourg, Netherlands, Slovakia, Sweden

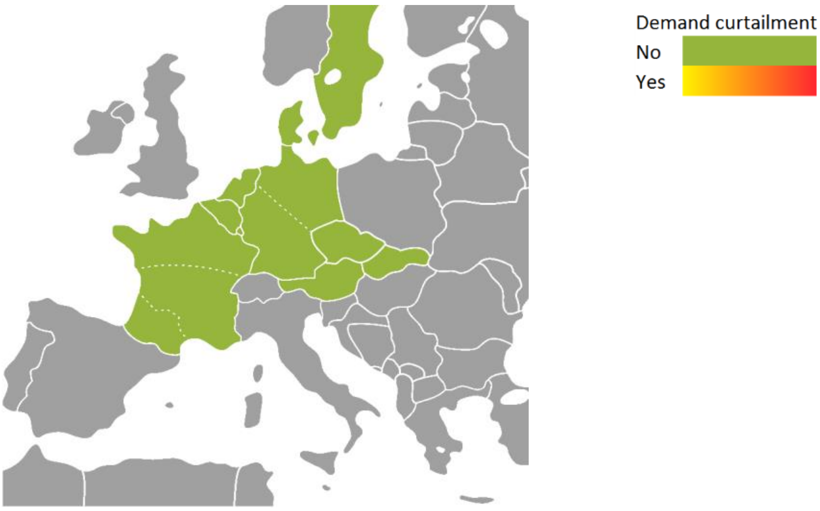
Scenario duration: 2 weeks (15 February – 28 February)

Simulation results

January - March







Supply

Pipeline and LNG supplies: During the disruption, flows from Russia are reduced compared to the reference case by around 5% but this can be compensated by higher imports later on. Increase of Russian gas via BY (maximum level towards Poland) and UA (maximum towards HU, PL, and SK).

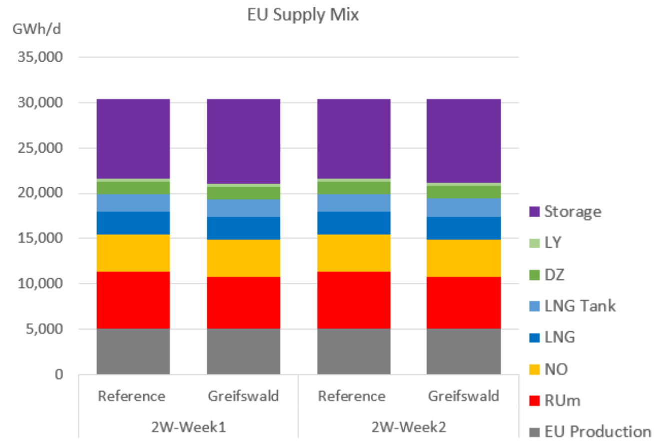
More flows to GASPOOL from Poland, no flows from CZ. Additional capacities to GASPOOL area in DE still available from BE, CZ, NL and PL.

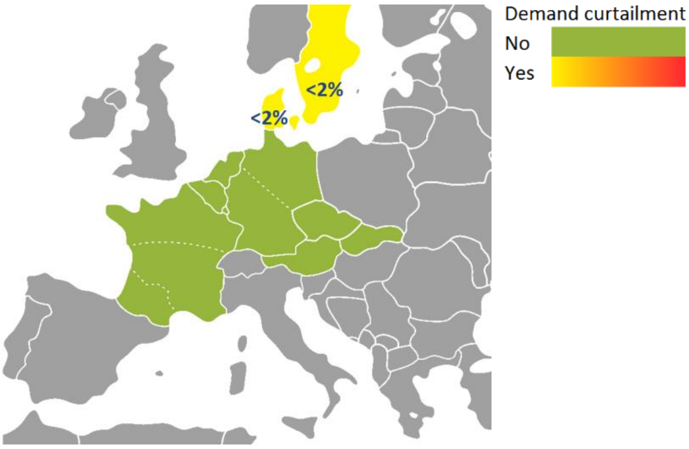
Demand

No demand curtailment.

Scenario #4 - Disruption of the onshore receiving facility of Nord Stream (Greifswald station)

2-week / 20 years – simulated from 15 to 28 February

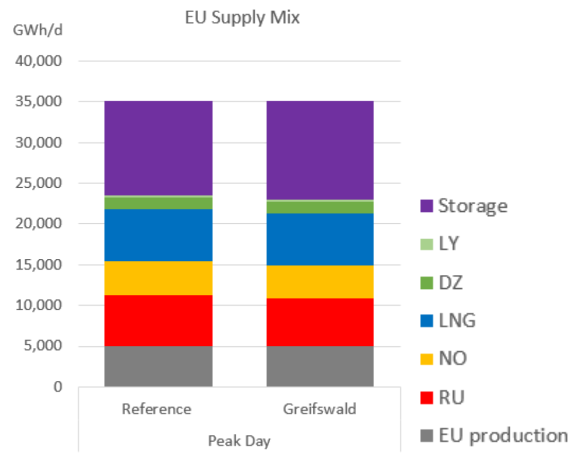


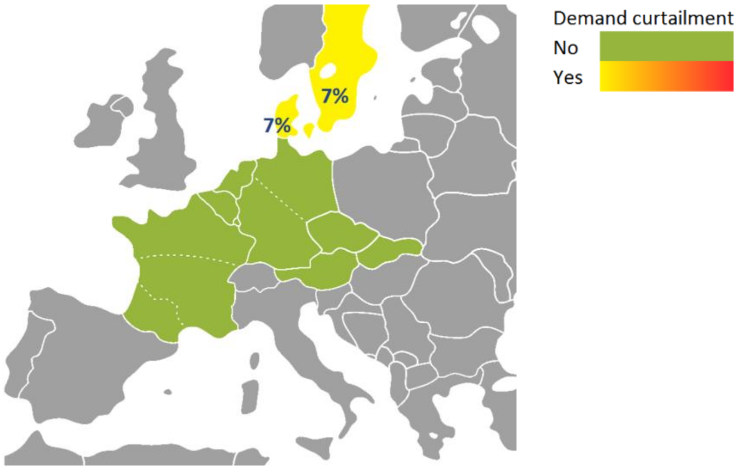


Supply
Storages: increased storage withdrawal.
Pipeline and LNG supplies: Increase of Russian supply via BY and UA. Since capacity limits are reached, the overall imports of Russian gas are reduced by 7% to around 5,800 GWh/d. This is compensated mostly by increased storage withdrawal. No more gas flows from CZ to GASPOOL but from GASPOOL to CZ partially replacing the flows through OPAL. Additional capacities to GASPOOL area in DE still available from BE, CZ, and NL.

Demand
No additional demand curtailment. (DK and SE are exposed to less than 2% demand curtailment in the reference case)

Peak day / 20 years – simulated on 15 February





Supply
Storages: Increased storage withdrawal.
Pipeline and LNG supplies: Increase of Russian gas via BY and UA. Since capacity limits are reached the overall import of Russian gas are reduced by 6% to around 5,900 GWh/d. No more gas flows from CZ to GASPOOL but from GASPOOL to CZ partially replacing the flows through OPAL. Additional capacities to GASPOOL area in DE still available from BE, CZ, and NL.

Demand
No additional demand curtailment. (DK and SE are exposed to 7% demand curtailment in the reference case)

Scenario #5 - Disruption of all imports to the Baltic states and Finland

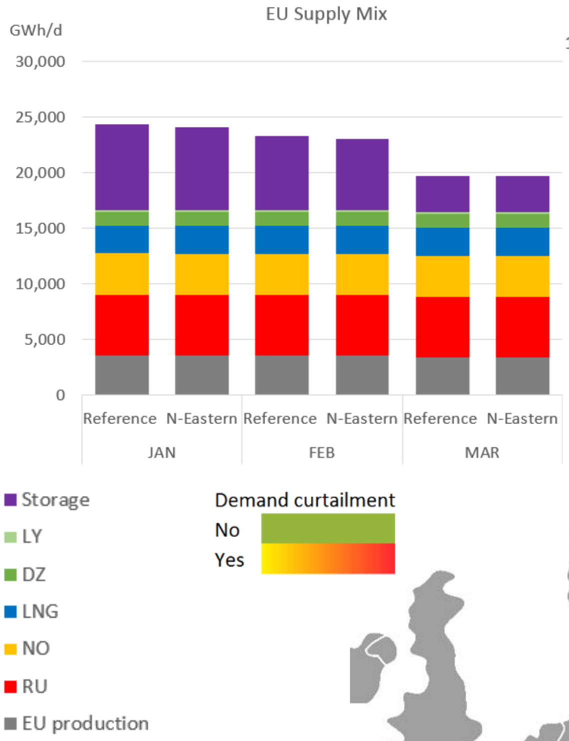
Risk group: Eastern gas supply – North-Eastern

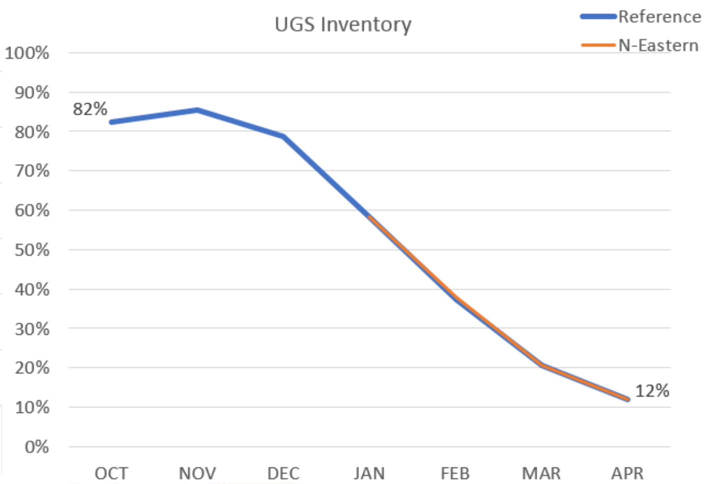
Estonia, Finland, Latvia, Lithuania

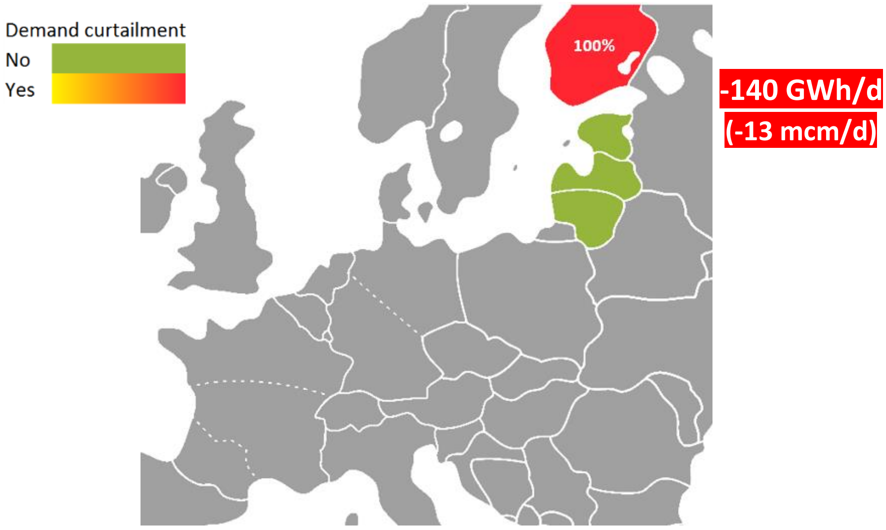
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Storages: Higher storage withdrawal in LV.

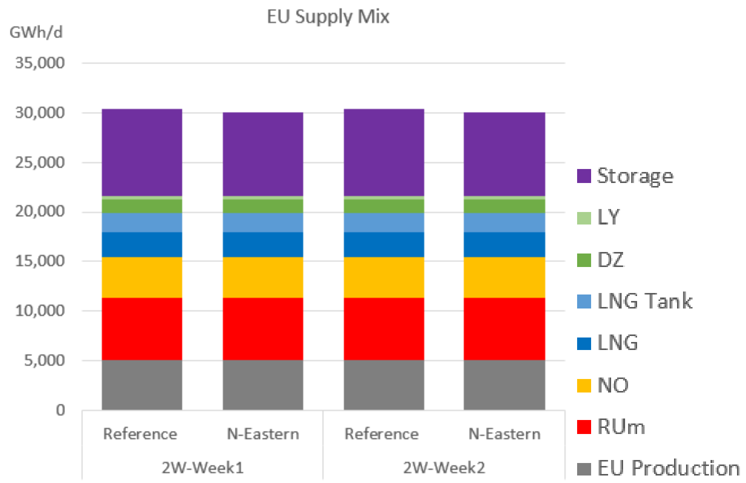
Pipeline and LNG supplies: LNG flows to Lithuania, still capacity available.

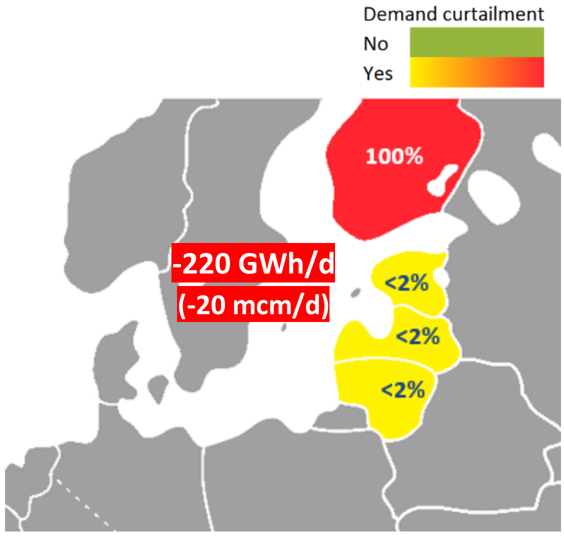
Demand

100% disruption in FI due to infrastructure limitation (no connection to any other country).

Scenario #5 - Disruption of all imports to the Baltic states and Finland

2-week / 20 years – simulated from 15 to 28 February





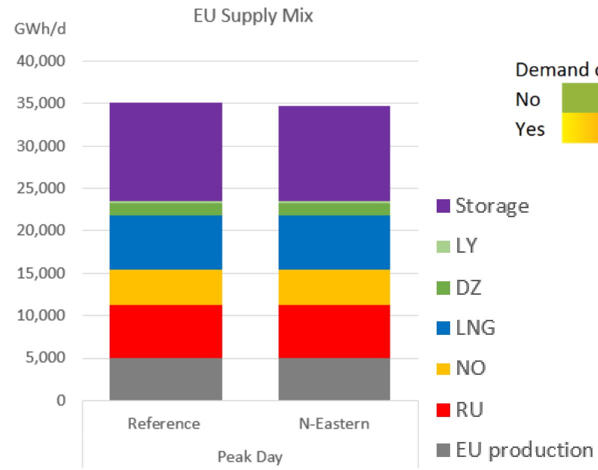
Supply

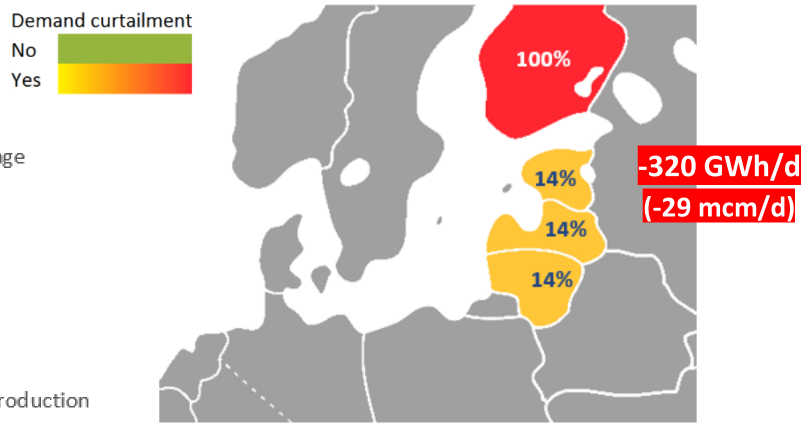
Storages: increased storage withdrawal.

