economie
FPS Economy, S.M.E.s, Self-employed and Energy

Preventive Action Plan Belgium

After Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard security of gas supply

16 January 2024

FPS Economy, S.M.E.s, Self-Employed and Energy
North Gate III, Koning Albert II-laan 16

1000 Brussels

Table of Contents

Executive summary

EN

The Security of Gas Supply Regulation

EU Regulation 2017/1938 ("The Regulation") mandates that EU Member States are required to implement measures to safeguard gas security of supply. To assess Member States' ability to supply gas, under predefined Standards (i.e. Infrastructure Standard and Supply Standard), Regulation 2017/1938 requires each Member State to prepare a National Risk Assessment. The National Risk Assessment identifies possible risks and hazards to Member States security of gas supply. In addition, Member States are required to prepare a Preventive Action Plan which outlines measures to either remove or mitigate the risks and hazards identified in the Risk Assessment.

Preventive Action Plan

Pursuant to the Regulation, Member States are required to implement measures to safeguard security of gas supply including, inter-alia, the development of this Preventive Action Plan. The purpose of this preventive action plan is to identify the possible measures the Belgian government and the stakeholders in the gas industry can take in order to reduce risks that could occur in the gas supply chain.

This Preventive Action Plan is developed by the Directorate General for Energy in concertation with the National Regulatory Authority (CREG) and the Transport System Operator (Fluxys Belgium). This plan shall be notified to the European Commission and made public and will be updated every 4 years.

The first sections of this Preventive Action Plan consists of information already present in the Risk Assessment that was notified to the Commission in February 2019, which is not made public. This information covers mainly the description of the gas system in Belgium and its compliance with the infrastructure standard, including in the regional context, and a summary of the scenarios examined in the Risk Assessment upon which the preventive measures are based.

The second part presents all the measures put in place in Belgium that can have a positive impact on the security of gas supply, including voluntary measures available to the market actors, other obligations or measures related to the security of supply and regional cooperation either between the TSOs (operational level) or directly between the Members States.

Belgium's Risk Assessment

The Infrastructure Standard: is assessed by performing the N-1 calculation. The N-1 calculation removes the technical capacity of the single largest piece of gas infrastructure on a peak day with a view to determining whether the remaining gas infrastructure can meet 100% of peak day gas demand. To comply with the standard, the calculation must equate to 100% or more. The result is well above 100% due to the many interconnection points with various supply routes. This means that the Belgian gas network is still able to supply the Belgian market during a day of peak consumption without the largest import infrastructure (Interconnection point with UK).

Disruption of the LNG terminal (Zeebrugge) or the Underground Gas Storage (Loenhout): while both these installations contribute to the diversification of gas sources and provide the market with

alternatives in case of a crisis, neither of them is found strictly essential on its own to supply the Belgian end-consumers during a peak day.

Nuclear phase out and L/H conversion: in the coming years, two events are going to have a noticeable impact on the H-gas consumption in Belgium: first, the further conversion of the L-gas network that will gradually shift the consumption of a large part of the public distribution from L-gas to H-gas. By the end of 2024 (1/09/24), all L-gas consumers in BE will have switched to H-gas; However, there will still be transit from L-gas to FR (as long as FR wishes, which is currently until 2030). The second event is the phasing-out of nuclear power plants. The nuclear phasing-out has been prepared for some time with the implementation of the CRM. This CRM mechanism is technologically neutral. At the moment, we have only contracted 2 new CCGTs since 2021 (Awirs and Seraing) – delivery year 2025 with a 15-year contract. The nuclear phasing-out will also be compensated by new batteries, DSM (demand-side management), major overhauls of existing gas-fired power plants, etc. However, with the Winter plan of July 2022, it was decided to extend Doel 4 and Tihange 3 for 10 years from November 25. These two events will have the effect of increasing the consumption of H-gas in Belgium. A first evaluation using the N-1 method with the existing H-gas entry capacities and predictions for the gas consumption in the coming years has shown no problem for the Belgian transmission network to cover this increasing demand (abstracting from transit).

Preventive Measures

Increased import flexibility: most companies have access to flexible contracts, both for the gas (molecules) and capacities on the transmission network. This allows them to react to events or evolutions of the situation by adjusting the level of utilization of the different supply routes according to the demand.

Commercial gas storage: there is one underground gas storage in Loenhout. At European level, storage generally contributes to the security of supply during the winter months. While it is not strictly essential on its own to supply the Belgian end-consumers during a peak day, it contributes to the diversification of gas sources and provide the market with alternatives in case of a crisis and provides the shippers and suppliers with one more arbitrage possibility. Under normal winter circumstances and if the storage is filled up to its full capacity, the stored gas can be used during about 60 days.

LNG terminal: in addition to the many supply sources available to the Belgian market by pipelines, the Zeebrugge LNG re-gasification terminal offers even more sources diversification by giving access to LNG producers all over the world. The availability of LNG on the global market is also expected to increase in the coming years following the discoveries of new gas reserves.

Diversification of gas supply sources and routes: most suppliers have multiple contracts with different suppliers and import gas via a variety of supply routes. The higher the diversification, the lower the impact of an incident on one supply source or route.

Bidirectional capacity and backhaul : capacity in both directions is offered at every interconnection point, either by physical bi-directionality or by reverse flow when the physical flows are consistently unidirectional. According to the network code on capacity allocation mechanisms, auctions are continuously organized giving the market the opportunity to signal capacity requirements. New investments in infrastructure to respond to market interests are analysed yearly by the TSO in the investment plan for the coming 10 years.

Interruptible contracts: as a form of demand-side management, suppliers may conclude interruptible contracts with their clients. In this case, they have the right to interrupt the customer, normally in return for a discount on price and with some notice. This type of contract is however seldom used, because many cheaper supply side measures are available to the suppliers in Belgium.

The TSO may also offer interruptible capacity at interconnection points, but only after all firm capacity is booked. Firm capacity being widely available, interruptible capacity is not often used either.

Regional cooperation

According to Annex I - Regional Cooperation of Regulation No 2018/1937, Member States' risk groups are the basis for risk-based cooperation. In accordance with Article 7 (2), significant transnational risks to the security of gas supply in the Union are identified and risk groups should be identified on this basis. These risk groups serve as a basis for enhanced regional cooperation with the aim to increase the security of gas supply and allow all Member States concerned to agree on appropriate and effective cross-border measures within or outside these groups alongside emergency corridors.

Belgium is a member of four risk groups that are dependent on supplies from the North Sea or from the East.

L-gas risk group

Member States: Belgium, France, Germany, the Netherlands

North Sea risk group

Member States: Belgium, Denmark, Germany, Ireland, Spain, France, Italy, Luxembourg, the Netherlands, Portugal, Sweden

Baltic Sea Risk Group

Member States: Germany, Czech Republic, Austria, Belgium, Denmark, France, Luxembourg, the Netherlands, Slovakia, Sweden

Belarus Risk group

Member states: Belgium, Czech Republic, Germany, Estonia, Latvia, Lithuania, Luxembourg, the Netherlands, Poland, Slovakia.

FR

Le Règlement sur la sécurité de l'approvisionnement en gaz

Le règlement de l'UE 2017/1938 («le Règlement») stipule que les États membres de l'UE sont tenus de mettre en œuvre des mesures pour garantir la sécurité de l'approvisionnement en gaz. Pour évaluer la capacité des États membres à fournir du gaz, selon des normes prédéfinies (c'est-à-dire une norme d'infrastructure et une norme d'approvisionnement), le Règlement impose à chaque État membre de préparer une évaluation nationale des risques. L'évaluation nationale des risques identifie les risques et dangers potentiels pour la sécurité de l'approvisionnement en gaz des États membres. De plus, les États membres sont tenus de préparer un plan d'action préventif qui décrit les mesures visant à éliminer ou à atténuer les risques et dangers identifiés dans l'évaluation des risques.

Plan d'action préventive

En vertu du règlement, les États membres sont tenus de mettre en œuvre des mesures visant à garantir la sécurité de l'approvisionnement en gaz, y compris, entre autres, l'élaboration de ce plan d'action préventive. L'objectif de ce plan est d'identifier les mesures que le gouvernement fédéral belge et les acteurs de l'industrie gazière peuvent prendre afin de réduire les risques qui pourraient survenir dans la chaîne d'approvisionnement en gaz.

Ce plan d'action préventive est élaboré par la direction générale de l'énergie en concertation avec l'autorité nationale de régulation (CREG) et le gestionnaire du système de transport (Fluxys Belgium). Ce plan sera notifié à la Commission européenne et rendu public et sera mis à jour tous les 4 ans.

Les premières sections de ce plan d'action préventif sont constituées d'informations déjà présentes dans l'évaluation des risques qui a été notifiée à la Commission en février 2019, qui n'est pas rendue publique. Ces informations couvrent principalement la description du système gazier en Belgique et sa conformité à la norme d'infrastructure, y compris dans le contexte régional, et une synthèse des scénarios examinés dans l'évaluation des risques sur laquelle repose les mesures préventives.

La deuxième partie de ce plan d'action préventive présente l'ensemble des mesures mises en place en Belgique qui peuvent avoir un impact positif sur la sécurité de l'approvisionnement en gaz, y compris les mesures volontaires à la disposition des acteurs du marché, d'autres obligations ou mesures liées à la sécurité d'approvisionnement et la coopération régionale soit entre les GRT (niveau opérationnel) ou directement entre les États membres.

Évaluation des risques en Belgique

La norme d'infrastructure est évaluée en effectuant le calcul N-1. Le calcul N-1 supprime la capacité technique de la plus grande pièce d'infrastructure gazière un jour de pointe afin de déterminer si l'infrastructure gazière restante peut répondre à 100% de la demande de gaz pendant la journée de pointe. Pour se conformer à la norme, le calcul doit être égal ou supérieur à 100%. Le résultat pour le gaz est bien supérieur à 100% grâce aux nombreux points d'interconnexion avec diverses routes d'approvisionnement. Cela signifie que le réseau belge de gaz est toujours en mesure d'approvisionner le marché belge pendant une journée de pointe de consommation sans la plus grande infrastructure d'importation (point d'interconnexion avec le Royaume-Uni).

Perturbation du terminal GNL (Zeebrugge) ou du stockage souterrain de gaz (Loenhout): si ces deux installations contribuent à la diversification des sources de gaz et offrent au marché des alternatives en cas de crise, aucune d'elles n'est jugée strictement indispensable à elle seule pour approvisionner les consommateurs finaux belges pendant une journée de pointe.

Sortie du nucléaire et conversion L / H: dans les années à venir, deux événements vont avoir un impact notable sur la consommation de gaz H en Belgique: premièrement, la poursuite de la conversion du réseau de gaz L qui va progressivement déplacer la consommation d'une grande partie de la distribution publique du gaz L au gaz H. D'ici fin 2024 (1/09/24), tous les consommateurs de gaz L en Belgique seront passés au gaz H ; cependant, il y aura toujours un transit de gaz L vers la France (aussi longtemps que la France le souhaite, ce qui est actuellement le cas jusqu'en 2030). Le deuxième événement est la fermeture progressive des centrales nucléaires. Le phasing-out nucléaire est préparé depuis un temps certain avec la mise en place du CRM. Ce mécanisme CRM est technologiquement

neutre. Pour le moment, nous n'avons contracté depuis 2021 que seulement 2 nouvelles CCGT (Awirs et Seraing) – année de livraison 2025 avec contrat de 15 ans. Le phasing-out nucléaire sera également compensée par de nouvelles batteries, de la DSM (gestion de la demande), des révisions majeures des centrales à gaz existantes, etc. Cependant, avec le Winter plan de juillet 2022, il a été décidé de prolonger par ailleurs Doel 4 et Tihange 3 pour 10 ans dès novembre 25. Ces deux événements auront pour effet d'augmenter la consommation de gaz H en Belgique. Une première évaluation utilisant la méthode N-1 avec les capacités d'entrée de gaz H existantes et les prévisions de consommation de gaz dans les années à venir n'a montré aucun problème pour le réseau de transport belge pour couvrir cette demande croissante (abstraction du transit).

Mesures préventives

Flexibilité d'importation accrue: la plupart des entreprises ont accès à des contrats flexibles, tant pour le gaz (molécules) que pour les capacités sur le réseau de transport. Cela leur permet de réagir aux événements ou évolutions de la situation en ajustant le niveau d'utilisation des différentes voies d'approvisionnement en fonction de la demande.

Stockage de gaz commercial: il existe un stockage de gaz souterrain à Loenhout. Au niveau européen, le stockage contribue généralement à la sécurité d'approvisionnement pendant les mois d'hiver. S'il n'est pas strictement indispensable à lui seul pour approvisionner les consommateurs finaux belges pendant une journée de pointe, il contribue à la diversification des sources de gaz et offre au marché des alternatives en cas de crise et offre aux affréteurs et aux fournisseurs un autre possibilité d'arbitrage. Dans des conditions hivernales normales et si le stockage est rempli à sa pleine capacité, le gaz stocké peut être utilisé pendant environ 60 jours.

Terminal GNL: en plus des nombreuses sources d'approvisionnement par pipelines disponibles pour le marché belge, le terminal de regazéification de GNL de Zeebrugge offre encore plus de diversification des sources en donnant accès aux producteurs de GNL partout dans le monde. La disponibilité du GNL sur le marché mondial devrait également augmenter dans les années à venir suite à la découverte de nouvelles réserves de gaz.

Diversification des sources et des itinéraires d'approvisionnement en gaz: la plupart des fournisseurs ont plusieurs contrats avec différents fournisseurs et importent du gaz via diverses routes d'approvisionnement. Plus la diversification est élevée, plus l'impact d'un incident sur une source ou une route d'approvisionnement est faible.

Capacité bidirectionnelle et backhaul: la capacité dans les deux sens est offerte à chaque point d'interconnexion, soit par bi-directionalité physique, soit par flux inversé lorsque les flux physiques sont systématiquement unidirectionnels. Selon le code de réseau sur les mécanismes d'allocation de capacité, les enchères sont organisées en permanence, ce qui permet au marché de signaler les besoins en capacité. Les nouveaux investissements en infrastructures pour répondre aux intérêts du marché sont analysés annuellement par le GRT dans le plan d'investissement pour les 10 prochaines années.

Contrats interruptibles: en tant que forme de gestion de la demande, les fournisseurs peuvent conclure des contrats interruptibles avec leurs clients. Dans ce cas, ils ont le droit d'interrompre le client, normalement en échange d'une remise sur le prix et avec un certain préavis. Ce type de contrat

est cependant rarement utilisé, car de nombreuses mesures moins chères du côté de l'offre sont disponibles pour les fournisseurs en Belgique.

Le GRT peut également proposer des capacités interruptibles aux points d'interconnexion, mais seulement après la réservation de toutes les capacités fermes. La capacité ferme étant largement disponible, la capacité interruptible n'est pas non plus fréquemment utilisée.

Coopération régionale

Selon l'annexe I du Règlement, les groupes de risque constituent la base d'une coopération régionale. Conformément à l'article 7, paragraphe 2, les risques transnationaux importants pour la sécurité de l'approvisionnement en gaz dans l'Union sont identifiés et les groupes de risques doivent être identifiés sur cette base. Ces groupes de risque servent de base à une coopération régionale renforcée dans le but d'accroître la sécurité de l'approvisionnement en gaz et de permettre à tous les États membres concernés de convenir de mesures transfrontalières appropriées et efficaces à l'intérieur ou à l'extérieur de ces groupes le long des corridors d'urgence.

La Belgique fait partie de quatre groupes de risque qui dépendent des approvisionnements en provenance de la mer du Nord ou de l'Est :

L-gas risk group

Etats membres: Belgique, France, Allemagne, les Pays-Bas

North Sea risk group

Etats membres: Belgique, Dannemark, Allemagne, Irelande, Espagne, France, Italie, Luxembourg, les Pays-Bas, Portugal, Suède.

Baltic Sea Risk Group

Etats membres: Allemagne, Tchéquie, Autriche, Belgique, Dannemark, France, Luxembourg, les Pays-Bas, Slovaquie, Suède.

Belarus Risk group

Etats membres: Belgique, Tchéquie, Allemagne, Estonie, Lettonie, Lituanie, Luxembourg, les Pays-Bas, Pologne, Slovaquie.

NL

Verordening betreffende de gasleveringszekerheid

De verordening van de EU 2017/1938 (« de Verordening ») bepaalt dat de Lidstaten van de EU verplicht zijn maatregelen te nemen om de gasbevoorradingszekerheid veilig te stellen. Om de gasleveringscapaciteit van de Lidstaten te evalueren volgens vooraf bepaald normen (d.w.z. een infrastructuurnorm en een bevoorradingsnorm) verplicht de verordening elke Lidstaat een nationale risico-evaluatie voor te bereiden. De nationale risico-evaluatie identificeert de potentiële risico’s en gevaren voor de gasleveringszekerheid van de Lidstaten. Bovendien moeten de Lidstaten een

preventief actieplan voorbereiden waarin de maatregelen beschreven staan om de risico's en gevaren die in de risico-evaluatie geïdentificeerd zijn, uit te schakelen of te verminderen.

Preventief actieplan

Krachtens de verordening zijn de Lidstaten verplicht maatregelen toe te passen om de gasleveringszekerheid te garanderen, waaronder ook de uitwerking van dat preventief actieplan. Dat plan heeft tot doel de maatregelen te identificeren die de Belgische federale regering en de spelers van de gasindustrie kunnen nemen om de risico's te verminderen die zich kunnen voordoen in de gasbevoorradingsketen.

Dat preventief actieplan wordt uitgewerkt door de algemene directie energie in overleg met de nationale reguleringsoverheid (CREG) en de beheerder van het vervoersnet (Fluxys Belgium). Dat plan zal aan de Europese Commissie ter kennis worden gebracht, zal openbaar worden gemaakt en zal elke 4 jaar worden bijgewerkt.

De eerste afdelingen van dat preventief plan bevat informatie welke reeds beschreven is in de risico-evaluatie die in februari 2019 aan de Commissie ter kennis is gebracht en die niet openbaar is gemaakt. Die informatie bestaat hoofdzakelijk uit een beschrijving van het Belgische gassysteem en de gelijkvormigheid ervan met de infrastructuurnorm, ook in de regionale context, en uit een samenvatting van de scenario's die onderzocht zijn binnen de risico-evaluatie waarop de preventieve maatregelen gestoeld zijn.

Het tweede deel van dat preventief actieplan geeft een overzicht van alle maatregelen die in België genomen zijn om een positieve impact te hebben op de gasbevoorradingszekerheid, inclusief de vrijwillige maatregelen waarover de marktspelers beschikken, andere verplichtingen of maatregelen die gelinkt zijn aan de bevoorradingszekerheid en de regionale samenwerking ofwel met de TNBs (operationeel niveau) of rechtstreeks tussen de Lidstaten.

Evaluatie van de risico's in België

De infrastructuurnorm wordt geëvalueerd via de berekening N-1. De berekening N-1 schrapt de technische capaciteit van het grootste gasinfrastructuuronderdeel op een piekdag om na te gaan of de overblijvende gasinfrastructuur voor 100% kan beantwoorden aan de vraag naar gas gedurende de piekdag. Om de norm te respecteren moet de berekening uitkomen op 100% of meer. Het resultaat voor gas bedraagt meer dan 100% dankzij de talrijke aansluitingspunten met diverse bevoorradingsroutes. Dat betekent dat het Belgische net voor gas steeds in staat is om de Belgische markt op een dag met piekverbruik te bevoorraden zonder de grootste invoerinfrastructuur (aansluitingspunt met het Verenigd Koninkrijk)

Storing in de LNG-terminal (Zeebrugge) of in de ondergrondse gasopslag (Loenhout) : hoewel beide installaties bijdragen tot de diversificatie van de aardgasbronnen en zij de markt alternatieven bieden in geval van crisis wordt geen van beide strikt onontbeerlijk geacht om de Belgische eindverbruikers te bevoorraden op een piekdag.

Nucleaire uitstap en L/H-conversie : in de komende jaren zullen twee belangrijke gebeurtenissen een aanzienlijke impact hebben op het verbruik van H-gas in België : ten eerste de verdere conversie van het netwerk voor L-gas waardoor het verbruik van L-gas van een groot deel van de openbare distributie geleidelijk zal verschuiven naar verbruik van H-gas. Tegen eind 2024 (1/09/24) zullen alle L-gasverbruikers in BE zijn overgestapt op H-gas; Er zal echter nog steeds doorvoer zijn van L-gas naar FR (zolang FR dat wenst, wat momenteel tot 2030 is). De tweede gebeurtenis is de geleidelijke sluiting van de kerncentrales. De nucleaire uitfasering is al enige tijd voorbereid met de implementatie van het CRM. Dit CRM-mechanisme is technologisch neutraal. Op dit moment hebben we sinds 2021 slechts 2 nieuwe STEG's gecontracteerd (Awirs en Seraing) – leveringsjaar 2025 met een contract van 15 jaar. De uitfasering van kernenergie zal ook worden gecompenseerd door nieuwe batterijen, DSM (beheer van de vraagzijde), grote revisies van bestaande gasgestookte elektriciteitscentrales, enz. Met het Winterplan van juli 2022 werd echter wel beslist om Doel 4 en Tihange 3 vanaf 25 november met 10 jaar te verlengen. Beide gebeurtenissen zullen ertoe leiden dat het verbruik van H-gas in België zal toenemen. Een eerste evaluatie waarbij gebruik werd gemaakt van de methode N-1 met de bestaande injectiecapaciteit voor H-gas en van de prognoses inzake het gasverbruik in de komende jaren hebben voor het Belgische transmissienet geen enkel probleem blootgelegd om aan die stijgende vraag te voldoen (abstractie makend van doorvoer).

Preventieve maatregelen

Grotere invoerflexibiliteit : de meeste ondernemingen hebben toegang tot flexibele contracten, zowel voor gas (moleculen) als voor de capaciteit op het vervoersnet. Zo kunnen zij reageren op gebeurtenissen of evoluties van de toestand door het gebruiksniveau van de verschillende bevoorradingsroutes bij te sturen in functie van de vraag.

Commerciële gasopslag : in Loenhout is er ondergrondse gasopslag. Op Europees niveau draagt opslag over het algemeen bij tot de bevoorradingszekerheid tijdens de wintermaanden. Ook al is deze opslag niet strikt onontbeerlijk om de Belgische eindverbruikers op een piekdag te bevoorraden, hij draagt hoe dan ook bij tot de diversifiëring van de gasbronnen en biedt de markt alternatieven in geval van crisis en biedt de bevrachters een andere arbitragemogelijkheid. In normale winteromstandigheden en als de opslag tot volledige capaciteit gevuld is, kan het opgeslagen gas gedurende ongeveer 60 dagen gebruikt worden.

LNG-terminal : naast de talrijke bevoorradingsbronnen via pijpleidingen die voor de Belgische markt beschikbaar zijn, biedt de terminal met hervergassing van LNG van Zeebrugge nog meer diversificatie van bronnen door aan LNG-producenten uit de hele wereld toegang te geven. De beschikbaarheid van LNG op de wereldwijde markt zou in de komende jaren eveneens moeten toenemen naar aanleiding van de ontdekking van nieuwe gasreserves.

Diversifiëring van gasbronnen en van gasbevoorradingsroutes : de meeste leveranciers hebben verscheidene contracten met verschillende leveranciers en voeren gas in via diverse bevoorradingsroutes. Hoe groter de diversificatie, hoe kleiner de impact is van een gebeurtenis op een bron of een bevoorradingsroute.

Bidirectionele capaciteit en backhaul1 : capaciteit in twee richtingen wordt op elk aansluitingspunt aangeboden, ofwel door fysiek tweerichtingsverkeer, ofwel door omgekeerde stroom wanneer de fysieke stromen zich systematisch in één enkele richting voortbewegen. Volgens de netwerkcode op de mechanismes voor capaciteitstoekenning worden permanent veilingen gehouden waardoor de markt de capaciteitsbehoefte kan aangeven. Nieuwe investeringen in infrastructuur om de belangen van de markt te behartigen worden elk jaar door de TNB geanalyseerd in het investeringsplan voor de 10 komende jaren.

Onderbreekbare contracten : als manier om aan vraagbeheer te doen, kunnen de leveranciers met hun afnemers onderbreekbare contracten afsluiten. In dat geval hebben zij het recht om de bevoorrading van de afnemer te onderbreken, normaal gezien in ruil voor een korting op de prijs en met een bepaalde opzegtermijn. Dit soort contract wordt echter zelden gebruikt want de leveranciers in België beschikken over tal van andere, minder dure maatregelen aan aanbodzijde.

De TNB kan ook onderbreekbare capaciteit op de aansluitingspunten voorstellen maar enkel na reservering van alle vaste capaciteit. Aangezien vaste capaciteit ruimschoots beschikbaar is, wordt de onderbreekbare capaciteit evenmin frequent gebruikt.

Regionale samenwerking

Volgens bijlage I van de Verordening dienen de risicogroepen als basis voor samenwerking in verband met risico's. Overeenkomstig artikel 7, paragraaf 2, worden de belangrijke grensoverschrijdende risico’s voor de gasleveringszekerheid in de Unie geïdentificeerd en moeten de risicogroepen op basis daarvan geïdentificeerd worden. Die risicogroepen dienen als basis voor nauwere regionale samenwerking met als doel de gasleveringszekerheid te vergroten en alle betrokken Lidstaten de mogelijkheid te bieden, binnen of buiten die groepen langs de noodcorridors, passende grensoverschrijdende maatregelen af te spreken.

België behoort tot vier risicogroepen die afhangen van bevoorrading via de Noordzee of de Oostzee :

L-gas risk group

Lidstaten: België, Frankrijk, Duitsland, Nederland

North Sea risk group

Lidstaten: België, Denemarken, Duitsland, Ierland, Spanje, Frankrijk, Italië, Luxemburg, Nederland, Portugal, Zweden, UK

Baltic Sea Risk Group

Lidstaten: Duitsland, Tsjechië, Oostenrijk, België, Denemarken, Frankrijk, Luxemburg, Nederland, Slovakije, Zweden

Belarus Risk group

1 capaciteitsboekingen in tegenstroom

Lidstaten: België, Tsjechië, Duitsland, Estland, Letland, Litouwen, Luxemburg, Nederland, Polen, Slovakije

0 Introduction

This Preventive Action Plan is developed pursuant to Regulation EU 2017/1938 concerning measures to safeguard the security of gas supply ("the Regulation") by the Directorate General for Energy of the Federal Public Service Economy, SMEs, Self-Employed and Energy, acting as the competent authority as defined in Article 2 of the Regulation. This Preventive Action Plan is developed in concertation with the National Regulatory Authority (CREG) and the Transport System Operator (Fluxys Belgium). This plan shall be notified to the European Commission and made public.

The purpose of this preventive action plan is to identify the possible measures the Belgian government and the stakeholders in the gas industry can take in order to reduce risks that could occur in the gas supply chain. It gives an overview of the actions that already exist and makes an analysis of new actions that could be introduced. The primary focus will be on the risk for the entire gas system. Risks that only have a local impact are part of the emergency planning of the transmission system operator and/or the distribution system operators.

In the risk assessment a series of risks were identified. The risk assessment gives a first indication of the main risk for our gas security of supply. The actions to take to reduce the risks and mitigate their impact have been included in this Preventive Action Plan.

As prescribed in the template given in Annex VI of the Regulation, this plain contains:

- A description of the gas system in Belgium, also in the regional context by giving overviews of the gas systems in the four risk groups;
- A summary of the Risk Assessment conducted pursuant to the Regulation, in order to identify the risks that will need to be addressed in this Plan;
- An explanation on how the Belgian gas system complies with the infrastructure standard, both at national and regional (risk group) level;
- An explanation on how the Belgian gas system complies with the supply standard, and the associated volumes consumed by the protected customers;
- A description of the market based preventive measures available to the gas sector to reduce the risks and mitigate their impact;
- A description of other measures and obligations imposed on the gas sector;
- A description of the recent and future gas infrastructure projects having a positive impact on the security of supply;
- A description of the public service obligations imposed on suppliers and system operator with a link to the security of supply; and
- A description of the cooperation put in place at regional level.

1 Description of the gas system

1.1 Regional systems in risk groups

The risk groups reflect the major transnational risks to the security of gas supply in the Union; their composition is based on the main gas supply sources and routes. Each risk group includes those Member States along a corridor that may play a strategic role in case of gas supply crisis. Belgium participated in five Risk groups, four since the United Kingdom ceased to be a Member State of the European Union (from 1 February 2020) and the UK group removed.

Besides those groups, Belgium is part of the Pentalateral Forum, and has built an integrated market with Luxemburg (Belux-market).

1.1.1 Regional risk groups

Belgium participates in four Risk groups, demonstrating its important role in the supply of the EU.

The main findings of the ENTSOG Union-wide simulation of gas supply and infrastructure disruption scenarios (SoS simulation) 2021 2 are:

- Even if the infrastructure allows for an efficient European gas market, an unexpected combination of extreme climatic conditions and supply route disruption may nevertheless result in local constraints and market limitations exposing some Member States to demand curtailment.
- The assessment confirms that the European gas infrastructure provides sufficient flexibility for the EU Member States to efficiently apply their cooperation mechanisms and ensure security of gas supply during extreme climatic conditions and individual supply route disruption scenarios.
- Nevertheless, in some scenarios infrastructure limitations and import limitations can prevent the Member States from fully efficient cooperation.
- Gas storages and LNG terminals are essential to ensure seasonal and short-term flexibility. The evolution of the storage levels results from market decisions and can significantly influence the withdrawal capacities and therefore the short-term flexibility gas storages can provide: a too low storage level at the end of the winter can increase the risk of exposure to demand curtailment in some countries and for some scenarios.
- Since 2017 the evolution of the European gas infrastructure considered in the simulation significantly improves the possible cooperation among Member States.
- Gas market evolution, changes in the Member States energy mixes, declining domestic production and coal-to-gas switch explain the evolution of the gas demand compared to the 2017 edition.

---

2 Before RU invasion of UA. Before progressively decline RU exports of pipeline gas to EU and the consequently reshuffling of supply in the EU (e.g. from east to west => west to east and replacement by LNG (mainly from US)).

- In all scenarios an efficient cooperation between EU Member States can export significant volumes to Energy Community Contracting Parties and other EU neighbouring countries.

Nine disruption scenarios in the four Risk Groups involving Belgium have been considered in the 2021 risk assessment by ENTSO-G (Table 1). Belgium is not exposed to a reduction in demand in any risk group or associated scenarios (2 weeks, 2 months) studied by ENTSO-G in 2021.

