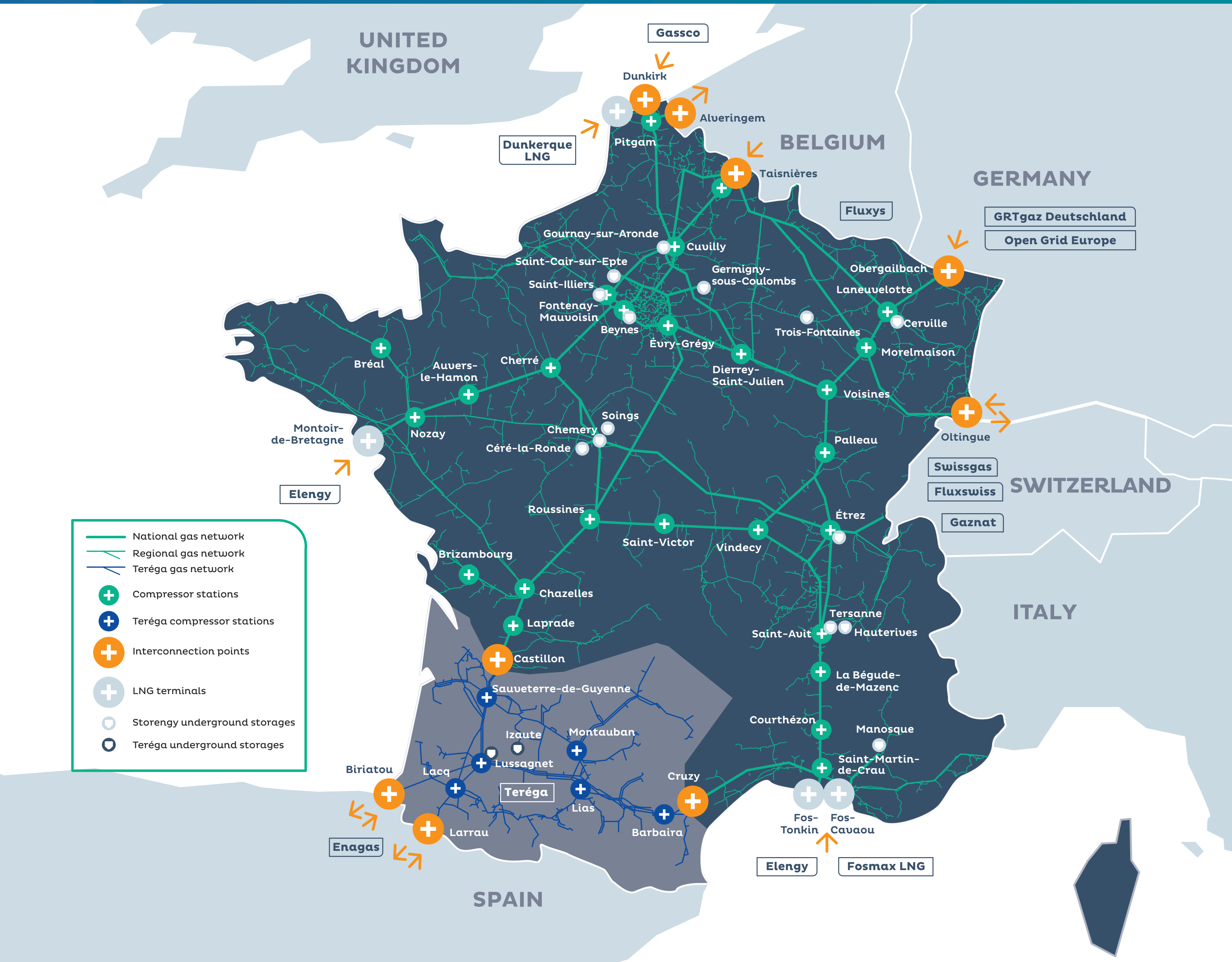
Ten-year development plan
for the GRTgaz transmission network

2019-2028 **2020-2029** **2021-2030**


Reverse flow station of Mareuil-lès-Meaux (77)

GRTgaz in maps and figures



Gas transported

701 TWh in 2019
639 TWh in 2020

Exchanges on the French market

936 TWh in 2019
969 TWh in 2020
at gas exchange points

Total consumption

453 TWh GRTgaz 2019 scope
420 TWh GRTgaz 2020 scope

Pipes

Total length in 2020:
32,527 km

Main network
7,904 km

Minimum diameter
DN 80 mm

Regional network
24,623 km

Maximum diameter
DN 1,200 mm

Compression

32
compressor stations in 2019

Total installed power (elec/gas):
598 MW

of which

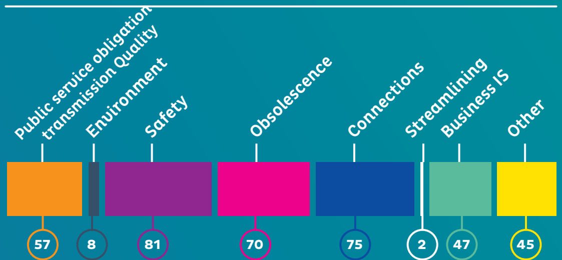
Electro
295 MW
(32 machines)

Turbo
298 MW
(42 machines)

Moto
5 MW
(5 machines)