Demand

100% disruption in FI due to infrasructure limitations (no connection to any other country).
EE, LT, LV less than 2% in week 2 due to infrastructure limitations (no connection to other countries).

Peak day / 20 years – simulated on 15 February





Supply

Storages: Storage withdrawal in LV is limited by withdrawal curve due to low fill level, leads to a lower storage withdrawal than in the reference case.
Pipeline and LNG supplies: No change for LNG to LT, use of maximum capacity.

Demand

14% demand curtailment in EE, LT, LV due to infrasructure limitations (no connection to other countries).
100% demand curtailment in FI due to infrasructure limitations (no connection to any other country).

Information

Demand curtailment in Finland is presented excluding the country-specific possibility in terms of use of back-up fuels for gas.

Scenario #6 - Disruption of the largest infrastructure to the Balkan region (RO –BG –GR)

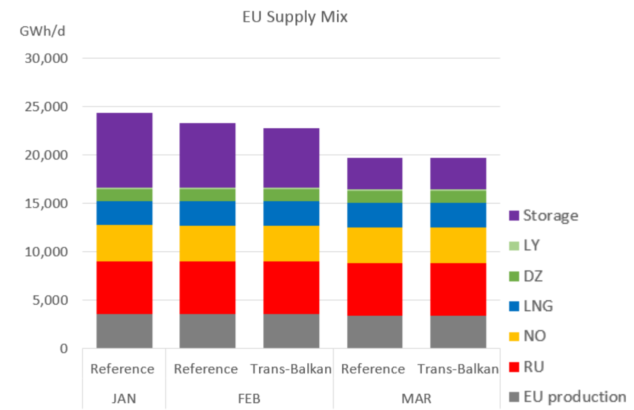
Risk group: Eastern gas supply – Trans-Balkan

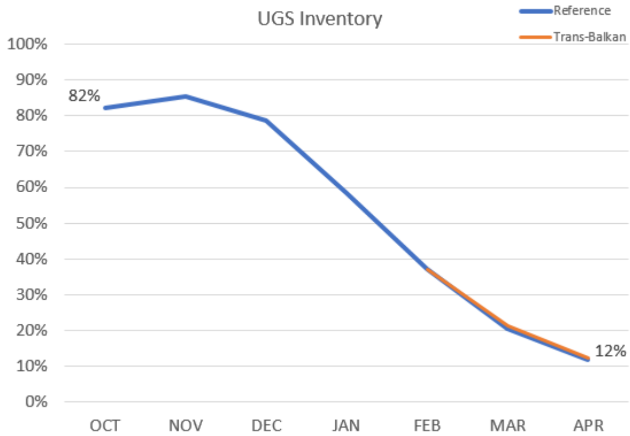
Bulgaria, Greece, Romania

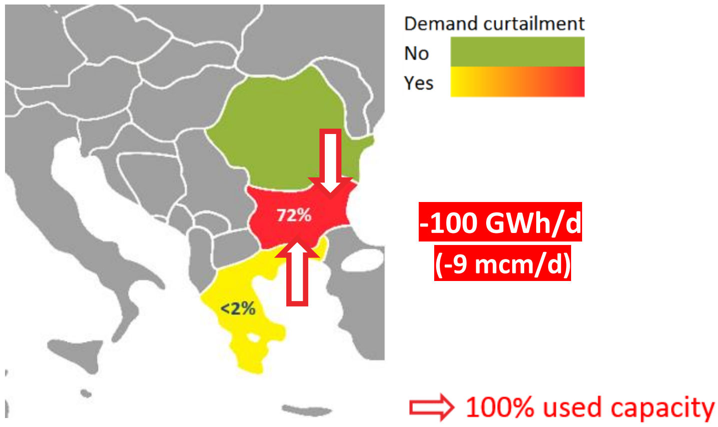
Scenario duration: 2 weeks (15 February – 28 February)

Simulation results

January - March







Supply

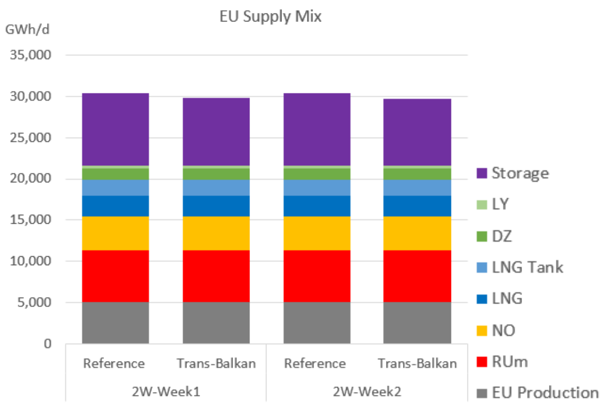
Pipeline and LNG supplies: More transits to Romania from Ukraine in Tekovo.
No more flows from Bulgaria to Greece.
As in Reference no flows from Hungary to Romania.
Higher use of LNG terminals in Greece up to maximum capacity.
Higher imports of gas in Kipi up to maximum capacity.

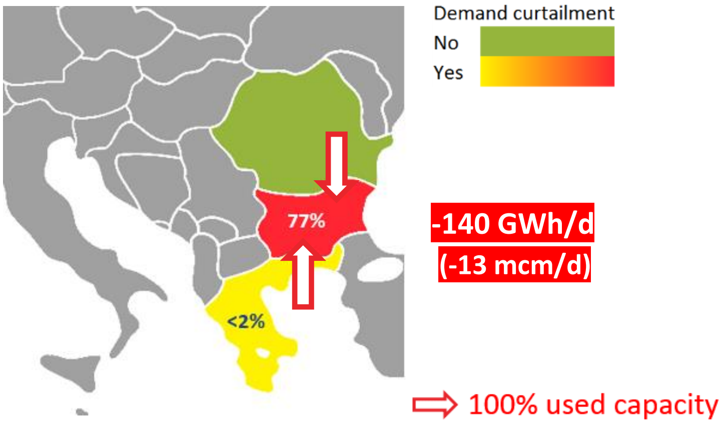
Demand

Demand curtailment in BG (72%) and GR (less than 2%) due to Infrastructure limitations: capacities towards BG are fully used.

Scenario #6 - Disruption of the largest infrastructure to the Balkan region (RO –BG –GR)

2-week / 20 years – simulated from 15 to 28 February





Supply

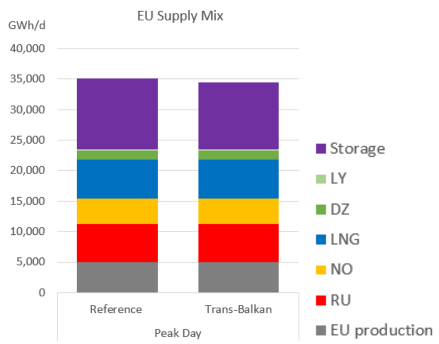
<u>Storages</u>: increased storage withdrawal.

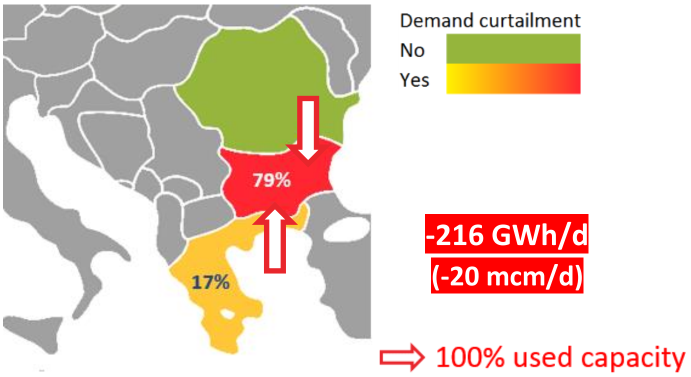
<u>Pipeline and LNG supplies</u>: No more flows from Bulgaria to Greece. Less flows from Hungary to Romania. Higher use of LNG terminals in Greece up to maximum capacity. Higher imports of gas in Kipi up to maximum capacity.

Demand

Demand curtailment in BG (77%) and GR (less than 2%) due to Infrastructure limitations: capacities towards BG are fully used.

Peak day / 20 years – simulated on 15 February





Supply

<u>Storages</u>: More transits to Romania from Ukraine in Tekovo.

<u>Pipeline and LNG supplies</u>: No more flows from Bulgaria to Greece.

As in Reference flows from Hungary to Romania. Higher imports of gas in Kipi up to maximum capacity.

Demand

Demand curtailment in BG (79%) and GR (less than 17%) due to infrastructure limitations: capacities towards BG are fully used.

Scenario #7 - Disruption of the largest offshore infrastructure to the UK

Technical disruption of Langeled pipeline

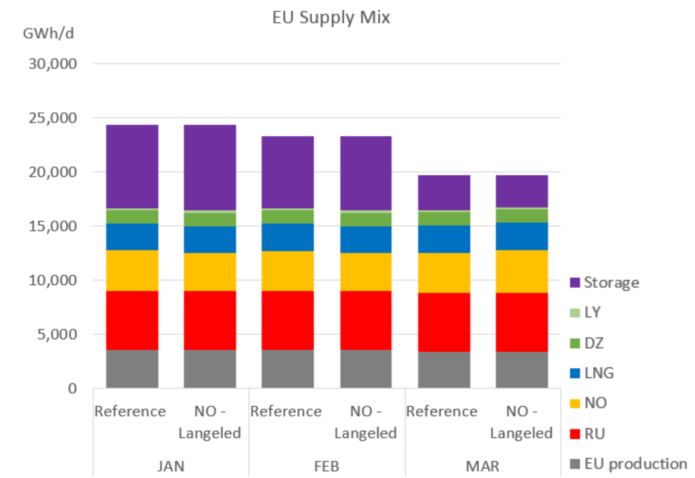
Risk group: North Sea gas supply – Norway

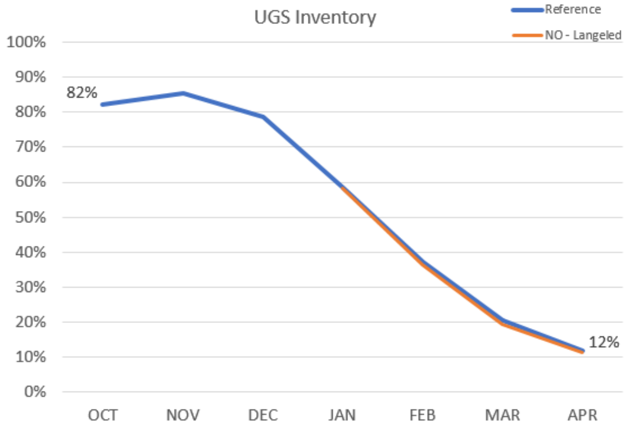
Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom

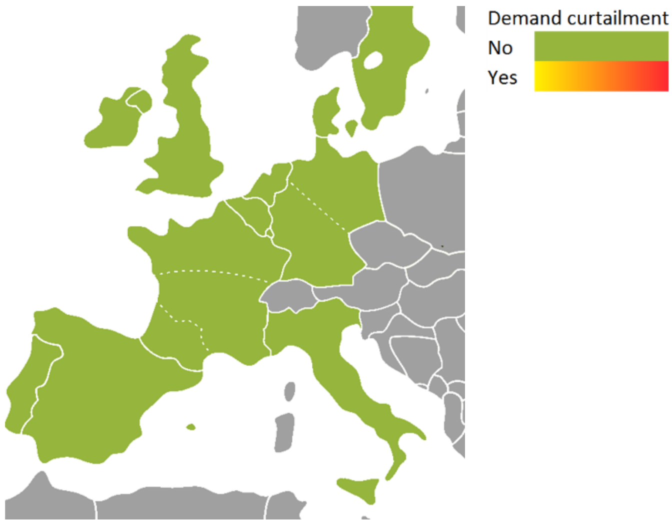
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Pipeline and LNG supplies: Less imports from NO to UK. Other import points for Norwegian gas show an increased flow up to the maximum capacity.
More LNG imports to UK. Higher use of BBL and Interconnector UK with still capacity available.

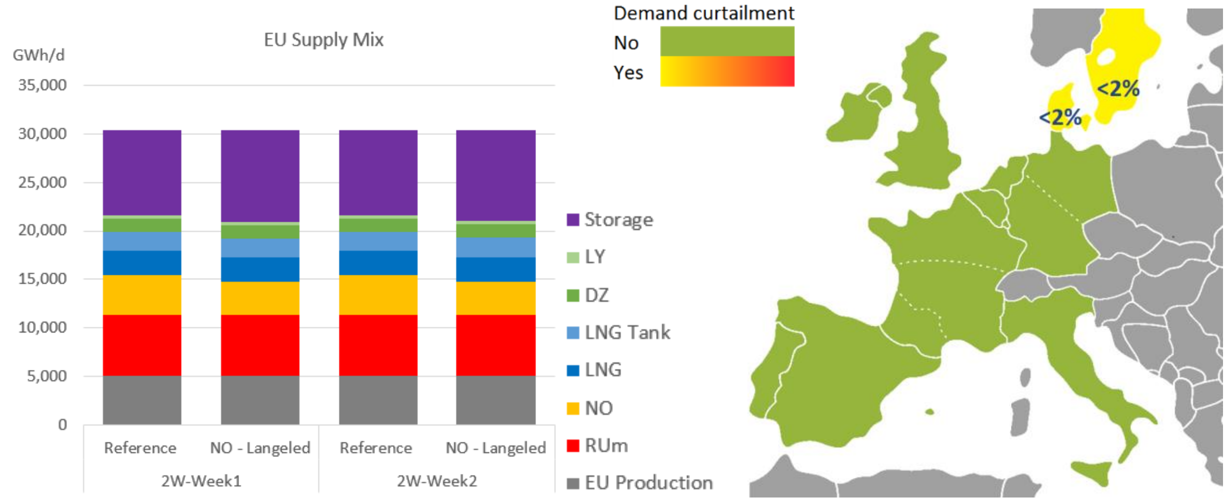
Demand

No demand curtailment.