Table 1: Disruption scenarios considered in the Risk Groups involving Belgium (ENTSO-G 2021)

Risk Group	Members	Disruption scenario in EU wide simulation 2021
Low calorific gas	Belgium, Germany, France, Netherlands	#10 Disruption of the largest L-gas storage (Gas Platform) #11 Disruption of the L-gas supply
Norway	Belgium, Denmark, Germany, Ireland, Spain, France, Italy, Luxembourg, Netherlands, Poland, Portugal, Sweden	#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)
Baltic Sea	Belgium, Czech Republic, Denmark, Germany, France, Luxembourg, Netherlands, Austria, Slovakia, Sweden	#3 Disruption of one Nord Stream offshore pipeline (50% NOS) #4 Disruption of the onshore receiving facility of Nord Stream (Greifswald station, 100% NOS)
Belarus	Belgium, Czech Republic, Denmark, Germany, Estonia, Finland, Latvia, Lithuania, Luxembourg, Netherlands, Poland, Slovakia, Sweden	#2 Disruption of all imports via Belarus

Norway risk group became the North Sea risk group.

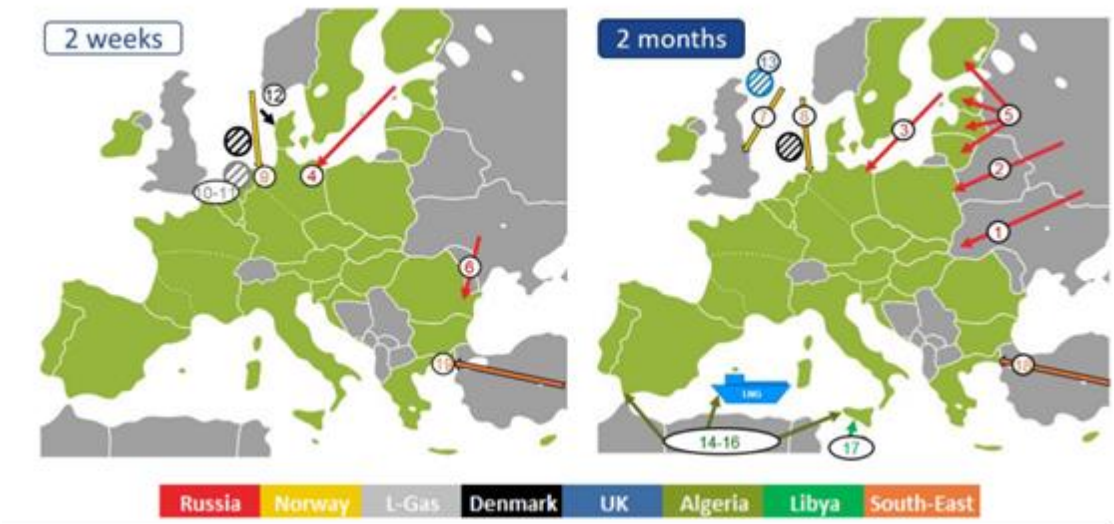


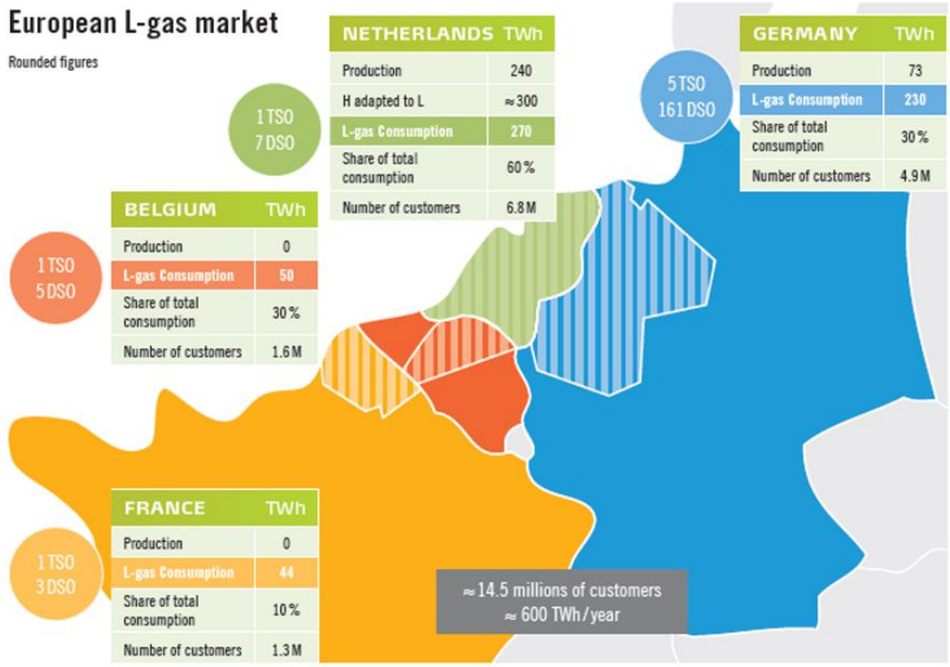
Figure 1: Disruption scenarios allocation Union-wide simulation (ENTSO-G 2021)

1.1.2 L-gas regional risk group

The low calorific gas risk groups encompasses Belgium, France, Germany and the Netherlands with the European Commission as an observer. The group is furthermore supported in its activities by the Benelux Secretariat.

The current market demand for all these L-gas consuming countries is shown in the overview below (Figure 2, based on 2017 data). The Netherlands is the largest consumer and main supplier of L-gas in the region. Germany, the second largest market, does also have L-gas production but this is insufficient to meet its domestic demand. Demand in Belgium and France is entirely supplied by imports from The Netherlands. L-gas exports from the Netherlands to Belgium/France is almost exclusively H-gas (from outside EU) and nitrogen3.

Figure 2: Overview L-gas market (Gas Regional Investment Plan North West 2017)



The last conversion phase in Belgium is foreseen in 2024 in 2 phases (1 June and 1 September) and has been formally validated. The GY 2023/24 conversion represents around 467.000 connections and a converted volume of 17,35 TWh under average weather conditions.

1.1.3 Baltic Sea

Risk group Baltic Sea consists of ten interconnected member states: Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxembourg, the Netherlands, Slovakia and Sweden.

3 E.g. BE L-gas depends on NL security of H-gas supply.

Figure 3: Baltic Sea Risk Group

1.1.4 Belarus

Risk group Belarus consists of thirteen interconnected member states: Belgium, Czech Republic, Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Luxembourg, the Netherlands, Poland, Slovakia and Sweden.

Figure 4: Belarus Risk Group

1.1.5 Norway and UK risk group - North Sea Risk Group

With the Brexit the UK risk group has been dissolved and relevant elements have been integrated and assessed in a newly created risk group: The North Sea Risk Group. The North Sea Risk Group results from the merger of the Norway Risk Group and the United Kingdom Risk Group. It is composed of the following twelve Member States: Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Poland, Portugal, Spain, and Sweden.

1.2 National system

1.2.1 Main gas consumption figures

Annual gas consumption

In 2021, the total measured gas demand of the Belgian end consumers amounted to 195,9 TWh, of which 153,2 TWh is H-gas (78% of total demand) and 42,6 TWh is L-gas (22% of total demand). This

results in about 16.9 bcm/year of total gas demand in Belgium. The Belgian gas consumption is divided over H-gas or high calorific gas and L-gas or low calorific gas, which we will treat separately.

The L-gas demand in Belgium also has a different behaviour than the H-gas demand due to the different consumers that are connected to the two networks. A large majority of the L-gas consumption (84%) is attributed to the public distribution and the remaining 16% goes to industrial consumers (large consumers) directly connected to the transmission network of Fluxys Belgium. There are no power plants on the L-gas transport network.

Gas demand by sector

The following figures show the breakdown of the total consumption for H-gas and L-gas network in 2021, of the public distribution (TD, normalized) (= households, small and medium enterprises, hospitals and schools), the large industrial players that are directly connected to the transmission network (TI), and for the electricity plants that are directly connected to the transmission network (TE).

Figure 5: Gas consumption (TWh) in 2021 - H- and L-gas

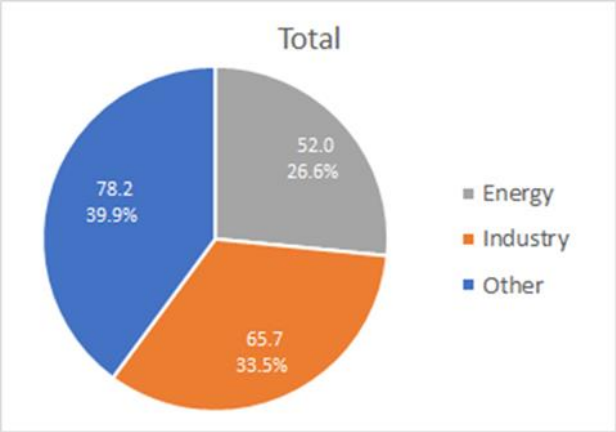


Figure 6: Gas consumption (TWh) in 2021 - H-gas

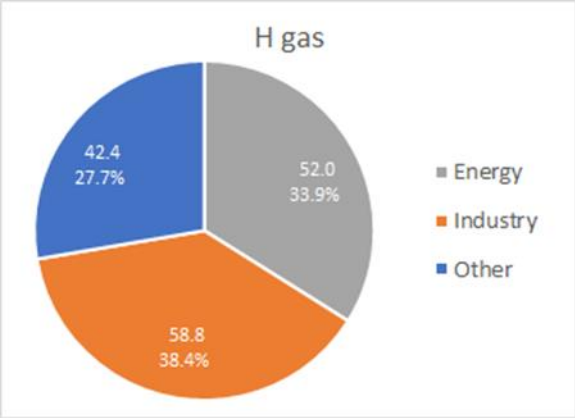
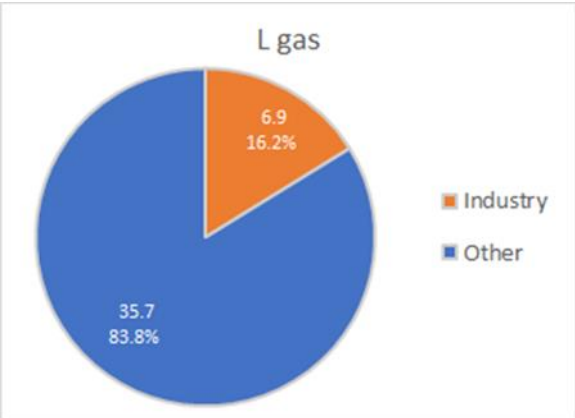


Figure 7: Gas consumption (TWh) in 2021 - L-gas



The above figures demonstrate the dominance of the “other” sector (residential, commercial, services, agriculture and transport) in Belgium. In 2021, 40% of the natural gas consumption in Belgium was used by the “other” sector, 34% by the industry and 27% by the energy sector. L gas is only used by the "other” sector (84%) and the industry (16%). H-gas is used by all three sectors, namely the “other” sector (28%), industry (38%) and the energy sector (34%).

Evolution of the yearly gas demand

Figure 8 and Figure 9 show the evolution of the total gas consumption in Belgium for the period 2012-2021 (in TWh/year) for the measured and a normalised temperature profiles. In Figure 8, we see that the consumption in 2014 has decreased due to the hotter year. Figure 8 also shows the breakdown of the H-gas and L-gas consumption, while Figure 9 shows the breakdown of the energy, industry and “other” sectors.

Figure 8: Evolution of yearly gas consumption (TWh) (2012-2021)

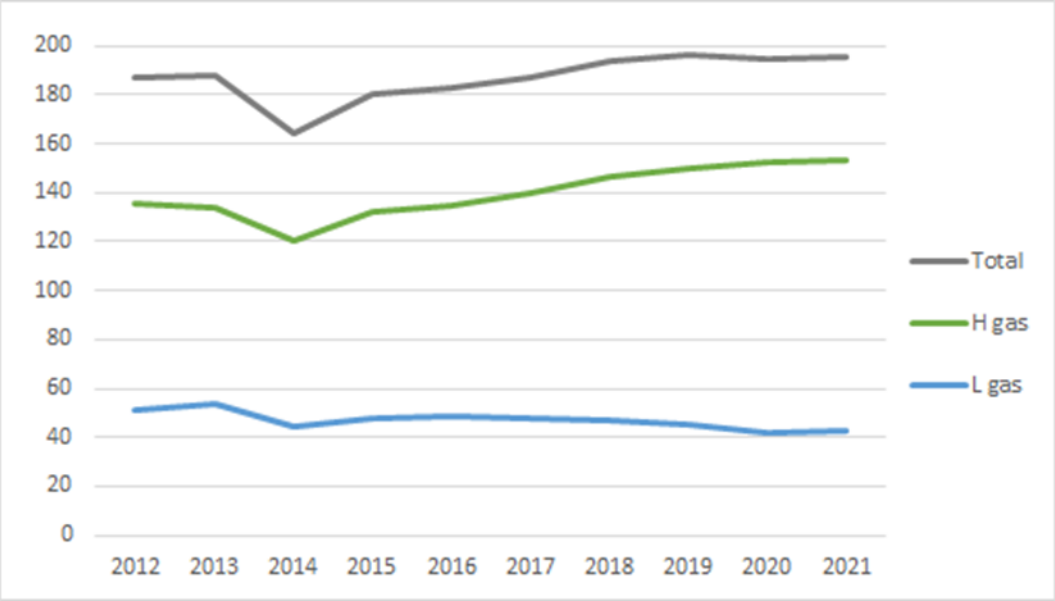
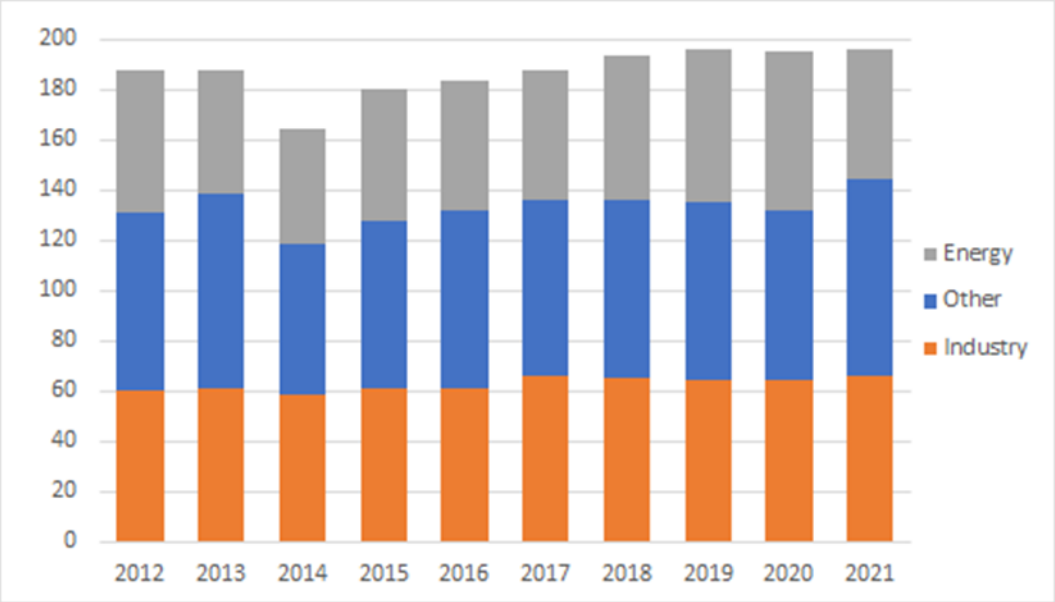
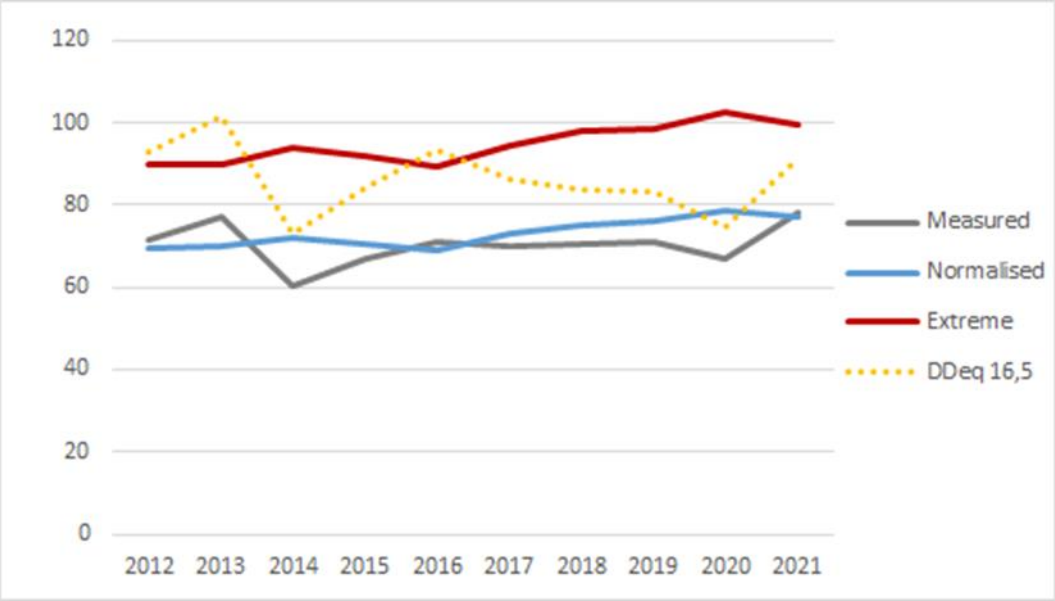


Figure 9: Evolution of yearly gas consumption (TWh) by sector (2012-2021)



A significant part of the gas consumption in the "other" sector is used for space heating, therefore it is sensitive to the outside temperature. The number of equivalent degree-days[4] as well as the pattern of the degree days over the year have a significant influence. Figure 10 shows that the "other" consumption decreased in 2014 and 2020, which were warmer years, and was highest in 2013 and 2021, both colder years. This link between degree-days and consumption is most noticeable in the residential sector, but also to a lesser degree in the commercial and services sectors. Until 2016, this link could also be seen in the agricultural sector, but this consumption has been steadily increasing since.

Figure 10: Evolution of yearly gas consumption (TWh) for the other sector (2012-2021)



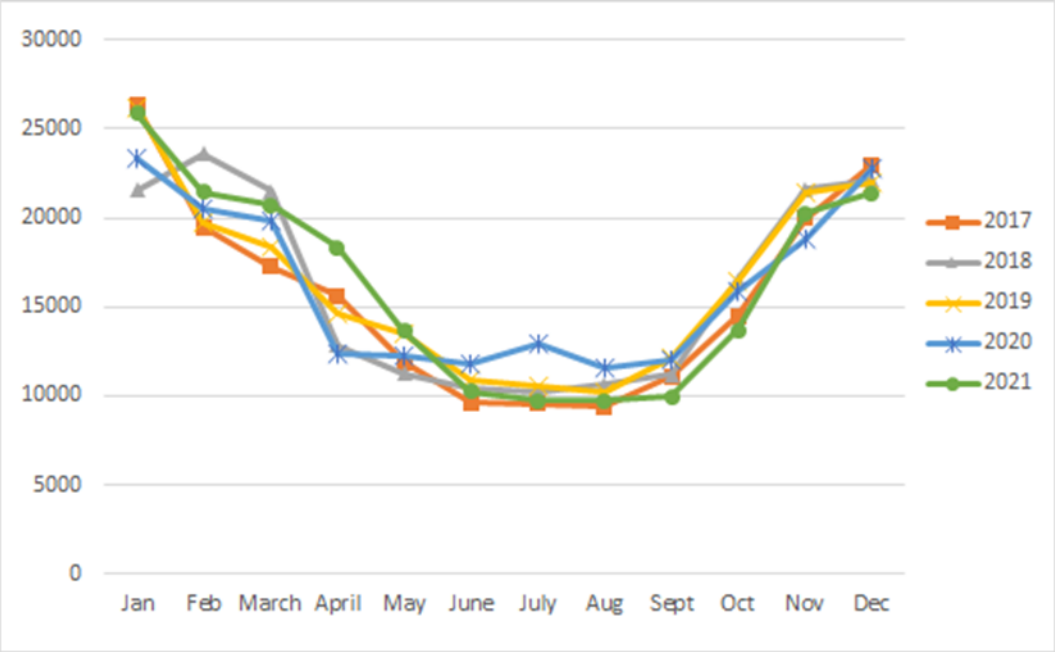
As already mentioned, primary gas demand is also expected to grow in medium and long term. The government's forecasts project a strong growth of gas consumption in power generation because the new capacities that need to be built (particularly to replace a significant portion of the nuclear generation capacity to be phased-out) will probably be mainly gas-fired. An increase in intermittent renewables-based power generation could also increase demand for gas to fuel back-up facilities. For the residential sector the gas demand is expected to decrease from 2026 because a part of the households gas consumption will move away to electricity due to the use of heat pumps for heating.

Monthly gas demand & seasonality

Figure 10 compares the measured, normalised[5] and extreme gas consumptions for the period 2012-2021 (in GWh/year). The extreme curve shows the calculated annual natural gas consumption for a temperature profile as obtained in the gas year 1962-63 with 3040 DD. This curve gives an estimation of the maximum natural gas volume that would be consumed in the "other" sector in an extremely cold year. The extreme natural gas volume follows the same evolution as the normalised temperature profile and is about 35% higher than the normalised temperature profile.

The monthly demand pattern is quite stable across the different years. We also see that the global gas demand is strongly linked to the outside temperature. Belgian gas consumption shows a strong seasonal pattern (Figure 11). The average gas demand in July and August is mostly independent on the outside temperature and consists mainly of the gas demand from the industrial and energy sectors. Gas use in the winter months can exceed 25.000 GWh/month.

Figure 11: Total monthly consumption in GWh (2017-2021)



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

Peak day demand

Table 2 illustrates the considerable difference between the gas demand on an average day and the peak demand day. This difference results in a very high peak day/average day ratio. In Belgium, peak day demand can be 276% as high as an average day. Belgium has a similar ratio to the average in the North-Western region. This high ratio can be explained by the high share of household demand, which can be very volatile in function of the temperature. Other countries have a lower share of the residential sector, but higher share of industry demand. This industry demand is mostly quite stable throughout the year and consequently results in a lower ratio peak day/average day demand. The peak day demand is the most representative of the needed infrastructure capacity.

Peak days are widely used, even if hourly consumption can be roughly 20% higher on that day. This is because the gas system gives some time to react to increasing demand, mostly by the use of the linepack as a temporary storage to momentarily bridge the gap between supply and demand. Suppliers can afterwards adjust their purchases of gas to balance their portfolios by the end of the gas day.

Table 2: Average daily demand vs. peak demand in BE (in GWh/day)

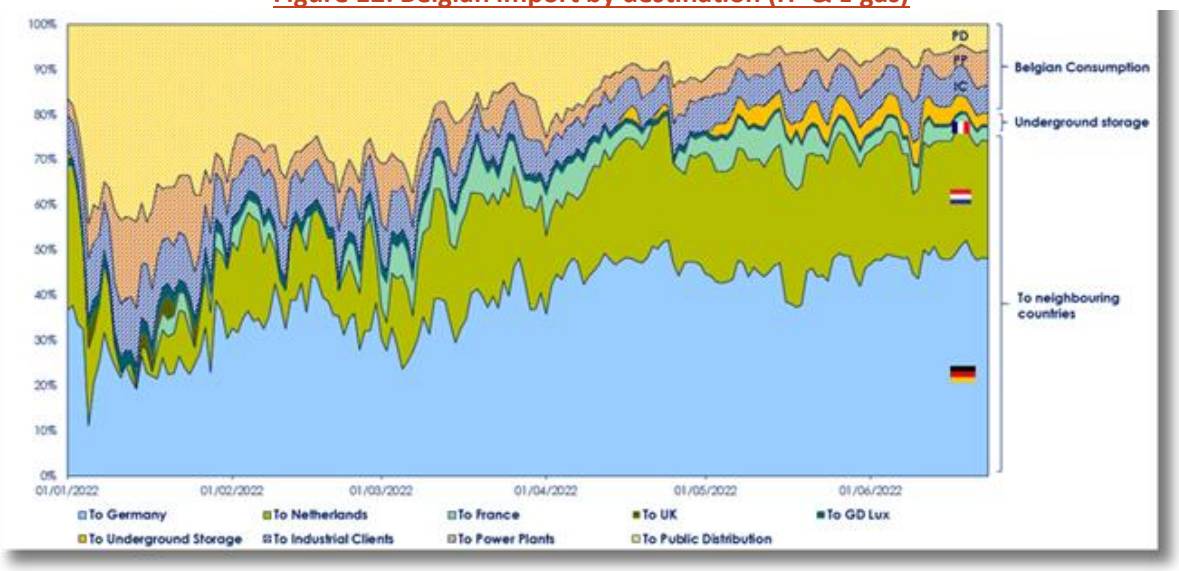
Country	OCT	NOV	DEC	JAN	FEB	MAR	2-Week	Peak day	Daily avr 2021	X Factor
BE H	681	781	982	985	974	782	1.136	1.202	404	3,0
BE L	162	178	217	217	217	182	227	239	117	2,0
BE L+H	843	959	1.199	1.202	1.191	964	1.363	1.441	521	2,8

Source: FPS Economy & Fluxys

Border to border transmissions

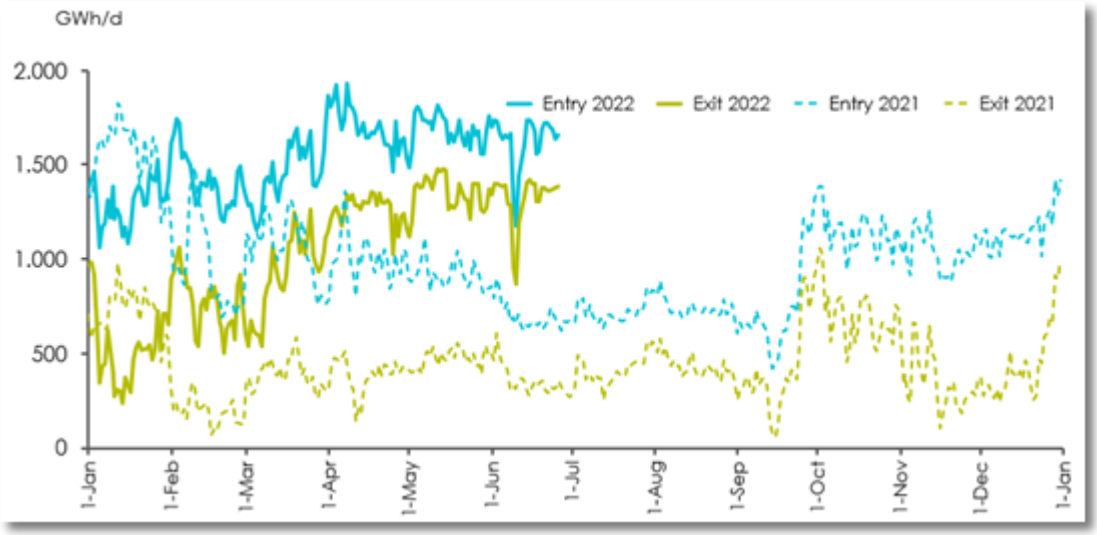
Most of the natural gas entering the Belgian territory is not consumed in Belgium itself. In 2022, the share of gas exported to neighboring countries increased significantly in the aftermath of the Russian invasion of Ukraine and the need to fill storage in Germany and in The Netherlands.

Figure 12: Belgian import by destination (H- & L-gas)



Source: Fluxys

Figure 13: Evolution physical flows (GWh/day) at interconnection points (2021-2022)



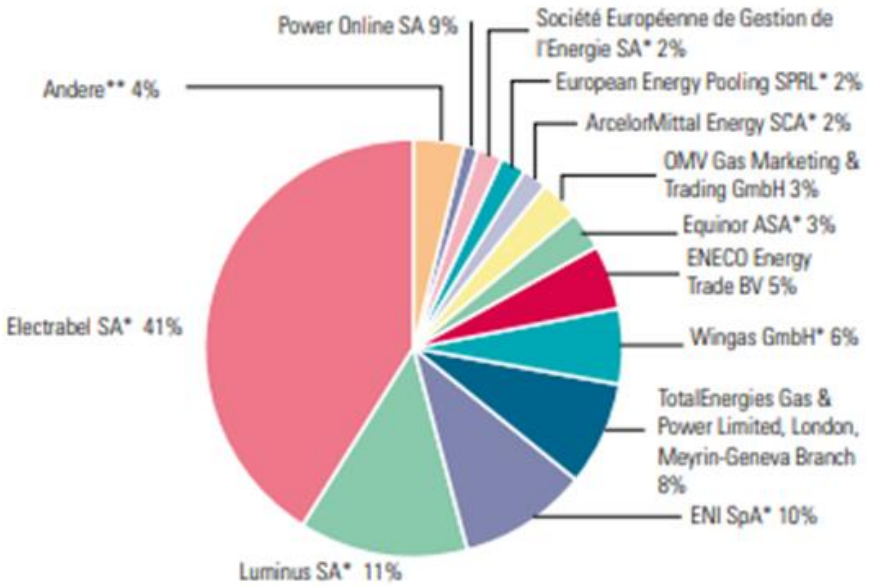
Source: Fluxys

1.2.2 Description of the functioning of the gas system at national level

Wholesale market players in Belgium provide natural gas to 17 distribution companies and to about 230 large industrial end-users and power plants connected directly to the transmission grid.

On 31 December 2022, 26 companies held a supply licence for H-gas on the Belgian market (the same as in 2020). There are currently 14 suppliers for the supply of L-gas (17 in 2021), who are also active on the Belgian H-gas market (CREG).