2020 investments

€386 million



Workforce

3,022 employees in 2019

Network pressure

74%
of the transmission network is operated at a maximum pressure of
67.7 bar

Maximum network pressure:
95 bar

Minimum network pressure:
16 bar

Odourization

31
THT injection sites, including 18 operated by GRTgaz

33
odourization control sites, including 32 operated by GRTgaz

Stations in 2019

Delivery stations

3,387
public distribution stations

981
stations of directly connected industrial consumers

760
high pressure regulator stations

4,812
block valve/valve stations

Customers

158
shipper customers at end-2019

733
active industrial customers in 2019, including 13 power plants

19
connected distribution system operators

GRTgaz

provides a secure, competitive and sustainable gas supply and energy solutions for the future

GRTgaz is the operator of the high-pressure natural gas transmission network that covers most of France. It supports the proper operation of the gas system to supply gas consumers, including:

- industrial sites directly connected to the transmission network, including gas-fired power plants;
- private individuals, local authorities and companies served by public distribution networks, which are themselves supplied by the transmission network.

GRTgaz's network is a major network in the heart of Europe. It is connected to the Norwegian, Belgian, German, Italian (*via* Switzerland) and Spanish (*via* the TERÉGA network) transmission networks; and to LNG terminals on the Atlantic, Mediterranean and North Sea coasts, which can receive liquefied natural gas (LNG) from all over the world, and to which renewable gas production units are connected. It also provides access to diversified gas sources and facilitates gas exchanges throughout Europe.


Functional tests on a delivery station.

GRTgaz thus contributes to the energy security of France and Europe and to the workings of an integrated, efficient and competitive gas market.

France and Europe are currently engaged in an energy transition that must combine security, competitiveness and sustainability. Gas infrastructures, and in particular transmission networks, play a key role in meeting these challenges and the successful construction of sustainable energy systems.

In 2020, GRTgaz set out a core purpose that drives its ambition of supporting the energy transition through its values of innovation, openness, responsibility, excellence and trust: “Together, we enable an energy future that is safe, affordable and climate neutral”.

Editorial

Thierry Trouvé
Chief Executive Officer

“This is a pivotal time for the gas industry and its infrastructures.”

Following a decade of major work that ended with the commissioning of the Val de Saône programme, and with the launch of the Trading Region France (TRF) single market zone on 1 November 2018, the French gas transmission network is now demonstrating both its resilience and the importance of its size on a daily basis, providing French consumers with security of supply and the most competitive gas prices.

For the first time ever in 2020, and for several months, gas prices in France were even lower than those seen in the other north-west European markets. The market tools used to limit the investments necessary for the proper function of the single market zone have been working well.

Network configuration and usage are not expected to change dramatically over the coming decade. Natural gas consumption is expected to decline, but logistics and transport needs, linked in particular to transit, seasonal storage and the modulation of usage power will remain significant throughout France.

Regarding uses, doubling the size of the southern Brittany network, work for which is underway, will allow a new gas-fired electricity generation unit to be connected in Landivisiau. This will strengthen the controllable means of balancing the electrical system, which have been under considerable strain in recent years. The connection of vehicle refuelling stations is also expected, while natural gas is increasingly needed to decarbonise heavy vehicles.

Likewise of note is the growing demand for biomethane injection into the transmission and distribution networks. The resulting adaptations (connections and reverse flow stations) confirm, once and for all, the transmission network's entry into the age of energy transition. These investments, approved by the French Energy Regulation Commission (CRE), are identified via shared analyses on the ground in the regions and optimised as part of stabilised national rules. The initial infrastructure construction and zoning operations confirm the high potential and relatively modest costs seen to date. All the conditions have now been met for the more widespread rollout of these facilities and to support the development of many projects in the capacity register.

Building on this experience, GRTgaz, working together with other infrastructure operators, must now define the procedures for injecting renewable and low-carbon gases from other technologies such as biomass gasification or water electrolysis into the network. These new gases are essential for achieving carbon neutrality. Their development will need to be stepped up to meet national targets for reducing greenhouse gas emissions by 2030, and to lend credibility to hydrogen's key role in the recovery plans. GRTgaz, which already has to respond to connection requests, decided to launch a public consultation with Térega on 1 June to assess the needs and expectations of market stakeholders.

The GRTgaz network is a powerful tool whose maintenance should not require a significant increase in renewal costs. It has undergone continuous, customized maintenance and benefits from modern facilities installed in recent years as part of the French market's integration. The information system, on the other hand, will be extensively revamped in the coming years to optimise the network's operation, provide all users with more data, and strengthen cybersecurity.

The economic lifespan of gas transmission infrastructures requires that we look beyond the next decade. In the longer term, changes to the network's uses are obviously more difficult to identify. Flows could be very different but require just as much transmission capacity, with decentralised production located far from consumption areas, renewable and low-carbon gas transits, including hydrogen from south-west to central Europe, or adjustments to specific uses over shorter periods.

Hybrid uses and technologies such as electrolysis and methanation are gateways between the different energy vectors with different geographical features. They will allow us to design energy flows that are optimised but still unprecedented. Hydrogen transmission could thus be expanded by capillary action using sections of the current gas transmission network that are freed-up due to the fall in methane consumption, with reuse costs being lower than the costs of a new network.

The process of developing our prospective operations is still largely confined to each energy vector. This poses a risk of fragmentation of the energy ecosystems and sub-optimal uses due to decentralisation. More than ever, I think there is an urgent need to increase convergence between the prospective operations in each sector and for each energy vector. This will ensure that the transformation of our energy system takes place under the best conditions in terms of cost, security of supply, and national cohesion.