Scenario #7 - Disruption of the largest offshore infrastructure to the UK

Technical disruption of Langeled pipeline

2-week / 20 years – simulated from 15 to 28 February



Supply

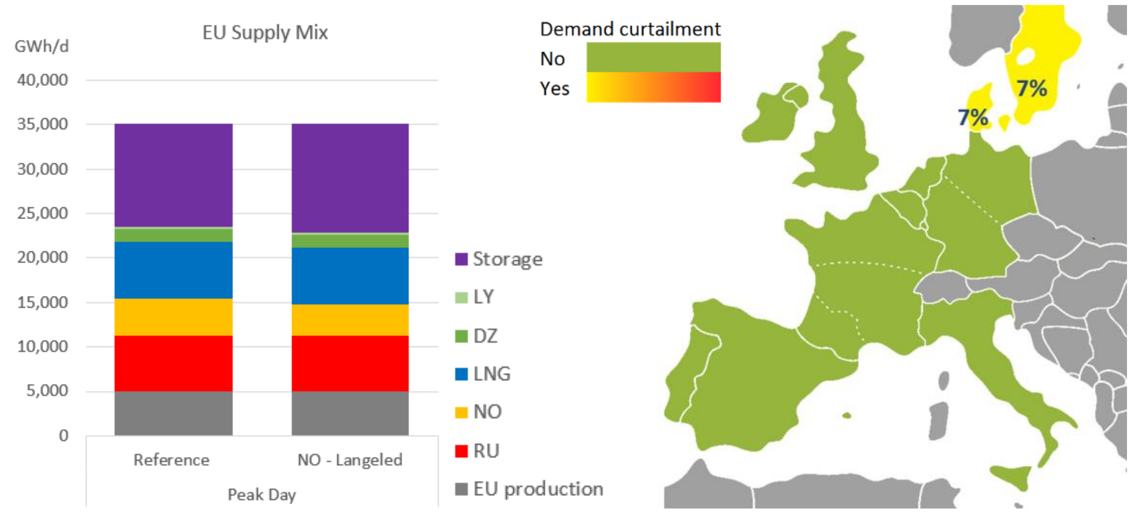
Pipeline and LNG supplies: Less imports from NO to UK. Other import points for Norwegian gas (Dornum, Zeebrugge) show an increased flow up to the maximum capacity.

More LNG regasification in UK. Higher use of BBL and Interconnector UK with still capacity available.

Demand

No additional demand curtailment compared to the reference scenario.

Peak day / 20 years – simulated on 15 February



Supply

Storages: Higher storage withdrawal in the UK.

Pipeline and LNG supplies: More transits to Romania from Ukraine in Tekovo. Less imports from NO to UK. Other import points for Norwegian gas (Dornum, Zeebrugge) show an increased flow up to the maximum capacity.

LNG terminals are used completely as in reference case. More flows via the BBL and the Interconnector UK. Still capacity available via the BBL.

Demand

No additional demand curtailment compared to the reference scenario.

Scenario #8 - Disruption of the largest offshore infrastructure to continental EU (EUROPIPE II)

Risk group: North Sea gas supply – Norway

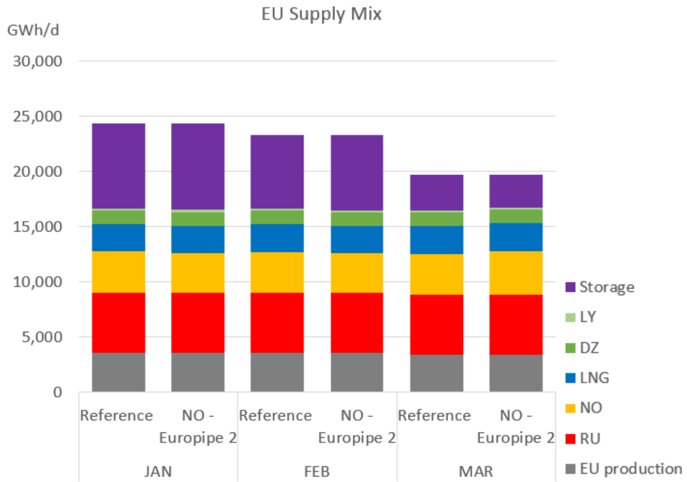
Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom

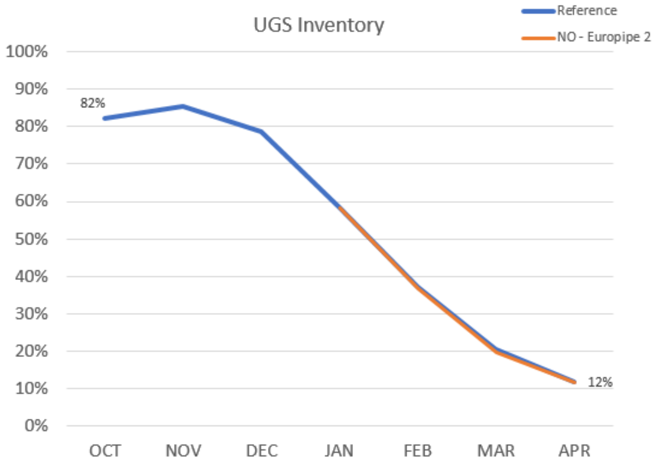
Scenario duration: 2 months (1 January – 28 February)

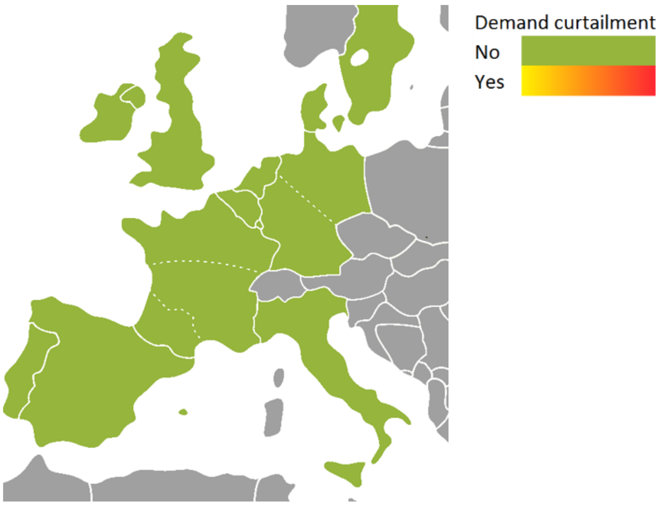
Simulation results

January - March

Technical disruption of Europipe II pipeline (72.1 MSCM/d), Europipe I with 45.7 MSCM/d remains operational.







Supply

Storages: Higher withdrawal from storages.

Pipeline and LNG supplies: Imports from Norway reduced due to the reduced import capacity.

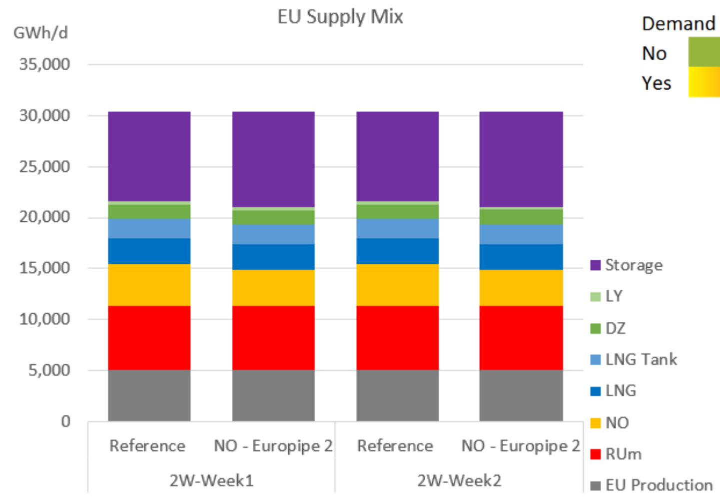
More LNG flows to the Netherlands.

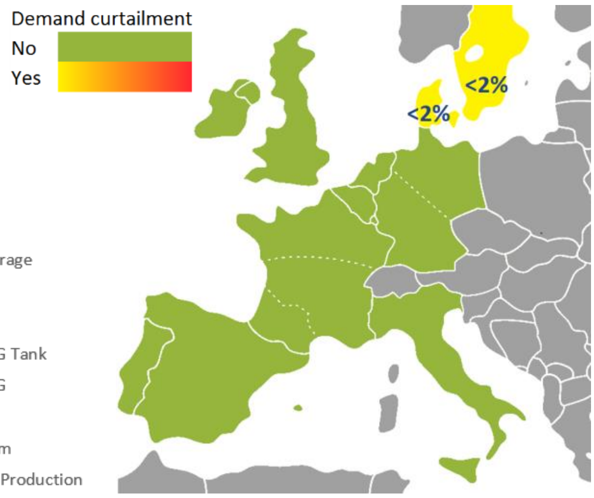
Demand

No demand curtailment.

Scenario #8 - Disruption of the largest offshore infrastructure to continental EU (EUROPIPE II)

2-week / 20 years – simulated from 15 to 28 February

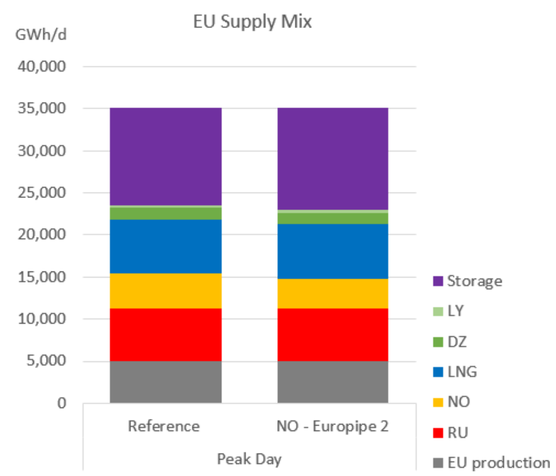


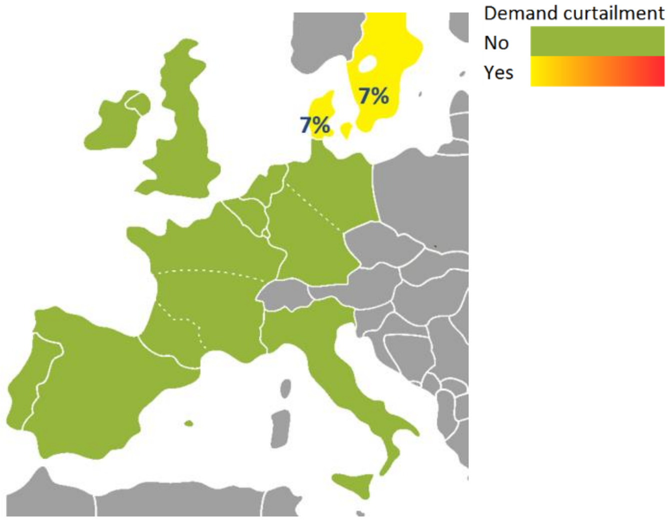


Supply
<u>Storages</u>: Higher withdrawal from storages.
<u>Pipeline and LNG supplies</u>: Imports from Norway reduced due to the reduced import capacity.

Demand
No additional demand curtailment compared to the reference scenario.

Peak day / 20 years – simulated on 15 February





Supply
<u>Storages</u>: Higher withdrawal from storages.
<u>Pipeline and LNG supplies</u>: Imports from Norway reduced due to the reduced import capacity.

Demand
No additional demand curtailment compared to the reference scenario.

Scenario #9 - Disruption of the largest onshore infrastructure from Norway

Technical disruption of Emden station

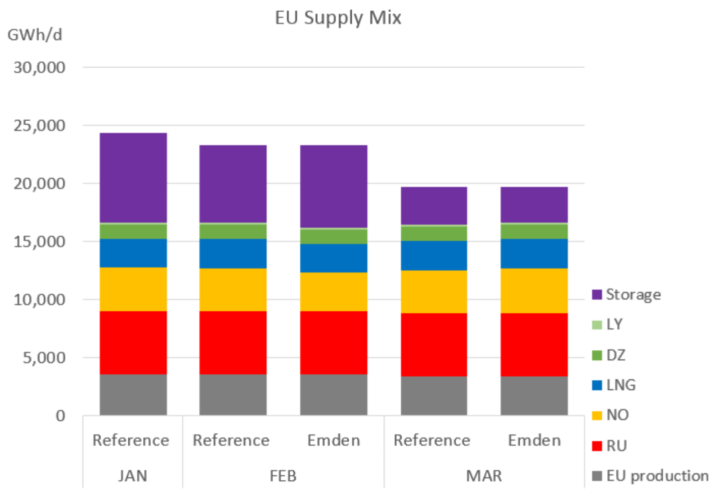
Risk group: North Sea gas supply – Norway

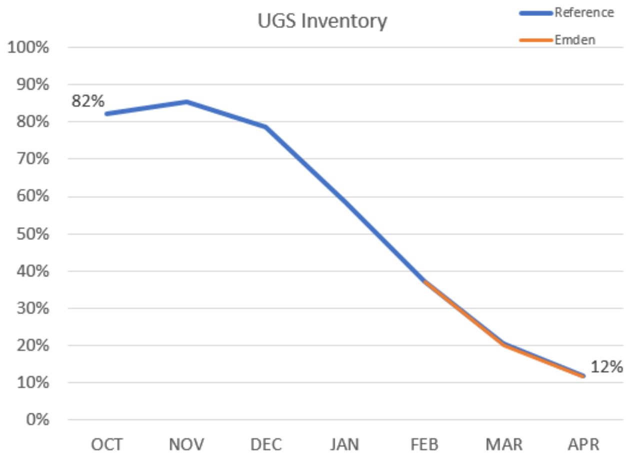
Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom

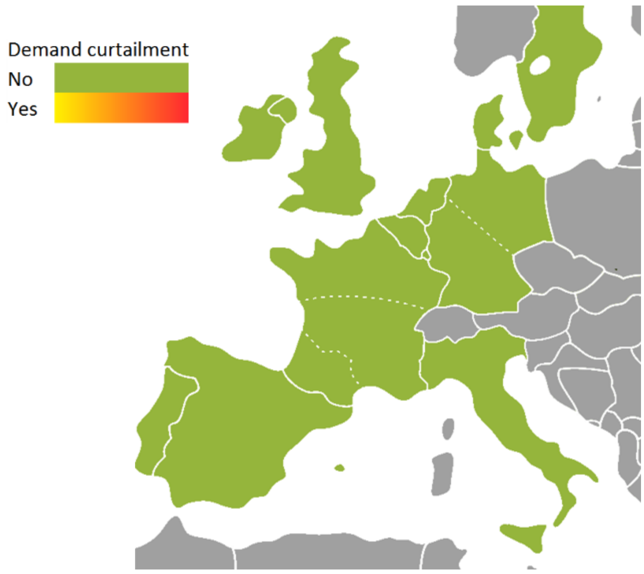
Scenario duration: 2 weeks (15 February – 28 February)

Simulation results

January - March







Supply

Pipeline and LNG supplies: Higher imports of Norwegian gas in Dornum, France, Belgium and UK. Overall less imports from Norway due to the reduced capacity.
Higher LNG imports to the Netherlands.