Figure 14: Market share of natural gas supply companies (2022)



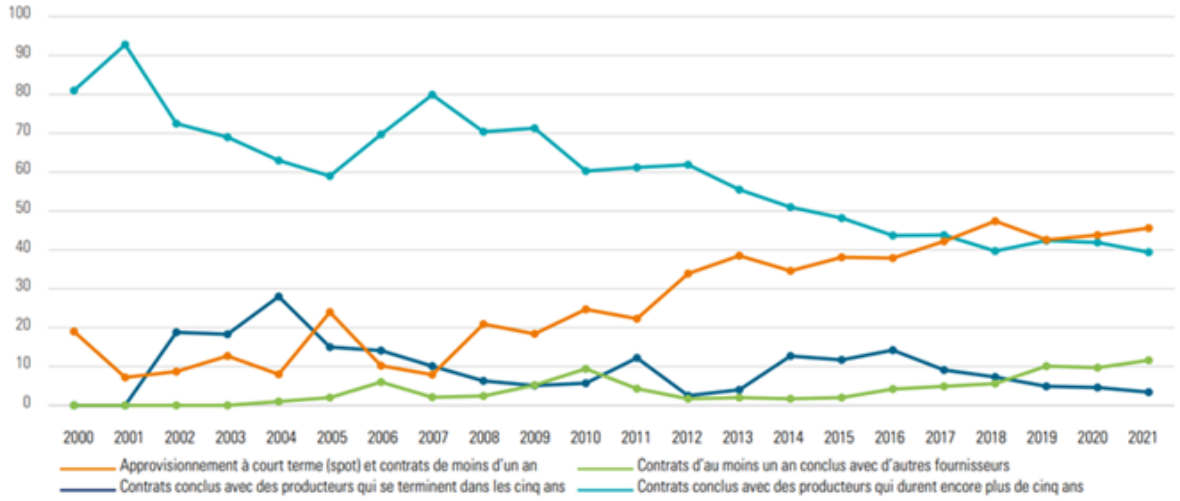
* Houders van een federale leveringsvergunning in de loop van het jaar 2022.

** Leveringsondernemingen actief op het vervoersnet met elk een marktaandeel van minder dan 1%: Axpo Solutions AG, Belgian Eco Energy nv, Energy Global Handel B.V., Enovos Luxembourg SA, GETEC Energie GmbH, Lampiris SA, Novatek Gas & Power GmbH, Progress Energy Services, Scholt Energy Control nv, Société Européenne de Gestion de l'Énergie S.A., TotalEnergies Electricité et Gaz France en Uniper Global Commodities SE.

Source: CREG

The market liberalisation has created the possibility to establish a wholesale market in which gas can be sold to other suppliers with their own portfolio. Historically, gas was (and for a large part still is) imported through long term contracts between the producers and suppliers. The creation of a wholesale and a retail market makes the decoupling possible between the gas producer and the final gas supplier. In order to have a good functioning of the gas market with a high security of supply, it is important to have a liquid market. This liquidity can be increased by the development of the gas hub. In the national gas trade, Zeebrugge has a key commercial role as one of Europe's major spot markets for natural gas. Fluxys Belgium, also offers the market regulated hub services, allowing them to buy and sell gas on Belgian gas trading place. These services facilitate over-the-counter trading of natural gas, while exchange-based trading is operated by APX Gas ZEE, established in 2005. It provides a spot market for trading of within-day and day-ahead gas contracts.

Figure 15: Evolution of the composition of SPOT and long term contracts for the Belgian market (2000-2021)



Source CREG

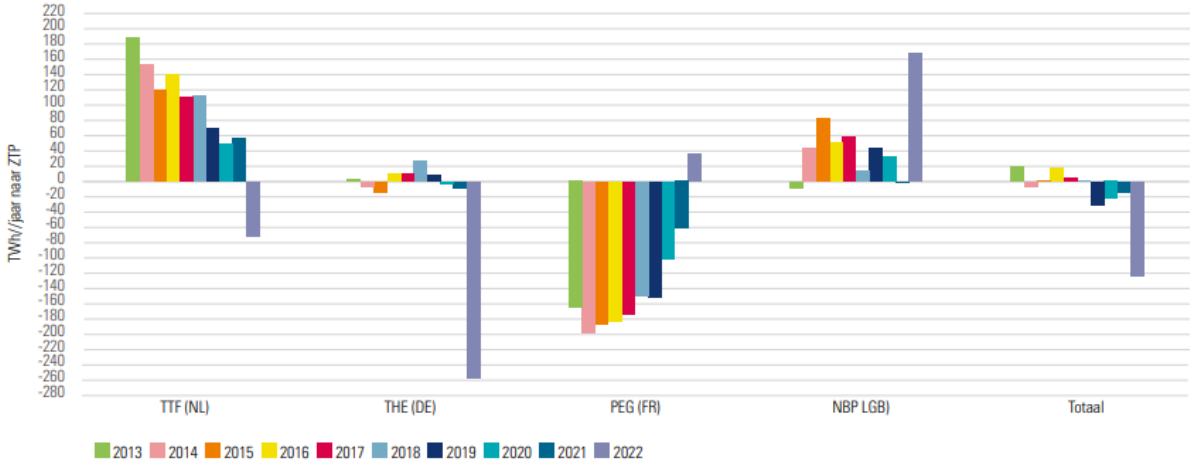
1.2.3 Zeebrugge Trading Point (ZTP)

The Zeebrugge area is one of the most important natural gas landing points in the EU28. Connecting to both pipeline gas and LNG sources, the Zeebrugge area has an overall throughput capacity of about 48 bcm/y. This corresponds with roughly 10% of the border capacity needed to supply the EU28. As for pipeline gas flows, the Zeebrugge area gives access to natural gas from Norwegian and British offshore production fields in the North Sea. Worldwide LNG supply is accessible through the Zeebrugge LNG terminal. The terminal has three primary shippers and standard provisions are in place to facilitate spot LNG deliveries. Any LNG or pipe gas brought into the Zeebrugge area can be traded at the Zeebrugge Hub or shipped through the Fluxys Belgium grid for delivery into the Belgian market or redelivery at one of the borders for onward transmission to the United Kingdom, the Netherlands, Germany, France and Southern Europe.

1.2.4 Market integration

Belgium and the surrounding countries represent 60% of the European natural gas market. Belgium is located at the centre of important natural gas corridors in North West Europe and is characterised by intensive cross-border trade in natural gas. The Dutch TTF is the main border market for trade in natural gas for the Belgian market.

Figure 16: Evolution of ZTP yearly traded values with bordering markets (2013-2022)

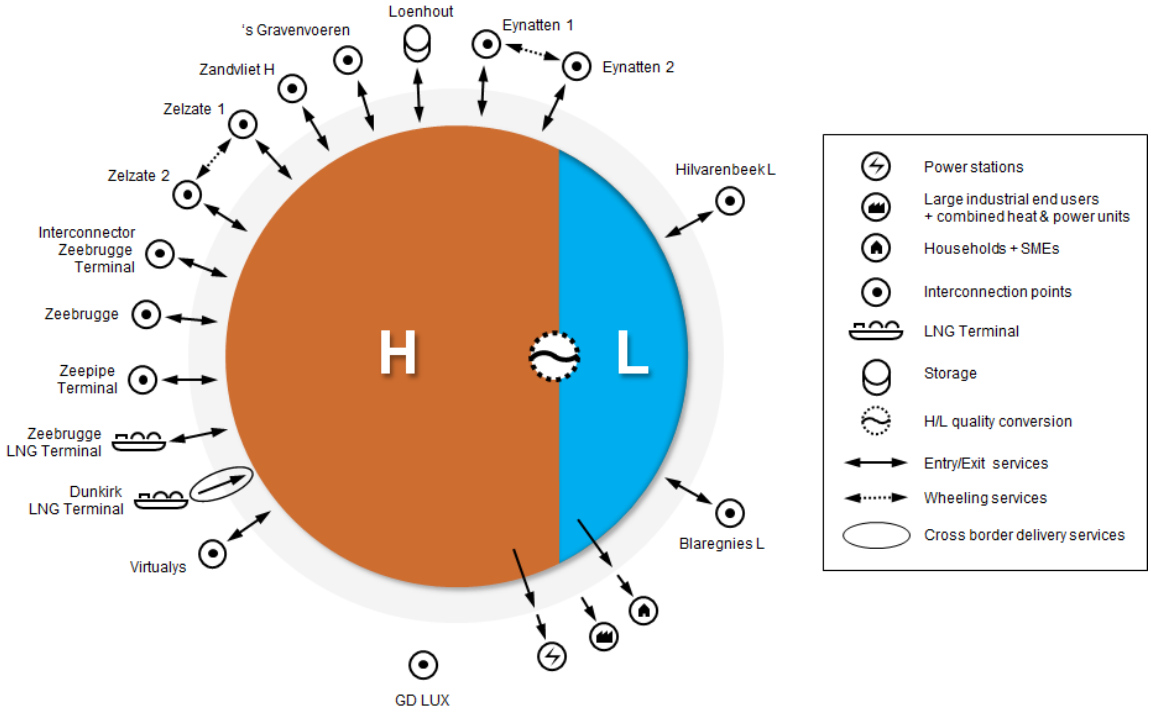


Source: CREG

Fluxys Belgium applies the entry-exit model. The border-to-border transmission of gas through Belgium is assured via the major two-way high-pressure pipeline systems connecting Belgium to its neighbours. The line from Zeebrugge to Blaregnies linking the North Sea and the UK to France (H-gas) is still used mainly for B2B transaction transit. Currently, gas flows (LNG) run from France to Belgium. A reshuffle since the Russian invasion of Ukraine. There is a separate pipeline, parallel to the Zeebrugge-Blaregnies pipeline, for domestic transmission in the western part of the country. Presently, all pipelines are meshed in one network and lined up to be used for border-to-border transmission as well as for domestic supply.

Fluxys Belgium manages grid users through an entry/exit model. Transmission services can be subscribed and used independently at interconnection points (entry & exit services) and at domestic exit points (exit services). The model enables parties to freely exchange quantities of gas within the Belgian system. Natural gas can be delivered from any interconnection point and taken off towards any interconnection point or any domestic exit point.

Figure 17: Belgian entry exit model (2018)



Source: Fluxys Belgium

The transmission grid is divided into H-zone and L-zone.

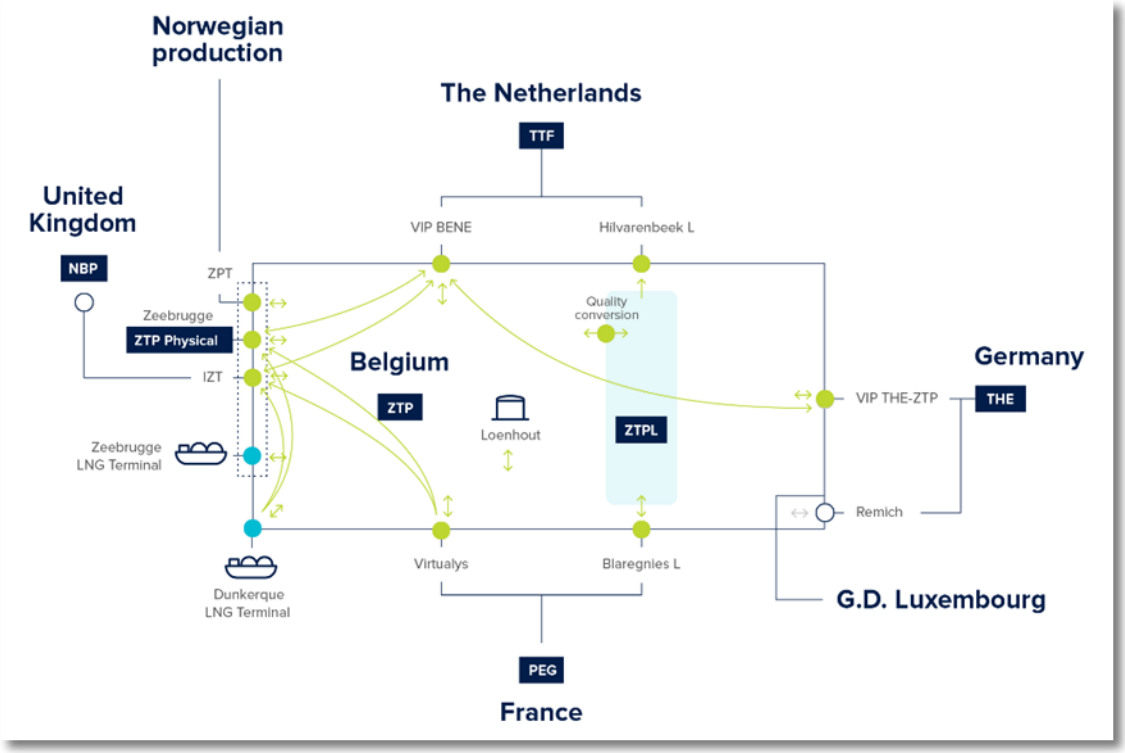
Within the day, the market balancing position, being the sum of the respective individual balancing position of each grid user, is assumed to remain within a predefined upper and lower market threshold, corresponding to the commercially offered flexibility within the system. This market balancing position is updated on an hourly basis, together with the individual balancing position of each grid user, representing the cumulated delta so far within the day. As long as the market balancing position remains within the predefined market threshold, there is no residual intervention. When the market position goes beyond the market threshold, also within a day, Balansys4 intervenes on the market in order to settle the residual excess or shortfall by a sale or purchase transaction on ZTP. Such intervention is reported to grid user(s) identified as contributing to the residual imbalance by a proportional settlement in cash of their individual balancing position.

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

---

4 Balansys is a joint undertaking founded by Creos Luxembourg (50%) and Fluxys Belgium (50%). The mission of Balansys is to act as balancing operator for the balancing in the BeLux area, being composed by the integrated H-gas market of Luxembourg and Belgium and the L-gas market in Belgium. (Who we are - Balansys)

Figure 18: Schematic of Belgian gas network



Source : Fluxys Belgium

With 17 physical interconnection points with neighbouring natural gas transmission systems, the Belgian grid is a central crossroads for gas flows in North-Western Europe:

transmission of Dutch and Norwegian natural gas to France, Spain and Italy

transmission of British natural gas to continental Europe

transmission of natural gas to Luxembourg

natural gas is also passed on to other end-user markets from the LNG terminal in Zeebrugge.

The system by which Fluxys Belgium offers the transmission services to the Grid Users is an entry/exit model. Through this entry/exit model, natural gas enters the Fluxys grid at an interconnection point and can either leave the grid at another interconnection point or be consumed by a Belgian final customer at a domestic exit point or at a public distribution exit point via a distribution system operator.

Transmission services can be subscribed and used independently at interconnection points (entry & exit services) and at domestic exit points (exit services). The model enables parties to freely exchange quantities of gas within the Belgian system. This natural gas can, by consequence, be delivered from any interconnection point and taken off towards any interconnection point or any domestic exit point.

The transmission grid is divided into two entry/exit zones: The H-zone and the L-zone.

The H-zone corresponds to the physical H-calorific subgrid and the L-zone to the physical L-calorific subgrid.

In addition, daily market-based balancing is applied. In order to reliably and efficiently operate the Fluxys grid, the total quantities of natural gas entering the Fluxys grid must be, on a daily basis, equal to the total quantities of natural gas leaving the Fluxys grid or consumed by Final Customers. Any remaining residual differences at the end of the day will be settled by Balansys (market short: Balansys buys gas at ZTP; market long: Balansys sells gas to ZTP) for the account of the causing shipper(s).

Within the day, the market balancing position, being the sum of the respective individual balancing position of each Grid User, is assumed to remain within a predefined upper and lower market threshold, corresponding to the commercially offered flexibility within the system. This market balancing position is updated on an hourly basis, together with the individual balancing position of each Grid User, representing the cumulated delta so far within the day. As long as the market balancing position remains within the predefined market threshold, there is no residual intervention by Balansys. When the market position goes beyond the market threshold, also within a day, Fluxys Belgium intervenes on the market in order to settle the residual excess or shortfall beyond market threshold, by a sale or purchase transaction. Such intervention is reported by Fluxys to Grid User(s) identified as contributing to the residual imbalance by a proportional settlement in cash of their individual balancing position.

Fluxys Belgium and the Luxembourg TSO Creos Luxembourg have worked on the integration of their respective H markets. Since 1 October 2015, the BeLux zone consists of an entry/exit system with Zeebrugge Trading Point (ZTP) as its virtual trading point. No capacity subscription is needed to have natural gas transported between Belgium and Luxembourg (and vice versa).

1.2.5 BELUX balancing zone

Luxembourg gas transmission system operator (TSO) Creos Luxembourg and Belgian TSO Fluxys Belgium and their respective regulators, ILR (Institut Luxembourgeois de Régulation) and the Commission for Electricity and Gas Regulation (CREG), worked together closely to integrate their national markets as from 1 October 2015. As from 1 June 2020 balancing operator Balansys has been active.

This initiative, reflecting the European Union's ambition to create a borderless European gas market, is the first market integration between two EU Member States – a move that will provide the regulators and TSOs of both countries with an expanded pool of knowledge and experience for further integration with other neighbouring markets.

With the creation of an integrated Belgian/Luxembourg market, these entry-exit access fees between Belgium and Luxembourg fall away and the Zeebrugge Trading Point (ZTP) became the gas trading point for the integrated market.

The balancing rules for the two countries are harmonised. Balansys, as a joint entity, manages the commercial balancing of the integrated market. At the same time, Creos Luxembourg and Fluxys Belgium keep their distinct identities and organisational structures.

Luxembourg enjoys enhanced security of supply thanks to a two-pronged strategy:

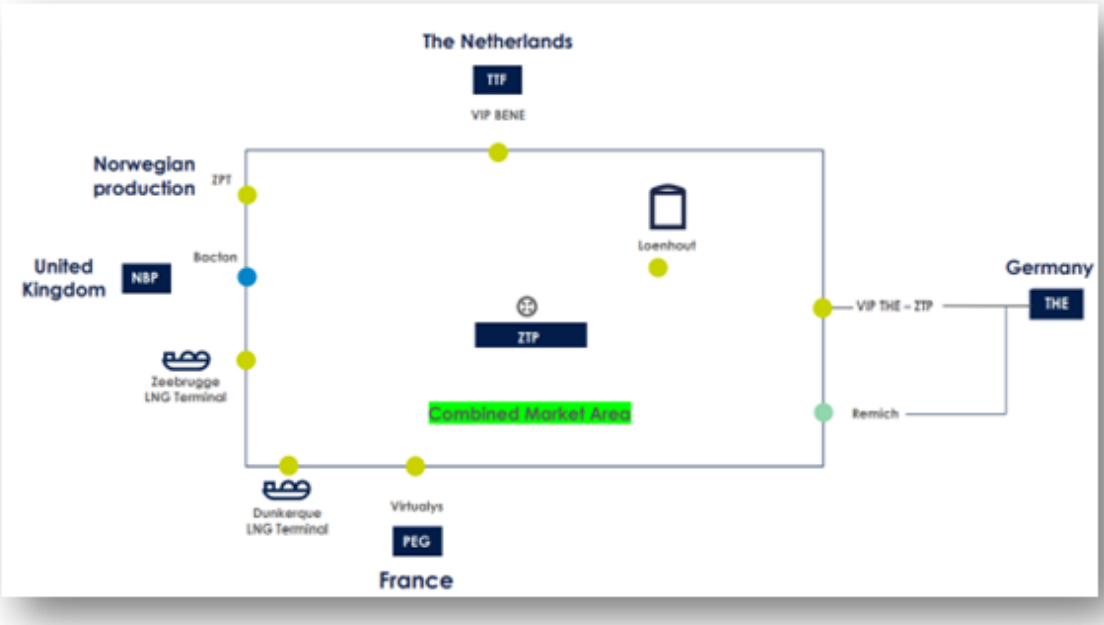
As from 1 October 2015, the physical capacity available for flows from Belgium to Luxembourg has increased in the integrated market area, thanks to a higher level of pressure being provided by Fluxys Belgium at the interconnection point between the two countries.

Network users will have the possibility to subscribe to a conditioned capacity product, with THE 5 being connected to ZTP via the interconnection point at Remich. On days when Luxembourg experiences high levels of consumption, the product offered will be subject to nomination obligations to guarantee the flows needed for the security of supply of Luxembourg customers.

Balansys is a joint undertaking founded by Creos Luxembourg (50%) and Fluxys Belgium (50%). The mission of Balansys is to act as balancing operator for the balancing in the BeLux area, being composed by the integrated H-gas market of Luxembourg and Belgium and the L-gas market in Belgium.

The transfer of the commercial management of the system balancing of the integrated Belux area started on 1 June 2020. From then on, the market participants must have concluded a balancing contract with Balansys. Regulatory documents for the management of the commercial system balancing in the Belux area include balancing contract, balancing programme and balancing code. (source : Balancys)[6]

Figure 19: Schematic of integrated BELUX market



Source: Fluxys Belgium

5 Trading Hub Europe (German gas trading platform)

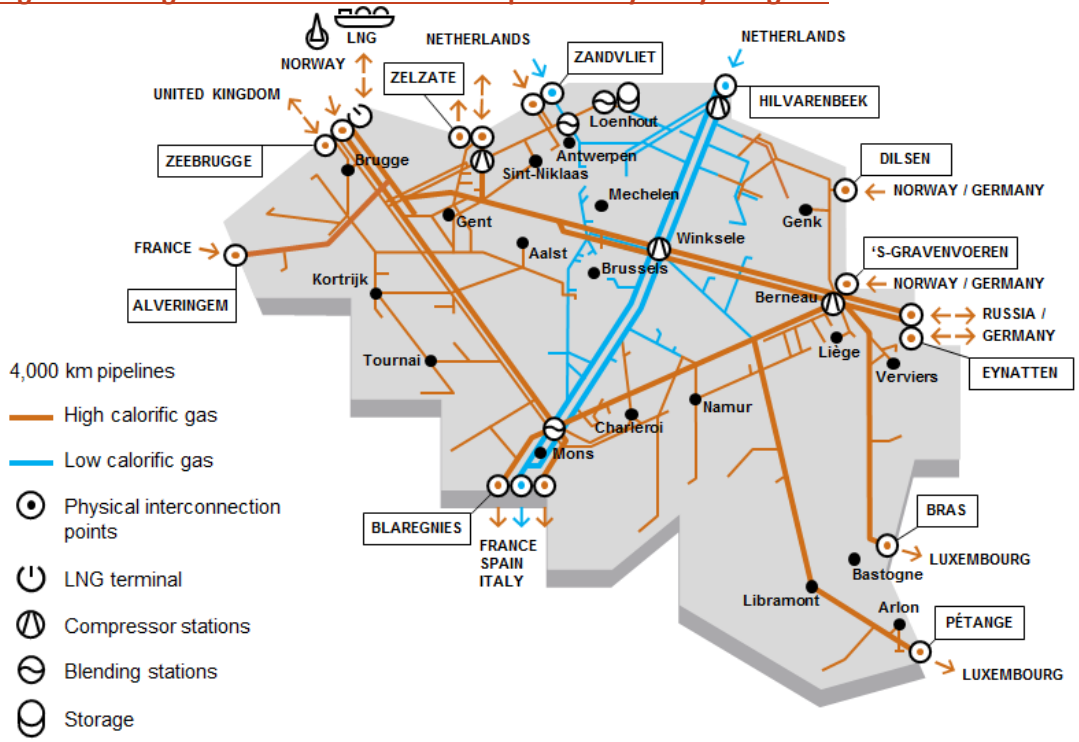
1.2.6 Key infrastructure relevant for security of gas supply

Overview of the pipeline network

Fluxys Belgium, Belgium's transmission system operator, has a network of about 4000 kilometres of pipelines with 17 physical interconnection points and four compression stations. The 8 cross border pipelines connect the Belgian gas market directly to Norway, UK, Germany, the Netherlands, France and Luxembourg. The four compressor stations are located in:

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

Figure 20: Belgian transmission network operated by Fluxys Belgium



Source: Fluxys Belgium

The Belgium gas transmission network delivers gas directly to about 220 large industrial end-users and power stations and supplies 4 distribution system operators which deliver gas to residential and small- to medium-sized industrial users in the three Regions (Flanders, Wallonia and Brussels), notably: Fluvius (Flanders), Sibelga (Brussels), RESA and ORES (Wallonia).

The need for new infrastructure is evaluated every year by Fluxys Belgium in the updated investment programme for the next 10 years (Fluxys, 2022)[8]. These updates take into account the changes in requirements in terms of natural gas supply, request for new connections and the changing needs of grid users identified through subscription periods and international market consultations among other things. Several simulations based on the winter peak (at -11°Ceq) and border to border transmission requirements are being set up to calculate the effects on the network.

Interconnections points and reverse flow capacity

The VTN-RTR pipeline (H-gas) is bi-directional linking the UK and the Zeebrugge hub with Germany and the Netherlands, the SEGEO pipeline (H-gas) runs from the Dutch border in 's Gravenvoeren to France and the Poppel-Blaregnies pipeline runs from north to south, linking the Netherlands with France (L-gas). In 2010, the Zelzate entry point (physical bi-directional) came into operation following investments in the Dutch grid through which the capacity on the East-West axis increased. This also shored up the supply into the Belgian market and enabled greater volumes of natural gas to be traded on the Zeebrugge hub. The Interconnector Zeebrugge Terminal (IZT) connects the Fluxys Belgium grid to the subsea Interconnector pipeline which runs to Bacton in the United Kingdom and is so far the only physical bi-directional link between the UK and continental Europe. IZT allows natural gas from

the Continent to be shipped to the United Kingdom. The Interconnector also serves as the only gas export route from the United Kingdom. Gassco's Zeepipe Terminal (ZPT) connects Norway's Troll and Sleipner offshore gas fields to the Fluxys Belgium grid via the subsea Zeepipe pipeline.

The table below gives an overview of the technical capacities in forward and reverse flow on each of the interconnection points in Belgium. These capacities only give an overview of the capacity (either in reverse or forward flow) on each interconnection point on the Belgian borders. Capacities are also dependent on capacities offered by adjacent TSO and could change over time. Belgium benefits from sufficient reverse flow capacity on the following axes: BE-UK, BE-DE, BE-NL.

Remarks:

- The technical capacity is not a fixed invariable value. An increase of the technical capacity can be allowed by reducing the technical capacity of other interconnection points (resulting in the same network load), by optimizing the steering possibilities or by modifying the network flow scenario's.
- Published firm capacity can be temporarily higher, based on temperature effect, network load and booked 'restricted' transmission services (wheeling, operational capacity usage commitments (OCUC)).
- Although individually available, the capacities on the interconnection points IZT, ZPT, LNG Terminal and ALV are limited in aggregate (as indicated on the Fluxys Belgium data platform).

Firm entry and exit capacity (GWh/d) offered on the connection points:

Table 3: Firm entry and exit capacity on interconnection points

Country	Interconnection points	Type	Firm capacity offered 2021 GWh/d	
			Entry	Exit
UK	IZT	EP	651,7	803,4
Norway	ZPT	EP	488,0	
France	Alveringem (Virtualys)	EP	270,0	
France	Blaregnies H (Virtualys)	EP		640,0
Germany	VIP THE-ZTP	EP	487,2	537,6
The Netherlands	VIP BENE	EP	801,6	427,0
Luxembourg	Pétange & Bras	EP		48,8

Source: Data compiled based on information of Fluxys

Creation of virtual interconnection points

On 1 april 2020 Fluxys Belgium and GTS have introduced VIP BENE a new virtual interconnection comprising of 3 physical interconnection points in Zelzate 1, 's'- Gravenvoeren and Zandvliet. An update of the existing interconnection agreement for H-gas Interconnection Points between Fluxys

Belgium N.V. and Gasunie Transport Services B.V. was laid down, intended to become effective with the integration of Zelzate 2 into the Virtual Interconnection Point VIP BENE on 1 January 2021. On 1 April 2022 a new Virtual Interconnection Point called VIP THE-ZTP is become active, providing a single capacity service between THE and BeLux market. The new VIP is a grouping of the Interconnection Points of Eynatten 1 and Eynatten 2.

Remarks:

- Quality conversion of H-gas into L-gas: the entry capacity is on the L-gas side and the exit on the H-gas side. The capacities shown in the table also consider the quality conversion unit in Loenhout, which was mothballed until June 2023 and dismantled after.
- Fluxys Belgium's network still has an interconnection point at Pétange & Bras (connection point Belgium-Luxemburg) but is not commercialized anymore (since this IP is located within the E/E zone Belux).

Supply routes

Belgium is directly connected to four upstream pipelines for H-gas and two for L-gas feeding directly into the Belgian gas system and to two LNG terminals, one in Zeebrugge and the other in Dunkirk.

The four upstream pipelines for H-gas and two for L-gas are:

- The Interconnector (bi-directional) connecting Belgium and the UK;
- Zeepipe providing a direct link to the Norwegian gas fields;
- Dorsales connecting the Netherlands to Belgium and France.

The BE gas network is also directly connected to two LNG terminals:

- LNG terminal of Zeebrugge
- LNG terminal of Dunkirk

LNG terminal of Zeebrugge

In operation since 1987, the LNG terminal is located in the outer port of Zeebrugge on a site of ca. 30 hectares. It comprises efficient reception facilities, five LNG storage tanks, vaporisation and send-out facilities for injection of regasified gas into the high-pressure gas network, and related facilities. The commissioning in 2019 of the fifth tank and its associated compressors marked the start of ship-to-ship and ship-storage-ship transshipment services. The LNG terminal can handle almost all different types of LNG carriers from 2 000 m³ LNG up to Q-max vessels with a capacity of up to 266 000 m³ LNG.

The east jetty of the Zeebrugge LNG terminal is equipped with four 16" LNG unloading arms and one vapour return arm, providing an unloading capacity of up to 14 000 m³ LNG/hour. Three of the existing storage tanks have a workable capacity of 81 500 m³ LNG each, while the fourth LNG storage tank has a workable capacity of 141 500 m³ LNG and the fifth tank a workable capacity of 180 000 m³ LNG. The firm send-out capacity of the LNG terminal amounts to 1 950 000 m³(n) per hour.

A second jetty (referred to as the west jetty) of the Zeebrugge LNG terminal enables the berthing of ships from approximately 2 000 m³ LNG up to a capacity of 217 000 m³ LNG. The west jetty gave rise to additional berthing rights offered to the market for the purpose of loading ships (i.e. LNG redelivery services).

The vaporizers installed consist of both submerged combustion vaporizers (SCV) and open rack vaporizer (ORV) – the latter in operation as from the second quarter 2013 onwards. In 2021, Fluxys LNG committed to build 3 new ORVs to reduce its greenhouse gases emissions and to increase its regasification capacity as from 2024.

The LNG infrastructure in Zeebrugge currently has an annual throughput capacity of approximately 9 billion m³(n) of natural gas. Following an open season conducted in 2003 and a subscription window conducted in 2019, the entire primary capacity was allocated on a long-term ship-or-pay basis and commercialized by means of slots. Under such slots, terminal users are allowed to:

- arrive and berth their LNG vessel within a defined window;
- use a basic storage capacity of 140 000 m³ LNG, linearly decreasing over 40 tides;
- use a basic send-out capacity of 4 200 MWh/h during the abovementioned 40 tides.