This is a pivotal period for the gas industry and its infrastructure. Initially designed to assist the European integration of the natural gas market, the ten-year development plan can be used to shed light on new adaptation challenges to support the energy transition. The aim of this plan is to introduce preliminary discussions that will be expanded, with your help, during future editions.

I hope you enjoy reading it.

Thierry Trouvé
Chief Executive Officer

Executive summary

This ten-year plan is part of a European and national regulatory framework defined by Article L431-6 of the French Energy Code. Its purpose is to identify the main gas transmission infrastructures to be built or strengthened in the upcoming decade, to list the investments approved or to be made within three years, and to set out a provisional schedule.

The plan is based both on existing gas supply and demand and on reasonable medium-term development forecasts for gas infrastructure, consumption and international trade. It includes a multi-year supply and demand forecast that meets the requirements of Article L141-10 of the French Energy Code.

This ten-year plan will feed into the work of the 2022 edition of the European Ten Year Network Development Plan (TYNDP) led by the European Network of Transmission System Operators for Gas (ENTSOG) under Regulation (EC) no. 714/2009 and Regulation (EC) no. 715/2009. The 2020 edition of the TYNDP, now published in its entirety, is based on data from GRTgaz's 2018 ten-year development plan.

Among the industry developments in 2019 and 2020, European energy policy has given a central role to the European Green Deal published on 11 December 2019, whose "do no harm principle" will be the bedrock of public policies. The resulting European strategies include the publication of the hydrogen strategies on 8 July 2020 and the integration of the energy system. In France, the revised 2018-2019 National Low Carbon Strategy (SNBC) was published on 21 April 2020, with the target of carbon neutrality by 2050 now enshrined in law. The Multi-Year Energy Programme (PPE) published in April 2020 sets out the intermediate stages leading up initially to 2023, then 2028. This relates in particular to reducing the consumption of primary fossil energy and natural gas, and to producing renewable gas and in particular biomethane. The French Energy-Climate Law of 8 November 2019 also puts an end to the production of electricity from coal and brings in support for the hydrogen sector.

In 2020, the Covid-19 health crisis raised awareness of the climate emergency. The European and French recovery plans were keen to make the environment a central concern. In France, this resulted in a hydrogen strategy that goes significantly beyond the initial targets of the Hulot Plan.

In 2019, the global gas market reached 23.2% of the worldwide energy mix, growing three times faster than the pace of global energy demand (+0.9%). This was driven in particular by the Asia-Pacific region and North America.

French gas consumption increased in 2019 to 494 TWh. This change is linked to an increase in gas consumption for centralised electricity generation of 50 TWh, with consumption for other uses (residential, tertiary, agriculture, mobility) remaining almost constant over recent years. In 2020, demand for gas-fired power plants was slightly less than in 2019, although it remained at a high level given the fall in energy consumption linked to the health crisis. Faced with the variable availability of nuclear power and hydraulic and renewable production, gas offers manageable production with lower emissions than other thermal sources, and at competitive prices.

In 2019, supply was affected by a fall in global prices. This is resulted in increased imports of LNG (+87%) for French and European consumers, with transit to Spain and Italy up by 50 TWh (+75%). These supply conditions were replicated in 2020, albeit with a slight drop in imports and transit linked to lower gas consumption in Europe due to the health crisis. On the other hand, biomethane production has expanded significantly over the last two years, reflecting the genuine emergence of this new gas.

Over the past two years, French consumption needs could be met at all times and throughout the country. There were no significant disruptions to import flows or the operation of the gas transmission infrastructure. Storage facilities could be used by suppliers to ensure the security of supply for their customers. The network was widely called upon, demonstrating the importance both of its size and of the GRTgaz offer that gives suppliers - and therefore consumers - secure access to gas at the most competitive prices. France has reaped the benefits of historically low gas prices in Europe, with prices frequently lower than those seen on the Dutch marketplace.

Looking ahead to the next ten years, most forecasts show gas demand declining in Europe. In France, the 2020 Gas Outlook produced by the gas network operators (GRTgaz, Teréga, GRDF, SPEGNN) likewise anticipates a decline in consumption over the coming decade. According to the three scenarios used, which stay close to the public authorities' SNBC framework, the fall between 2019-2030 could be between 15-22%. To expand the plan's strategic scope, another scenario is highlighted in which gas consumption falls less rapidly (-10% by 2030 compared to 2019) while remaining compatible with the carbon neutrality target via a more sustained use of renewable gases, particularly imported gases. This alternative was not included in the SNBC. Consumption under extreme weather conditions (the so-called "2% peak") is also on a generally downward trend. Nevertheless, it should be noted that changes to this peak demand are highly sensitive to scenarios with a high degree of uncertainty, such as increasing energy efficiency in buildings or industry. For infrastructure sizing operations, the reduction should also be viewed in light of the near-stability of gas consumption in recent years.

In terms of supply, natural gas remains available in large quantities to support the European energy transition, replacing more carbon-intensive fossil fuels or supported by CO_2 capture and sequestration technologies. Renewable gases will need to take over from natural gas, and these could represent between 39-73 TWh in 2030 according to the *2020 Gas Outlook*. In addition to the large-scale increase in biomethane produced from anaerobic digestion, the next decade should see the emergence of gases produced by biomass gasification and hydrogen as an energy vector.

At the conclusion of the plan, beyond the availability of gas to meet consumption needs, the current sizing of France's gas infrastructure will ensure the country's continuity of supply, with satisfactory levels of resilience and flexibility. This includes in high-stress scenarios relating to the climate or gas transmission, as specified in French and European regulatory legislation.