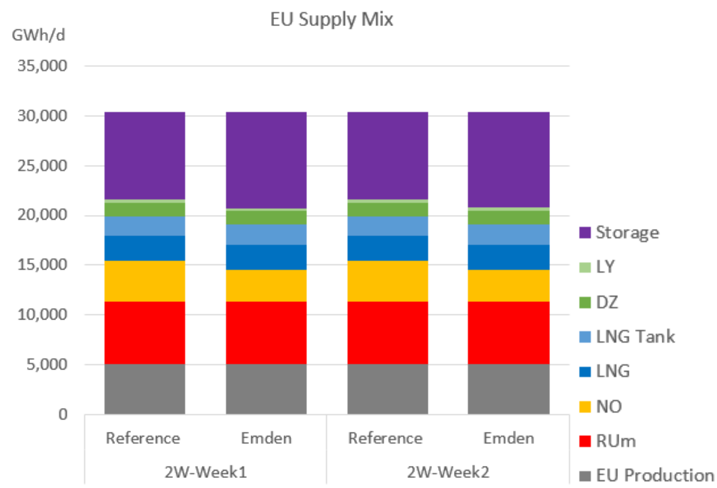
Demand

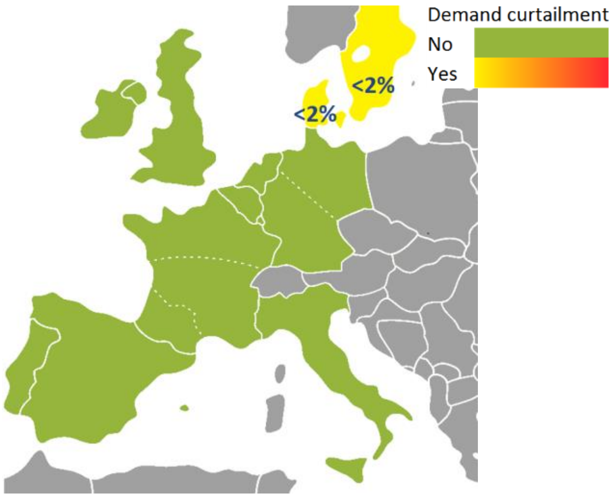
No demand curtailment.
Note: no additional curtailment is observed when considering the capacity restriction of the TENP pipeline announced on 27 September 2017.

Scenario #9 - Disruption of the largest onshore infrastructure from Norway

Technical disruption of Emden station

2-week / 20 years – simulated from 15 to 28 February





Supply

Storages: Higher withdrawal from storages.

Pipeline and LNG supplies: Overall less imports from Norway due to the reduced capacity.

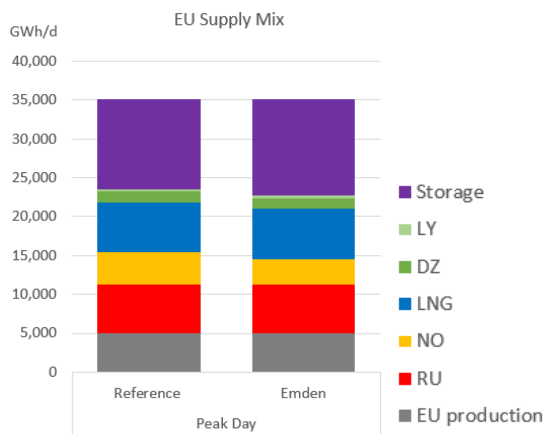
Higher LNG imports to the Netherlands.

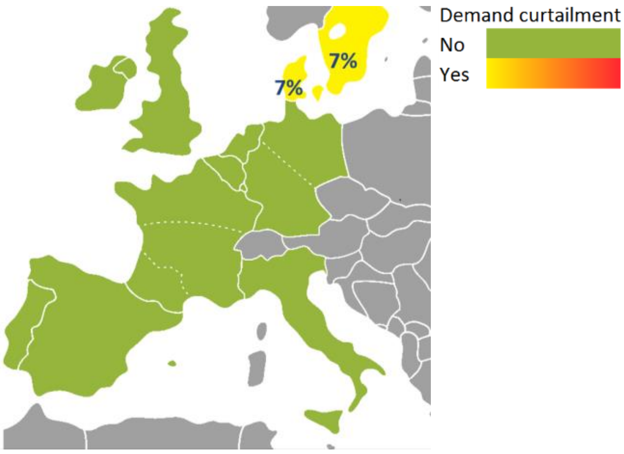
Demand

No additional demand curtailment compared to the reference scenario.

Note: no additional curtailment is observed when considering the capacity restriction of the TENP pipeline announced on 27 September 2017.

Peak day / 20 years – simulated on 15 February





Supply

Storages: Higher withdrawal from storages.

Pipeline and LNG supplies: Overall less imports from Norway due to the reduced capacity.

Higher flows from the Netherlands to GASPOOL market area in Germany, still below capacity.

Demand

No additional demand curtailment compared to the reference scenario.

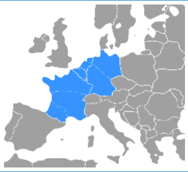
Note: no additional curtailment is observed when considering the capacity restriction of the TENP pipeline announced on 27 September 2017.

Scenario #10 - Disruption of the largest L-gas storage (UGS Norg – The Netherlands)

North Sea gas supply – Low calorific gas: UGS Norg

Following the discussion in the Gas Coordination Group of 21 June 2017, helped by a timeline prepared by ENTSOG, the involved TSOs of the Gas Platform have prepared the L-gas scenario. The coordinators of the involved members states (Belgium, France, Germany and the Netherlands) of the Gas Platform have agreed upon the L-gas scenario.

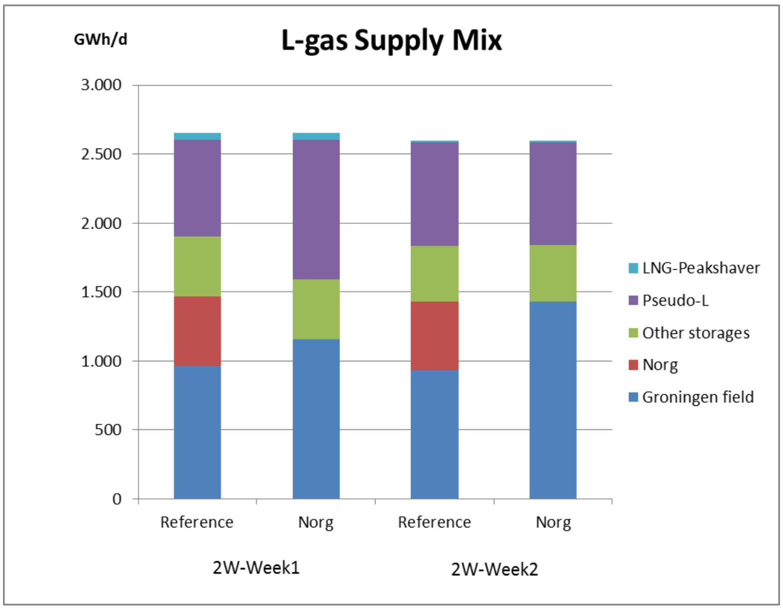
The Gas Platform is the regional cooperation for gas for Belgium, France, Germany, Luxembourg and the Netherlands. It is an intergovernmental initiative where ministries responsible for energy policy discuss issues related to security of supply and market integration, in close cooperation with the National Regulatory Authorities and Transmission System Operators. Ad hoc, the European Commission or other European authorities participate as observer. The Benelux Secretariat provides support.

Scenario #10	Disruption of the largest L-gas storage (UGS Norg – The Netherlands)	Gas Platform
Risk group:	Low Calorific Gas	
Germany, Belgium, France, The Netherlands		
Scenario duration:	2-week and peak	

Simulation results

2-week

2-week period during a cold spell (coldest period of two weeks of the last 20 years, reference period used in simulations: December 27 1996 – January 9, 1997).



Supply

Increased production of (mainly) Groningen field within the boundaries set by the Dutch government and pseudo L-gas production (enrichment and quality conversion).

Demand

No demand curtailment.

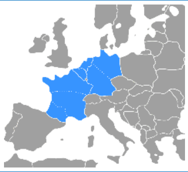
Dutch domestic demand can be supplied and exports to Germany, Belgium and France can be maintained.

Scenario #10 Disruption of the largest L-gas storage (UGS Norg – The Netherlands) **Gas Platform**

Risk group: Low Calorific Gas

Germany, Belgium, France, The Netherlands

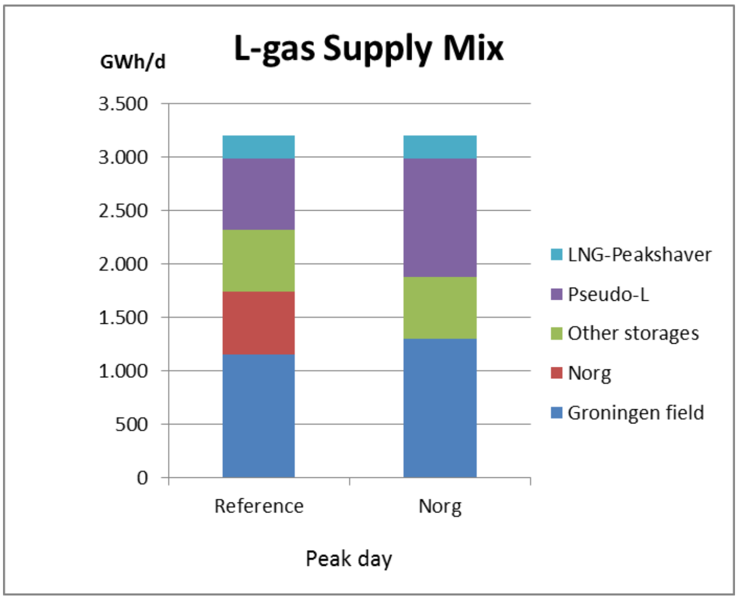
Scenario duration: 2-week and peak



Simulation results

Peak day

The peak is considered at minus 17°C (effective temperature at weather station De Bilt, The Netherlands), because this temperature is used as the design temperature of the transmission system in The Netherlands (reference day used in simulation: January 14, 1987)



Supply

Increased production of (mainly) Groningen field within the boundaries set by the Dutch government and pseudo L-gas production (enrichment and quality conversion).

Demand

No demand curtailment.

Dutch domestic demand can be supplied and exports to Germany, Belgium and France can be maintained.

Results analysis

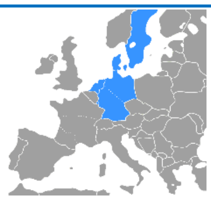
Sufficient compensation available within The Netherlands

Scenario #11 – Disruption of the L-gas supply

Further scenarios with regard to the L-gas supply will be developed within the framework of the Gas Platform and communicated later.

Scenario #12 - Disruption of the largest infrastructure to Denmark

Technical disruption of Ellund



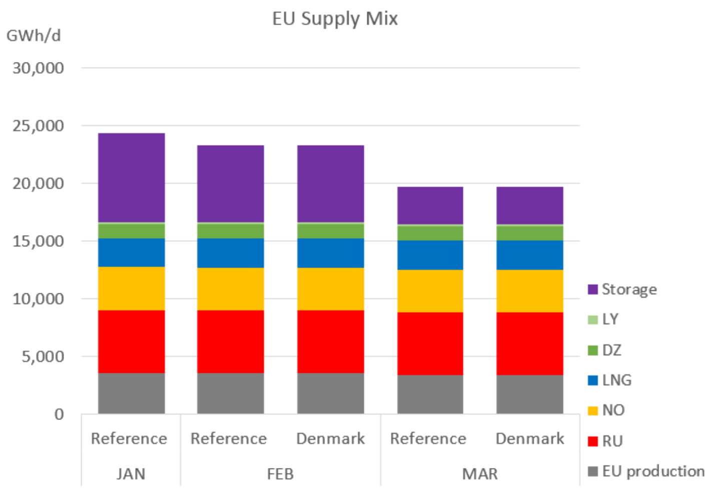
Risk group: North Sea gas supply – Denmark

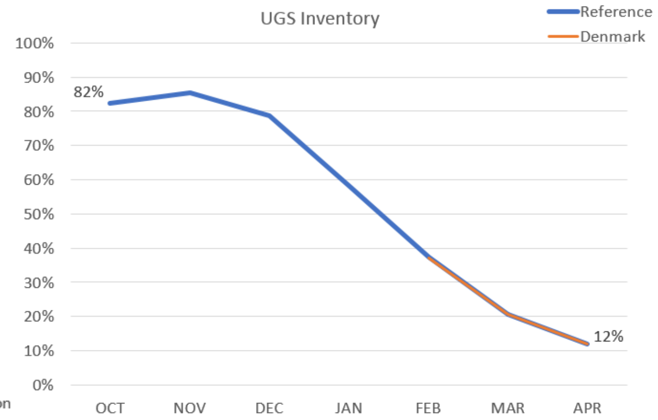
Denmark, Luxembourg, Netherlands, Germany, Sweden

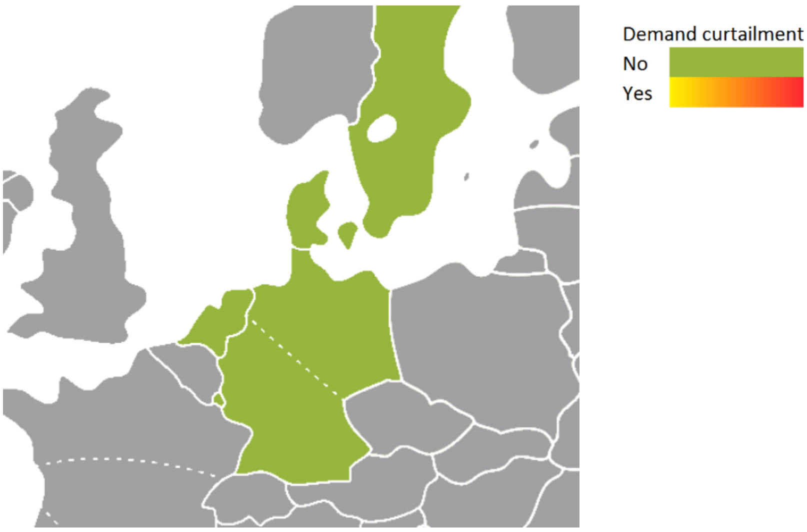
Scenario duration: 2 weeks (15 February – 28 February)

Simulation results

January - March







Supply

Storages: Increased storage withdrawal in DK and SE.

Pipeline and LNG supplies: No more flows from Germany leads to limited NP production and storage being the only supply sources for DK and SE.

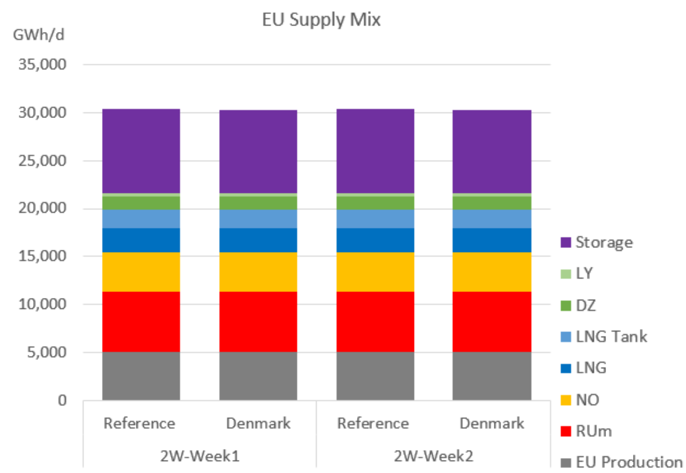
Demand

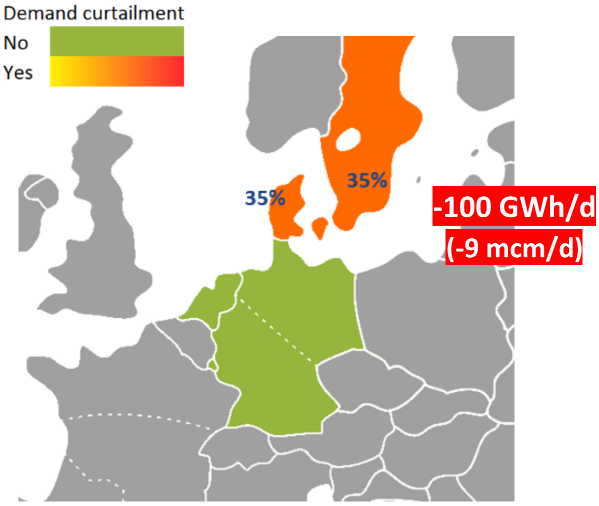
No demand curtailment.