Occasionally, capacity is made available for LNG services on the primary market. In addition, LNG services can be traded on the secondary market. These LNG services are available to terminal users and other parties having signed the required contractual agreements.

Additional storage and send-out capacities are available as well. The LNG terminal in Zeebrugge also wants to play a leading role in the development of small scale LNG in Northwest Europe, be it as a fuel for industry or heavy-duty transport via ships and trucks. The LNG terminal therefore offers loading and unloading services for small LNG ships as well as truck loading capacity thanks to two truck loading bays.

Increased stand-alone send out capacity will become available at the Zeebrugge LNG terminal through a further expansion of the terminal. Following a successful open season process, this project foresees the construction of new regasification capacity to increase the stand alone send out capacity in a first step up to 8,2 GWh/h and then in a second step up to 10,5 GWh/h. The commissioning of the first step is expected early 2024 and the commissioning of the second step early 2026. Following the fast growing interest in small scale LNG, Fluxys LNG also decided in 2021 to build four new truck loading bays. These new bays should be commissioned in 2024.

LNG Terminal of Dunkirk

Occupying a 56 ha site alongside Dunkirk's Western Harbour, the Dunkerque LNG terminal offers:

- a jetty ready to accommodate vessels from 5,000 m^3 to the world's largest Qmax LNG carriers (265,000 m^3) and able to unload at a maximum flow rate of 14,000 m^3 per hour and 8,800 m^3 per hour for reloading ;
- 3 storage tanks, each capable of storing 200,000 m^3 of LNG at -162°C;
- 10 Open Rack Vaporizers (ORV) or regasifiers to raise the temperature of the LNG and enable it to return to its natural gas state ready to be sent out into the supply network;
- a 5 km tunnel between the discharge canal of the Gravelines nuclear power plant and the terminal – to carry some of the heated cooling water discharged by the power plant for use in reheating the LNG in the ORVs.

The Dunkerque LNG terminal has an annual regasification capacity of 13 billion m^3 of gas, which is sufficient to meet approximately 20 % of annual consumption in France and Belgium. It is the 2nd largest terminal in continental Europe. It is also the only terminal to be connected directly to 2 markets – France and Belgium – using 2 separate pipelines.

Table 4: Technical specifications of Dunkirk and Zeebrugge LNG terminals

	DUNKIRK	ZEEBRUGGE
Services		
LNG ship unloading	YES	YES
Large LNG ship loading	YES	YES
Small LNG ship loading	YES	YES
Transshipment		
- Ship - To - Ship	NO	YES
- Ship - Transshipment Storage - Ship	NO	YES
LNG Truck loading	YES	YES
Gas liquefaction	NO	YES
Infrastructure		
Number of jetties	1	2
Min. size of LNG ship	65.000 m³	1.000 m³
Max. size of LNG ship	267.000 m³	267.000 m³
Total storage capacity	600.000 m³	566.000 m³
Max. annual regas. capacity	13.000.000.000 m³/year	14.840.000.000 m³/year*
Max. regasification capacity	520 GWh/day	541 GWh/day
Max. unloading rate	14.000 m³/h	14.000 m³/h
Max. loading rate	8.800 m³/h	10.000 m³/h
Max. transshipment rate	n/a	10.000 m³/h
Number of truck loading stations	1	2
* Subject to optimised planning		
Connection		
Direct access to the neighboring markets	France (TRF) & Belgium (ZTP)	Belgium (ZTP)
Indirect access to the other markets	The Netherlands (TTF) United Kingdom (NBP) Germany (THE)	France (TRF) The Netherlands (TTF) United Kingdom (NBP) Germany (THE)
Tariffs		
LNG Tariffs	Non regulated	Regulated

Infrastructure in the L-gas market

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

- a physical entry point from NL at Poppel/Zandvliet L: The corresponding point at the Dutch side of the border (exploited by GTS) is Hilvarenbeek and Zandvliet L. The available capacity at Poppel is 65.52 mcm/d.
- A cross-border exit point at Blaregnies to FR: The corresponding entry point in the French network (exploited by GRTgaz) is Taisnières. The entry capacity at Taisnières is 24.96 mcm/d.
- Two quality conversion installations existed but have been taken out of commission following the conversion of the L-gas network, one at Loenhout and one at Lillo.

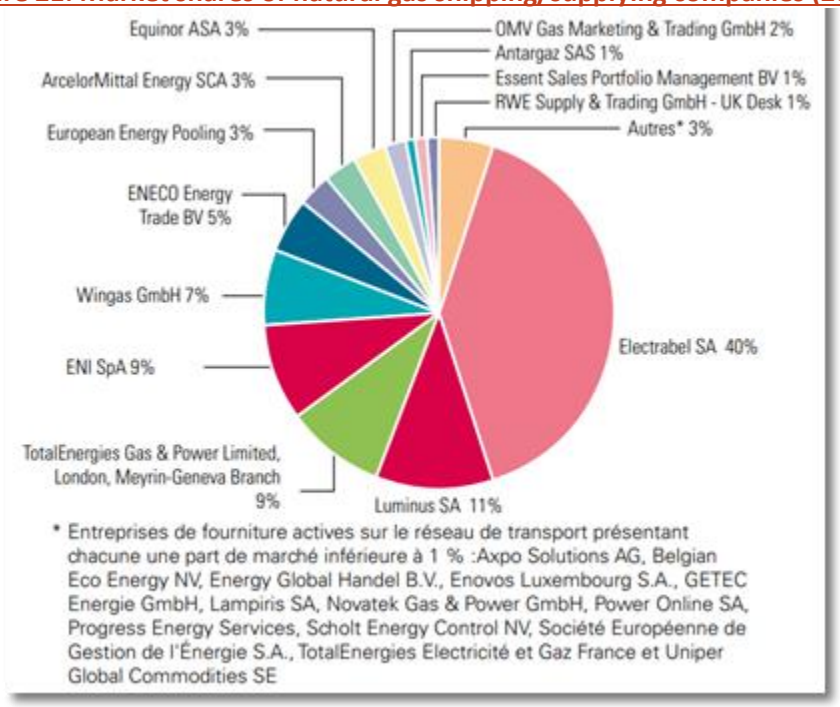
Belgium has no storage facilities for L-gas.

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

1.2.7 Gas import sources per country of origin

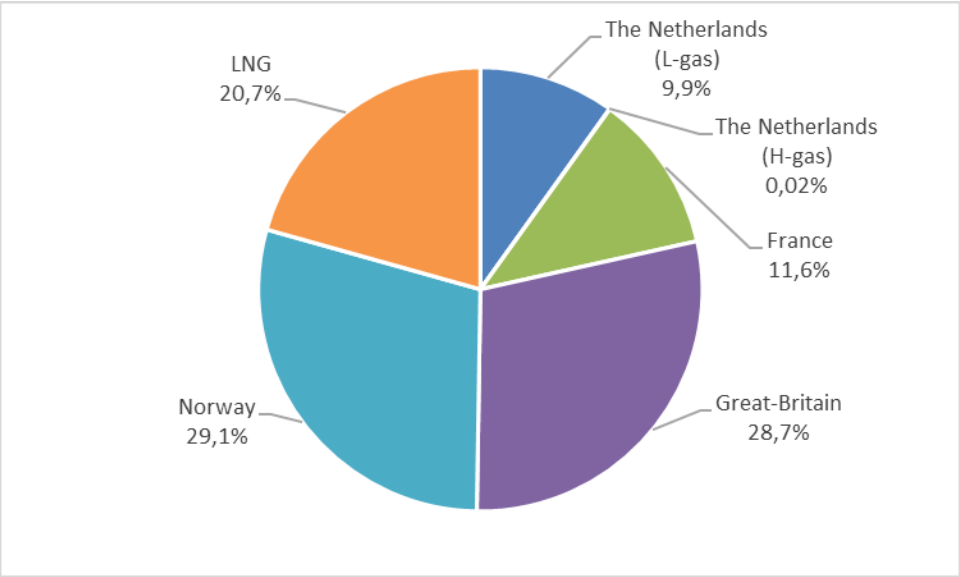
Belgium is directly connected to four upstream pipelines for H-gas and two for L-gas offering sources from the Netherlands, UK, Norway, Germany and France.

Figure 21: Market shares of natural gas shipping/supplying companies (2022)



Source: CREG

Figure 22: Gas flows to Belgium (2022)



Source: Creg

Belgium has no significant indigenous (bio-) gas production. As such, it relies entirely on imports. The current import portfolio is well diversified by origin and type of supply: Norway and Great-Britain are the principal pipeline suppliers, while Qatar is the main source of LNG imports.

1.2.8 Role of storage

A valuable tool for dealing with demand swings is storage. Belgium has only one underground storage installation operated by Fluxys Belgium (used for commercial storage), which is the aquifer in Loenhout. Its firm storage capacity is 673 mcm (or 7,61TWh) with additional capacities ranging between 70,8 mcm and 115 mcm – depending on yearly physical conditions of the underground. Only high calorific gas is stored at this facility. Short term LNG storage is also available at the Zeebrugge LNG terminal. Part of the stored gas is reserved by Fluxys Belgium for normal operational balancing of the network. The rest of the storage capacity is commercialized under a regulated regime on the market for dealing with seasonal swings and situations of peak demand.

Storage users with subscribed storage capacity in Loenhout are obliged to achieve a gas filling level of at least 90% on the 1st of November. Additionally, during the storage year they must reach the Filling Trajectory Targets applied by the European Commission.

Table 5: Filling Trajectory Targets

1 May	1 July	1 September	1 November	1 February
5%	40%	78%	90%	30%

Table 6: Natural Gas storage capacity in Belgium (H-gas)

Location	Type	Working capacity	Peak output
		GWh	GWh/day
Loenhout	Underground	8192,5	169,5

Table 7: Gas in underground storage, winter period 2022-2023

	2022						2023					
	jul	aug	sep	oct	nov	dec	jan	feb	mar	apr	may	june
Gas storage capacity (GWh)	8703	8703	8703	8703	8703	8703	8703	8703	8703	9130	9130	9130
Gas amount in storage[9] (GWh)	6853	7972	8288	9191	8175	6890	5450	3999	2922	4017	5264	6844
Gas stocks change (GWh)												
- withdrawal	0	0	0	0	-1016	-1285	-1440	-1451	-1077	0	0	0
+ injection	1538	1119	316	903	0	0	0	0	0	1095	1247	1580
Maximum withdrawal capacity (GWh/d)	68	68	68	68	170	170	170	170	68	68	68	68
Remaining days for using the stored gas	101	117	122	135	48	41	32	24	43	59	77	101

Furthermore, the storage facility at Loenhout cannot be considered as a 'strategic' storage facility. Compared with the national consumption in winter, the facility can only bridge a cold spell of ca. 10 days.

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

1.2.9 Domestic production

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

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

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

At the end of 2021, there were 6 injection sites which introduced 157,8 GWh of biomethane into the main gas network. In addition, 133,4 GWh of colliery gas was extracted and used for electricity production in 2021.

1.2.10 The role of gas in the electricity production

The ECG and GCG together analysed in summer 2022 the gas-power situation in Europe.

Table 8: Volume of gas used for power generation and electricity produced by gas power plants

MS	Volume of gas for power generation (bcm)*		% of gas used for power generation		Electricity produced by gas power plants (TWhe)**		% of electricity produces by gas power plants		TWht/ bcm	Electric efficiency dimensionless
	2019	2020	2019	2020	2019	2020	2019	2020		
BE	4.77	5.01	26%	27%	25.53	26.77	27%	30%	10.622	50.3%

*The columns Volume of gas for power generation (bcm) correspond to the EUROSTAT annual energy balance for gas [NRG_CB_GAS], in particular from the Transformation input - electricity and heat

generation - to the sum of the quantities of electricity only and combined heat and power for both main activity producer and auto-producer.

**The columns Electricity produced by gas power plants (TWh) correspond to the EUROSTAT dataset Production of electricity and derived heat by type of fuel [NRG_BAL_PEH], in particular to the Gross electricity production using natural gas.

***The electric efficiency is highly influenced by the ratio electricity/heat generation on each Member State.

Source: Joint Research Centre (JRC) of the European Commission, based on EUROSTAT data

The last two columns contain the average energy content of gas in Belgium (TWHt/bcm – thermal Terawatt-hour per billion cubic metre) and the average electric efficiency of power generation with gas (electric Terawatt-hours produced per thermal Terawatt-hour of gas).

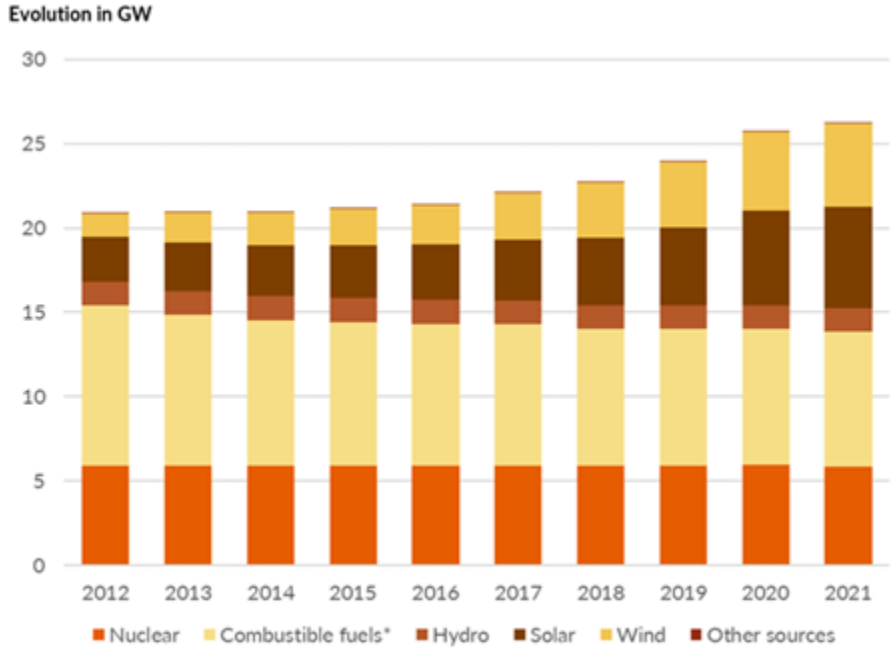
Compared with the entire EU, where the average is approximately 44.5%, Belgium is more efficient. In the EU, on average one bcm is needed to produce 10.55 TWht.

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

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

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

Figure 23: Evolution of installed electricity generation capacity (2012-2021)



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

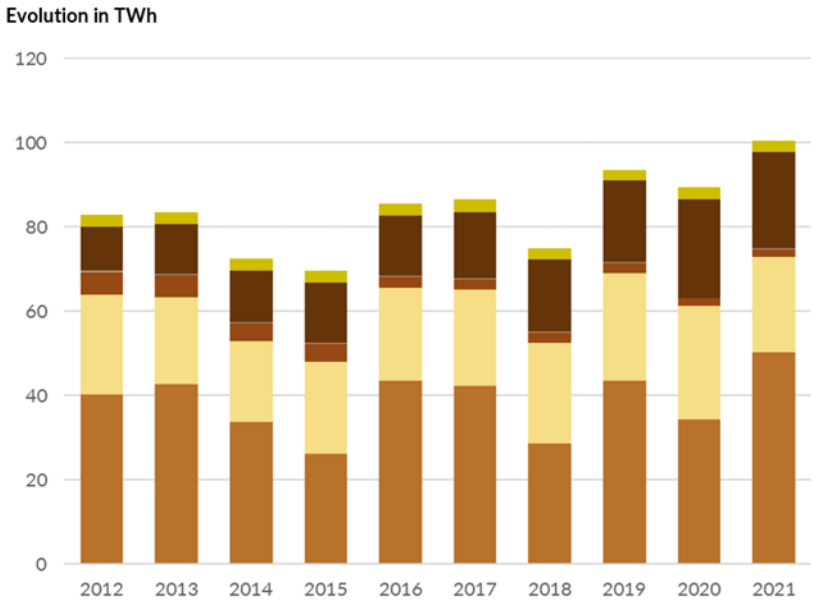


Table 9: Gross electricity production (2021)

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

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

In 2021, gross electricity production in Belgium was 100.5 TWh. During the last decade, the largest increase can be found in renewable energy, where production increased by 116.0% or 12.2 TWh compared to 2012. The use of oil products and solid fossil fuels strongly decreased (respectively -45.8% and -62.9% over the last decade), mainly in favour of renewable energy. The last power plant running on solid fossil fuels closed in 2016. The electricity still produced today from this group of fuels comes from gases manufactured in the steel industry and from small multi-fuel cogeneration plants.

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

In 2018, gas-fired power plants and cogenerations (CHP) accounted for 27.6% of the total installed production capacity (See Table 10). This is nearly as much as the nuclear power plants (28.7%) and rises when considering only production capacities that are independent from the weather conditions. Natural gas then accounts for 40% of the production capacities that could theoretically be available all year round.

Another advantage of gas-fired power plants is their flexibility, which cannot be offered by other climate-independent sources like nuclear and CHP. These gas-fired power plants represent nearly 60% of the flexible production capacity, which is essential for the balancing of the electricity grid.

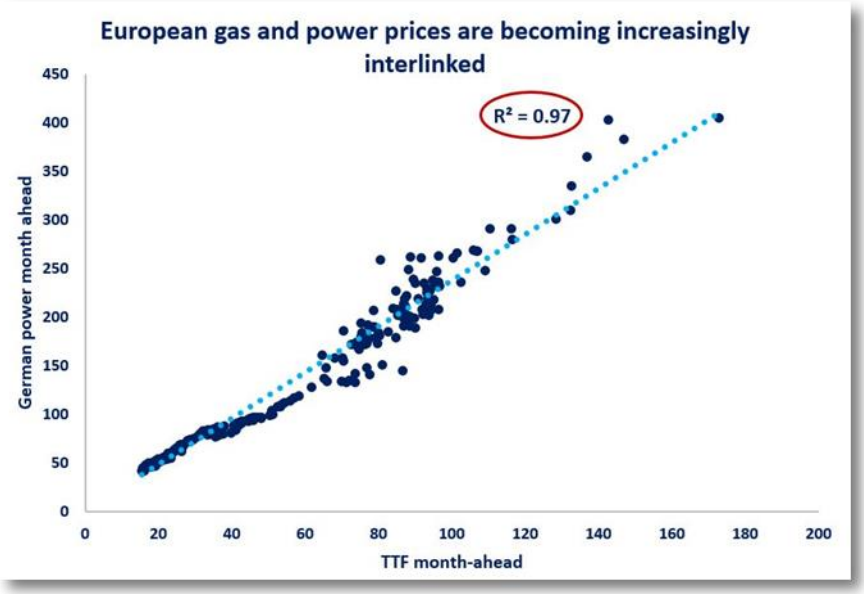
Table 10: Installed electricity production capacity (2018)

	Installed production capacity	% of total production capacity	Flexible	Climate independent
	MWe			
Non-renewable thermal production	**11758**	**57.1%**		
Nuclear	5919	28.7%	NO	YES
Gas-fired	3846	18.7%	YES	YES
CHP	1835	8.9%	NO	YES
Turbojet (oil)	158	0.8%	YES	YES
Renewable, climate independent production	**1125**	**5.5%**		
Biomass	794	3.9%	YES	YES
Waste	331	1.6%	YES	YES
Renewable, climate dependent production	**6414**	**31.1%**		
Wind	2774	13.5%	NO	NO
Solar	3526	17.1%	NO	NO
Hydro	114	0.6%	NO	NO
Storage	**1308**	**6.3%**		
Pumped hydro	1308	6.3%	YES	YES
Total	**20605**	**100%**		

To determine which production units must be used, a detailed modelling of the power plants' economic dispatch is performed. The assessment takes into account the power plants' marginal costs and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled. Economic availability depends on the generation capacity available for the hour in question. The price in any given hour is determined by the intersection between the curve for supply (ranking of the power plants) and demand. Demand is considered inelastic in this context. The market response to high prices is also taken into consideration.

Due to the merit order system, it is the most expensive plant needed to balance the market (the intersection of the supply and demand curves) that determines the price received by the producers. When gas prices are high, in the Belgian electricity generation fleet, gas-fired power plants come last, and therefore determines the compensation price. This makes the price of electricity in Belgium very sensitive to fluctuations in the gas price. In Belgium as well as in Europe, there is a strong correlation between gas prices and electricity prices.

Figure 24: Correlation between M-1 TTF gas prices and electricity prices in Germany since the beginning of 2021



Source: (IEA)

Overproductions are due to certain types of production considered as priority ('must-run'), most of them non-flexible and can occur in a context of low consumption. This so-called "must run" production will generate an excess of production in any situation where consumption is lower than this non-flexible production, even though the vast majority of flexible production has been shut down.

1.2.11 Fuel switching

Fuel switching capability is the short-term capability of a manufacturing establishment to use substitute energy sources in place of those currently consumed. Capability to use substitute energy sources means that the establishment's combustors (for example, boilers, furnaces, ovens, and blast furnaces) had the machinery or equipment either in place or available for installation so that substitutions can be introduced within 30 days without extensive modifications. Fuel-switching capability does not depend on the relative prices of energy sources; it depends only on the characteristics of the equipment and certain legal constraints.

Fuel switching possibilities, short-term switching away from the use of natural gas to another fuel, are limited in Belgium since the phasing out of coal. Fuel switching is only possible in a limited number of industry facilities. A questionnaire of the DG Energy (June 2022) among ca. 500 large consumers of natural gas, showed that less than 5% had the possibility to switch fuels.

In Belgium there is no program to encourage or otherwise require users of gas to switch to another fuel source in case of a disruption of natural gas supply. Also, the new power plants do not have the built-in capability to switch fuel.

1.2.12 Energy efficiency measures

Taking measures regarding energy efficiency falls under the competence of the regions.

At Flemish level, there is energy performance regulation (EPB) that sets requirements for new construction and thorough renovation. There are regulations regarding energy performance certificates (EPC) for the sale and rental of buildings. There is also a long-term strategy for the renovation of buildings. In addition, there are also rational energy use (REG) public service obligations that are imposed on grid operators with the aim of encouraging end customers to save energy. Finally, there is also a European energy efficiency directive in which it was decided at Flemish level that, among other things, all entities of the Flemish government are obliged to comply with the applicable requirements for renovation work requiring a permit for the same renovation works that do not require a permit. (For more information: Energie-efficiëntie | Vlaanderen.be)

In the Walloon Region, there are mainly measures regarding the energy performance of buildings; the regulations on the energy performance of buildings (PEB) apply to all buildings (except for the exceptions explicitly mentioned in the regulations), for all construction, reconstruction and transformation works that require an urban development permit. (For more information: La performance énergétique des bâtiments - Site énergie du Service public de Wallonie)

Measures have also been taken in the Brussels-Capital Region, mainly for the construction sector. These construction measures are largely based on the strategy for the reduction of the environmental impact of the existing buildings. (For more information: Energie-Klimaatplan 2030 *The right energy for your Region*, 2019)

2 Summary of the risk assessment

For the national level, we can draw the following conclusions for natural gas:

1) The security of natural gas supply may not be guaranteed in all circumstances, and LNG will play/plays a major role in national and European supply.

Although there is currently no problem with the security of natural gas supply in Belgium or Europe, it cannot be ruled out that there may be tense situations in the future.

The Ukrainian crisis has profoundly changed the structure of gas flows in Europe and in Belgium. As a result, the entry of gas into the Belgian network is now concentrated in the Zeebrugge zone (West zone).

Belgian consumption of H-gas, as well as peak consumption, is set to increase significantly over the next few years as a result of:

- the migration of L gas to H, which will be completed in September 2024,
- the construction of two new natural gas-fired power plants (at Seraing and Les Awirs), which should be operational in 2025;

Against this backdrop, market players in the Member States, including Belgium, have managed to fill their storage facilities to record levels, partly thanks to flows from Norway and LNG, but also thanks to Russian gas flows that are still available.

Although Belgium itself is not very dependent on physical imports of Russian natural gas, the absence of natural gas flows from Russia to Europe means that Belgium's neighbours (the Netherlands, Germany and others) are transporting gas through Belgium on an unprecedented scale. However, if domestic consumption rises, which is of course expected during the winter period as temperatures fall, Belgium will no longer be able to maintain these high levels of exports to the north and east. This situation will lead the countries of Central Europe in particular to withdraw natural gas from their storage facilities during periods of high demand.

For the winter of 2023/24, ENTSO-G believes that the probability of a physical shortage of natural gas in Europe is low. For the winter periods 2024/25 and 2025/26, no assessment is currently available.

As far as LNG is concerned, we have seen that by 2022, at European level, the loss of Russian gas has largely been made up by LNG. LNG therefore plays a critical role in Europe's natural gas supply. However, forecasts indicate that record LNG imports in 2022 may not be repeated in the coming years.

It is therefore very important to monitor supplies to Belgium, but also to Europe, given the decisive role that LNG will play in the security of supply of natural gas.

Furthermore, it cannot be ruled out that the reduction in Russian natural gas flows will continue in 2024 and beyond. This will make it even more difficult for storage facilities in Europe to reach a fill level of 90%. This would leave Europe more exposed to physical shortages of natural gas, especially in winter.

If we make the link with the various European regulations, which further strengthen the solidarity mechanism between Member States, this means that even if, under normal circumstances (infrastructure and molecules available), Belgium would be able to cover its own consumption in winter with imports mainly[15] from Norway and the rest of the world (LNG), an (organised) shortage on the Belgian market could nevertheless occur in the event of requests for solidarity during a cold spell, for example (or the imposition by Europe of compulsory measures to reduce natural gas consumption), through a cascade effect.

In addition, we assume that all 'western' import channels remain available for Belgium. It has already been shown above that the supply of molecules from the UK may not be fully available in winter and may even be absent.

It has also been shown that the supply of LNG to the world market is strongly influenced by long-term contracts, on the one hand, and by the spot price, on the other, for players who have not concluded a long-term price contract. As the market is liberalised, it is unfortunately difficult for the authorities to influence this aspect of supply.

Finally, the incidents on the two Nord Stream pipelines and Baltic-connector have also shown that pipeline imports from Norway and the UK are not guaranteed in all circumstances.

The four entry points located in the west of the Belgian natural gas transmission network must be considered essential and therefore strategic for the security of supply of natural gas (type H natural gas) for Belgium and Europe. The LNG Terminal and the two offshore pipelines (Interconnector and Zeepipe) stand out as being more important, given their large capacities.

In the current configuration, the loss of just one of these entry points could have a serious impact on Belgium's natural gas supply in the event of a peak or cold spell. The total unavailability of one of these entry points would lead to a significant reduction in the reliability of supply, insofar as it would be necessary to be able to rely on the 100% capacity of the other entry points and the total availability of the upstream molecules in order to be able to cover Belgian peak demand.

In addition, during the winter months, and especially in the event of a cold spell, it is likely that the UK market will no longer be able to export natural gas to mainland Europe. As a result, we would not be able to import natural gas via the Interconnector. In this case, the loss of an entry point or a reduction in the capacity of one or more points would have an even greater direct impact on Belgium's security of natural gas supply.

These three facilities (LNG Terminal, Interconnector and Zeepipe) must therefore be considered as strategic and be closely monitored to deal with any risks of deliberate or unintentional damage.

All this (loss of Russian gas, principles of European solidarity, uncertainty about imports, etc.) leads us to conclude that the security of natural gas supply for Belgium and Europe in general can no longer be regarded as absolute and predictable.

2) The Loenhout storage infrastructure could contribute to the security of supply, but does not have sufficient capacity for prolonged use in the event of a long, cold winter.

The first part of this analysis also deals with the Loenhout storage. In the event of strong national demand, this storage is important to ensure security of supply. For short periods of high demand (cold spells), the storage facility could provide a fairly modest additional flow, which would nonetheless be useful for covering peak consumption. However, the facility's limited capacity means that it cannot offer a solution for longer periods of high demand. In the event of high demand with limited imports, access to storage facilities outside of Belgium would seem to be essential to ensure the necessary supplements to our security of supply.

3) European initiatives must be closely monitored because of their impact on national security of supply.

The adaptation of security of supply rules at European level must therefore be closely monitored in order to analyse the impact of the European proposals on Belgium's natural gas supply.

The same applies to the price cap policy at European regional level, where the impact on the global competitiveness of the European market must be carefully analysed.

4) A problem with the supply of natural gas should not cause problems with the supply of electricity

The rules put in place at European level by the various regulations make it possible to maintain supplies to the gas-fired power plants needed to balance the electricity network. Natural gas-fired power stations therefore have a priority customer status. A shortage of natural gas in Belgium will therefore first of all be offset by voluntary or compulsory reductions in consumption by unprotected customers (industry, SMEs, etc.).

3 Infrastructure standard

3.1 N-1 calculation: national level

In accordance with Article 5 of the European Regulation, in the event of failure of the largest gas infrastructure, the technical capacity of the remaining infrastructures, determined in accordance with formula N - 1 described hereinafter, enables to meet the total gas demand of the area covered during a day of exceptionally high gas demand occurring with a statistical probability of once in twenty years. Due to the Russian-Ukraine crisis (in which countries mainly wanted to have their emergency plans completed), no assessment was made of the N-1 calculation at regional level, with the result that the N-1 calculation is only available at the national level.

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

Where

EP_m: technical capacity of entry points, other than production
P_m: maximal technical production capacity
S_m: maximal technical storage deliverability
LNG_m: maximal technical LNG facility capacity
I_m: technical capacity of the single largest gas infrastructure
D_{max}: total daily gas demand
D_{eff}: demand-side measures in accordance with the above, the values to be included in the above formula for the winter 2023/24 are:

the sum of the technical capacities of the entry points to the Belgian network will be 112.5 GWh/h during the winter of 2023/24
EP_{BE} = 112,5 GWh/h

the sum of (bio-)methane production capacities is currently negligible
P_{BE} = 0 GWh/h

The emission capacity of the only Belgian storage facility in Loenhout is 7 GWh/h

S_{BE} = 7 GWh/h

The regasification capacity of the Zeebrugge terminal is 22 GWh/h

LNG_{BE} = 22 GWh/h

The largest infrastructure is currently the Interconnector, with a physical capacity of 27.15 GWh/h

I_{BE} = 27,15 GWh/h

Peak demand from the internal market is estimated at 56.2 GWh/h

I_{BE} = 56,2 GWh/h

No demand management measures are required in the event of failure of the largest infrastructure

I_{BE} = 0 GWh/h

Applying the N-1 formula gives the following result for the winter 2023/24:

[N-1] % = (112,5+0+7+22-27,15) / (56,2 – 0) = 114,35 / 56,2 = 204 %

Even taking into account the total conversion of the L market to H and the arrival on the market of two new power stations of 850 MWe each for the winter 2025/26, using the formula once again gives a result in percentages higher than 100%.