In terms of capacity, the network now seems well-suited to shippers, given the reservations made for the coming years and feedback from the incremental process consultation. Adjacent transmission network operators also did not indicate the need to increase network interconnection capacities at the borders; rather, they stated the need to improve coordination for potential cross-border exchanges of pure or blended hydrogen. Given the attractiveness of LNG, however, French LNG terminals are considering projects to increase capacity, which may have an impact on the transmission network, particularly at Montoir-de-Bretagne and Fos-Cavaou. Details of these projects must be provided to assess the works and strengthening measures required on the network, which will only be carried out with the proper contractual commitments.

For the next ten years, the network's development needs will be generated by injection from renewable gas production units, by connecting the Landivisiau electricity generation unit, and, to a lesser extent, by connecting industrial customers and vehicle refuelling stations.

Regarding electricity generation, the transmission network operator has not identified the need for any new units generating electricity from gas by 2030, beyond the commissioning of the Landivisiau gas-fired combined cycle power plant (CCPP) in Brittany. The connection of this plant is underway, with strengthening work required on the transmission network over nearly 100 km to the south of Brittany.

Concerning the integration of biomethane under the newly introduced "Right to Injection", some large projects are connected directly to the transmission network. However, most are connected to the distribution network, where the area's injections can exceed its consumption, particularly in summer when consumption is lower. Transporting excess gas to other consumption areas or storage facilities via the transmission network requires the installation of compressor stations (reverse flow). Optimising network investments is based mainly on an economic tests and works planning via zoning mechanisms approved by the CRE. At end-March 2021, 216 zones were submitted to the regulator, i.e. approximately 50% of the country, with a target optimisation potential of 25 TWh. Three reverse flow stations were commissioned, with approval granted for the construction of nine others. This momentum, confirmed by the numerous projects included in the capacity register (1,147 projects i.e. a capacity of 26 TWh), could require the installation of 70 or 130 reverse flow stations to accommodate 30 or 50 TWh of biomethane, respectively, on the networks.

Given this enthusiasm for promoting the emergence of hydrogen, GRTgaz is working to be able to inject this new energy vector into its network in complete safety. The integration of blended hydrogen into the gas networks forms part of an expanded third-party access to the networks for all renewable gas and low-carbon hydrogen producers. This is already a topical issue. Expectations are for it to scale up in the coming years, with the implementation of support mechanisms for decarbonised hydrogen production, as provided by the recent French Hydrogen Development Strategy, and with production projects flourishing in France. At end-2020, GRTgaz was examining or had examined nearly 30 feasibility studies for connection to the network, at the request of project leaders. Support for the sector will also include the publication in 2021 of a map for hydrogen producers seeking to inject into the GRTgaz network. This will enable them to quickly identify areas suitable for injecting hydrogen in the short term.

With major projects to streamline the network coming to an end, a large part of GRTgaz's investments during the coming years will be geared towards maintenance and adaptation.

To ensure the continuity of supply for consumers in the Hauts-de-France region that is historically supplied by L-gas (low calorific value) from the Groningen gas field in the Netherlands, whose production is likely to stop, GRTgaz is conducting a project to convert the network into H-gas (high calorific value), with the same specifications as the rest of the French network. The pilot phase was successfully completed in autumn 2020, despite the health crisis, with the conversion of the Dunkirk sector. Eighty thousand customers were connected to the distribution network and seven connected directly to the transmission network. The conversion phase was launched in 2021, with new changes to the transmission network enabling the conversion of 550,000 distribution customers, with 54 customers connected to the GRTgaz network. GRTgaz is adapting its network to enable the gradual conversion of these customers, while ensuring continuity of transmission for all. This project will result in the end of the "peak" service for the conversion of H-gas into L-gas and the gradual disappearance of entry firm capacity at Taisnières B.

Beyond conversion, recent changes in regulations (the "Multi-fluid Order"), increasing attention to cybersecurity, network deviations due to major works (waterways, Greater Paris, etc.) and ageing equipment are all factors requiring the adaptation of the network or its ancillary facilities. Nevertheless, these adaptations should remain contained. Some compressor stations may need to be overhauled in the coming decade. As has been the case to date, these operations will be analysed and sized according to the benefits they offer for all users of the network.

Finally, GRTgaz pays particular attention to its carbon footprint. Efforts made in recent years have enabled it to reduce its methane emissions by a factor of three between 2016 and 2020, mainly through customised operational management. More generally, GRTgaz will make annual investments towards the energy transition of nearly €70 million in the coming years.

The service life of energy infrastructure also calls for longer timeframes than those of a ten-year plan.

In the long term, there are clearly significant uncertainties about consumption and production volumes, but above all requirements and locations - elements that determine delivery needs in the first instance. The network will remain a key tool for transporting gas to uses whose needs are difficult to meet with electricity, such as heavy vehicles or high-temperature industrial thermal uses. Its ability to offer flexibility (through linepack or access to storage) and to deliver high power could also prove essential for the balance of the electrical system by ensuring that buildings remain heated during cold periods or by offering controllable electricity generation or consumption reduction systems (CCPP, electrolysers, etc.).

In addition, the network, which is required to connect decentralized production, should see its role expanded to ensure solidarity between regions with different types of renewable gas resources, and continue to guarantee consumers secure access to energy at the most competitive prices.