Scenario #12 - Disruption of the largest infrastructure to Denmark

Technical disruption of Ellund

2-week / 20 years – simulated from 15 to 28 February





Supply

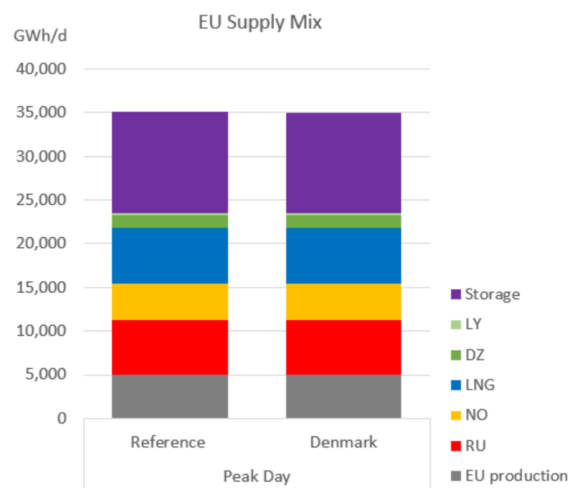
Storages: Storages in DK and SE can increase the storage withdrawal until they reach the capacity limit due to the withdrawal curve.

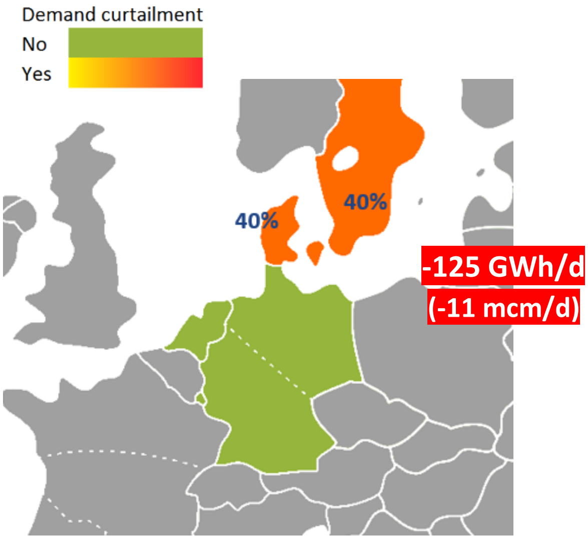
Pipeline and LNG supplies: No more flows from Germany leads to limited NP production and storage being the only supply sources for DK and SE.

Demand

Demand curtailment in DK and SE around 35%.

Peak day / 20 years – simulated on 15 February





Supply

Storages: Storage in DK could not be used more as it is already reaching the maximum from the withdrawal curve.

Pipeline and LNG supplies: No more flows from Germany leads to limited NP production and storage the only supply sources for DK.

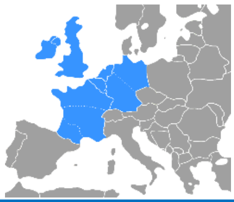
Demand

Demand curtailment in DK and SE (40%).

Scenario #13 - Disruption of the largest offshore production infrastructure from the UK

Technical disruption of Forties Pipeline system

Risk group: North Sea gas supply – United-Kingdom

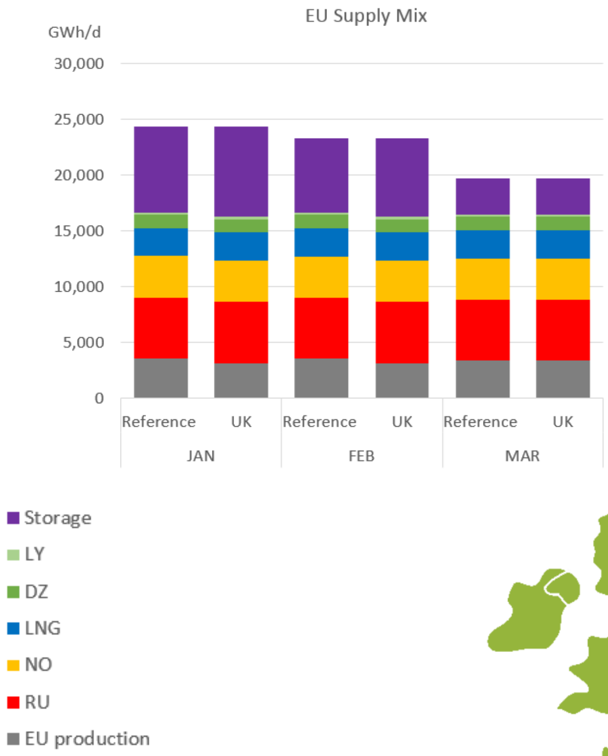


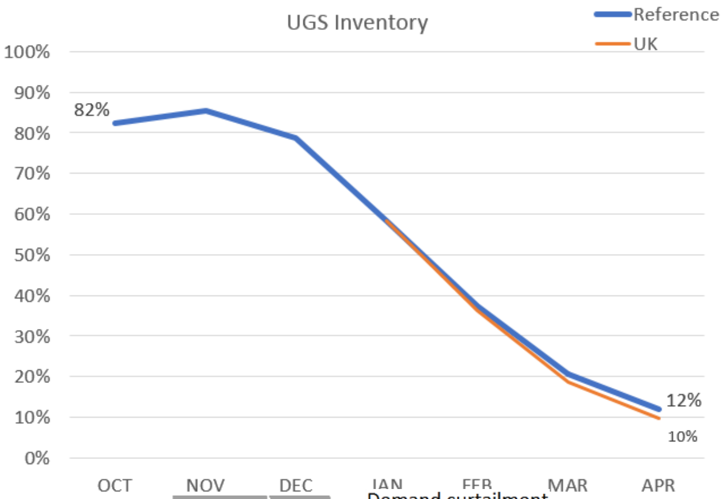
Belgium, Germany, Ireland, Luxembourg, Netherlands, United Kingdom

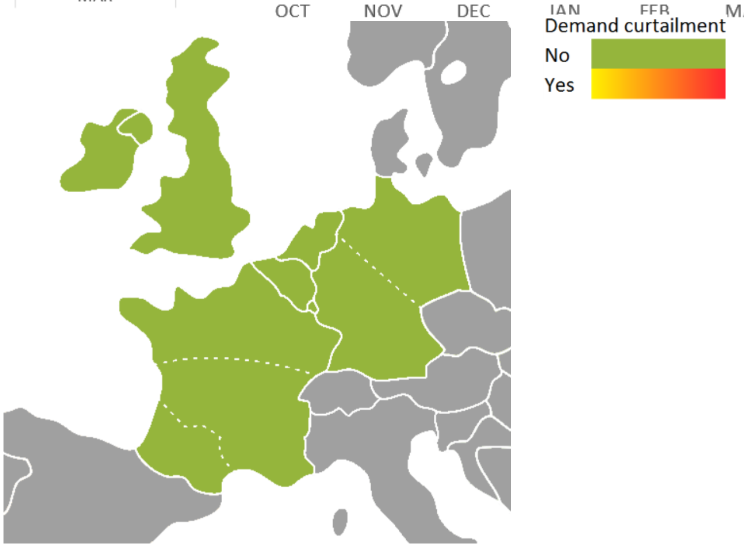
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Storages: higher withdrawal from storages.

Pipeline and LNG supplies: Less NP to UK, higher flows from Norway, LNG imports increased. Increased flows through BBL and IUK. Still capacities available for all of these import options to the UK.

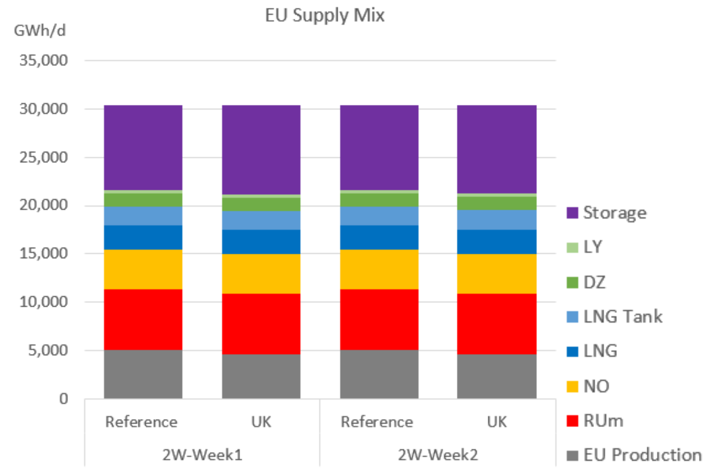
Demand

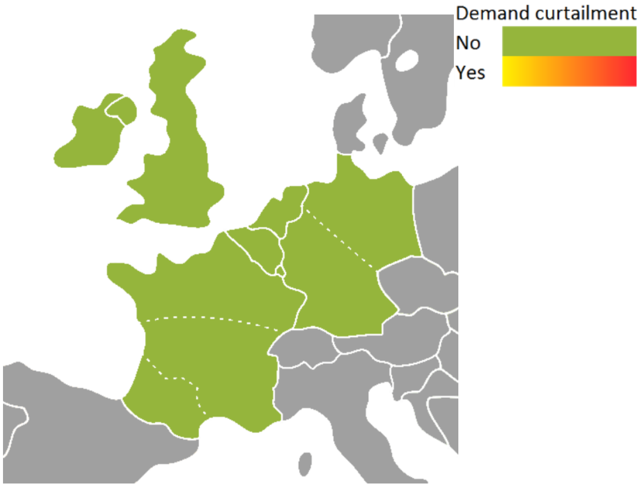
No demand curtailment.

Scenario #13 - Disruption of the largest offshore production infrastructure from the UK

Technical disruption of Forties Pipeline system

2-week / 20 years – simulated from 15 to 28 February





Supply

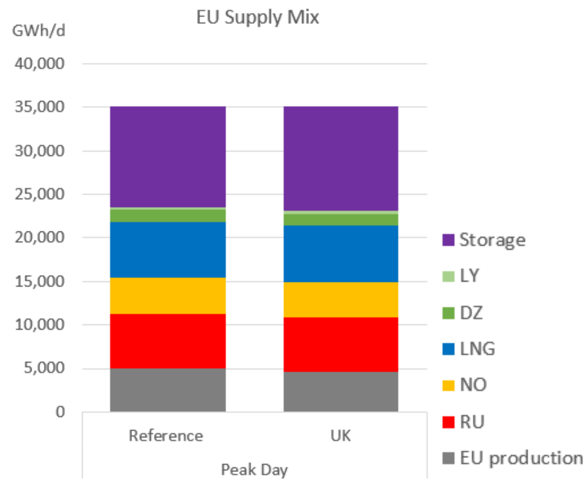
<u>Storages</u>: Storage withdrawal in the UK is increased.

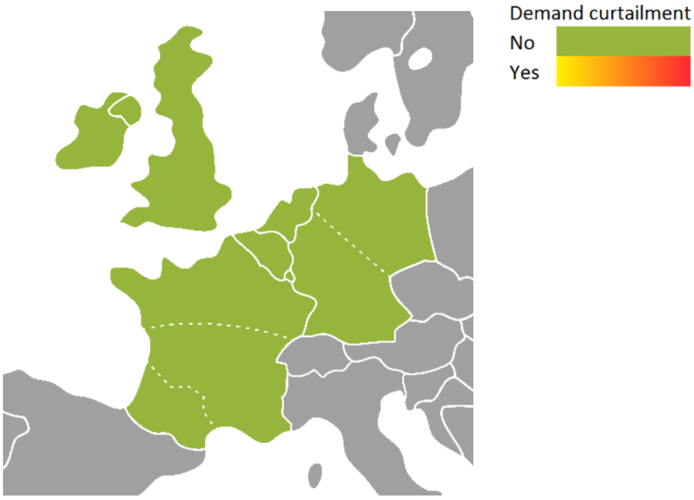
<u>Pipeline and LNG supplies</u>: Less NP to UK, higher flows from Norway up to maximum capacity, LNG increased with capacity still available. Increased flows through BBL and IUK with capacity still available.

Demand

No demand curtailment.

Peak day / 20 years – simulated on 15 February





Supply

<u>Storages</u>: Storage withdrawal in the UK is increased.

<u>Pipeline and LNG supplies</u>: Less NP to UK, as in reference case the imports from NO and LNG are used to the max as well the IUK. Increased flows via BBL with still capacity available.

Demand

No demand curtailment.

Scenario #14 - Disruption of the largest offshore infrastructure to Italy

Technical disruption of the Transmed system

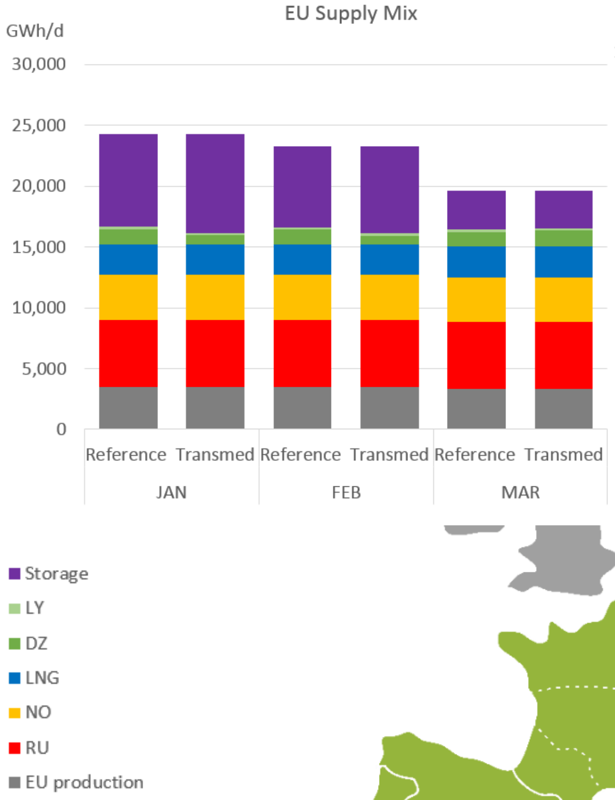
Risk group: North-African gas supply – Algeria

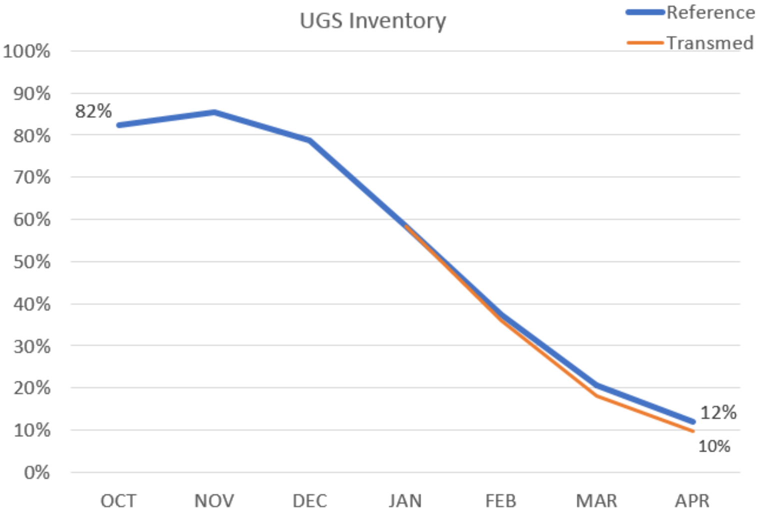
Austria, Croatia, France, Greece, Italy, Malta, Portugal, Slovenia, Spain

Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March





Supply

Storages: Higher storage withdrawal in Italy.