[N-1] % = (112,5+0+7+30,2-27,15) / (56,2 – 0) = 122,55 / 65,6 = 187 %

Conclusion: Application of the N-1 formula shows that this infrastructure standard has been largely met considering the result higher than 100% for the coming years.

Given the redundancy of the Belgian transmission network, no measures to reduce demand seem necessary even in the event of a failure of the largest gas infrastructure.

3.2 Bi-directionality

As required under Article 5(4) of the Regulation, the following tables indicate bi-directional capacities or exemptions for all the interconnection point in Belgium.

Table 11: Interconnection points not subject to the obligation

IP	Connection with	Description of the arrangements
LNG Terminal	n.a.	The interconnection point LNG Terminal of Zeebrugge is a connection to an LNG facility, which falls under the exceptions defined in Article 5(4) (a).
ZPT	Norway	The cross-border interconnection Zeepipe Terminal with Norway is a connection to a production facility, which falls under the exceptions defined in Article 5(4) (a).
Hilvarenbeek	Netherlands	The interconnection point Hilvarenbeek is a connection to a production facility, which falls under the exceptions defined in Article 5(4) (a).

Table 12: Interconnection points equipped with permanent bidirectional capacity

IP	Connection with	Description of the arrangements
IZT	UK	Bi-directional firm capacity is offered at the interconnection point. Currently, the interconnection point IZT is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Zelzate 1	Netherlands	Bi-directional firm capacity is offered at this interconnection point, but is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Eynatten 1	Germany	Bi-directional firm capacity is offered at this interconnection point, but is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Eynatten 2	Germany	Bi-directional firm capacity is offered at this interconnection point, but is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Blaregnies H	France	Bi-directional firm capacity is offered at this interconnection point. However, physical reverse flow will only be accepted for non-odorised gas, except in case of emergency. The market consultation with a view to developing firm transmission capacity from France to Belgium indicated that the scenario for creating a new capacity at the interconnection point Blaregnies H through the construction of a deodorization facility was not requested by the market

Table 13: Exempted interconnection points

IP	Connection with	Description of the arrangements
Zandvliet H	Netherlands	Firm entry capacity is offered on this interconnection point to serve a local area in Belgium. A bilateral meeting between Fluxys Belgium and GTS led to the conclusion that firm reverse capacity is not requested by and is not useful to the Dutch market because there is no source of gas available for firm reverse capacity to be useful. (Backhaul Capacity and Backhaul Level 1)
's Gravenvoeren	Netherlands	Firm entry capacity is offered at this interconnection point. Results of recent market consultation by GTS have shown no need for additional reverse firm capacity. In emergency however, physical reverse flow is possible.
Zelzate 2	Netherlands	Firm exit capacity is offered on this interconnection point to serve a local area in the Netherlands. Firm entry capacity is not requested by and not useful for the Belgian market because there is no source of gas directly available on the upstream network. Fluxys Belgium never received a request for entry capacity from Zelzate 2. In case of emergency the interconnection points Zelzate 1 and 's Gravenvoeren are the main sources for physical flow towards Belgium.
Bras/Pétange	Luxembourg	Not used commercially: single market, balancing zone and entry/exit model with Luxembourg
Alveringem[10]	France	Firm entry capacity is offered at this interconnection point since this connection is not odorized.

4 Compliance with the supply standard

4.1 Definition of protected customers

In the regulation EU 2017/1938 regarding measures to safeguard the security of gas supply ("the Regulation"), the eligibility of clients to be considered as protected customers is defined depending on their profile as end users (households, SMEs, social services, district heating, etc.) and also depending on their level of consumption (threshold of 20% of the annual gas consumption for SMEs and essential social services). On the Belgian grid we determine five end user types (customer segments):

- Telemetered end user:
  1. Automatic Meter Reading "AMR"
     → Hourly consumption registration with data transmission at H+1.
     → 2 different types: AMR client & AMR Production (Biomethane)
- Two end user types "SmartMeter":
  2. Smart Meter Regime 3 "SMR3":
     → Hourly consumption registration without data transmission at H+1 (transmission at M+1)
  3. Smart Meter Real Monthly Volume "RMV":
     → Monthly consumption registration precisely between 1st of M at 06h00 and 1st of M+01 at 06h00
- Two end user types "non-SmartMeter":
  4. Estimated Monthly Volume "EMV":
     → Profile end user with monthly consumption registration but not exactly 1 month
  5. Estimated Annual Volume "EAV":
     → Profile end user with annual consumption registration but not exactly 1 year

However, the type of end user does not provide us with specific information on what kind of activity is behind the meter. Therefore, in the previous version of the Preventive Action Plan, Belgium had offered the pragmatic solution to consider every customer connected to the distribution network as a protected customer. Although prudent, this definition of protected customer has been declined by the European Commission as it is too broad.

Therefore, a new definition has been proposed where only essential social services and households have been defined as protected customers. As such, this definition converges with the definition of solidarity protected customers.

In Belgium, a "protected customer" is defined in Article 2 point 5 of the Regulation:

a. A household customer[1] connected to the distribution network, including a household living in a block of flats with a collective gas installation managed by a condominium, managing agent or social housing agency.

The Eurostat definition of Residential includes, in principle, households in condominiums. However, as a conservative measure, consumption declared by real estate property managers under the following NACE-BEL codes is also included here:

68.321 Management of residential real estate on a fee or contract basis
68.201 Renting and operating of own or leased real estate, excluding social housing
68.202 Rental and operation of social housing

b. Provided that it is connected to a gas distribution or transport system, a health care service under one of the following NACE-BEL codes and/or of which the address is listed on https://www.health.belgium.be/fr/sante/organisation-des-soins-de-sante/partage-de-donnees-de-sante/institutions-de-soins:

86.101 Activities of general hospitals, except geriatric and specialised hospitals
86.102 Activities of geriatric hospitals
86.103 Activities of specialised hospitals
86.104 Activities of psychiatric hospitals
86.109 Other hospital activities
86.210 General medical practice activities
86.220 Specialist medical practice activities
86.230 Dental practice activities
86.901 Activities of medical laboratories
86.902 Activities of blood collection centres, blood and organ banks
86.903 Ambulance transport
86.904 Mental health activities, except hospitals and psychiatric homes
86.905 Outpatient rehabilitation activities
86.906 Activities of nursing practitioners
86.907 Activities of midwives
86.909 Other human health activities n.e.c.
75.000 Veterinary activities

c. Provided that it is connected to a gas distribution or transmission system, and that it offers accommodation and/or meal preparation services, a social assistance service or an emergency service, under one of the following NACE-BEL codes:

87.101 Activities of nursing homes
87.109 Other residential nursing care activities
87.301 Activities of nursing homes for the elderly
87.302 Residential services activities for the elderly
87.303 Residential care activities for minors with motor disabilities
87.304 Residential care activities for adults with motor disabilities
87.309 Other residential care activities for the elderly or disabled
87.901 Youth hostel services with accommodation
87.902 General social services with accommodation
87.201 Residential care activities for minors with a mental disability
87.202 Residential care activities for adults with a mental disability
87.203 Residential care activities for people with a psychiatric problem
87.204 Residential care activities for drug-dependent persons
87.205 Protected housing activities for people with a psychiatric problem
87.209 Other residential care activities for persons with mental disabilities, persons with psychiatric problems or drug-addicted persons

88.999 Other social work activities without accommodation n.e.c. (includes day centres for the homeless and other socially deprived groups; charitable activities such as fundraising or other related social work activities)
84.232 Prisons
84.241 Federal Police
84.242 Local police
84.250 Fire service activities
84.249 Public order and safety activities
84.220 Defence activities

Including, solely for the provision of accommodation and/or meal preparation services carried out at the request of a health care service, an essential social assistance service or an emergency service, as defined in points b or c above, the private structures included in the following NACE-BEL codes:

55.100 Hotels and similar accommodation
55.201 Youth hostels
55.202 Holiday centres and villages
55.203 Holiday cottages, apartments and self-catering accommodation
55.204 Guest rooms
55.209 Holiday and other short-stay accommodation n.e.c
56.290 Other food service activities

d. A district heating system, provided that it supplies heating to at least one of the above customers (a, b or c) as categorized by NACE-BEL code:

35.300 Steam and air conditioning supply (District heating)

As part of the Preventive Action Plan and Emergency Plan, measures are considered in order to limit the consumption of customers non-eligible under the Regulation in a crisis situation. However, given the complex situation, both technically and institutionally (public distribution is a Regional competence in Belgium), the efficiency and impact of such measures are difficult to identify accurately.

4.2 Consumption of protected customers

On the basis of data obtained from distribution system operators, protected customers represent a consumption of around 56 TWh in 2021, i .e. 56% of total public distribution consumption in a year with average weather conditions such as 2021. We have not taken into account the transport network seeing as no protected customers are connected to it.

These data are based on the analysis carried out by Fluxys Belgium and the various distribution system operators on the one hand, and by the DG Energy on the other hand. Consumption data from distribution system operators were used as the basis for this analysis. Thanks to the NACE code assigned to each connection (EAN code), connections have been assigned to protected or non-protected customers.

According to information obtained from Synergrid, *"the distribution system operators (DSOs) Fluvius, Sibelga, Ores and Resa used their databases in which a NACE code is generally linked to the EAN code for most customers connected to the distribution system. These NACE codes are supplied by natural gas suppliers to the distribution system operator. The reliability of the collected data therefore depends on the quality of the data supplied by the suppliers to the distribution system operator. Although the NACE code is generally available, for around 3% of connection points, no NACE code could be linked and had to be considered as unknown. In energy terms, this represents around 3,4 TWh in Belgium in 2021 (less than 2% of the annual consumption). In a conservative application of the use of these data, the annual energy consumed by these connection points without a NACE code has been equated with that of protected customers, and has therefore been added to the quantities consumed by protected customers who can be identified by means of a NACE code"*.

The NACE codes used by Synergrid to identify protected customers can be found in the following scheme.

Table 14: Repartition of gas consumption over protected and not-protected customers (2021)

DNO - Data's 2021		Distribution network	% of total
Protected (solidarity)	Telemetered	847.567	0,8%
	Not telemetered	51.607.953	51,4%
	Subtotal	52.455.519	52,2%
Not protected	Telemetered	24.073.366	24,0%
	Not telemetered	20.555.862	20,5%
	Subtotal	44.629.228	44,4%
Unknown		3.359.087	3,3%
Total		100.443.834	100,0%
Protected + unknow		55.814.606	56%
Not protected		44.629.228	44%
Total		100.443.834	100%

Source: Synergrid & SPF Economy

As was also the case for the various common regional risk assessments, it appears to be very difficult for the Member States to specify the volumes of gas consumption corresponding to customers belonging to the categories referred to in Article 2, point 5) a) and b) of the SOS Regulation and the percentage that each of these groups of customers represents in the total annual final consumption of gas. As a result, we were unable to include this specific information in our preventive action plan.

4.3 Volumes and capacities associated with the supply standards

Criteria's

According to article 8 of the regulation, the gas undertakings have to be able to supply the protected customers of the Member State in the following cases:

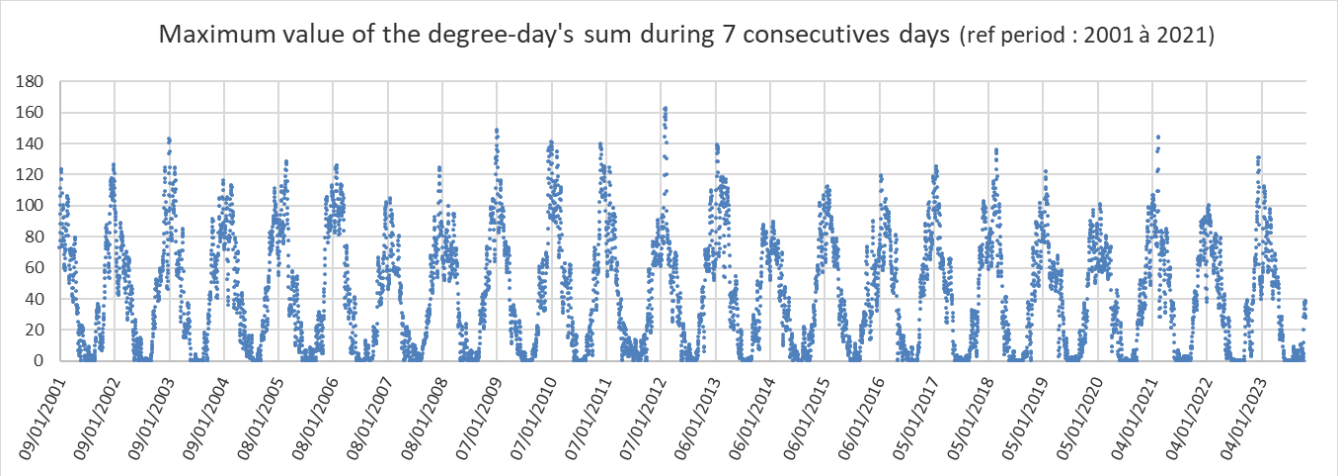
1. Extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years
2. Any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years
3. For a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions

Who is concerned? The gas undertakings that will need to live up to those standards are all gas undertakings that deliver gas to protected customers.

4.3.1 Scenario 1: extreme temperatures during a 7 day peak period (risk 1/20)

The first task consists of translating into equivalent degree days a period of extreme temperatures occurring in Belgium with a statistical probability of once in twenty years. We have limited ourselves to recent data from the last 21 years, i.e. with the reference period 2001 to 2021.

Figure 25: Maximum value of degree-day's sum (7 days)



The analysis shows that the maximum number of degree days was observed during the reference period, from Thursday 2 February to Wednesday 8 February 2012.
During this week, temperatures were as follows: -5.9°C, -7.2°C, -8.6°C, -7.5°C, -5.6°C, -7.0°C and -5.6°C. This represents heating requirements equivalent to a total of 162.9 degree days during these 7 days.

If we had taken into account a longer period based on temperature data for the last 120 years, we would have obtained the following data:

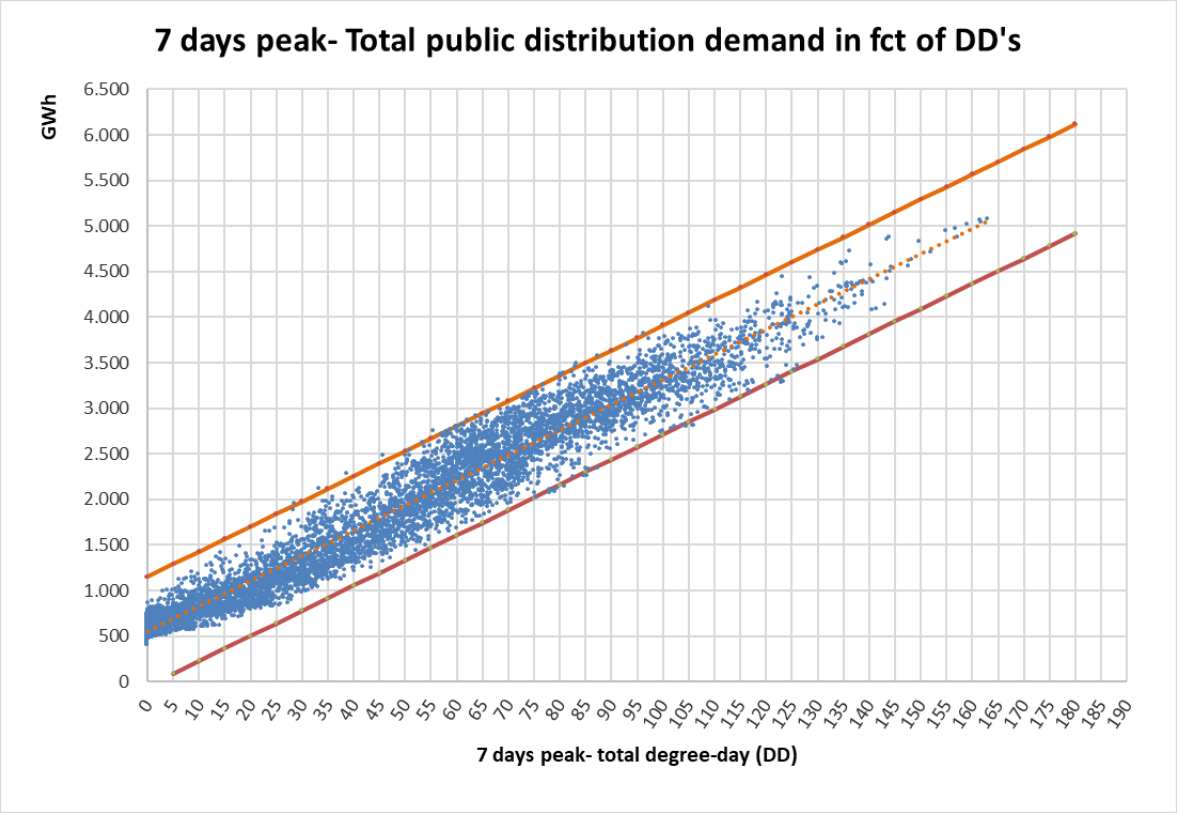
Table 15: Coldest historical Degree Day periods (7 days)

begin	end	Degree Day/Equivalent temperatures							Sum/mean
28/12/1996	3/01/1997	23.1	23.3	20.1	23.1	26.9	27.4	25.3	169.2
		-6.6	-6.8	-3.6	-6.6	-10.4	-10.9	-8.8	-7.7
1/01/1979	7/01/1979	25.6	24.6	23.7	22.9	24.6	25.7	22.9	170.0
		-9.1	-8.1	-7.2	-6.4	-8.1	-9.2	-6.4	-7.8
17/01/1963	23/01/1963	23.6	26.9	26.2	22.8	22.9	23.9	22.3	168.6
		-7.1	-10.4	-9.7	-6.3	-6.4	-7.4	-5.8	-7.6
17/12/1946	23/12/1946	23.4	23.5	24	25.8	25.6	23.6	23.4	169.3
		-6.9	-7	-7.5	-9.3	-9.1	-7.1	-6.9	-7.7
19/01/1940	25/01/1940	24,5	25.6	23.5	26.5	24.6	23.6	22.2	170.5
		-8	-9.1	-7	-10	-8.1	-7.1	-5.7	-7.9
	Average	24,0	24,8	23,5	24,2	24,9	24,8	23,2	169,5
		-7,5	-8,3	-7,0	-7,7	-8,4	-8,3	-6,7	-7,7

Source: FPS Economy

On the basis of the observations over the last 120 years, the number of degree days of these extreme events over 7 days represents a total average value of 169 degree days. Compared with the extreme value of the last 20 years (163 DD), this value has only been reduced by 3.6%. This is very low compared with the effect of global warming on annual values. Important conclusion: based on the observations, although global warming has a significant observable effect on annual weather conditions, we can see that the extreme situation shows an almost identical intensity over short periods (for example 1 day or 7 days) whether we choose the last 120 years or the last 20 years as reference period.

Figure 26: 7 days peak - Total distibution

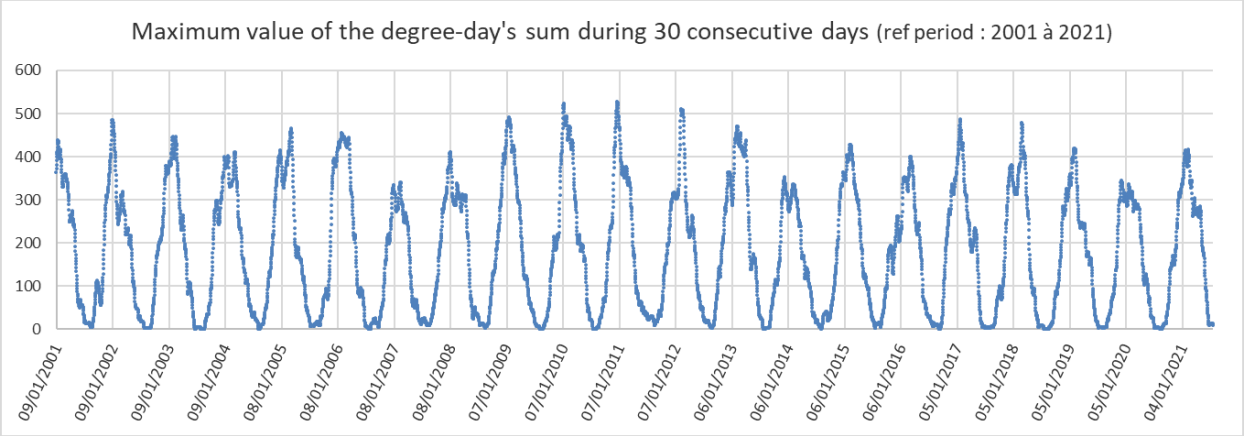


The graph above shows the evolution of the total public distribution consumption as a function of degree days. The value of this consumption corresponds to 162.9 DD over 7 days and is equivalent on average to around 5,025 GWh/7 days, with a maximum corresponding to around 5,700 GWh/7 days and a minimum of around 4,500 GWh/7 days. However, at this stage we are unable to identify the share represented by the protected customers in this total, as this information is not available at the level of the distribution system operators.6

4.3.2 Scenario 2: period of 30 days of exceptionally high demand (risk 1/20)

As for the first scenario, based on historical data for the last 20 years, we have looked for the period of extreme consumption during thirty days at the level of public distribution with a statistical probability of once in twenty years.

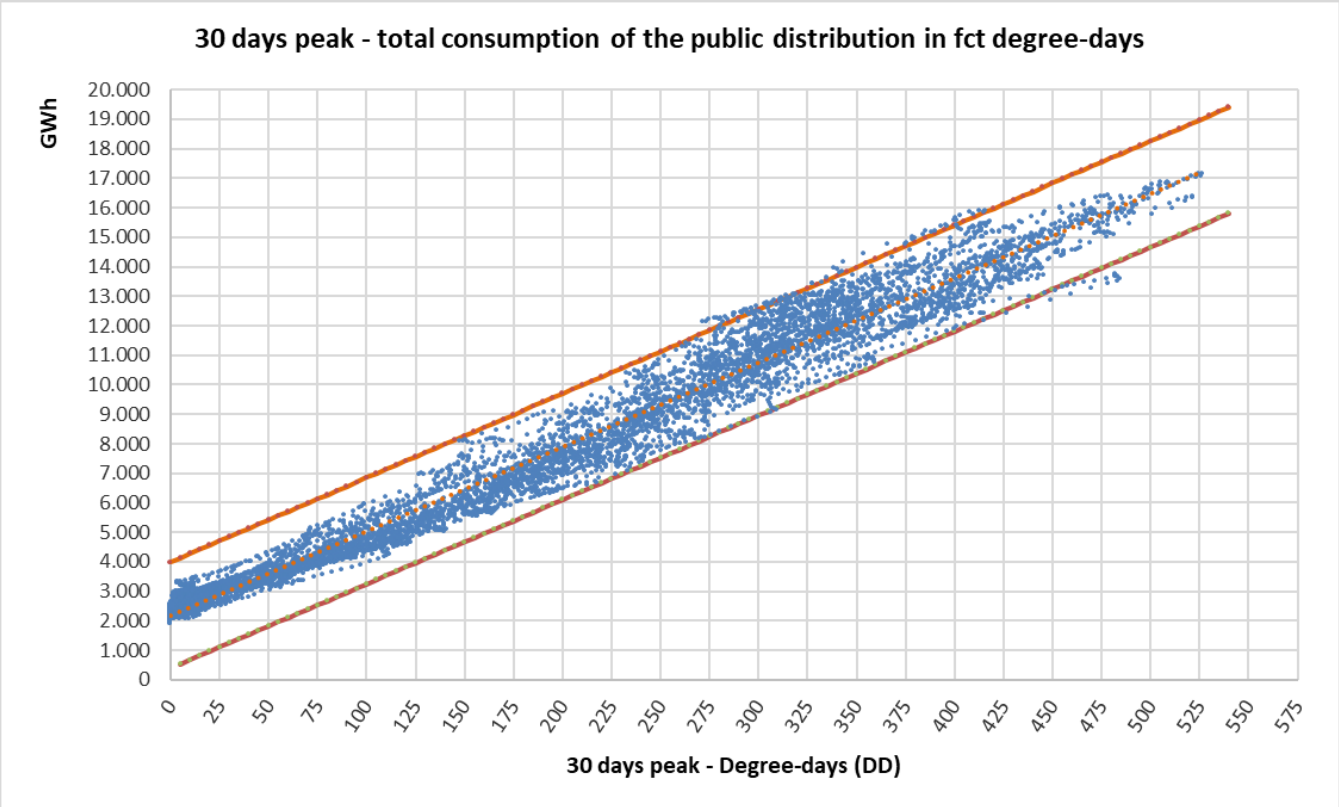
Figure 27: Maximum value degree days (30 days)



This also corresponds to the period with the maximum number of degree days with a value of around 526.2 degrees days. This corresponds to the period from 28/11/2010 to 27/12/2010. It was also during this period, shifted by a single day, that the maximum total consumption over 30 consecutive days was obtained. This confirms, as we already suspected, that outside temperatures play a major role in public distribution consumption in Belgium.

6 We did not mention the breakdown between the rich gas (H) and lean gas (L) markets, given the current total conversion process for the L market which should be completed in September 2024.

Figure 28: 30 day peak total consumption distribution



Over the last 20 years, the maximum consumption during 30 consecutive days of public distribution was observed from 29/11/2010 to 28/12/2010 with a value of 17.18 TWh/30 days for a duration of 30 consecutive days. The corresponding maxima and minima are around 19 TWh and 15.4 TWh/30 days.

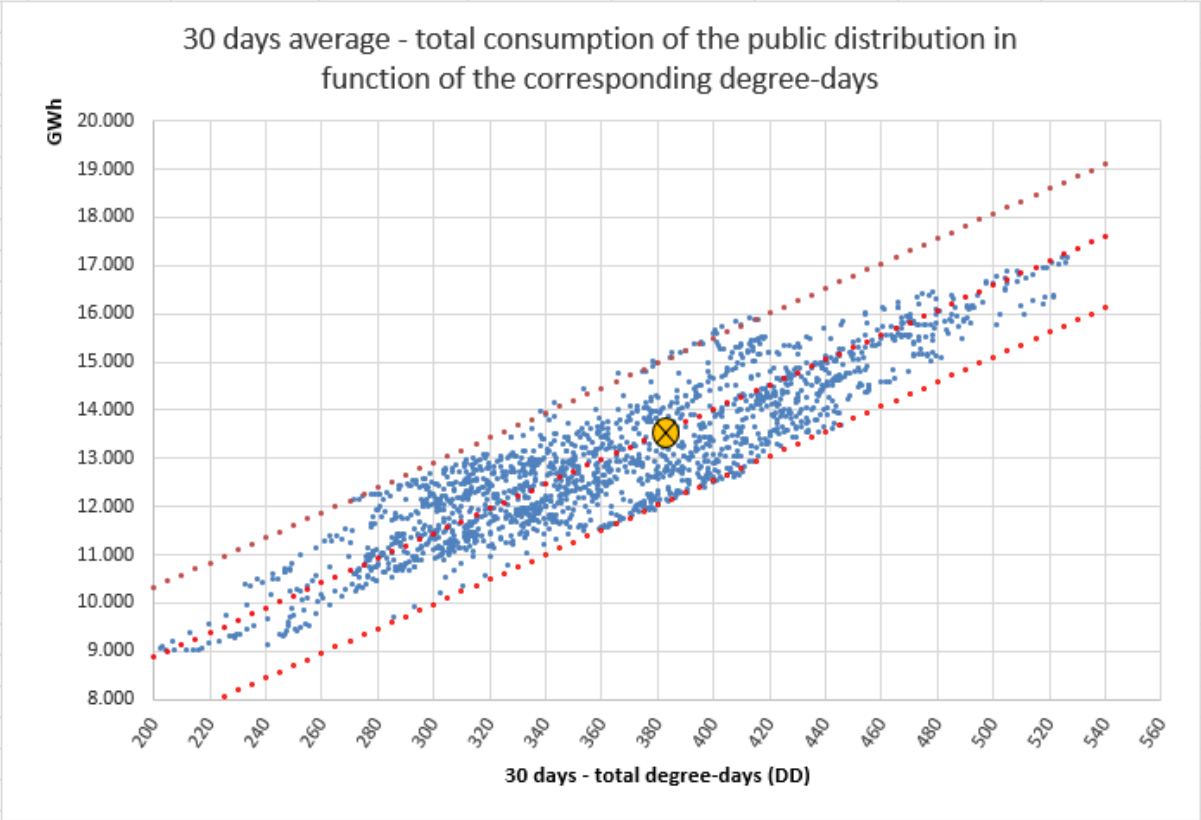
As for scenario 1, we are unable at this stage to identify the share represented by the protected customers in this total, as this information is not available at the level of the distribution system operators.

4.3.3 Scenario 3: thirty-day period in average winter conditions (risk 1/20) and failure of the largest gas infrastructure

The reference winter period chosen is the 30-day period in the middle of the meteorological winter that runs from 22 December of year N to 21 March of year N+1. It is the period from 17 January to 15 February. Over the last 20 years, this period counts on average 381 DD/year.

The total average public distribution consumption over this 30-day period was 13.56 TWh on average (see ⊗ mark on graph below), or an average of 452 GWh/day.

Figure 29: 30 day average total consumption distribution



The maximum and minimum values corresponding to 381 DD are around 15 TWh/30 days and around 12 TWh/30 days respectively.

As for scenario 1, we are unable at this stage to identify the share represented by the protected customers in this total, as this information is not available at the level of the distribution system operators.

4.4 Measures in place to comply with the supply standards

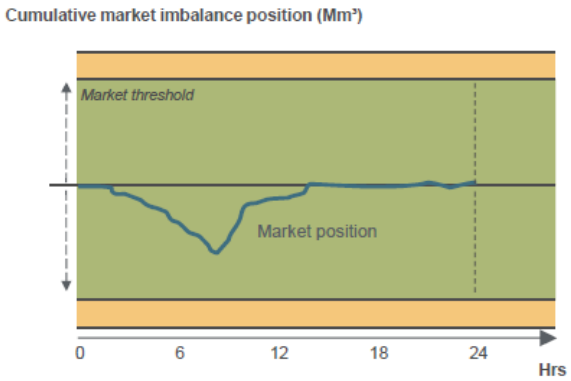
4.4.1 Market based balancing

As discussed in previous section, the peak winter peak value occurring once in 20 years is -11°C_{eq}. The above criteria fall into two parts. The first part is the infrastructure obligations and the second part is the molecule obligation.