As well as injecting blended hydrogen into the network, transporting this new energy vector in dedicated networks could be necessary to link large-scale production to distant consumption hubs. In its hydrogen strategy, the European Commission has highlighted the key role of pipeline transport infrastructures in developing an efficient hydrogen-energy market in Europe. The forecast reduction in gas consumption in the years ahead could have the long-term effect of reducing the stress on several sections of the network. These pipes could then be used to transport hydrogen at a cost much lower than that of constructing a new network. To better understand these long-term growth opportunities for the network, GRTgaz has been involved in the European Hydrogen Backbone initiative and in the mosaHYc project (Moselle Sarre HYDrogène Conversion), the first demonstrator in France to convert existing natural gas pipes for the transmission of pure hydrogen.

Multi-year forecast and ten-year development plan: regulatory requirements

Article L141-10 of the French Energy Code, updated by Order 2018-1165, provides that *"transmission network operators shall produce a multi-year forecast every year […], taking into account changes in consumption as a result of low-consumption; efficiency and substitution of uses; transmission, distribution, storage, regasification, renewable production, erasure and interruptibility capacities; and exchanges with foreign gas networks. The multi-year forecast covers a minimum period of ten years from the date of publication."*

Furthermore, and in accordance with Article 22 of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 on common rules for the internal natural gas market, transposed into Article L431-6 of the French Energy Code, GRTgaz produces a ten-year development plan each year for its gas transmission network in France, which it submits to the CRE for review.

The purpose of this ten-year plan is to:

- identify the main gas transmission infrastructures to be built or strengthened in the coming decade;
- list the investments approved or to be made within three years;
- present a provisional schedule for all the investments listed, distinguishing between approved and non-approved projects.

The plan is based both on existing gas supply and demand and on reasonable medium-term development forecasts for gas infrastructure, consumption and international trade. It includes obligations imposed on carriers to produce the aforementioned multi-year forecast, taking into account changes in consumption, transport, distribution, storage, regasification, renewable production and exchanges with foreign gas networks. It also takes into account the needs and plans expressed by stakeholders at national, supranational and European levels.

Given the uncertainties surrounding both the market and projects in a fast-changing energy environment, this document does not commit GRTgaz beyond its legal obligations regarding the completion of planned developments.

European legislative framework

- Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 on common rules for the internal natural gas market.
- Regulation 715/2009 of the European Parliament and of the Council of 13 July 2009 on access conditions to natural gas transmission networks.
- Regulation 994/2010 of the European Parliament and of the Council of 20 October 2010 on measures to guarantee the security of supply of natural gas.
- Regulation 347/2013 of the European Parliament and of the Council of 17 April 2013 on trans-European energy infrastructure guidelines.

French legislative framework

- French Energy Code, created by Order no. 2011-504 of 9 May 2011.
- Article L431-6, describing the transmission system operators' duties relating to the ten-year development plan for their network.
- Article L141-10, describing the production of a multi-year forecast by transmission system operators.

Coordinated actions with documents produced by ENTSOG

A development plan for the European gas network is drawn up every two years by ENTSOG [1], the association of European gas network managers, as provided for by regulation EC/714/2009. ENTSOG uses a broad consultation process open to all stakeholders (regulators, European Commission, infrastructure operators, suppliers, NGOs, consumers, etc.). The TYNDP [2] lists the infrastructure projects submitted by developers, and assesses their impacts on the gas system. Projects seeking to benefit from the "Common Interest Project" label are also subject to a cost-benefit analysis, in accordance with the methodology developed by ENTSOG and approved by the European Commission.