Pipeline and LNG supplies: Reduced imports from North Africa to Italy. LNG imports to Italy are increased. Flow between Italy and Slovenia reverse in January so that Italy receives gas from Slovenia. Algerian exports to Spain increased up to capacity limit. Flows to Italy in Passo Gries and Tarvisio increased, in Tarvisio up to capacity limit.

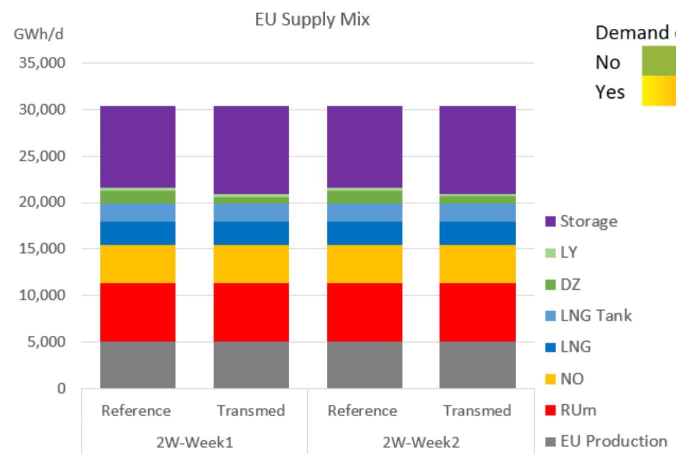
Demand

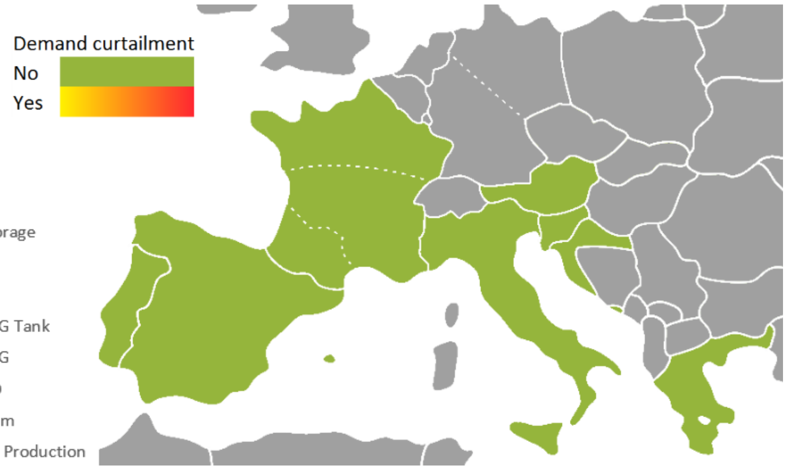
No demand curtailment.

Scenario #14 - Disruption of the largest offshore infrastructure to Italy

Technical disruption of the Transmed system

2-week / 20 years – simulated from 15 to 28 February





Supply

Storages: Higher storage withdrawal in Italy

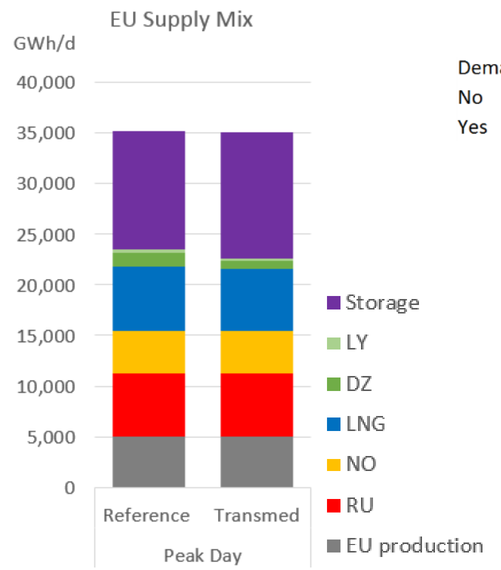
Pipeline and LNG supplies: Reduced imports from North Africa to Italy.

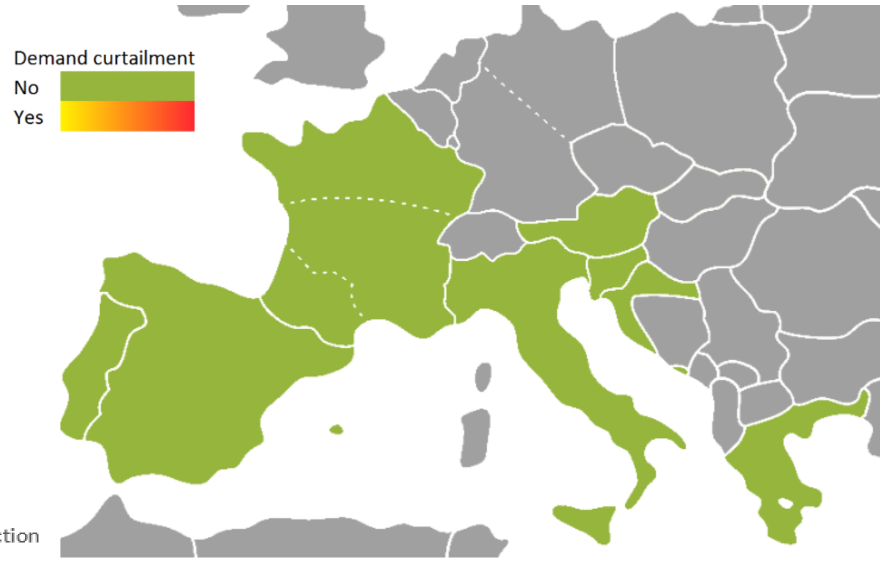
Algerian exports to Spain increased up to capacity limit.

Demand

No demand curtailment

Peak day / 20 years – simulated on 15 February





Supply

Storages: Lower storage withdrawal in Italy due to low filling level caused by the higher withdrawal during January and February.

Pipeline and LNG supplies: Reduced imports from North Africa to Italy.

As in reference LNG regasification up to maximum capacity.

Flows to Italy in Passo Gries and Tarvisio increased to maximum capacity.

Demand

No demand curtailment.

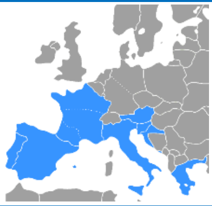
Results analysis

Italy's access to diversified supply sources prevent it from being impacted by Transmed disruption.

Scenario #15 - Disruption of the largest offshore infrastructure to Spain

Technical disruption of the MEG system

Risk group: North-African gas supply – Algeria

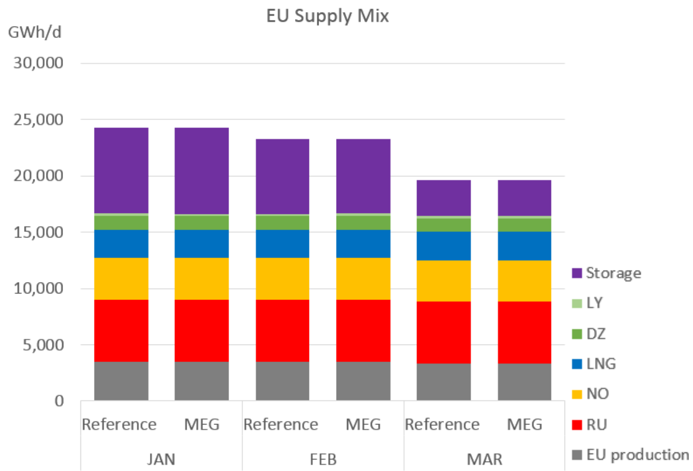


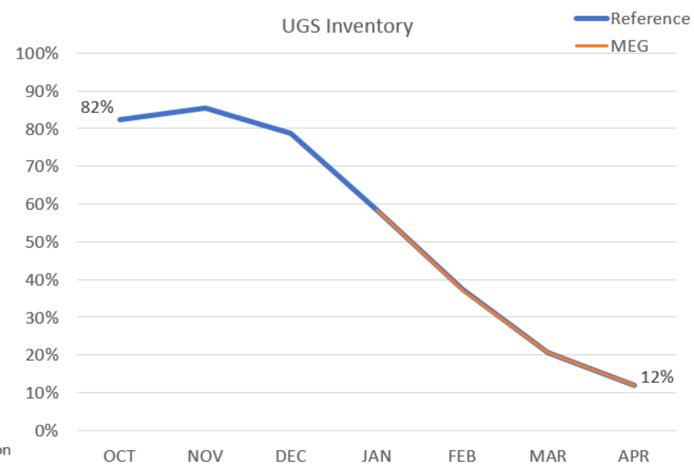
Austria, Croatia, France, Greece, Italy, Malta, Portugal, Slovenia, Spain

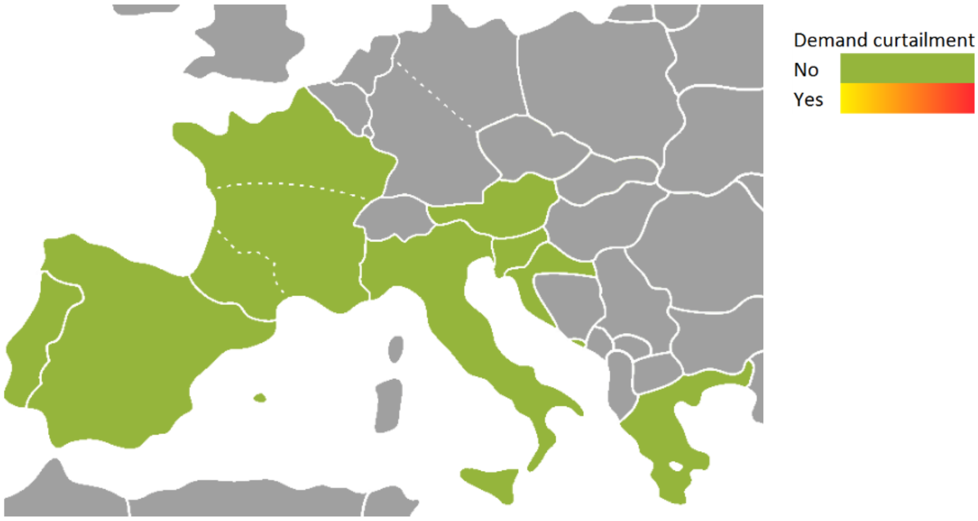
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Pipeline and LNG supplies: Reduced imports from Algeria to Spain only via Medgaz pipeline. More Algerian gas exported towards Italy.

Higher LNG imports to Spain.

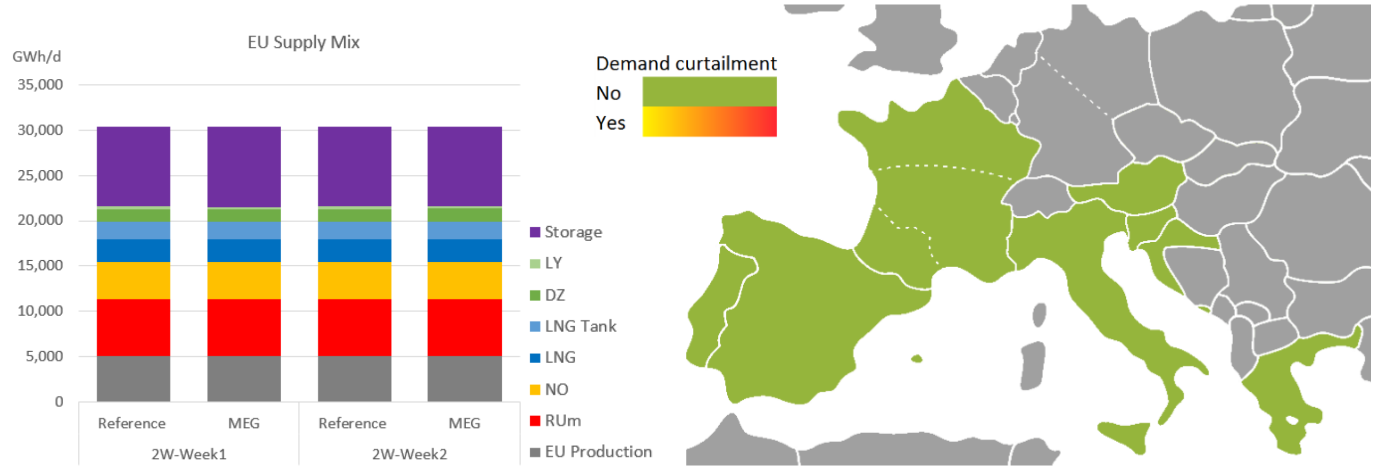
Demand

No demand curtailment.

Scenario #15 - Disruption of the largest offshore infrastructure to Spain

Technical disruption of the MEG system

2-week / 20 years – simulated from 15 to 28 February



Supply

Storages: Higher storage withdrawal in Italy

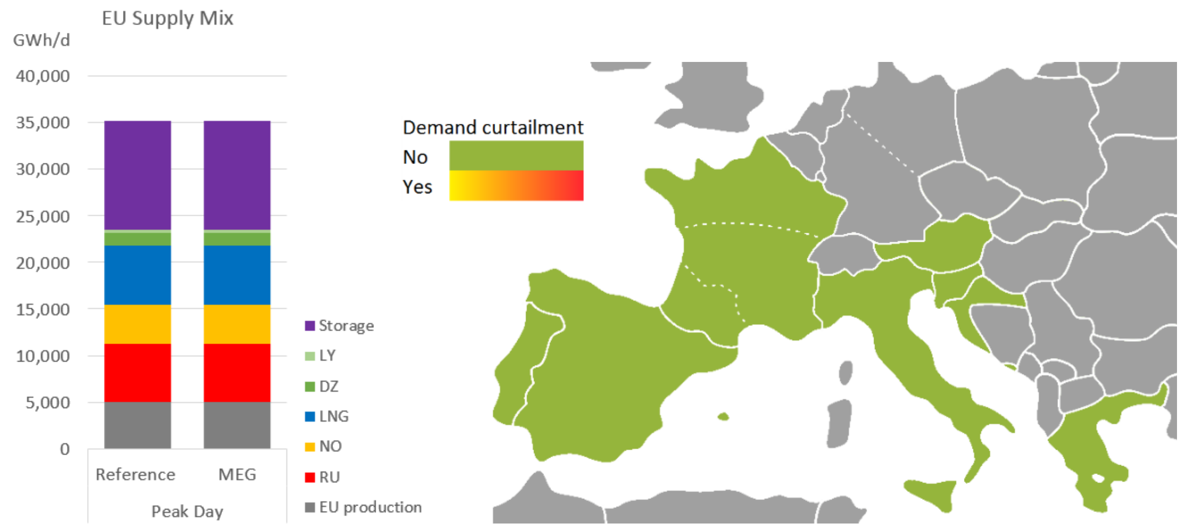
Pipeline and LNG supplies: Reduced imports from Algeria to Spain only via Medgaz pipeline. More Algerian gas exported towards Italy.