For the infrastructure calculations, the TSO still bases its investment plan on the -11°Ceq hourly peak criterion. By introducing the same criteria for the shippers, both the molecule standards will be in line with our infrastructure standard. An improvement is already made through the introduction of the new entry-exit model. The TSO will calculate the needed capacity per aggregated receiving station (ARS) to cover the full demand distribution network behind that specific ARS at -11°Ceq. The shippers and suppliers will then be forced to book the capacity calculated by the TSO in order to cover the

winter peak demand and to avoid free riding. This way, at least the capacity is already in place to cover the peak demand.

Another measure that is already in place to make sure suppliers deliver gas to Belgian end-users, is the daily market balancing regime. Balansys monitors the balance between entry and exit on a cumulative basis for all hours of a given day and intervenes in order to keep the system balanced at all times.



Two kinds of interventions are possible:

- Within day interventions
- End of day interventions

Within day interventions:

In case the market balancing position goes beyond the upper (or lower) market threshold during a gas day, Balansys intervenes through a sale (or purchase) transaction on the commodity market.

- The considered volume is then settled in cash with the grid user (s) contributing to such imbalance in proportion of their individual contribution.
- Grid users which are causers are penalized by 3% of the Belgian TSO price for the settled volumes, and grid users helping the system are settled at the Belgian TSO price (no penalty).

In the year 2021-2022 there were approximately 365 interventions by Balansys (responsible for the Belgo-Luxemburg market). Compared to the 2017-2018 gas year, Flx had to intervene in 2022-2023 about 2,3 times (365 instead of 159) more to rebalance the market. This seems to indicate that the market is clearly struggling to balance supply and demand.

End of day interventions:

At the end of the gas day, each grid user is returned to zero individually by a settlement in cash:

- Grid users helping the system pay (or get paid) the Belgian TSO price (no penalty).
- Imbalance causing grid users pay (or get paid) the Belgian TSO price with an additional penalty of 3%.

To settle the balancing position of all the grid users to zero at the end of the gas day, the TSO has bought about 1,390 GWh of gas for the H-gas market and 465 GWh for the L-gas market. We can therefore conclude that grid users trust the balancing system and rely on the TSO to establish their equilibrium position at the end of the day and that the balancing system makes it possible to avoid cases of tension and crisis through adequate flexibility and a well-functioning information system to all market players in this area. During the "Beast of the East" event in February-March 2018, there was no declared crisis on the gas market in Belgium, which proves once again the robustness of the system in place.

To conclude, in case of an imbalance of the market caused by suppliers that don't fulfil their contractual engagements related to their clients, there are mechanisms in place that allow to reduce this imbalance to a level acceptable for the network. The Belgian TSO will take care of the purchase of gas and charge it to the causing grid user that they identify, thus ensuring the gas supply to the end consumers.

4.4.2 Supply standard – national initiative

In accordance with Article 6 of Regulation (EU) 2017/1938 (gas supply standard), natural gas undertakings are obliged to take the necessary measures to ensure the supply of gas to Belgium's protected customers in each of the following cases:

(a) extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;
(b) any period of 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years;
(c) for a period of 30 days in the case of disruption of the single largest gas infrastructure under average winter conditions.

In the context of the gas supply standard, suppliers to households were asked to provide information in accordance with the European Regulation 2017/1938. Specifically, on the one hand, the share of the gas volumes of protected customers that has been hedged by the company was requested, and on the other hand, a confirmation that the company guarantees the security of supply of its protected customers for that part of the gas volumes in accordance with the scenarios set out in Article 6 of Regulation (EU) 2017/1938. Monitoring will be done based upon the information provided by the suppliers.

With respect to possible sanctions the Belgian authorities have to use the options as provided in the Gas law of 12th of April 1965. However, the Belgian government has taken the initiative to update

these possibilities and DG Energy is working on a new sanction law (that will apply to all energy vectors, including natural gas)

The suppliers that were contacted are the following: ENGIE, Power Online (MEGA), Elindus, Electriciteitsbedrijf Merksplas BVBA (EBEM), ENECO, Energie, Octa+, Luminus, Total, Antargaz, Bolt Energie SA, DATS 24 SA, Trevion NV, Elegant BVBA, Essent, Energy Together BV and Frank Energie België BV.

5 Preventive measures

In this chapter, we will make an evaluation of the possible market-based measures (supply side & demand side) and attempt to assess the most efficient means that can be used to reduce the impact of an incident. We will discuss each measure separately. For each of the measures we will check if they are already applied in Belgium, what the potential impact is of the measure, what the potential costs are to apply it, if the measure could be carried out and if it is supported by the gas sector and what actions would be necessary to execute the measure in Belgium.

5.1 Increased import flexibility

Most companies have access to flexible contracts. This is either included in their long-term contracts (generally a provision is foreseen of 85%-115% or 90%-110% of the contracted gas volume), or they hold forward contracts on the European Hubs. Companies can either buy all their gas to cover the winter demand at -11°C with forward contracts, or they can foresee gas to cover the average winter demand, and if necessary, buy additional gas on a short-term basis. There is no obligation in Belgium to integrate flexibility in the supply contracts. This is entirely the responsibility of the company.

A total picture of the costs of the flexible contracts is very hard to obtain as the costs for flexibility differ according to the contracts. Every single company can have multiple contracts and prices which may vary substantially, so it is impossible to give an estimate for Belgium as a whole.

The import flexibility is monitored by an obligation on the gas companies to report on their gas contracts. This monitoring is done by the CREG, the Belgian Energy regulator.

5.2 Facilitating the integration of gas from renewable energy sources into the gas network infrastructure

Integrating gas from renewable (e.g. Biogas) sources only accounts for a very limited volume in Belgium. Most of this gas is injected onto the distribution network although since 2018 several projects has been realized where biomethane can be injected on the transport network. The production of biogas and biomethane is a regional competence in Belgium, so a federal policy option

here is not possible. As the production of biogas/biomethane remains limited, the potential for biogas/biomethane to serve as a preventive measure for incidents is negligible.

Depending on the prospects for the production of biogas/biomethane in the future, we can reassess the situation to see whether this could serve as a preventive measure and if government action needs to be taken at this point.

5.3 Commercial gas storage – withdrawal capacity and volume of gas in storage

The aquifer in Loenhout is the only underground storage installation (for H-gas) in Belgium and is used for commercial storage. The useful storage capacity at Loenhout is 770 mcm, with a send out capacity of 625.000 cubic metres per hour and injection capacity of 325.000 cubic metres per hour. Under normal winter circumstances and if the storage is filled up to its full capacity, the stored gas can be used during about 60 day (in accordance with continued import from other sources).

All companies can subscribe (a part of the) storage capacity at Loenhout on a short term basis (within the storage year) on a yearly term basis (service period for one year) or on long term basis (service period between two and ten storage years). During a storage year in function of optimisation of the Storage Installation, the storage operator could offer additional services for injection, storage volume, and for withdrawal, on a short-term basis (e.g. daily, weekly, monthly, or yearly or another term). The Yearly Term and Long-Term Storage Services on the Primary Market can be subscribed and allocated through a Subscription Window or an Auction window organised by Storage Operator, after which the principle of First Committed First Served is applied. Participation to such allocation process is open to all Storage Users having registered as Participants and signed a Storage Agreement, according to the Terms and Conditions of a particular Subscription Window or Auction Window. In a Subscription Window priority is given to Participants who commit to subscribe the longest service duration for their Storage Services. Services on a short-term basis can be subscribed and allocated via an Auction Window or on a First Committed Fist Served Basis.

Although gas storage possibilities remain limited in Belgium, it is surrounded by countries that have high gas storage possibilities (e.g. Germany, France, and The Netherlands) and as Belgium has high interconnection capacities with these countries, gas stored in neighbouring countries could also be used in Belgium. This possibility is reinforced by the European regulations adopted to bolster the storage filling levels in Europe.

There is no storage for L-gas. Currently Belgium uses, for the L-gas grid in particular, the Dutch conversion installations to act as swing supplier and the flexibility provided in the supply contracts. With a full L to H conversion completed in 2024, L-gas storage will no longer be needed in Belgium as from September 2024.

As most companies operate at a European level, part of them have contracted storage capacity outside of Belgium. In case of an emergency, these gas companies can exercise a swap of gas from storage abroad and gas transmission in Belgium.

5.4 LNG terminal capacity and maximal send-out capacity

The Zeebrugge LNG re-gasification terminal (in operation since 1987) has today a yearly throughput capacity of 9 bcm per year. It comprises 5 LNG storage tanks. Three of these tanks have a workable capacity of 81 500 m3 LNG each, a fourth tank has a workable capacity of 141 500 m3 LNG and the fifth and final tank has a workable capacity of 180 000 m3 LNG. The commissioning in 2019 of this fifth tank marked the start of ship-to-ship and ship-storage-ship transshipment services.

Thanks to its two jetties, the LNG terminal can handle almost all different types of LNG carriers, from 2 000 m3 LNG up to Q-max vessels of up to 266 000 m3 LNG. Currently the terminal has a send-out capacity of up to 1,95 mcm/h but is finalizing the extension of the send-out capacity in order to increase the total send-out up to 2,6 mcm/h.

Because of the high number of slots that are allocated, the LNG must be sent out almost immediately after the LNG cargos have been unloaded. Therefore, the LNG storage tanks do not operate as storage as such but more as a very temporary buffer (3-4 days) before sending out in the pipelines.

The capacities of the LNG terminal are allocated through an open season procedure and are subscribed through long term contracts (15-20 years) on the primary market. With the high demand for LNG regasification capacity that followed the invasion of Ukraine by Russia and the reduction of Russian gas import to Europe, Fluxys LNG adapted its slots scheduling process to be able, in coordination with its long term shippers, to maximize the number of slots offered per year. Through this process, Fluxys LNG can increase the number of slots by 10 to 20%. Up to 50% of these extra slots can be acquired by long term shippers while the rest is offered to the global LNG market via auctions. Currently, three long-term shippers have slots reserved in the LNG terminal. Apart from these long-term contracts, tankers from USA, Egypt and Qatar, etc. deliver spot LNG.

5.5 Diversification of gas supplies and gas routes

As already mentioned above, gas supplies are well diversified. There is no legal obligation in Belgium for portfolio diversification or for entry point diversification. We do however note that most gas undertakings have a very well diversified portfolio and use at least two entry points to bring the gas into Belgium. The suppliers have multiple contracts with different suppliers and bring the gas in via a variety of supply routes. The higher the diversification, the lower the impact of an incident on one supply source or route.

The costs of diversification depend more on the contract type and conditions and cannot really be seen as costs as such, but as a proper procedure for due diligence in the gas business. Certainly, the larger companies with many long-term contracts dispose of a very well diversified portfolio. We have noted that smaller companies depend more on contracts on the gas hubs than contracts directly with producers.

5.6 Reverse flow and investments in infrastructure

Reverse flow exists already on all borders with the neighbouring countries. Open seasons were conducted on most borders in the period 2006-2011. In the meantime, the CAM network code has been implemented and auctions are continuously organized giving the market the opportunity to signal capacity requirements. Reverse flows and investments in infrastructure are analysed yearly by the TSO in the investment plan for the coming 10 years. This investment plan is reviewed by the NRA and the Competent Authority to analyse whether the infrastructure expansions are in line with the predicted gas demand.

Capacity on the Belgian side of the interconnection points is mostly higher than on the adjacent networks. There is enough flexibility left in the network to deal with a cold wave, as the Belgian network is designed on an -11°C standard. This was also proven during the February 2012 cold wave. The gas consumption on the distribution network had reached peak level on 3 February 2012 (1.165 GWh) and 7 February 2012 (1.181 GWh). The gas flows on the transmission network (entry) to assure the total domestic consumption and the border-to-border transmission reached their peak level of a little bit over 80 GWh/h on 14 February 2017. About 40% of the 80 GWh/h was destined for the Belgian gas consumption, the rest being destined for export, mainly to France, UK, Netherlands and Germany. There was enough flexibility remaining in the network. In the H-gas network, about 50% of the available demand capacity was used and about 70% of the demand capacity on the L-gas network (L-gas demand almost exclusively for distribution networks).

5.7 Coordinated dispatching by transmission system operators

Fluxys Belgium has several Operating Balancing Agreements (OBA) with the TSOs in neighbouring countries, namely GRTGas (FR), GTS (NL), OGE (DE), Gassco (NO), IUK (UK) en Gascade. This agreement between TSOs can contribute to reduce the impact of an incident.

5.8 Use of interruptible contracts

Suppliers have the right to interrupt the customer (assuming that such contracts have been concluded), normally in return for a discount on price and with some notice. The notice period will be specified in the energy contract. Most interruptible contracts specify that there will only be a few hours' notice, unless it is specified otherwise in the contract. Customers with an interruptible contract have agreed to receive gas but are willing to have supply interrupted at some point, according to the reasons in the contract (mostly meteorological circumstances) and for a maximum number of hours or days per year.

Interruptible contracts are hardly offered anymore to (large) end consumers (industry, power producers) in Belgium. This is because the attributed discounts are no longer a sufficient incentive on the longer term. In the industrial sector, interruptible contracts account for less than 5% of the total

contracted volumes between end users and suppliers. Interruptions are also limited to force majeure events. For the electricity plants, we also see a tendency towards more firm contracts.

The TSO must interrupt supply (this is to interruptible contracted customers) in the event of technical difficulties with the transportation system or in the event of congestion. Again, this will be covered in the customer's contract. Interruptible capacity is hardly booked by the shippers because Fluxys Belgium only offers interruptible capacity to the market if there is no firm capacity left. Therefore, we can say that interruptible capacity for the shippers is negligible in Belgium.

We have to be clear however that the above-mentioned interruptions are separate to other interruption rights, which exist for use only in potential or actual emergency situations. In emergency situations, some companies can reduce demand considerably when prices are high or maintain production by switching to back up fuels. However, they still need to maintain a certain level of gas to keep systems going and to let their plant safely shut down.

At any point an accident could damage a major part of the gas infrastructure and cut off supply. Some gas users have back-up systems and fuels to switch to in the event of an emergency or if commercial incentives make using an alternative fuel source preferable. Not every gas user has back up fuels (most of the end consumers in Belgium do not have back up fuels), so the gas system and the procedures that exist within it are designed to minimise the risk of gas being switched off from those who don't expect it to be (those not on interruptible contracts). Appliances for commercial premises generally incorporate flame out safety devices. These allow for supplies to be quickly and safely reinstated following a cessation in gas supplies.

In the event of an emergency, the safe provision of gas to domestic users and other essential social services (all connected to the distribution network) is the top priority. Before firm customers are interrupted, emergency plans provide for the suspension of the normal market for gas. After the suspension, it will depend on how quickly gas supply and demand is balanced, before firm customers start to be interrupted. Before firm customers are interrupted, firm border-to-border transmission will be interrupted (unless there's a request for solidarity, and only in the case that we are effectively able to give that solidarity). Public appeals may take place asking the public to restrain gas usage but this would depend on the type of emergency.

5.9 Fuel switch possibilities including use of alternative back-up fuels in industrial and power generation plants

Fuel switching from gas to fuel oil or diesel is no longer applied in Belgium. The remaining capacity is only used for black-start and not for fuel switching purposes. Also the environmental limitations do not allow fuel switching from gas to fuel oil or diesel. Therefore, we do not take into account any fuel switching capacity in the natural gas sector.

5.10 Voluntary firm load shedding

The impact of voluntary firm load shedding is very limited in Belgium and is an option the government cannot control as it is highly dependent on price signals. It will mainly be used by companies that contract their own gas, like for example power plants. Only companies with real time measuring will be able to adjust their gas consumption. Of course, also the type of contract the companies have with their gas supplier is determining whether it will be possible to see how the price fluctuates on a real time basis, and how the consumption can be adjusted to it. A study is being conducted on possible measures that can be taken to reduce demand, within this study voluntary firm load shedding is one of the topics which will be investigated.

6 Other measures and obligations

Different policies are put in place to reduce the probability of occurrence of the causes that may lead to an incident.

The causes covered by the policies put in place are the following:

- Intrinsic safety of pipelines
- Safety vis-à-vis third parties working near pipelines
- Critical Infrastructure Security (EPCIP)
- Cybersecurity (NIS)

6.1 Intrinsic safety of pipelines

The intrinsic safety of pipelines in Belgium is regulated by the Royal Decree of 19 March 2017.

This decree prescribes the general and fundamental safety measures to be taken in the context of the establishment and operation of pipelines intended for the transport of gaseous products and others.

This Royal Decree is part of the regulatory framework relating to the safety of pipeline transport installations, which includes rules, ranging from the most general to the most detailed, whose completeness, precision and consistency ensure a high level of safety. This regulatory system is composed of three levels:

1. The Royal Decree of 19 March 2017 on safety measures for the establishment and operation of installations for the transport of gaseous and other products by pipeline, incorporating general safety requirements;
2. Technical Codes specifying the detailed technical requirements applicable in 4 particular areas (Design and Construction, Exploitation, Risk Analysis and Safety Management System). These Technical Codes are intended to reflect industry best practices and European and international standards. These must therefore be reviewed regularly to maintain, where appropriate, a match between the technical measures described therein and the evolution of these best practices and standards;
3. Transport authorizations including any individual requirements.

This regulation takes into account technological developments, current best practices in the safety of pipeline transportation and some elements highlighted during incidents. It takes into account the rules of good industry practice as well as the functional standards established at European and international

level, among others by the "gas infrastructure" Technical Committees of European and international standardization institutes.

In terms of safety management, this regulation notably requires the transmission system operator to have a safety management system. This system must include:

- the role, responsibilities and training of staff. This involves defining the organization of the personnel (and any subcontractors) associated with accident risk management, identifying training needs and establishing training plans;
- the identification and evaluation of accident risks. The aim is to define and implement procedures for this purpose, covering all the phases of life of transport installations: design, construction, operation, maintenance and decommissioning;
- the control of exploitation; it involves the adoption and implementation of procedures and instructions for the safe operation of transport facilities;
- procedures for managing changes to existing transmission facilities;
- the emergency plan. This involves adopting and implementing procedures to identify foreseeable emergencies and develop an emergency plan to deal with them;
- the prevention and analysis of accidents as well as the follow-up of corrective actions: The aim is to define and implement the procedures, in particular feedback procedures, to analyse accidents and thus identify corrective actions in relation to these.

The transport authorization holder shall submit an external safety audit to his safety management system within one year of the start of operation of his first transport facility and every five years thereafter.

6.2 Safety vis-à-vis third parties working near pipelines

The Royal Decree of 19 March 2017 creates a reserved area inside the protected area. This is of smaller width and depends on the operating pressure of the pipe. No intervention is allowed in this zone, except in special cases listed in the annexes of the Royal Decree.

To protect pipelines from degradation by third parties working nearby, another Royal Decree, the Royal Decree of 21 September 1988, requires contractors to consult the pipeline owner before carrying out any work within a 15 m radius on either side of the pipeline.

For this reason, an electronic platform, the Federal Cable and Conduct Information Contact Point (CICC) has been created. Anyone wishing to carry out work can check on this website whether facilities for the transport by pipeline or underground or overhead high-voltage links are present nearby. This site automatically reports planned work also to the relevant transport operators with infrastructure nearby.

6.3 7Security of Critical Infrastructures (EPCIP)

The European Program for Critical Infrastructure Protection (EPCIP) sets the overall framework for activities aimed at improving the protection of critical infrastructure in Europe - across all EU States and in all relevant sectors of economic activity. It is implemented in a European directive (2008/114/EC) on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection.

On 1 July 2011 the Belgian Government has transposed the European directive on Critical infrastructure in Belgian Law with the possibility to not only identify European critical infrastructure but also national critical infrastructure. The Belgian law aims at covering not only terrorism, but also criminal activities, vandalism and another human made malicious threats. The energy sector with its subsectors: gas, electricity and petroleum is one of the key subjects within this law, next to transport, telecom and the banking sector.

The Royal Decree specifically for the energy sector was published on 11 March 2013 setting out the arrangements for monitoring by the sectoral authority. The Belgian Law was updated on 15 July 2018 with a law laying down various provisions, dealing, among other things, with the concept of critical groups for nuclear power plants. The recent law of 11 June 2023 and the royal decree of 15 September introduce additional security requirements in preparation for the application of the future Critical Entities Resilience (CER) law, which will repeal the EPCIP law.

The Belgian implementation of the EPCIP Directive foresees the implementation of measures in order to improve the physical protection of critical infrastructures to strengthen their protection against human-made, physical attack. It established regulations requiring the identification and designation of Belgian and European critical infrastructures and assessment of their physical protection. The NCCN is the Belgian point of contact for critical infrastructures for Belgium and the EU. The identification of critical infrastructures is done by the sectoral authority, the Federal Minister of Energy, in concertation with the NCCN and is based on sectoral and intersectoral criteria.

The first list of Belgian critical infrastructures has been established in 2014 and are periodically reviewed. In the beginning of 2022, a new analysis has been conducted and several additional critical infrastructures have been identified. The analysis and consultations with several stakeholders are continuously on-going. The DG Energy has also launched bilateral meetings with neighboring countries

---

7 Critical infrastructures and operators of essential services have been defined, identified and designated for the energy sector, as this sector is both concerned by the law of 1 July 2011 on the identification and protection of critical infrastructures (transposed from the Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection – EPCIP Directive) and the law of 7 April 2019 establishing a framework for the security of network and information systems of general interest for public security (transposed from the European Network and Information Security (NIS) Directive 2016/1148 of 6 July 2016).

in order to analyze the eventual designation of European Critical Infrastructure, as foreseen in the EPCIP Directive.

When identified and designated, the operator of a critical infrastructure has several obligations – one of them is the drafting of a security plan. This so-called Operator Security Plan should contain security measures that are applicable at any given moment, additional measures depending on the level of threat, a contact point (24/7) for the government, a process and methodology for organizing exercises and inspections, and a mechanism for reporting every incident to the competent authorities. The critical infrastructures are subject to inspections by the sectoral authority in order to verify the proper implementation of the measures described in the OSP.

6.4 8Networks and Infrastructure Systems (NIS)

The Network and information System Directive was adopted by the European Parliament on 6 July 2016 and entered into force in August 2016. This directive was transposed in Belgian legislation by the NIS law of 7 April 2019, establishing a framework for the security of network and information systems of general interest for public safety.

The NIS law foresee the implementation of cyber security measures to contribute to the continuity of the provision of essential services. For the energy sector, the Federal Minister of Energy, with support of the administration, has been designated as the sectoral authority and has the responsibility to identify the essential services and the operators of these essential services for energy, and is also responsible for the supervision of the designated operators. It has to be noted that by default, an operator of a critical infrastructure - following the EPCIP law – is designated as an Operator of Essential Service

Every operator of essential services identified by the authorities must have a security policy for its network and information systems that includes technical and organisational measures to manage security risks, prevent incidents or minimise the impact of incidents, report any security incident involving its network and information systems to the NIS authorities, conduct regular internal and external audits of its network and information systems, as well as cooperate and exchange information with the authorities. As for the EPCIP Directive and the critical infrastructures, these security measures implied by the Belgian NIS law are audited and inspected on a regular basis.

---

8 Critical infrastructures and operators of essential services have been defined, identified and designated for the energy sector, as this sector is both concerned by the law of 1 July 2011 on the identification and protection of critical infrastructures (transposed from the Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection – EPCIP Directive) and the law of 7 April 2019 establishing a framework for the security of network and information systems of general interest for public security (transposed from the European Network and Information Security (NIS) Directive 2016/1148 of 6 July 2016).

Besides, an operator of essential services is obliged to notify all incidents with significant consequences for the availability, authenticity, integrity or confidentiality of its network and information systems. A dedicated platform has been established for incident reporting. Under the guidance of the Federal Minister of Energy, the DG Energy has taken into consideration the different stakeholders of the electricity sector (producers, distributors, suppliers, traders, data analysts, etc.).

Updates of both the current EPCIP and NIS Directives will be provided via two new European Directives: the Critical Entities Resilience (CER) and the Network and Information Security 2 (NIS 2) Directives. Both Directives have recently been adopted and are currently being transposed into national legislation. These aim to further ensure adequate protection of providers of critical services by increasing their resistance and resilience, thereby guaranteeing the continuity of these processes more effectively. The new Directives will also cover new sectors (e.g. public administration) and new sub-sectors (e.g. hydrogen) and emerging risks such as climate change, pandemics and major natural disasters. Since these Directives are still under development and a translation into national legislation will still need to occur (a period of 21 months is currently foreseen), these will probably only come into effect within the coming two years (i.e. 2023-2025 timeframe). Please note that the implementation of the CER Directive will also require further alignment in Belgium since it will concern both federal and regional authorities (i.e. broader than physical security which is a federal competence today).

7 Infrastructure projects

7.1 New infrastructure development

The need for new infrastructure is evaluated every year by Fluxys Belgium in the ten-year indicative network development. These updates take into account the changes in requirements in terms of natural gas supply, request for new connections and the changing needs of grid users identified through subscription periods and international market consultations among other things. Several simulations based on the winter peak (January at -11°Ceq) are being set up to calculate the effects on the network. The calculations are based on the Entry-Exit model.

Main infrastructure investments identified in the Fluxys Belgium TYNDP 2023-2032 9 are underway or will start in the coming year(s) depending on an investment decision by Fluxys Belgium:

- Finalisation of the enhancement of the Zeebrugge LNG terminal: The project of a third capacity enhancement of the Zeebrugge LNG terminal consists in an increase in regasification capacity, with an additional 8.2 GWh/h available from 2024 onwards, reaching 10.2 GWh/h as of 2026. Moreover a project for building an additional (third) jetty is being evaluated in order to increase the security of supply.
- Replacement of gas motors at Loenhout storage facility: Driven by new NOx and CO emissions regulation and its willingness to decrease the CH4 emissions at its facilities, Fluxys Belgium

9 Our infrastructure (fluxys.com)

took the decision in 2023 to replace five gas motors of its compressors by electrical motors at its storage facility of Loenhout. Works are planned to start in 2024 and commissioning of the new motors is expected gradually in the course of 2025.

- L/H Conversion: As coordinator of the L/H conversion Synergrid produced an indicative conversion timetable. The indicative timetable is based on re-using as much as possible the existing infrastructure with a view to avoid investments that are only necessary for the transition period. To realize the conversion, Fluxys Belgium will gradually have to adapt its grid to ensure the continuity of transmission services for both converted and non-converted markets. The required adjustments are assessed, costed and included in the yearly indicative investment plan. One of the main adaptation is to build new connections between the L-gas backbone and the H-gas backbone in the existing Winksele station. The Belgian L-gas to H-gas migration will be finalized in September 2024.
- Backbone reinforcement: The planned nuclear phase out and the construction of supplementary gas powerplants was the starting point to evaluate the capacity of the Belgian gas transport system. Following this analysis, Fluxys Belgium decided to build a pipeline between Desteldonk and Opwijk to reinforce the entry capacity from the zone Zeebrugge. This pipeline will be operational early 2024. An additional reinforcement of the same route is foreseen (but not decided yet) between Zeebrugge and Desteldonk. Moreover depending on the decisions related to gas fired power plants in Limburg, a new pipeline between Glabbeek and Halen could be required.
- Adapting the network for third party needs : Fluxys Belgium needs to modify/divert some pipeline routes in order to allow new, generally public, constructions. Projects (not limited to) like the enlargement of the Albert canal in Genk (2019) require network adaptations.
- Connections for new biomethane production: Some projects are in discussion for new biomethane production plans. Two additional plants are expected to be commissioned in 2025.
- New city gates for DSO : Several city gates are projected to be adapted/upgraded over the coming years.
- Methane emissions reduction plan: A plan has been elaborated aiming at reducing the emissions of methane in the Fluxys Belgium network. This consists of the replacement of pneumatic driven operators and regulators by electric driven ones.

Table 16: Summary of main infrastructure projects by Fluxys Belgium (2023)

Project	Estimated commissioning date
Increase LNG Terminal capacity emission	Q1 2024
LH Conversion finalisaton	Q3 2024
Reinforcement VTN Phase 1 (Desteldonk-Opwijk)	Q1 2024
Reinforcement VTN Phase 2 (Zeebrugge-Desteldonk)	**Q1 2026**
Glabbeek-Halen	Q3/2026
Extension LNG Terminal (new jetty)	2026-2030

8 Public service obligations related to the security of supply

Public Service Obligations (PSOs) are part of the criteria to grant natural gas supply and transport authorizations, which are established by royal decree following the recommendations of the Regulator (CREG).

The royal decree of 23 October 2002 regarding public service obligations in the natural gas market imposes on the gas undertakings that were granted a supply authorization to ensure the continuity of gas supply to the distribution networks and their end-consumers according to the contracts concluded with these parties. The supply of gas may, however, be reduced or interrupted in the following cases, provided that the reduction or interruption is necessary :

- in case of force majeure;
- in case of connection of new transport or distribution facilities or for the maintenance of existing installations.

This royal decree also imposes on gas undertakings that were granted a transport authorization to build and/or operate additional transport facilities under economically justified conditions allowing end-customers to either increase the maximum hourly rates provided at the supply points already connected or to supply new supply points.

These PSOs are subject to a compensation covered by the tariffs to the end-consumers, which are approved by the Regulator who also controls the executions of those obligations.

PSOs are also imposed on the Distribution System Operators (DSOs) and suppliers by the 3 regions. Their execution and compensation in the tariffs are controlled by the respective regional regulator. These PSOs impose on the DSOs and suppliers to ensure the regularity and quality of the gas supply to their end-customers (or only for the households customers in the Brussels-Capital Region).

9 Consultation of stakeholders

As mentioned higher, no consultation has been organized on the Preventive Action Plan. For the Emergency Plan, a limited number of consultations was made between the update of April 2022 and the update of September 2022 (also taking into account the voluntary survey among large gas consuming end users by the FPS Economy – DG Energy). As such, the Belgian Federation for Enterprises (BFE), Essencia (federation for chemical industry and life sciences), Febeliec (federation of Belgian industrial energy consumers) and FEBEG (federation of Belgian electricity and gas enterprises).