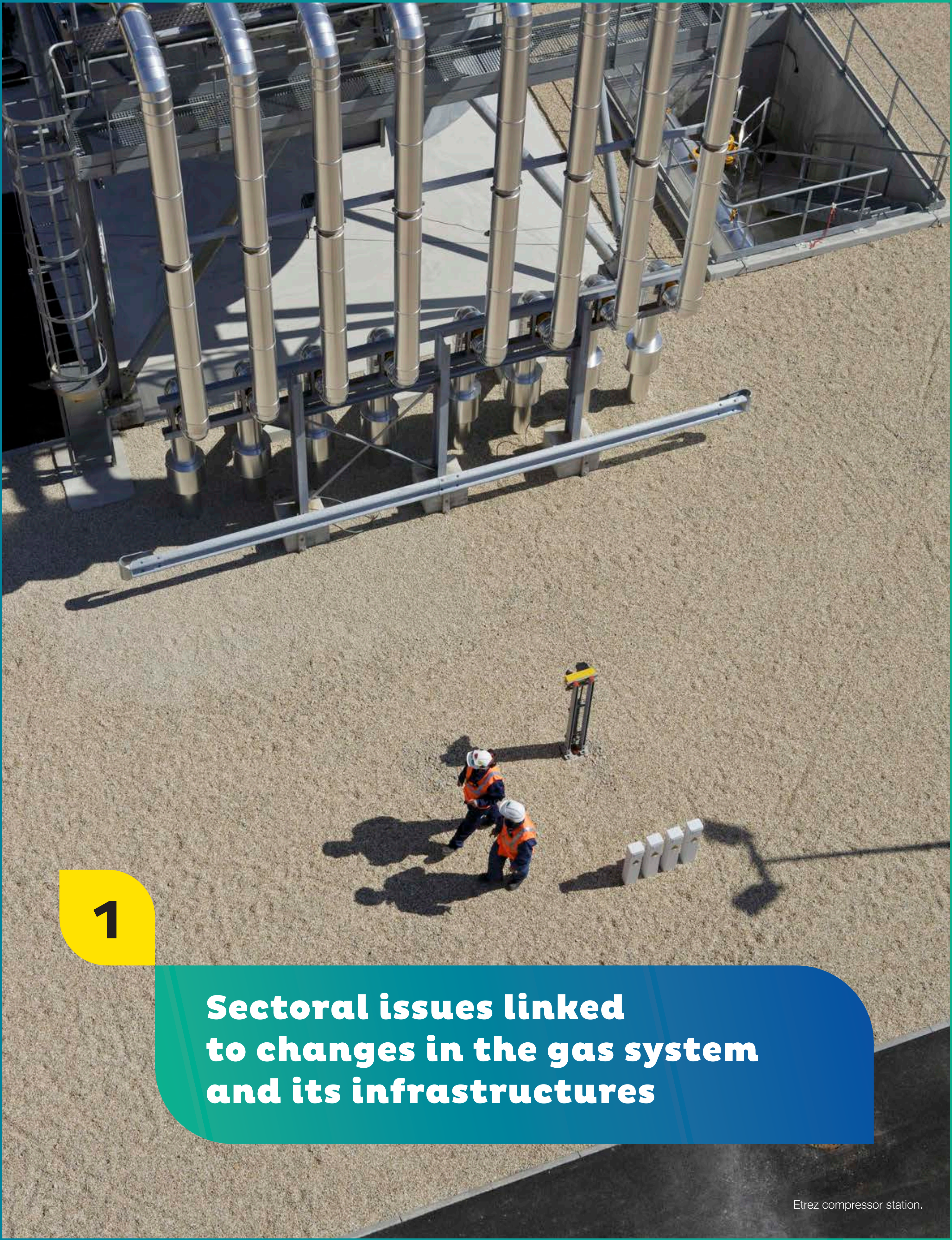
The 2020 edition of the TYNDP has just been published in full. It is based on gas supply and demand scenarios co-constructed with ENTSOE [3], the association of electricity network managers, published in June 2020 by the two associations in the Final Scenario Report. These scenarios were drawn up based on data from GRTgaz's 2018 TYNDP.

In consultation with stakeholders and using consistent modelling tools, the two energy carrier associations pooled their efforts and expertise to come up with common scenarios. This collaboration signifies the growing synergies between energy networks linked to decarbonisation, while also ensuring consistency in the development of gas and electricity networks.

The European gas system analysis was published in November 2020 and the development projects cost/benefit analysis in January 2021. Projects in these publications concerning the GRTgaz network are taken from the 2018 TYNDP.

At the same time, work on the 2022 TYNDP has begun. Scenarios for gas demand and production will use data from the current edition of the GRTgaz TYNDP.

1 | *European Network of Transmission System Operators for Gas.*
2 | *Ten-Year Network Development Plan (TYNDP).*
3 | *European Network of Transmission System Operators for Electricity.*



1

Sectoral issues linked to changes in the gas system and its infrastructures

Etrez compressor station.