Higher LNG imports to Portugal and Spain.

Demand

No demand curtailment

Peak day / 20 years – simulated on 15 February



Supply

Pipeline and LNG supplies: Imports from Algeria to Spain only via Medgaz pipeline used up to the maximum.

As in Reference the regasification capacity from the terminals can be used up to the maximum.

Demand

No demand curtailment.

Results analysis

In case of a 2-month disruption of the MEG system, LNG terminals in Spain offer sufficient flexibility to mitigate the situation, while extra flexibility is still available at interconnections.

Scenario #16 - Disruption of all imports from Algeria including LNG

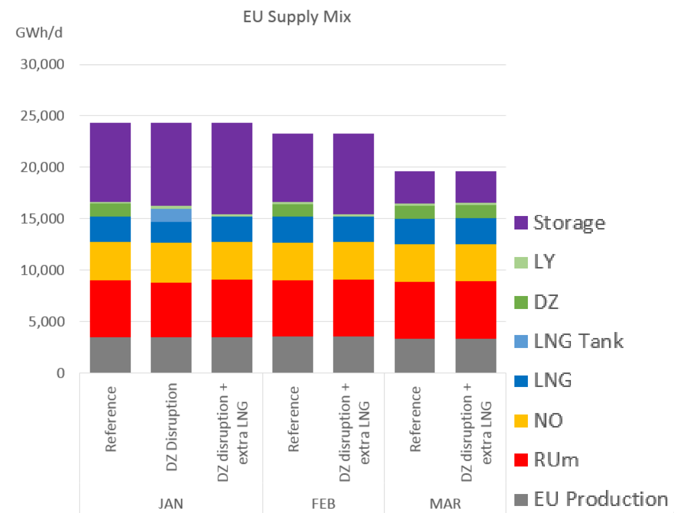
Risk group: North-African gas supply – Algeria

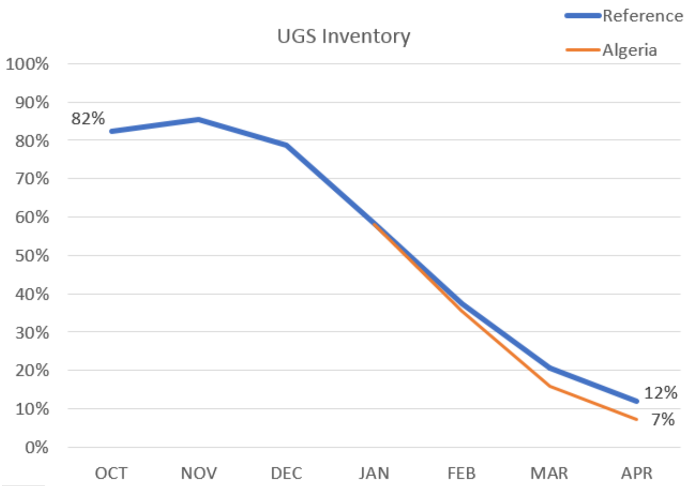
Austria, Croatia, France, Greece, Italy, Malta, Portugal, Slovenia, Spain

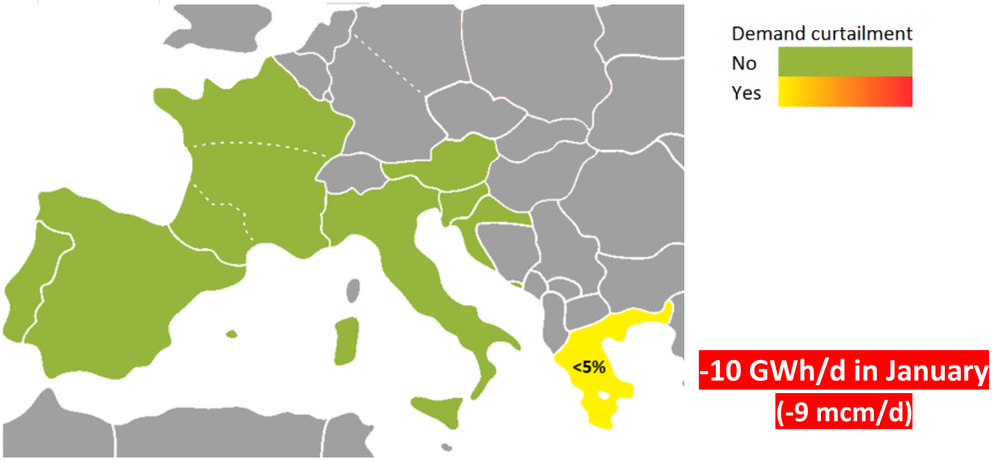
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Specificity of scenario #16 - Algerian disruption:
Disruption scenario #16 considers the disruptions of the imports from Algeria via both pipelines and LNG cargos. However, different supply assumptions are made regarding pipelines, that cannot physically be rerouted, and LNG, to consider that additional cargos can come from different suppliers. Therefore, it is assumed that a period of 3 weeks is necessary to attract more LNG cargos to substitute the Algerian LNG (see table 3 for more details).

Supply

Storages: Higher use of storages in January and February (around 60 TWh).

Pipeline and LNG supplies: Flow from France to Spain increased compared to reference (up to 66% of the capacity).

LNG tanks: Gas from LNG tanks is used to compensate the missing LNG cargos during the first 3 weeks (total 28 TWh).

Scenario #16 - Disruption of all imports from Algeria including LNG

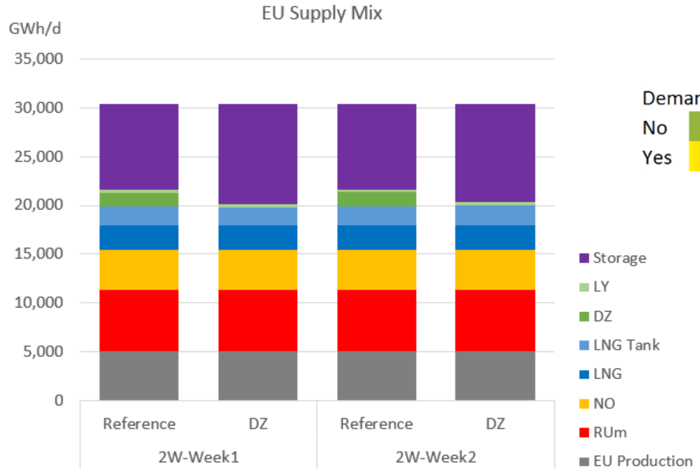
Demand

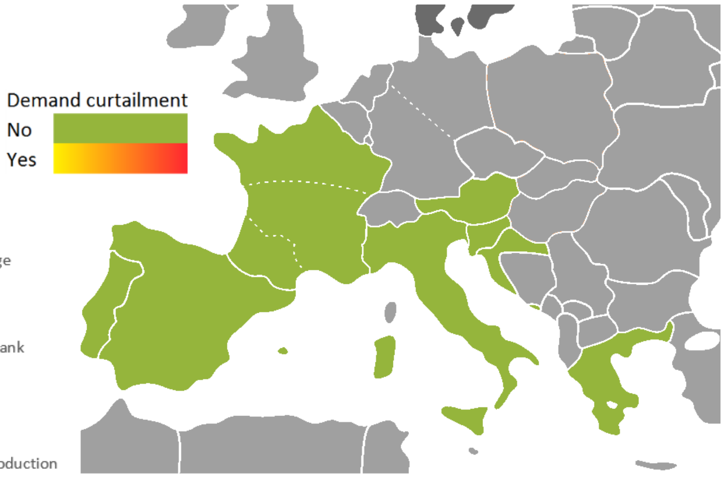
EU: no demand curtailment except for GR due to infrastructure limitations.

Infrastructure limitations:

During first three weeks GR is exposed to 5% demand curtailment due to infrastructure limitations: capacity from BG to GR is fully used)
From week 4 on, no demand curtailment is observed.

2-week / 20 years – simulated from 15 to 28 February





Supply

Storages: UGS are used at their maximum withdrawal capacities except for FR, DE, IT, PT and UK.

Pipeline and LNG supplies: capacities from AT to IT are used at their maximum

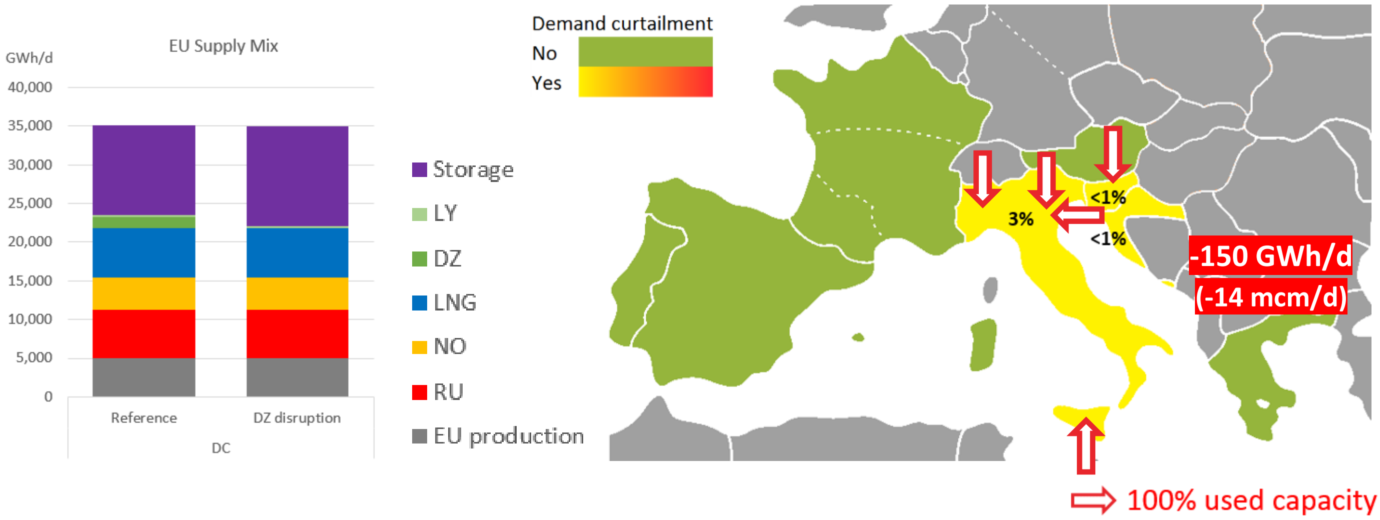
LNG tanks: at EU level, a minimum of 12 TWh of LNG is necessary in the tanks at the beginning of the 2-week event (17% of the total EU capacity of the tanks) to avoid demand curtailment during a 2-week in 20 years situation.

Demand

No demand curtailment considering a minimum volume of 12 TWh (1.1 bcm) available in the LNG tanks at the beginning of the 2-week event.

Scenario #16 - Disruption of all imports from Algeria including LNG

Peak day / 20 years – simulated on 15 February



Supply

<u>Storages</u>: all storages are used at their maximum withdrawal capacities except AT, DE and UK.

<u>Pipeline and LNG supplies</u>: All supplies are used at their maximum potential.

<u>LNG tanks</u>: tanks are used to satisfy the higher demand.

Demand

<u>Infrastructure limitations:</u>

IT, HR and SI are exposed to little demand curtailment because of infrastructure limitations.

Capacities towards IT and from AT to SI are fully used during the Peak day.

<u>EU-wide:</u>

Demand curtailment: 150 GWh/d due to infrastructure limitations (0.5% of EU demand)

<u>Within the risk group:</u>

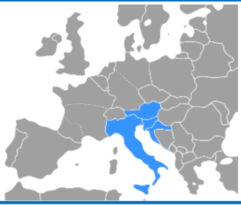
Demand curtailment is around 1% of the risk group demand (12,000 GWh/d).

Results analysis

A high fill level of LNG tanks can help mitigating spontaneous risks and delays for new LNG to arrive

Scenario #17 - Disruption of the largest offshore infrastructure to Italy

Technical disruption of Green Stream



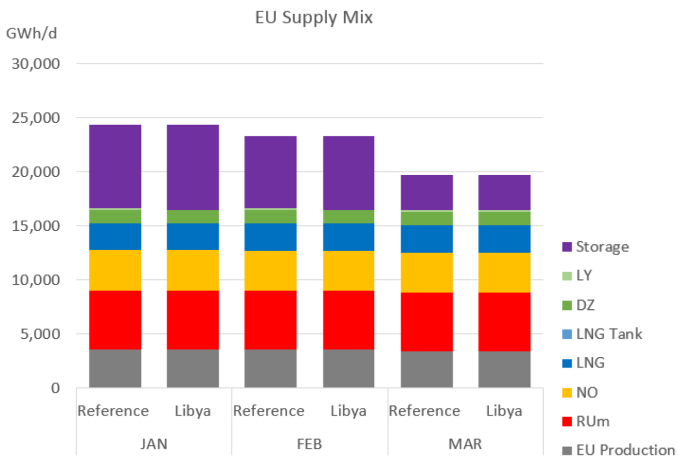
Risk group: North-African gas supply – Libya

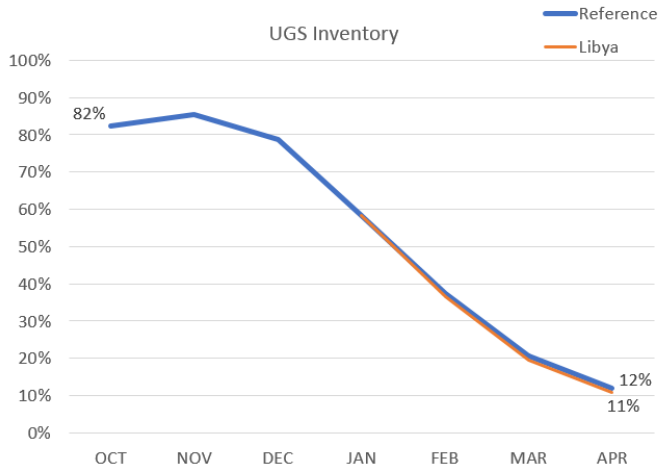
Austria, Croatia, Italy, Malta, Slovenia

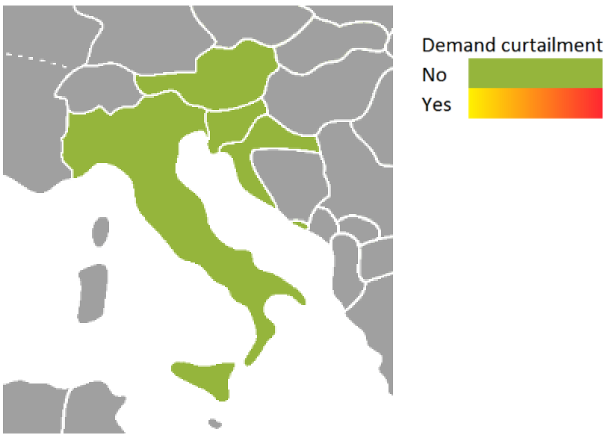
Scenario duration: 2 months (1 January – 28 February)

Simulation results

January - March







Supply

Storages: Higher storage withdrawal in Italy.