10 Regional dimension

10.1 Operational cooperation between TSOs

Due to the imposed timing and the special circumstances for the update of this Preventive Action Plan, no consultation has been organized, hence no comments were taken into account.

10.1.1 Cooperation in North West Europe

TSOs are tasked to run their networks as efficiently as possible either through incentives or other mechanisms, and as such solving constraints on cross-border points is part of the day-to-day operational business of TSOs. Neighbouring dispatching centres work closely together, where required, optimising gas flows and operation of the network in the region.

The dispatching centres of the region have various means to deal with such cross-border issues. For example:

- to swap gas (re-routing), not only bilaterally but also tri-laterally;
- operational Balancing Agreements (OBAs);
- mutual assistance, for instance to reduce fuel gas;
- exchange of personnel, knowledge and knowhow.

All these years of cooperation and experience have resulted in intensive contacts between the neighbouring TSO's in North West Europe. Working with Neighbouring Network Operators (NNOs) is for GTS a common practise as is working nationally with Distribution System Operators.

In case of a constraint at an interconnection point (whether this is due to maintenance, climatic conditions or interruption of supply) NNOs inform each other and relevant shippers immediately through bilateral contacts and through publication on the respective websites. Various actions can be taken to overcome or minimize the constraint. Either through the balancing regimes, or by re-routing gas via other entry/exit points in case the preferred route is constrained.

10.1.2 Regional cooperation within ENTSOG

With the 3rd Energy Package the European Network Transmission System Operators (ENTSOG) was founded. The Netherlands has been an active member from the start.

The bi-annual publication of the Ten Year Network Development Plan (TYNDP) and the Gas Regional Investment Plan (GRIP NW) are examples of these new ways of cooperation in North West European.

10.2 Regional cooperation between Member States

10.2.1 L-gas risk group

Regional issues related to security of supply are addressed and discussed in the Pentalateral Gas Platform. In this platform the following Ministries responsible for energy policy participate: Belgium, France, Germany, Luxembourg and the Netherlands, while the Commission is sometimes invited as an observer. The Benelux Secretariat provides logistic support. National Regulatory Authorities and TSOs are also sometimes invited, just as the European Commission.

The L-gas risk group activities have been and are conducted within the framework of the Pentalateral Gas Platform under the chairmanship of the Netherlands who currently acts as the group's coordinator.

If necessary, these arrangements make it possible to scale up rapidly to the political level if needed. The earthquake in Zeerijp in 2018 illustrates this. Directly after this earthquake there has been a meeting of the responsible directors-general of the L-gas countries to discuss the situation, followed by bilateral phone calls between the Dutch Minister of Economic Affairs and Climate Policy and his colleagues.

Preventive measures

The preventive measures to enhance the security of supply of L-gas supply and to diminish the dependence on the Groningen field, where the permitted production of gas has already been reduced to 0, are the following:

- The building of a new nitrogen plant by GTS at Zuidbroek. This GTS's new nitrogen plant is now largely operational and is expected to be fully operational before the end of this year. The plant will be able to produce a maximum of 97 TWh additional pseudo L-gas. With the construction being heavily impacted by the outbreak of COVID-19, consequent lockdowns and a dispute between the EPC contractor and subcontractor, the planned commissioning date of the nitrogen plant is delayed.
- The enhancing of the nitrogen production capacity on nitrogen blending facility Wieringermeer is completed.
- Additional nitrogen purchases by GTS for one of the existing blending stations to further increase the production of pseudo L-gas have been realised. An estimated amount of gas of 10 to 15 TWh (1 to 1.5 bcm) is saved from the Groningen field.
- UGS Norg is filled with pseudo L-gas (Lately, there was not enough gas from the Groningen field to fill Norg (size approx. 6 bcm) anyway).
- The conversion of the gas storage Grijpskerk from an H-gas storage to an G-gas storage is expected to be finished this year. This conversion of the storage was planned so that it could, when volume and capacity are sufficient, take over the back-up functionality of the Groningen field and speed up the closure of the latter.
- Converting nine large-scale users of L-gas in the Netherlands to H-gas or other sources of energy. This would lead to an estimated amount of gas saved from the Groningen field of approximately 20 TWh (2 bcm) by 2022. Of the nine large-scale consumers to be converted, five have already been converted.
- Conversion of the Belgian, French and German L-gas markets to adapt all gas appliances and networks to H-gas supply.

In addition, a possible future measure has also been identified in the Netherlands:

- Decreasing gas demand by enhanced energy transition measures (switch to renewable energy sources instead of H-gas).

The feasibility of this future measure will be assessed in the forthcoming period. But it is the clear intention of the Dutch government to end the gas production from the Groningen field by 1 October

2024 at the latest. A legal proposal that secures this has been submitted to the Dutch Parliament for approval.

Conversion of the Belgian L-gas network

After the Dutch authorities announced the deadlines for a reduction in production, Belgium has developed a conversion plan. Although the date announced by the Netherlands for the beginning of the decrease in exports was 2024, a pilot phase of conversion was carried out in 2016 and 2017. Moreover, as of 2015, the last major industrial zone fueled by L-gas has been converted. No power station is supplied with L- gas anymore.

A notable difference between the conversion process in Belgium and in the other concerned Member States is that all appliances sold in Belgium should be fit for both gas qualities since 1978. In most cases, no replacement of the appliance is therefore necessary, but a verification by a qualified technician is strongly recommended.

In 2017, there were about 1.6 million clients connected to the Belgian L-gas network. Synergrid (Belgian federation of transport and distribution networks) had put into place an indicative planning for the conversion of these connections that would be finalized in 2029. Each year the switchover would be carried out in several municipalities during the summer, when consumption is lower. A public information campaign was set up in 2017 and was launched at a press conference of the Belgian Energy Ministers (federal and regional). The switchover started in 2018. In 2021 Synergrid, based on the experience from previous conversions, made an accelerated indicative planning to achieve a full conversion of the Belgian final customers by Q4 2024, the details of which can be found in Figure 30. The acceleration allows to mitigate uncertainties related to the availability of L-gas supply linked to the situation of Belgium's dependence on a single source.

As of the moment of writing, only two conversion phases planned for 2024 remain. After this, all Belgian connections[10] will have been switched. The Netherlands-France connection remains to transport L-gas until the full conversion of the French L-gas market is realized.

[10] At the exception of one single final customer that is supplied directly from NL since it is located at the NL-BE border at Veldwezelt and the enclave Baarle-Hertog.

Figure 30: Indicative conversion planning Belgium

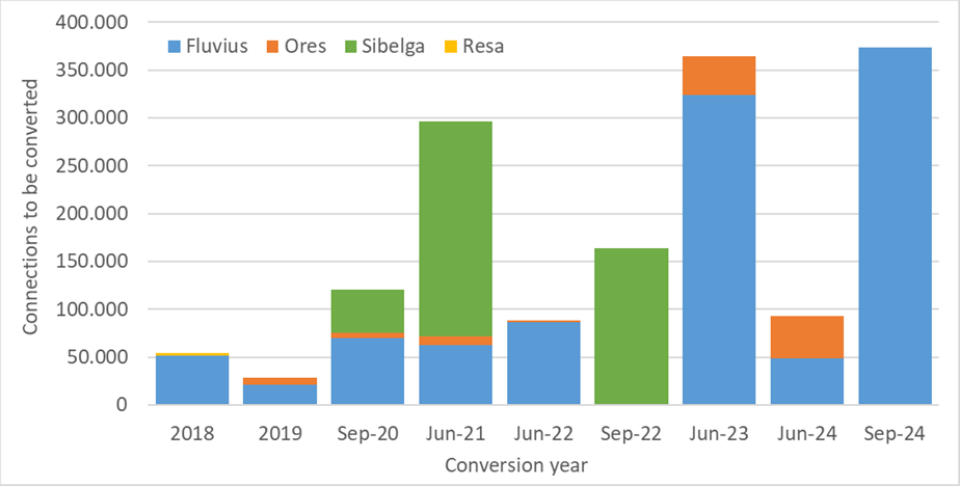


Figure 31: Overview conversion municipalities year by year

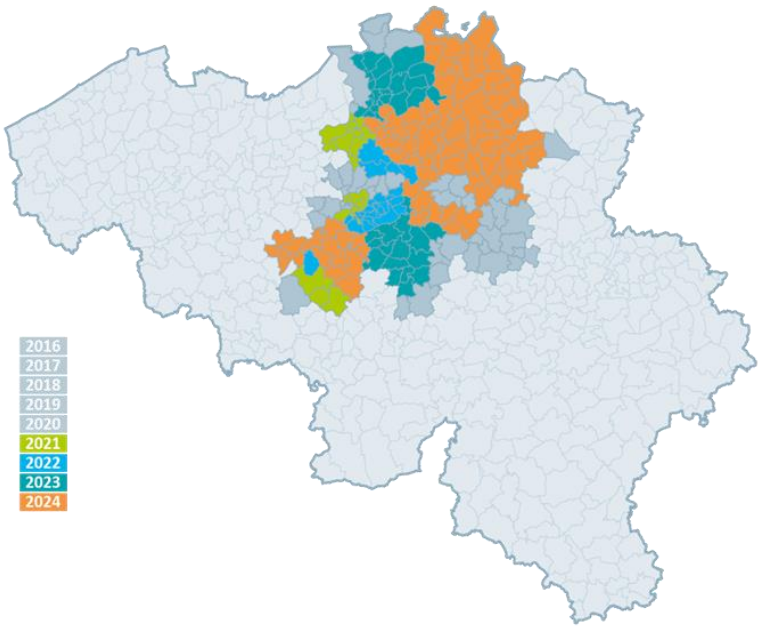
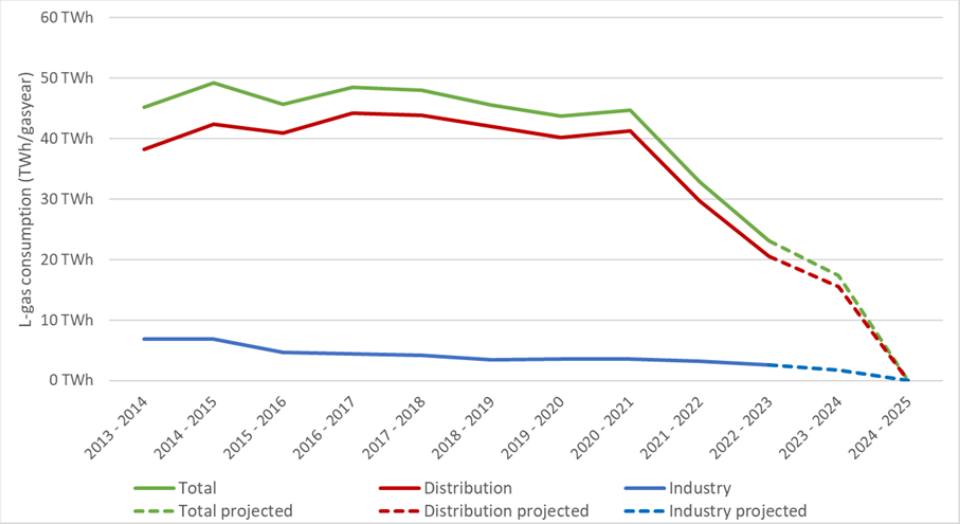


Figure 32 shows the evolution of the Belgian L-gas markets consumption given on a gas yearly basis up to October 2023. For gas year 2023-2024 a projection of 17,4 TWh is made based on the winter analyses and historical data of the clients and infrastructure still active in gas year 2023-2024 and taking into account the remaining conversion phases. As of gas year 2024-2025 and onwards the remaining L-gas consumption in the Belgian market will be Baarle-Hertog (a municipality that is completely dependent on the Dutch distribution network) and a single L-gas end user who is directly supplied via the Dutch distribution system.

Figure 32: Yearly consumption on Belgian L-gas network (Gas years 2013-2025)



10.2.2 Baltic sea risk group

No new measures have been taken since the previous preventive action plan of 2018.

A cooperation mechanism has been drawn up pursuant to Art.8(4) SOS Regulation. It basically provides for all forms of communication to be used for the cooperation within the risk group. Conference calls have proved to be an efficient method. Prior to a conference, the chair presents a proposal for discussion during the conference. Objections and requests for changes which affect all Member States equally are resolved if possible in consensus. In terms of crisis prevention, it is important to have expert contacts in order to avert harm by engaging in an early and transparent exchange of information. It has proved worthwhile also to use these forms of cooperation for the drafting of the preventive action and emergency plans in order to facilitate contacts in a crisis.

Crisis prevention is in principle a national responsibility; consultations take account of cross-border issues. In order to be able to take measures to maintain security of supply in neighbouring member states on a cross-border basis in the case of a crisis, it is urgently necessary to engage in advance in cross-border coordination between the relevant German and neighbouring TSOs at the respective international IPs, if necessary with the backing of the competent authorities. In particular, a common understanding of the handling of crisis levels and resulting measures should be reached, so that crisis management can be undertaken in line with the SoS Regulation in the case of a bottleneck, particularly where there is a shortage on both sides, and the burden of the measures can be distributed equally (i.e. on a non-discriminatory basis).

The TSOs also involve neighbouring cross-border system operators in their considerations about the expansion of infrastructure in the context of the consultations on the Network Development Plan.

Preventive measures

The risk analysis has shown that the risk of a disruption to supply in the Baltic Sea risk group – caused by technical failure – is calculable. Nevertheless, it is important to continue to ensure that the system is reliably maintained and secure.

The Network Development Plan Gas plays an important role in the ensuring of an orderly gas supply – including in the international context. It must contain all the effective measures which are technically required in the coming ten years for a secure and reliable operation of the system. These include:

- the needs-based optimisation and strengthening of the grid
- the needs-based expansion of the grid
- the maintaining of security of supply.

It thus makes a major contribution towards ensuring security of supply throughout the Baltic Sea region.

In particular, the Network Development Plan contains all the grid expansion measures which must be undertaken in the coming three years, including the timetables necessary for the implementation. The NDP is a key element for Germany, as a central transit country for gas flows. All the members of the Baltic Sea risk group – like other neighbours of Germany – benefit from Germany's security of supply and benefit from a high standard of planning. The ever-broader updating of the NDP is an indispensable element of this.

In order to enable TSOs to continue to fulfil their responsibility for a secure and reliable operation of the grid in future, they are required to produce a joint Network Development Plan in every even calendar year and to present it to the Bundesnetzagentur, the competent regulatory authority, by 1 April (Section 15a Energy Industry Act). This Network Development Plan is based on the scenario framework, and the TSOs must use this framework as they draw up the Plan (Section 15a subsection 1 sentence 4 Energy Industry Act).

The scenario framework must include appropriate assumptions about the development of gas production, supply, consumption and exchange with other countries. Also, the TSOs must take account of planned investment projects in the regional and EU grid infrastructure, in storage facilities and in LNG regasification facilities. Finally, they must include the effects of possible disruption to supply.

In order to identify these measures, the Energy Industry Act requires that the TSOs model the German long-distance gas grids when they draw up the Network Development Plan.

The draft Gas Network Development Plan is presented to the Bundesnetzagentur for scrutiny.

There is a legal requirement that the Bundesnetzagentur confirms the scenario framework, taking account of the results of the public consultation carried out by the TSOs.

10.2.3 North Sea risk group

With the Brexit the UK risk group has been dissolved and relevant elements have been integrated and assessed in a newly created risk group: The North Sea Risk Group. The North Sea Risk Group results from the merger of the Norway Risk Group and the United Kingdom Risk Group. It is composed of the

following twelve Member States: Belgium, Denmark, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Poland, Portugal, Spain, and Sweden.

No new measures have been taken since the previous preventive action plan of 2018.

The United Kingdom Risk Group comprised the United Kingdom, Belgium, Germany, Ireland, Luxembourg, the Netherlands. The group operated on a consultative basis: the UK holds the pen on drafting the implementation of regional aspects of the Regulation, with all decisions made in consultation with members of the Risk Group. Regular group meetings held via teleconference and in person at the Gas Coordination Group are supported by email discussions and, where appropriate, bilateral communication.

In the event of a national gas system emergency, the emergency measures set out in National Emergency Plans (NEPs) demonstrate how the Risk Group has adopted a collaborative approach to handling NGSE, where applicable.

Preventative Action Measures

Political risks associated with the UKRG

UKCS offshore production infrastructure is directly connected to the United Kingdom and Netherlands transmission networks. The Netherlands' production infrastructure is directly connected to the Netherlands transmission network. There are no third countries through which gas transits within the UKRG; there is, therefore, no need for preventative measures concerning transit of third countries.

UK risks associated with the UKRG

The production of natural gas from the United Kingdom Continental Shelf has declined since the turn of the millennium, although a small increase due to new fields was seen in 2015 and 2016. Despite this, the UK, along with the Netherlands, remains one of the two major gas producing nations within the EU.

UK oil and gas production is expected to start to fall again in the years ahead, though production estimates are subject to uncertainty. There are a wide range of possible outcomes because the future rate of production is dependent on a number of different factors including the level of investment and the success of further exploration. Operators continue to find it difficult to accurately predict additional production from investing in older fields as they mature. The projections are therefore the best estimates rather than a definitive prediction of future production of oil and gas from the UKCS.

For the United Kingdom's Continental Shelf (UKCS), the Oil and Gas Authority (OGA) has set out the Maximising Economic Recovery (MER) Review which allows the OGA to consider a regional element of security with the objective of maximising the economic recovery of the UK's oil and gas resources in the North Sea.

In the South of the North Sea (SNS) UKCS area, there is a risk of decline in the production of oil and gas based on a lack of investment. The lack of investment in SNS infrastructure puts at risk the production life of current assets in the SNS that retrieve 'stranded reserves' of oil and gas. At current the SNS is not being heavily invested in as it is a mature site of exploration, having been exploited since 1967. By leaving oil and gas reserves 'stranded' in the SNS from lack of coordinated investment; fiscal opportunities are being lost to the market and assets of gas security in the UKRG are also lost.

The OGA is working to maximise the economic recovery of hydrocarbons from the UKCS by creating an environment that stimulates exploration activity leading to the discovery of new oil and gas reserves. The OGA has made available large amounts of exploration data, including new government-funded seismic data, data on wells, prospects, geological mapping and lessons learned. This has helped generate new interest in UKCS oil and gas acreage.

Most issues are addressed and resolved through the stewardship process. Asset stewardship is crucial to maximising economic recovery from the UKCS and to delivering greater value overall. Effective stewardship means that asset owners consistently do the right things to identify and then exploit opportunities and that assets are in the hands of those with the right behaviours and capabilities to achieve MER UK.

The OGA has worked closely with operators, licence holders and other interested parties to develop Area Plans across the oil and gas life cycle that integrate exploration, development, production, operations and decommissioning to maximise economic recovery – for example, through the optimum use of infrastructure to extend the life of hubs. The OGA has reaffirmed its focus on the importance of collaboration and urged industry to increase the pace at which licensees develop a culture of collaboration internally and externally within existing joint venture (JV) partnerships and beyond.

Working with industry, government, and the research community, the OGA is committed to overcome current constraints on technology innovation and commercialisation. The OGA works closely with industry and government, including BEIS, HM Treasury and other key government departments, providing expertise and evidence where appropriate. The OGA works with a range of stakeholders including the Scottish Government to Over the last two years, we have seen many positive examples of collaboration between companies leading to solutions to long-running issues. The MER UK Strategy requires licence holders to ensure that optimal technologies are used for MER UK. As part of its Asset Stewardship Strategy, the OGA expects that licence operators have technology plans which identify actions and timelines to access and/or develop the critical technologies needed for their assets.

The MER Review is an example of how non-market-based Government actions can create positive impacts on the private market and a positive outcome for the UKRG security

Netherlands risks associated with the UKRG

For many years, total annual production in the Netherlands was about 80bcm. In the gas year 2023-2024, the permitted production of gas from the Groningen field has been reduced to 0 and production is only allowed if there are extreme exceptional circumstances (in case of extreme low temperatures

and disruption of the single largest infrastructure to fill the peak demand or to fill the seasonal storages after they have been heavily used for security of supply during a cold winter). Closure of the field is planned for October 1, 2024 at the latest.

As a result of earthquakes related to gas production in Groningen, the volume allowed to be produced has been restricted in the past few years. In 2018, the Netherlands decided to reduce production from Groningen as fast as possible to 12bcm and then continue to 0bcm, i.e. to terminate production from the Groningen field. Since 2013, gas production from Groningen has fallen from 54bcm to 23.98bcm in 2017. In addition, reduced production from Dutch small fields will further constrain natural gas production in the Netherlands.

On the 8th of January 2018, a gas production-induced earthquake occurred at Zeerijp. Following the advice of the State Supervision of the Mines, the Dutch Minister has decided to reduce production from Groningen as fast as possible to 12bcm and then continue to 0bcm, i.e. to terminate production from the Groningen field. Today, the permitted production of gas has already been reduced to 0 on the Groningen field.

To achieve this, GTS has invested in a new nitrogen plant at Zuidbroek which can produce up to 7bcm of pseudo L-gas in a cold year. In addition, GTS has purchased additional nitrogen which can produce 1 to 1.5bcm of pseudo L-gas. Furthermore, industrial clients are converted between gas year 2019-2020 and gas year 2022-2023 from L-gas to H-gas. Possibilities to accelerate the market conversion in Germany, Belgium and France have also been investigated.

As the production of gas on the Groningen field has been reduced to 0, the blending stations of GTS produce baseload (on average, 85% of blending stations Ommen and Wieringermeer); the new nitrogen plant at Zuidbroek covers the rest of the market. Because of this, we can say that the baseload nitrogen installations produce 100%. An utilisation rate (of the nitrogen facilities) above 100% would indicate the use of back-up nitrogen capacity to produce higher volumes of pseudo G-gas. Due to the restrictions on the production from the Groningen field, namely 0 for gas year 2023/24, the utilisation rate of the nitrogen facilities is no longer of relevance.

With the ending of the natural L-gas production from the Netherlands, the production of pseudo L-gas will have to foresee in the total L-gas demand.

Germany

In 2017, Germany produced 7.9bcm of natural gas with a calorific value of 9.77kWh/m^3 which is classified as L-Gas. Production in 2017 decreased by 8.6% compared to 2016, with the forecast production continuing to decline due to the depletion of existing reserves. L-gas production is expected to decrease at an annual average rate of ~7% from 24.3 TWh in GY 2023/24 to 13.2 TWh by GY 2029/30. There is one peak nitrogen/H-gas blending facility in Germany, in Rehden, supplying only limited volumes of converted L-gas. In 2021, the blending facility in Rehden was extended with a local nitrogen plant for backing of the local supply demand balance.

In addition, the German TSO GTG Nord built a blending facility at the Dutch border. This facility allows for blending Dutch Groningen gas with H-gas. This blending facility is in operation since April 2021 and

allows for an annual decrease of L-gas deliveries from the Netherlands of up to 30% (5-6 TWh/y approx.) of the demand of GTG's cross border point Oude Statenzijl, depending on, inter alia, the actual amount of gas imports. In GY 2021/22 1 TWh was blended. Thus, the facility is a further relief to the Groningen production. The building costs of the facility and its operational costs are borne by network users.

Ireland

The Kinsale Heads storage facility is now in blowdown mode and is therefore classed as production until its expected final closure in 2020. The gas security of Ireland is however ensured by the new Corrib gas field which commenced production during the 2015/16 gas year and supplied 62% of gas demand in Ireland in 2016/17. The Moffat Entry Point accounted for 31% of the overall requirement with the remaining 5% supplied from production gas from an off-shore gas field at the Inch entry point.

The Corrib gas field would be expected to supply approximately 27.7% of ROI peak day gas demand in 2018/19 in the event of a 1-in-50 winter peak day, with Inch accounting for around 2.3%. The Moffat Entry Point would be expected to meet nearly 69.9% and 78% of ROI demand and Gas Networks Ireland system demands respectively in 2018/19, in such circumstances. Moffat is anticipated to meet 89.5% and 92.2% of ROI and Gas Networks Ireland system peak day demands respectively in 2026/27.

Connection with Member States outside of the risk group

Germany

Germany has an extensive transmission system. The network of the transmission system operators is connected to the systems of neighbouring countries via a large number (>25) of cross-border interconnection points. In the southern part there are significant import points on the borders of the Czech Republic and Austria. The major export points are on the borders to France, Switzerland and Austria. The transmission system is thus used for both transit and supply services.

In the past, gas consumed in the northern part of the supply area in Schleswig-Holstein and Hamburg largely came from Danish reserves. For some years now, Denmark has been stepping up preparations for supply from German imports via the Ellund station. The Nord Stream and Baltic Sea Pipeline Link (OPAL) pipelines were put into operation at the end of 2011. The OPAL can transport up to 35 bcm of natural gas a year from Nord Stream. This means that Nord Stream and the OPAL, together with pipelines in the Czech Republic (Gazelle), ensure supply volumes for the Waidhaus import point and strengthen the security of supply for Germany, France and the Czech Republic.

Netherlands

In the Netherlands there is a total of 135,000 km of gas pipelines. There are 8 Local Distribution Companies for gas in the Netherlands, of which there are 7 operating gas transmission grids for L-gas and 1 for H-gas.

On the Maasvlakte in Rotterdam, Gate terminal has built the first LNG import terminal in the Netherlands which consists of three storage tanks, two jetties and a process area where LNG will be re-gassified. The capacity of the Gate terminal has already been expanded from 12 bcm/year to 16 bcm/year, fur-ther expansion to 20 bcm/year is planned for 2026. The terminal dovetails with Dutch and European energy policies, built on the pillars of strategic diversification of LNG supplies, sustainability, safety and environmental awareness. In addition to the Gate terminal, the Netherlands now has a second LNG terminal: the Eems Energy Terminal (EET) with an annual throughput of 8 bcm.

Non-Market Preventative Measures

The countries within the United Kingdom Risk Group adopt a market-based approach to guaranteeing security of supply, although a number of countries do adopt measures which they consider to be necessary to guarantee security of supply. The Preventative Action Plan focuses on those measures which proceed the declaration of an NGSE in Member States; as such, no measures relating to stages of an emergency are discussed here.

10.2.4 Belarus risk group

No new measures have been taken since the previous preventive action plan of 2018.

Placeholder for the regional chapter of the Belarus risk group (To be developed by Poland)

11 Conclusions

This Preventive Action Plan was established according to the SoS Regulation 2017/1938.

It describes on the one hand all the tools available to the market (market based measures) to ensure the security of supply to the end consumers in Belgium and to cope with unforeseen incidents. While these market based measures are an essential part of the normal functioning of the market, they can still be used in crisis situations, as is detailed in the Emergency Plan.

These market based measures are mostly based on and take advantage of the facts that the Belgian gas infrastructure is well developed and that the gas supply sources are well diversified. Most of the preventive measures consist in giving the market participant an optimal access to the gas infrastructure. On the other hand, this plan describes the legal obligations that apply to the market, either the suppliers or the system operators, in order to ensure that they use the tools available to them to ensure the supply of gas to end-consumers and especially to the Protected Customers.

Nine disruption scenarios in the four Risk Groups involving Belgium have been considered in the 2021 risk assessment by ENTSO-G, and Belgium is not exposed to a reduction in demand in any of those risk groups or associated scenarios (2 weeks, 2 months) studied by ENTSO-G in 2021. Europe's gas infrastructure provides sufficient flexibility for EU Member States to efficiently apply their cooperation

mechanisms and ensure security of gas supply during extreme climatic conditions and individual supply route disruption scenarios. Also, in all scenarios an efficient cooperation between EU Member States can export significant volumes to Energy Community Contracting Parties and other EU neighbouring countries.

Although there is currently no problem with the security of natural gas supply in Belgium or Europe, it cannot be ruled out that there may be tense situations in the future. The Ukrainian crisis has profoundly changed the structure of gas flows in Europe and in Belgium. As a result, the entry of gas into the Belgian network is now concentrated in the Zeebrugge zone (West zone). Market players in the Member States, including Belgium, have managed to fill their storage facilities to record levels, partly thanks to flows from Norway and LNG, but also thanks to Russian gas flows that are still available. It cannot be ruled out that the reduction in Russian natural gas flows will continue in 2023 and beyond. This will make it even more difficult for storage facilities in Europe to reach a fill level of 90%. This would leave Europe more exposed to physical shortages of natural gas, especially in winter. If we make the link with the various European regulations, which further strengthen the solidarity mechanism between Member States, this means that even if, under normal circumstances (infrastructure and molecules available), Belgium would be able to cover its own consumption in winter with imports mainly from Norway and the rest of the world (LNG), an (organised) shortage on the Belgian market could nevertheless occur in the event of requests for solidarity during a cold spell, for example (or the imposition by Europe of compulsory measures to reduce natural gas consumption), through a cascade effect.

As far as LNG is concerned, we have seen that by 2022, at European level, the loss of Russian gas has largely been made up by LNG. LNG therefore plays a critical role in Europe's natural gas supply. It is therefore very important to monitor supplies to Belgium, but also to Europe, given the decisive role that LNG will play in the security of supply of natural gas.

Furthermore, there will always be uncertainty about the import of gas due to incidents to pipelines that may occur, etc. The four entry points located in the west of the Belgian natural gas transmission network must be considered essential and therefore strategic for the security of supply of natural gas (type H natural gas) for Belgium and Europe. The LNG Terminal and the two offshore pipelines (Interconnector and Zeepipe) stand out as being more important, given their large capacities. In the current configuration, the loss of just one of these entry points could have a serious impact on Belgium's natural gas supply in the event of a peak or cold spell. The total unavailability of one of these entry points would lead to a significant reduction in the reliability of supply, insofar as it would be necessary to be able to rely on the 100% capacity of the other entry points and the total availability of the upstream molecules in order to be able to cover Belgian peak demand. The Loenhout storage infrastructure could contribute to the security of supply, but does not have sufficient capacity for prolonged use in the event of a long, cold winter.

Finally, the Belgian consumption of H-gas, as well as peak consumption, is set to increase significantly over the next few years as a result of:

- the migration of L gas to H, which will be completed in September 2024,
- the construction of two new natural gas-fired power plants (at Seraing and Les Awirs), which should be operational in 2025.

Looking at the future (winter 2023/24), ENTSO-G believes that the probability of a physical shortage of natural gas in Europe is low. For the winter periods 2024/25 and 2025/26, no assessment is currently available. But the loss of Russian gas, principles of European solidarity, uncertainty about imports, etc. leads us to conclude that the security of natural gas supply for Belgium and Europe in general can no longer be regarded as absolute and predictable.