1.1 | **The energy transition** at the heart of French and European policies

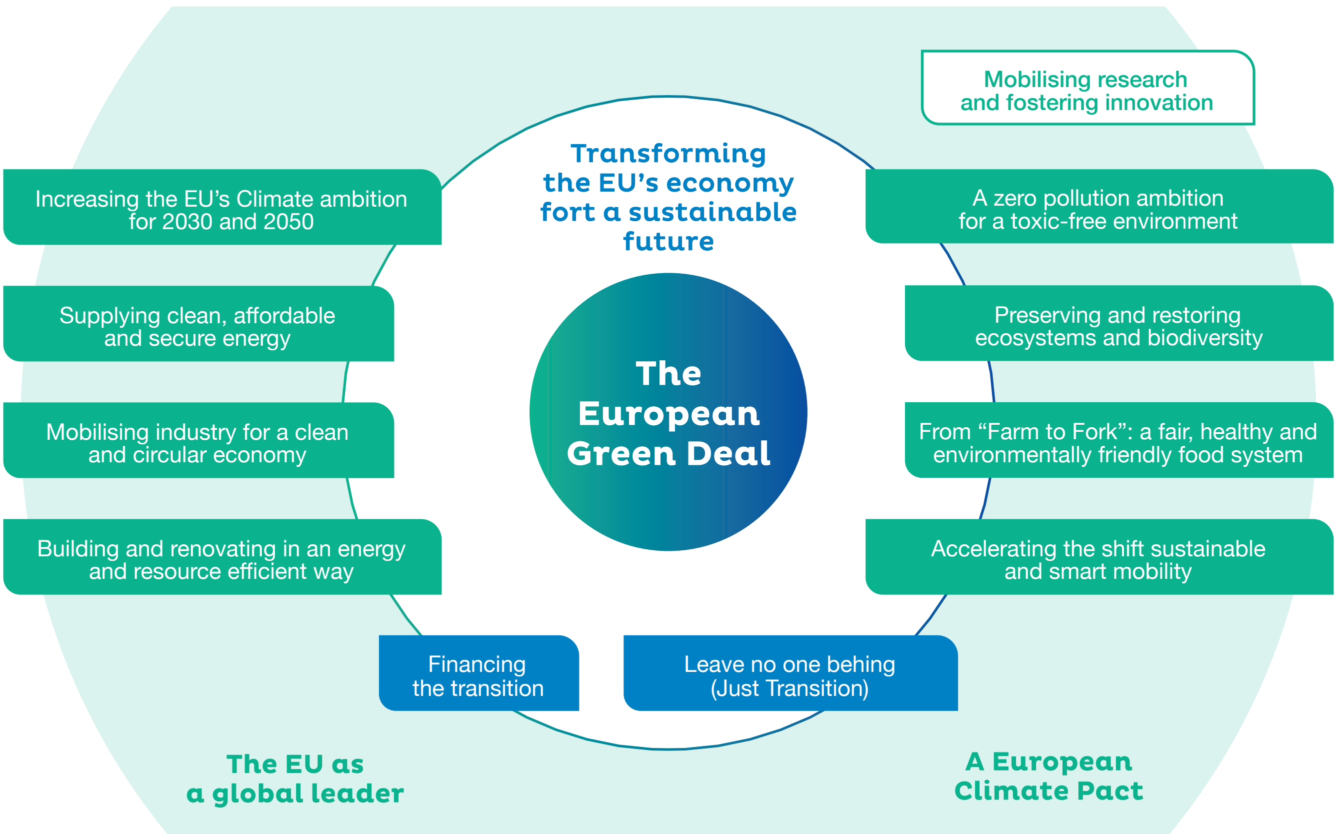
The European Green Deal

On 11 December 2019, before the COVID-19 health crisis, the European Commission released information on the work programme to implement its so-called "Green Deal". This programme structures all the policies proposed and implemented by the Von der Leyen Commission over the next five years. The EU's new College of Commissioners' political programme is based on a cross-sectoral approach to public policies. Each policy and strategy will be analysed through the lens of the Green Deal and the precautionary "do no harm principle".

The Green Deal's 10 pillars aim to reconcile the needs of our economy with those of the planet. Some of these could have a direct impact on activities related to energy transmission.

The **"Climate Ambition"** pillar reflects the target of carbon neutrality by 2050, which requires political agreement. Some legislation relating to climate goals will therefore need to be revised. For example, the Renewable Energy Directive will be part of this revised legislation, with details provided on terminology relating to

FIGURE 1 | **The Investment Plan within the European Green Deal**



Source: European Commission

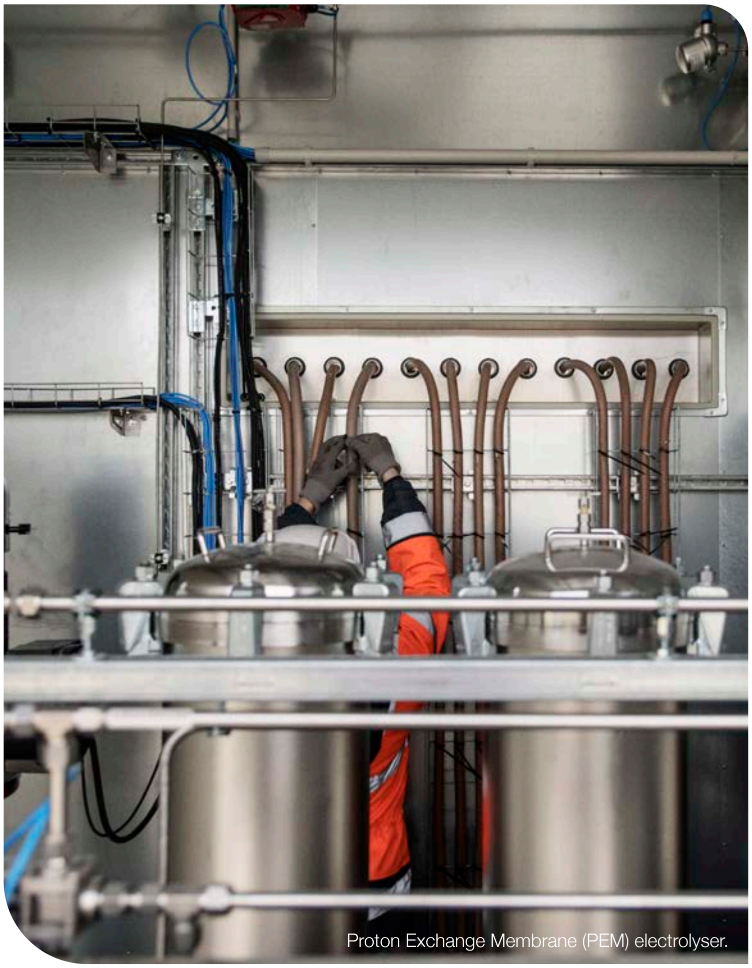
renewable gases. A Europe-wide mechanism for adjusting carbon prices at borders should be implemented to protect European industry in the absence of a worldwide agreement between states on carbon price mechanisms. Finally, the programme also provides for a revision of the Energy Taxation Directive. The goal of reducing greenhouse gas (GHG) emissions breaks down into several objectives aimed at increasing the share of renewables in the European energy mix. The roles of bioenergy, hydrogen and electrification in the energy transition are acknowledged, and the Commission stresses the importance of infrastructure planning and the need to reduce energy sector emissions, particularly methane emissions, a strategy for which was published in October 2020.

The **"Clean, Affordable and Secure Energy"** pillar consists on the one hand of an Energy System Integration strategy published on 8 July 2020, and on the other hand of a revised TEN E[4] regulation in line with the carbon-neutrality target. The Commission considers that the sectoral integration of renewables and other sustainable solutions will contribute to achieving decarbonisation at the lowest cost by promoting innovative technologies and infrastructures such as smart grids, hydrogen networks, and CO_2 capture technologies.