Pipeline and LNG supplies: Higher imports from Algerian pipe gas to Italy.

Flows from Italy to Switzerland reverse compared to the reference scenario, resulting in a flow from Switzerland to Italy.

Higher flows from Austria to Italy.

LNG flows to Italy are increased in January and lower in February following the demand evolution.

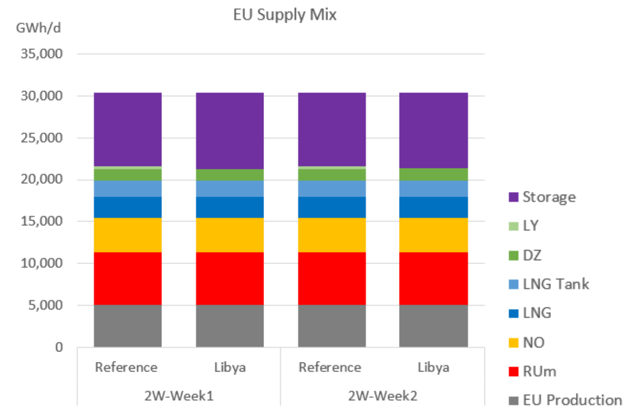
Demand

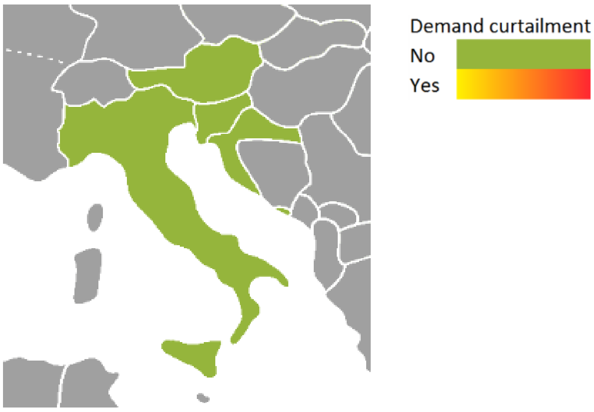
No demand curtailment

Scenario #17 - Disruption of the largest offshore infrastructure to Italy

Technical disruption of Green Stream

2-week / 20 years – simulated from 15 to 28 February





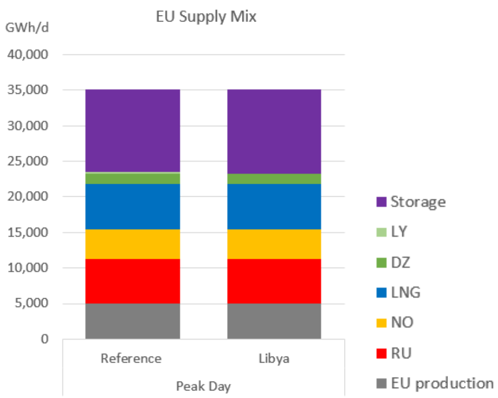
Supply

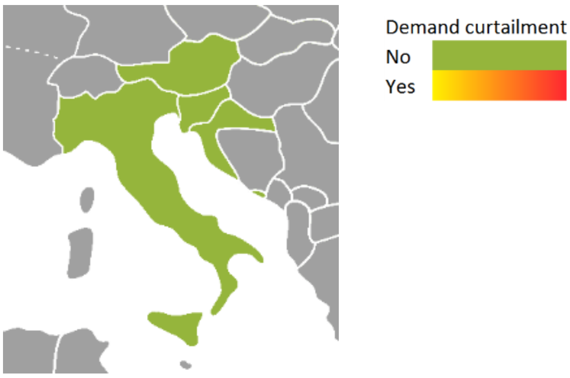
Storages: Higher storage withdrawal in Italy.
Pipeline and LNG supplies: Higher imports from Algerian pipe gas to Italy.
Higher flows from Austria to Italy.
Higher LNG flows to Italy.

Demand

No demand curtailment.

Peak day / 20 years – simulated on 15 February





Supply

Storages: Higher storage withdrawal limited by withdrawal characteristics from the storages.

Pipeline and LNG supplies: Higher imports from Algerian pipe gas to Italy. Higher flows from Austria to Italy.
Reduced flows from Italy to Switzerland.
LNG flows in reference already making use of the maximum regasification capacity.

Demand

No demand curtailment.

Results analysis

A high fill level of LNG tanks can help mitigating spontaneous risks and delays for new LNG to arrive.

Annexes: data tables

Annex I: Demand

Average daily demand and exports [GWh/d]								
Country	OCT	NOV	DEC	JAN	FEB	MAR	2-week	Peak day
AT	302	335	441	414	412	339	471	471
BA	4	6	9	11	7	5	12	16
BEh	404	483	614	718	663	527	883	964
BEl	113	135	171	200	185	147	378	454
BGn	87	107	127	150	128	101	157	173
CH	109	151	184	219	162	119	225	230
CZ	259	303	479	421	432	315	592	727
DEg	912	1,165	1,482	1,384	1,387	1,255	1,572	1,914
DEgL	187	265	397	344	343	286	434	571
DEn	801	1,141	1,710	1,478	1,477	1,229	1,870	2,460
DEnL	398	553	801	703	703	595	871	1,131
DK	66	93	115	126	122	106	190	230
EE	16	22	39	38	31	36	57	70
ES	1,031	1,257	1,281	1,292	1,269	1,135	1,549	1,823
FI	103	114	148	152	131	140	220	240
FRn	781	1,181	1,594	1,376	1,286	1,062	2,112	2,456
FRnL	143	206	265	223	187	150	336	391
FRs	344	550	718	681	633	516	952	1,107
FRt	72	113	154	186	169	133	214	330
GR	125	158	152	186	191	149	191	228
HR	91	121	107	107	145	93	161	175
HU	314	425	539	623	574	443	780	820
IB-RUek	-	-	-	-	-	-	-	-
IE	146	166	193	202	201	188	220	282
IT	2,139	2,718	3,618	3,590	3,373	2,885	4,122	4,825
LT	76	74	82	98	68	76	128	151
LU	43	46	57	54	53	47	59	72
LV	49	60	89	79	95	70	104	135
MK	8	11	14	17	13	4	19	19
NL	1,189	1,297	1,742	2,058	1,921	1,496	3,454	3,706
PL	460	588	647	746	669	550	929	973
PT	160	180	176	198	181	176	221	252
RO	353	538	528	561	638	458	719	776
RS	62	62	62	62	62	62	95	104
RUk	79	79	79	79	79	79	109	109
SE	23	31	37	43	41	34	86	86
SI	33	40	42	47	46	39	56	62
SK	156	205	269	281	253	229	441	496
TRe	393	393	393	393	393	393	480	480
UAe	363	363	363	363	363	363	416	416
UK	2,450	3,165	3,969	4,325	4,107	3,551	4,403	5,144
UKn	61	66	68	74	72	68	93	94

Table 5: Demand

Annex II: National production

	Average daily production [GWh/d]							
Country	OCT	NOV	DEC	JAN	FEB	MAR	2-week	Peak day
AT	38	36	40	39	33	33	40	40
BGn	2	2	2	2	2	2	3	3
CZ	4	4	4	4	4	4	5	5
DEg	55	54	54	53	53	52	11	11
DEgL	131	129	128	126	125	123	175	175
DEn	9	9	9	9	9	9	9	9
DEnL	-0	-0	-0	-0	-0	-0	-0	-0
DK	7	7	7	7	7	7	7	7
EE	-0	-0	-0	-0	-0	-0	-0	-0
FI	0	0	0	0	0	0	0	0
HR	36	36	36	36	36	36	37	37
HU	44	44	44	44	44	44	82	82
IE	97	96	95	94	93	92	97	97
IT	188	188	188	180	187	180	189	189
LU	-0	-0	-0	-0	-0	-0	-0	-0
NL	1162	1309	1397	1400	1419	1300	2769	2769
PL	74	74	74	74	74	74	74	74
RO	251	279	297	306	305	284	310	310
SE	1	1	1	1	1	1	2	2
SI	-0	-0	-0	-0	-0	-0	-0	-0
SK	3	3	2	2	2	2	3	3
UK	1066	1079	1088	1131	1116	1088	1250	1250

Table 6: National production

Annex III: Storages

Name	Working Gas Volume [GWh]	Initial filling level [% of WGV]
AT	42,367	82%
ATm	19,415	82%
ATn	29,980	82%
BEh	9,001	82%
BGn	6,270	82%
CZ	31,419	82%
CZd	6,117	82%
DE	4,767	82%
DEd	1,832	82%
DEdL	4,392	82%
DEg	101,563	82%
DEgL	15,020	82%
DEm	42,228	82%
DEmL	3,338	82%
DEn	74,388	82%
DEnL	6,162	82%
DK	10,820	82%
ES	31,619	82%
FRn	57,700	82%
FRnL	13,100	82%
FRs	31,150	82%
FRt	32,515	82%
HR	5,605	82%
HU	67,125	82%
IT	192,939	82%
LV	25,520	43%
NL	130,127	93%
PL	33,201	82%
PT	3,570	82%
RO	33,944	82%
RS	4,950	82%
SE	105	82%
SKm	36,728	82%
UK	14,106	82%

Table 7: Storage working gas volumes and initial levels (WGV: source AGSI+)

UGS inventory

Injection availability

Name	100%	99%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%
AT	0%	63%	74%	81%	90%	93%	97%	98%	99%	99%	100%	100%
ATm	0%	63%	74%	81%	90%	93%	97%	98%	99%	99%	100%	100%
ATn	0%	63%	74%	81%	90%	93%	97%	98%	99%	99%	100%	100%
BEh	0%	37%	50%	50%	100%	100%	100%	100%	100%	100%	100%	100%
BGn	0%	55%	56%	56%	100%	100%	100%	100%	100%	100%	100%	100%
CY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CZ	0%	30%	30%	35%	70%	75%	99%	100%	100%	100%	98%	96%
CZd	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
DE	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEd	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEdL	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEg	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEgL	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEm	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEmL	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEn	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DEnL	0%	50%	59%	69%	80%	88%	97%	98%	99%	99%	100%	100%
DK	0%	56%	61%	68%	79%	85%	93%	96%	98%	99%	100%	100%
EE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ES	0%	55%	85%	90%	90%	90%	95%	100%	100%	100%	100%	100%
FI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FRn	0%	62%	68%	78%	94%	95%	96%	97%	98%	98%	99%	100%
FRnL	0%	62%	68%	78%	94%	95%	96%	97%	98%	98%	99%	100%
FRs	0%	26%	36%	44%	51%	58%	65%	72%	80%	87%	93%	100%
FRt	0%	75%	82%	89%	96%	100%	100%	100%	100%	100%	100%	100%
GR	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HR	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
HU	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
IE	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
IT	0%	54%	54%	62%	73%	82%	92%	97%	100%	100%	100%	100%
LT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LV	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
NL	0%	62%	68%	73%	82%	87%	92%	94%	96%	98%	99%	100%
PL	0%	53%	76%	77%	81%	81%	81%	85%	87%	88%	99%	100%
PT	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
RO	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
RS	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
SE	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SKm	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%
UK	0%	55%	63%	70%	81%	87%	94%	96%	98%	99%	100%	100%

Table 8: injection curves

UGS inventory

Name	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	1%	0%
AT	100%	99%	98%	97%	97%	95%	90%	83%	73%	63%	51%	0%
ATm	100%	99%	98%	97%	97%	95%	90%	83%	73%	63%	51%	0%
ATn	100%	99%	98%	97%	97%	95%	90%	83%	73%	63%	51%	0%
BEh	100%	100%	100%	100%	100%	100%	100%	100%	35%	35%	24%	0%
BGn	74%	74%	100%	100%	100%	100%	89%	79%	79%	60%	37%	0%
CY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CZ	100%	100%	100%	100%	100%	97%	75%	70%	45%	40%	37%	0%
CZd	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
DE	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEd	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEdL	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEg	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEgL	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEm	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEmL	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEn	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DEnL	100%	99%	97%	96%	95%	93%	85%	75%	63%	51%	34%	0%
DK	100%	100%	100%	100%	100%	100%	100%	100%	85%	40%	30%	0%
EE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ES	100%	80%	72%	67%	63%	60%	55%	50%	45%	40%	37%	0%
FI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FRn	100%	98%	96%	93%	90%	86%	78%	68%	56%	44%	31%	0%
FRnL	100%	100%	100%	100%	100%	100%	100%	100%	99%	93%	85%	0%
FRs	100%	95%	91%	87%	82%	78%	70%	60%	55%	49%	32%	0%
FRt	100%	98%	96%	93%	91%	89%	83%	73%	64%	55%	45%	0%
GR	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HR	100%	100%	100%	100%	100%	96%	80%	65%	48%	32%	14%	0%
HU	100%	100%	100%	100%	99%	97%	95%	87%	78%	62%	52%	0%
IE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IT	100%	100%	96%	94%	93%	91%	89%	77%	69%	62%	25%	0%
LT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LV	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
NL	100%	97%	94%	92%	90%	86%	80%	72%	63%	54%	34%	0%
PL	100%	100%	99%	98%	97%	92%	86%	79%	74%	63%	39%	0%
PT	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
RO	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
RS	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
SE	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SKm	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%
UK	100%	98%	96%	95%	94%	91%	85%	75%	65%	54%	37%	0%

Withdraw deliverability

Table 9: withdrawal curves

Annex IV: LNG

Name	LNG Tank Capacity [GWh]	LNG Tank Flexibility [% of LNG Tank Capacity]
BE	5,206	35%
ES	22,718	41%
FRn	6,371	73%
FRs	2,809	58%
GR	2,432	35%
IT	3,322	15%
LT	2,329	3%
NL	7,398	35%
PL	2,192	33%
PT	2,672	32%
UK	14,351	35%

Table 10: LNG tank capacity and flexibility

Annex V: Capacities

Capacity data is available at this link https://entsog.eu/publications/security-of-gas-supply#All

Abbreviations:

Country codes are defined according to the ISO standard 3166-1
DC: Design Case, identical with Peak Day
EC: European Commission
ENTSOG: European Network of Transmission System Operators for Gas
EU: European Union
GCG: Gas Coordination Group
GIE: Gas Infrastructure Europe
GLE: Gas LNG terminals operators Europe
GSE: Gas Storages operators Europe
H-gas: High calorific gas
L-gas: Low calorific gas
LNG: Liquified Natural Gas
NeMo: ENTSOG's modelling tool
SoS: Security of Supply
TSO: Transmission System Operators
UGS: Underground Gas Storage
WGV: Working Gas Volumes
WSO: Winter Supply Outlook

ENTSOG AISBL

Avenue de Cortenbergh 100
1000 Brussels, Belgium
Tel. +32 2 894 51 00

info@entsog.eu
www.entsog.eu