Annex 1a: Degree-days and equivalent temperatures

The public distribution sector uses gas primarily for space heating. This results in a strong correlation between gas consumption levels and exterior temperatures when they drop below 16.5°C.

Above this temperature, consumption remains relatively stable because gas is barely used for space heating anymore and the other uses (such as cooking and domestic hot water) are not temperature dependant.

Below 16.5°C, we can observe a direct proportionality between the gas consumption on a given day and the difference between the average outside temperature and this threshold temperature of 16.5°C on the same day. This difference, or number of degree-days (DD), is therefore best suited to represent the influence of outside temperatures on gas consumption on the public distribution networks. For example, if the average temperature for a day was -2°C, the number of degree-days for that day is 18.5 (DD = 16.5 - (-2)).

The correlation between the consumption of natural gas and degree-days gets even better if you replace the average temperature of the day by an equivalent temperature (T_{eq}) calculated as 60% of the temperature of the same day, 30% of the temperature of the previous day and 10% of the temperature of the day preceding yet. This improvement reflects notably better thermal inertia of the buildings.

This methodology is applied in Belgium since 1993. In order to not cause confusion, it was decided to talk about equivalent degree-days (DDeq) which differ from the ordinary degree-days.

Where $DD_{eq} = 16,5 – T_{eq}$

and $T_{eq} = 0,6\ T_m + 0,3\ T_{m-1} + 0,1\ T_{m-2}$,

with T_m the real average temperature i.e. the arithmetic average on day m of 13 surveys measured by RMI (Royal meteorological Institute) every two hours in Uccle (place of reference currently used for all of the country).

Table 17: Examples of equivalent degree-days calculations

day 1 : mean temperature of 18°C	day 1 : mean temperature of -2°C
day 2 : mean temperature of 14°C	day 2 : mean temperature of +3°C
day 3 : mean temperature of 12°C	day 3 : mean temperature of -4°C
then	then
DD (day 1) = 0	DD (day 1) = 18,5
DD (day 2) = 2,5	DD (day 2) = 13,5
DD (day 3) = 4,5	DD (day 3) = 20,5
DDeq (day 3) = 3,45	**DDeq (day 3) = 18,2**

Equivalent degree days can also be added over a given period (week, month, year, etc.) while maintaining the link with the total consumption of gas in the same period. When for a given month, there is no equivalent degree days found in Uccle (i.e. when the equivalent temperature does not fall below 16.5 ° C), the number of degree-days monthly is taken as equal to 1 for this month.

This property is used to define normal conditions for a month or year as the average number of degree days observed for this period over the reference period of 30 years, updated every 5 years.

Since January 1, 2021, the reference period is 1991-2020 and includes 2 250 normal degree days.

For the correction of annual and monthly consumption linked to an "extreme temperature profile" (extreme temperatures), DDeq are taken for the period 1962 to 1963 (gasyear) characterized by an extremely cold winter. The annual DDeq for extreme temperature profile totalled 3.040 DDeq.

It should be noted that in terms of the hottest years in terms of DD, the period from 2017 to 2022 has 4 gas years belonging to the top 10 hottest years in the last 60 years.

The lowest value in terms of DD in the last 120 years (i.e. corresponding to the hottest gas year) was recorded in the 2006/2007 gas year with 1,718 DD.

Table 18: Monthly degree-days in normal and extreme conditions

	DDeq (t° norm.)	Ddeq (t° extreme)
J	395	648
F	349	520
M	293	329
A	187	208
M	99	161
J	35	32
J	11	13
A	11	47
S	55	68
O	161	175
N	277	349
D	377	490
Total	2.250	3.040

Table 19: Ranking of the coldest gas years according to the Degree Days (DD)

Ranking	GasYear	DDeq	Ranking	GasYear	DDeq
30	2005 - 2006	2.380	1	2006 - 2007	1.718
29	1974 - 1975	2.407	2	2013 - 2014	1.873
28	1970 - 1971	2.433	3	2019 - 2020	1.923
27	1979 - 1980	2.445	4	2021 - 2022	2.038
26	1973 - 1974	2.452	5	2015 - 2016	2.047
25	2009 - 2010	2.457	6	2018 - 2019	2.054
24	1965 - 1966	2.457	7	1989 - 1990	2.093
23	1990 - 1991	2.475	8	2001 - 2002	2.104
22	1980 - 1981	2.489	9	2017 - 2018	2.125
21	1993 - 1994	2.491	10	1988 - 1989	2.139
20	1996 - 1997	2.494	11	1997 - 1998	2.168
19	1977 - 1978	2.497	12	2007 - 2008	2.181
18	1981 - 1982	2.505	13	2020 - 2021	2.191
17	1972 - 1973	2.534	14	2002 - 2003	2.206
16	1976 - 1977	2.557	15	2014 - 2015	2.207
15	1963 - 1964	2.571	16	1994 - 1995	2.212
14	1971 - 1972	2.583	17	1999 - 2000	2.214
13	1975 - 1976	2.584	18	2011 - 2012	2.224
12	1967 - 1968	2.597	19	2010 - 2011	2.253
11	2012 - 2013	2.598	20	2016 - 2017	2.263
10	1968 - 1969	2.620	21	1998 - 1999	2.272
9	1983 - 1984	2.643	22	2000 - 2001	2.284
8	1984 - 1985	2.661	23	2004 - 2005	2.319
7	1969 - 1970	2.670	24	2008 - 2009	2.328
6	1986 - 1987	2.678	25	1987 - 1988	2.329
5	1995 - 1996	2.696	26	2003 - 2004	2.332
4	1964 - 1965	2.746	27	1991 - 1992	2.345
3	1978 - 1979	2.807	28	1982 - 1983	2.347
2	1985 - 1986	2.901	29	1966 - 1967	2.349
1	1962 - 1963	3.040	30	1992 - 1993	2.362

Annex 1b: Normalisation of the consumption

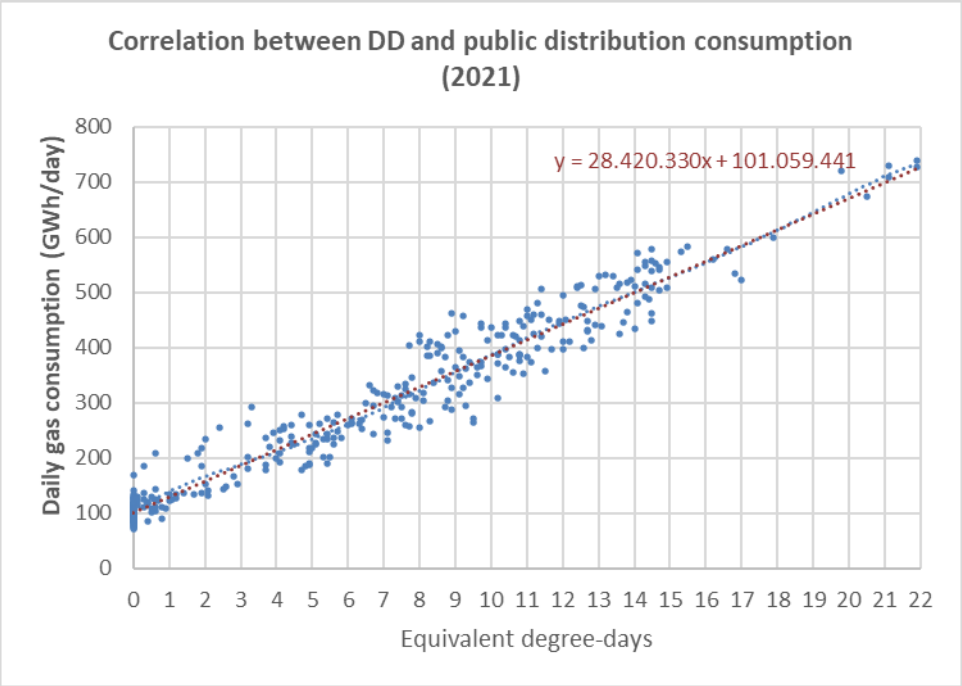
As stated in annex 1a, the gas consumption by consumers connected to the public distribution is strongly linked to the weather conditions. When comparing the market shares of the three sectors (public distribution, large industries and power generation), this can lead to a relatively higher share of the public distribution in case of a colder year, or a lower share in case of a warmer year. This effect is particularly unwanted when comparing consumptions or market shares between different years.

For this reason, total yearly consumptions on the public distribution are usually normalised to correspond to an average year, with DD_{norm}= 2 250.

To proceed with this normalisation, a link must first be established between daily gas consumption on the public distribution and the number of equivalent degree-days on the same day. This can be done by a linear approximation based on the measured daily consumptions and equivalent degree days over the year. Such an analysis is shown on Figure 33 for the year 2021. The resulting theoretical relation between the daily gas consumption (TD) and equivalent degree-days (DD_{eq}) is as follows:

TD[GWh/day] = 28.4* DD_{eq} + 101

Figure 33: Correlation between equivalent degree-days and daily gas consumption on the public distribution (2021)



For the purpose of normalising the yearly consumption, the previous relation can be adapted by multiplying the offset parameter by 365 (or 366 for a leap year):

TD_{norm}[GWh/year] = 28.4* DD_{norm} + 365*101 = 28.4 * 2 250 + 365*101= 100 765 GWh/year (or 100.77 TWh/year).

Annex 2a: Extreme weather conditions (1 in 20 years)

We start from the basic principle that the peak consumption is obtained at a winter peak day. A winter peak day is considered as one day with extreme temperature occurring with a statistical probability of once in 20 years conform the provisions of article 5 of Regulation (EU) 2017/1938 for the infrastructure standards.

To be able to find the number of DD corresponding to the equivalent temperature occurring with a statistical probability of once in 20 years, we have to observe values in the winter months (December to February). We look for the 20 days representing the coldest day temperatures in the last 100 years. Table 20 shows us that the fifth value registered in the last 100 years gives us 28,4 DD or an equivalent temperature of -11,9°C. This 5th value (5th percentile) can be considered as a temperature occurring statistically once in 20 years.

Table 20: Climatic peak values in winter during last 100 years

Climatic peak values in winter during last 100 years			
Ranking	Date	DD	Teq
20	18/01/1963	26,9	-10,4
19	1/01/1997	26,9	-10,4
18	2/02/1954	27	-10,5
17	23/02/1956	27,1	-10,6
16	12/01/1987	27,1	-10,6
15	3/02/1917	27,2	-10,7
14	19/12/1938	27,2	-10,7
13	12/02/1929	27,3	-10,8
12	13/01/1987	27,4	-10,9
11	14/01/1987	27,4	-10,9
10	2/01/1997	27,4	-10,9
9	21/12/1938	27,5	-11
8	15/01/1987	27,6	-11,1
7	8/01/1985	27,7	-11,2
6	13/02/1929	27,9	-11,4
5	21/01/1942	28,4	-11,9
4	2/02/1956	28,4	-11,9
3	14/02/1929	28,9	-12,4
2	20/12/1938	29,1	-12,6
1	22/01/1942	29,6	-13,1

This value can be further refined by taking global warming into account. Pour cette raison, nous nous sommes limité aux données des 60 dernières années (période 1963 à 2022).

Table 21: More recent climatic peak values in winter during last 60 years

Climatic peaks values in winer during last 60 years			
Ranking	Date	DD	Teq
1	08/01/1985	27,7	-11,2
2	15/01/1987	27,6	-11,1
3	02/01/1997	27,4	-10,9
4	18/01/1963	26,9	-10,4
5	06/01/1979	25,7	-9,2
6	18/01/1966	25,6	-9,1
7	04/02/2012	25,1	-8,6
8	07/02/1991	24,8	-8,3
9	10/01/1982	23,7	-7,2
10	29/12/1996	23,3	-6,8

Based on the results obtained above, we can set the reference value for the winter peak occurring once in 20 years at rounded -11°C, corresponding to 27,5 DD.

Annex 2b: Winter analysis, peak day consumption

In order to estimate the consumption levels of the peak demand on the distribution network, we make an estimation of the natural gas demand during the winter peak period. We assume that the peak consumption is obtained at a winter peak day. As explained in annex 2a, the winter peak day is considered as one day with an extreme temperature occurring with a statistical probability of once in 20 years. Belgium considers the use of -11°C_{eq} or 27.5 DD_{eq} as the reference value for the winter peak occurring once in 20 years.

The evolution of the natural gas demand on the distribution network at -11°Ceq (27.5 DDeq) is estimated based on a linear regression model. According to the determined parameters for this regression, we can compute:

- the average value of the natural gas consumption level at -11°Ceq, this is a 50% chance that the actual natural gas demand will be higher than the calculated demand;
- the natural gas consumption level at -11°Ceq with a 1% risk of exceeding the calculated natural gas demand[11];
- an estimation of the peak natural gas consumption in the coming winter.

The calculations are based on the average demand on a peak day. We do have to keep in mind that this differs from the maximum hourly consumption during a peak day which can be up to 20% higher than the average peak day demand. This difference will have to be absorbed by the flexibility in the system (This flexibility should be either imported by cross border gas trading, covered by the linepack within the network or provided by the underground natural gas storage (H-gas) in Loenhout or additional gas send out from the LNG terminal in Zeebrugge).

Peak demand on the L-gas distribution network (TDL)

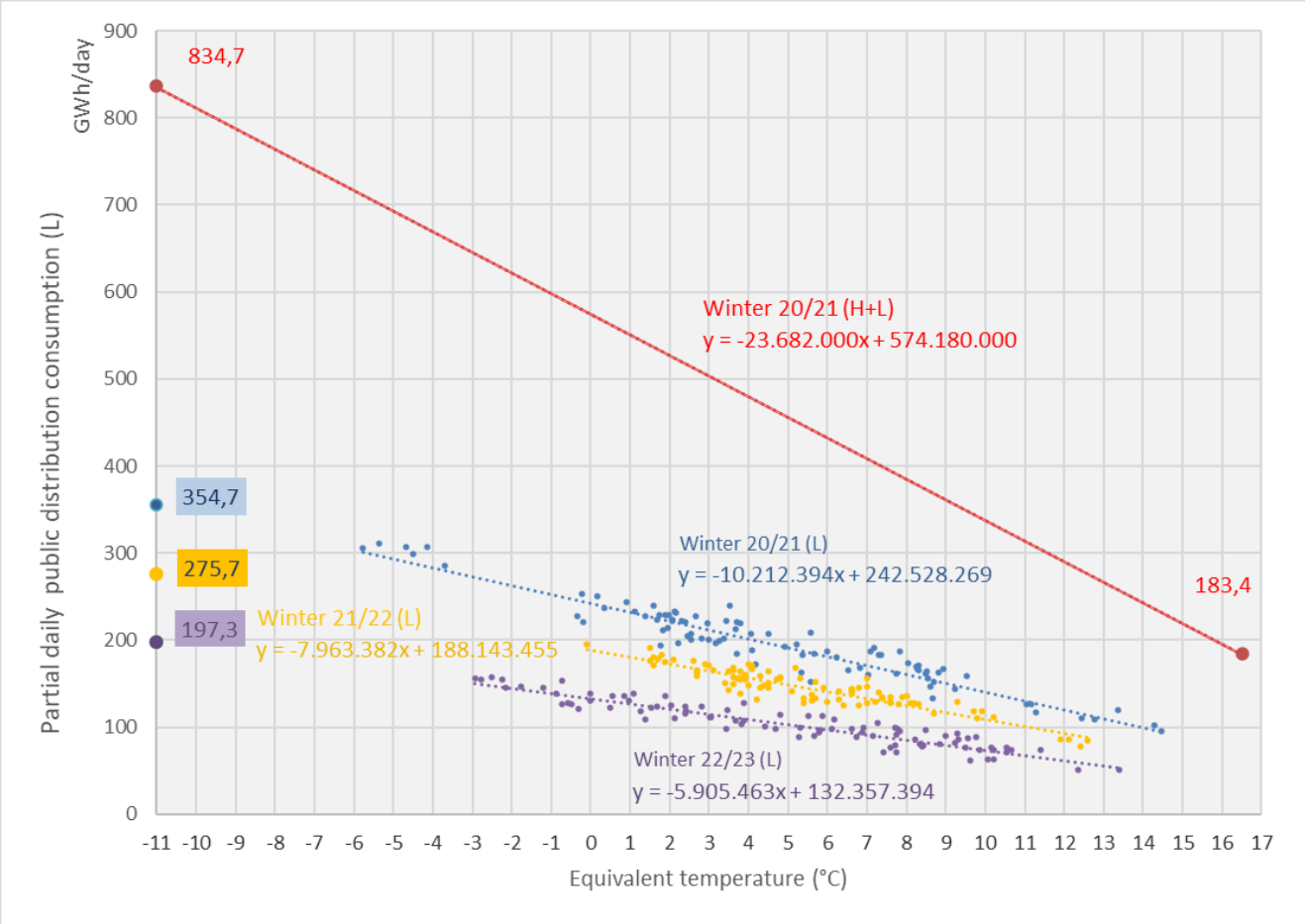
Based on the daily measured consumptions of the distribution network for a given winter period, we can deduce the linear relation between the daily equivalent temperature and the daily consumption. Based on this correlation, we can extrapolate the consumption to -11°C_{eq} in order to deduce the amount of natural gas that the distribution network will need at -11°C_{eq}.

This process is similar to the one used for the normalisation of yearly consumption, but in this case we limit the considered data to days more representative of a peak day. Only the days corresponding to all of the following criteria are taken into account:

- Between 5th November and 5th March
- Teq < 6°C
- Weekdays (no weekends)
- No holidays

[11] A correction factor is applied to the linear regression to cover 99% of the measured data (so called 1% risks).

Figure 34 Correlation between equivalent temperatures and consumption levels on the L-gas distribution network (winter 2020/21 ; winter 2021/22 ; winter 2022/23)



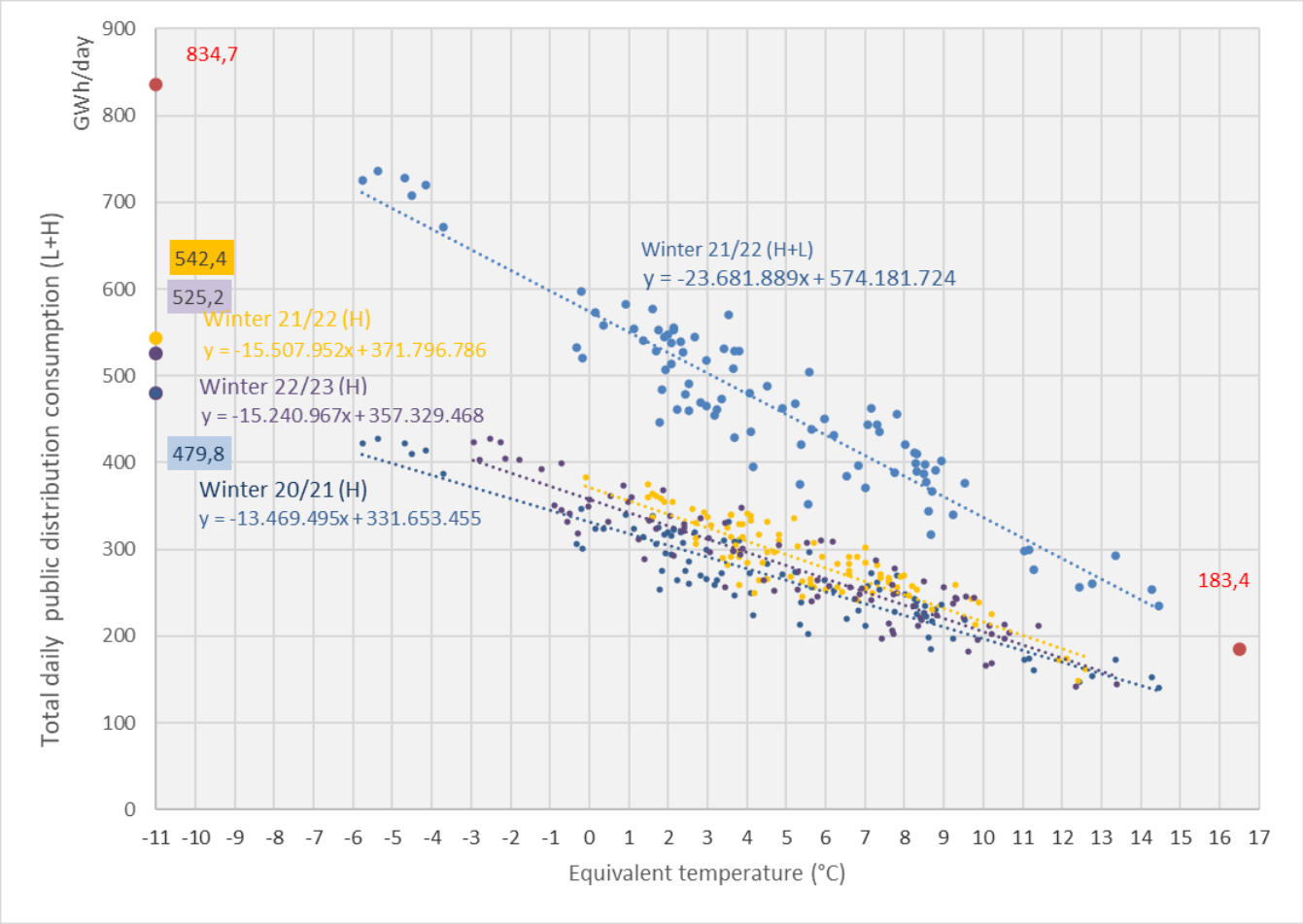
Source: FPS Economy calculation based on data available on gasdata.fluxys.com

This estimation is at the centre of the confidence interval, so there is a 50% probability that, on a cold day with -11°C_{eq}, the actual measured consumption would be higher. In order to better represent a maximum daily consumption, we also calculate a level of consumption with a 1% probability of being exceeded. (Upper limit of the 99% confidence interval).

Peak demand of the H-gas distribution network (TDH)

The same method as for L-gas described above is now used to obtain the linear regression curve for the H-gas growth rate. For the 2021/22 and 2022/23 winter period, the estimated consumption at -11°C_{eq} was respectively 542 GWh, and 525 GWh for the 50% confidence interval.

Figure 35 Correlation between equivalent temperatures and consumption levels on the H-gas distribution network (Winter 2020/21, 2021/22 and 2022/23)



Source: FPS Economy calculation based on data available on gasdata.fluxys.com

As a result of the conversion from L gas to H gas until September 2024, the consumption development profile as a function of the equivalent temperature will change significantly from year to year in both H and L. On the other hand, the sum of the L and H profiles should more or less remain stable outside of a situation of reduction or destruction of demand as a result of the war in Ukraine.

It should also be noted that the regressions obtained with a 50/50 risk on all the data for one year give a limit value of -11°C, which is probably well below reality. This is what can be observed from the graph below, namely that for real equivalent temperatures of less than - 1°C, the actual measured consumptions are all higher than the corresponding value located on the regression line. Therefore, these values cannot be considered as reference values for estimating the winter peak.

Annex 3: UKRG N-1 parameters

This annex reports the breakdown of the parameters used to compute the N-1 score for the United Kingdom Risk Group.

Table 22: Technical capacity of entry points

Technical capacity of entry points (EP_m)			Historical Data			Projected Data		
			2015	2016	2017	2018	2019	2020
			GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	Norway	ZPT (Zeepipe)	515	515	515	515	515	515
BE	France	Alveringem	0	271	271	271	271	271
DE	Denmark	Ellund	37	91	33	33	33	33
DE	Austria	Oberkappel	133	160	160	160	160	160
DE	Austria	Überackern 2	230	230	230	230	230	230
DE	Austria	Überackern	54	61	61	61	61	61
DE	Czech Republic	Deutschneudorf	198	198	198	198	198	198
DE	Czech Republic	Brandov-Stegal (Olbernhau)	9	5	0	0	0	0
DE	Czech Republic	Waidhaus	904	907	907	907	907	907
DE	Norway	Dornum	774	721	721	721	721	721
DE/NL	Norway	Emden EPT	989	989	989	989	989	989
DE	Poland	Mallnow	931	932	932	932	932	932
DE	Poland	Kamminke/Gubin/Lasow	0.0	0.1	0.1	0.1	0.1	0.1
DE	Russia	Greifswald	618	618	618	618	618	618
UK	Norway	Langeled	770	770	770	836	836	836
UK	Norway	Vesterled	396	396	396	451	451	451
UK	Norway	FLAGS	275	275	275	330	330	330
Total			**6,833**	**7,140**	**7,076**	**7,252**	**7,252**	**7,252**

Table 23: Maximum technical production capacity

Maximum technical production capacity (P_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	0	0	0	0	0	0
DE	301	301	301	301	301	301
IE	0	104	104	110	94	92
LU	0	0	0	0	0	0
NL	2,994	2,218	2,156	2,144	1,959	1,818
UK	1,111	1,232	1,319	1,355	1,349	1,327
Total	**4,406**	**3,854**	**3,879**	**3,910**	**3,702**	**3,538**

Table 24: Maximum technical storage deliverability

Maximum technical storage availability (S_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	170	170	170	170	170	170
DE	4,600	4,600	4,600	4,600	4,600	4,600
IE	33	33	33	0	0	0
LU	0	0	0	0	0	0
NL	4,180	4,180	4,163	4,163	4,163	4,163
UK	1,650	1,606	1,231	1,279	1,279	1,279
Total	**10,632**	**10,588**	**10,197**	**10,212**	**10,212**	**10,212**

Table 25: Maximum technical LNG facility capacity

Maximum technical LNG facility capacity (LNG_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE: Zeebrugge LNG Terminal	461	461	461	461	461	461
NL: Gate	399	399	399	399	399	399
UK: South Hook	649	649	660	663	663	663
UK: Dragon	297	297	297	229	229	229
UK: Isle of Grain	649	649	649	653	653	653
Total	**2,455**	**2,455**	**2,466**	**2,405**	**2,405**	**2,405**

Table 26: 1-in-20 gas demand

1 in 20 gas demand (D_{max})	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	1,307	1,303	1,357	1,466	1,478	1,490
DE	5,460	5,460	5,460	5,460	5,460	5,460
IE	207	221	206	277	281	288
LU	6	6	5	5	5	5
NL (1-in-50 demand)	3,729	3,648	3,678	3,692	3,678	3,664
UK	4,970	5,013	5,343	5,039	5,008	4991
Total	**15,680**	**15,651**	**16,048**	**15,940**	**15,910**	**15,898**

This annex reports the breakdown of the parameters used to compute the N-1 score for the United Kingdom Risk Group.

Table 27: Technical capacity of entry points

Technical capacity of entry points (EP_m)			Historical Data			Projected Data		
			2015	2016	2017	2018	2019	2020
			GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	Norway	ZPT (Zeepipe)	515	515	515	515	515	515
BE	France	Alveringem	0	271	271	271	271	271
DE	Denmark	Ellund	37	91	33	33	33	33
DE	Austria	Oberkappel	133	160	160	160	160	160
DE	Austria	Überackern 2	230	230	230	230	230	230
DE	Austria	Überackern	54	61	61	61	61	61
DE	Czech Republic	Deutschneudorf	198	198	198	198	198	198
DE	Czech Republic	Brandov-Stegal (Olbernhau)	9	5	0	0	0	0
DE	Czech Republic	Waidhaus	904	907	907	907	907	907
DE	Norway	Dornum	774	721	721	721	721	721
DE/NL	Norway	Emden EPT	989	989	989	989	989	989
DE	Poland	Mallnow	931	932	932	932	932	932
DE	Poland	Kamminke/Gubin/Lasow	0.0	0.1	0.1	0.1	0.1	0.1
DE	Russia	Greifswald	618	618	618	618	618	618
UK	Norway	Langeled	770	770	770	836	836	836
UK	Norway	Vesterled	396	396	396	451	451	451
UK	Norway	FLAGS	275	275	275	330	330	330
Total			**6,833**	**7,140**	**7,076**	**7,252**	**7,252**	**7,252**

Table 28: Maximum technical production capacity

Maximum technical production capacity (P_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	0	0	0	0	0	0
DE	301	301	301	301	301	301
IE	0	104	104	110	94	92
LU	0	0	0	0	0	0
NL	2,994	2,218	2,156	2,144	1,959	1,818
UK	1,111	1,232	1,319	1,355	1,349	1,327
Total	**4,406**	**3,854**	**3,879**	**3,910**	**3,702**	**3,538**

Table 29: Maximum technical storage deliverability

Maximum technical storage availability (S_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	170	170	170	170	170	170
DE	4,600	4,600	4,600	4,600	4,600	4,600
IE	33	33	33	0	0	0
LU	0	0	0	0	0	0
NL	4,180	4,180	4,163	4,163	4,163	4,163
UK	1,650	1,606	1,231	1,279	1,279	1,279
Total	**10,632**	**10,588**	**10,197**	**10,212**	**10,212**	**10,212**

Table 30: Maximum technical LNG facility capacity

Maximum technical LNG facility capacity (LNG_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE: Zeebrugge LNG Terminal	461	461	461	461	461	461
NL: Gate	399	399	399	399	399	399
UK: South Hook	649	649	660	663	663	663
UK: Dragon	297	297	297	229	229	229
UK: Isle of Grain	649	649	649	653	653	653
Total	**2,455**	**2,455**	**2,466**	**2,405**	**2,405**	**2,405**

Table 31: 1-in-20 gas demand

1 in 20 gas demand (D_{max})	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	1,307	1,303	1,357	1,466	1,478	1,490
DE	5,460	5,460	5,460	5,460	5,460	5,460
IE	207	221	206	277	281	288
LU	6	6	5	5	5	5
NL (1-in-50 demand)	3,729	3,648	3,678	3,692	3,678	3,664
UK	4,970	5,013	5,343	5,039	5,008	4991
Total	**15,680**	**15,651**	**16,048**	**15,940**	**15,910**	**15,898**

Table 32: Assessed Margin

Assessed Margin	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
Technical capacity of entry points (EP_m)	6,833	7,410	7,076	7,252	7,252	7,252
Maximal technical production capacity (P_m)	4,406	3,854	3,879	3,910	3,702	3,538
Maximal technical storage deliverability (S_m)	10,632	10,588	10,197	10,212	10,212	10,212
Maximal technical LNG facility capacity (LNG_m)	2,455	2,455	2,466	2,405	2,405	2,405
Total peak supply	24,326	24,037	23,618	23,779	23,571	23,407
1 in 20 gas demand (D_{max})	15,680	15,651	16,048	15,940	15,910	15,898
Margin	8,646	8,386	7,570	7,839	7,662	7,509
Margin (%)	36%	35%	32%	33%	33%	32%