The Commission is taking strong action on gas issues, in particular to develop a regulatory framework tailored to renewable and low-carbon gases. Gas infrastructure is seen as a key support for the energy transition by providing affordable, safe energy with the development of renewable gases, such as biomethane, which are distinguished by their ability to develop a circular energy system, offer an additional waste recovery route, and provide a decarbonisation solution for sectors such as agriculture.

The rollout of hydrogen in Europe *via* hydrogen valleys and a "European Backbone" has become a Europe-wide priority to "green up" the gas network and the sectors whose links to industry and transport make decarbonisation problematic.

This pillar is largely based on the ability of the gas sector to offer innovative solutions. It makes network managers central to both the European discussion and regulatory issues linked to the energy transition.


Proton Exchange Membrane (PEM) electrolyser.

The **"Mobilising Industry for a Clean and Circular Economy"** pillar is centred on a European industrial strategy aimed at modernising the economy by developing circular markets and products. It will focus mainly on energy-intensive industries. In addition, this pillar will be supplemented by a proposal to support the development of zero-carbon industrial processes, a batteries and the circular economy strategy, and legislative reforms targeting waste management.

The **"Sustainable and Smart Mobility"** pillar aims to increase the share of renewable energy in transport and to drastically reduce GHG emissions in a sector that is currently one of the worst offenders. The EU should incentivise the production and deployment of sustainable substitute fuels.

4 | *Trans-European Networks for Energy*.

The **"Integrating Sustainability into European Policies"** pillar includes a sustainable investment plan and the integration of a fair transition mechanism. The rules for state environmental and energy aid will also be revised to reflect new climate targets, facilitate the abandonment of fossil fuels, and address the issue of barriers to market entry for the cleanest energy products.

Focus on the European Hydrogen Strategy

As things stand, hydrogen is used almost exclusively as a raw material. However, it could become a major energy vector for carbon-neutral economies in the coming decades. It could also make a major contribution to decarbonising uses in industry and mobility (road, river, rail – diesel), which currently have the highest levels of GHG emissions. Given the prospect of intermittent, uncertain renewable electricity generation, producing hydrogen from electricity and water by electrolysis could be a means of storing surplus electricity, thus contributing to the general optimisation of the gas-electricity-heat energy system.

In its June 2019 report The Future of Hydrogen, the International Energy Agency (IEA) makes a set of recommendations for developing decarbonised hydrogen. These include using the existing gas infrastructure to introduce blended hydrogen and boost demand, thus benefiting from economies of scale.

In Europe, the Commission and many Member States are supporting the development of this low-carbon energy sector with the publication on 8 July 2020 of the European Hydrogen Strategy [5] as well as many national strategies. These strategies are key pillars of both the Green Deal and multiple recovery plans linked to the health crisis.

The European scenarios for the 2020 TYNDP also confirm that establishing a decarbonised energy system by 2050 will require a significant portion of hydrogen in the energy mix.

The Commission sees the development of hydrogen as a geopolitical issue. In particular, it emphasises the importance of strengthening Europe's leadership in this sector with regard to the balance of trade, energy independence, and security of supply.

The Commission is focused primarily on the development of renewable hydrogen. As such, it estimates that a carbon price of between €55 and €90/tCO_2 will be necessary to make low-carbon hydrogen competitive with hydrogen from fossil fuels, and that clean hydrogen could meet 24% of global energy demand by 2050. Hydrogen's share in the European energy mix in 2050 is estimated at just under 15%, compared with less than 2% today. The outlook for investment in European renewable hydrogen would be between €180-470 billion by 2050. Investments in hydrogen transmission, distribution, storage and refuelling stations are estimated at €65 billion.

The *Clean Hydrogen Alliance* launched on 8 July 2020 by the European Union as part of the rollout of a new industrial strategy for Europe will be tasked with supporting the implementation of this strategy, in particular by identifying strategic projects for financing. This financing will be based, among others, on pre-existing European tools such as InvestEU or the IPCEI [6], the Innovation Fund and the Cohesion Fund. The recovery plan mentioned below will also contribute to financing the sector.

Increasing hydrogen supply and demand

To promote the growth of this new energy vector, the European Commission recommends several mechanisms aimed at both production and consumption. The revised versions of the ETS and the RED II directive, for example, anticipate the implementation of CO_2 quotas to increase demand in the heavy vehicles, maritime transport and aviation sectors.

The commission identifies three phases of market growth:

- 2020-2024: goal of producing 1 million tonnes of renewable hydrogen in 2024 with 6 GW of electrolysers installed, with the target of decarbonising current hydrogen users, in particular industry and the transport sector; adapting hydrogen production sites with CO_2 capture and storage systems (CCS [7]); developing electrolyser manufacturing. Infrastructural requirements are viewed as limited due to the local nature of production and demand;

5 | *"A hydrogen strategy for a climate-neutral Europe"*: https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

6 | *Important projects of Common European Interest.*

7 | *Carbon Capture and Storage* (CCS).

- 2025-2030: goal of producing 10 million tonnes of renewable hydrogen by 2030 with 40 GW of electrolysers installed; expanding demand to other sectors such as maritime transport; extending the role of hydrogen to offer flexibility to the electricity network and developing "Hydrogen Valleys". This phase entails a greater need for a European infrastructure. In this section, the conversion of sites producing hydrogen from fossil fuels to low-carbon hydrogen production continues to be encouraged;
- post-2030: renewable hydrogen technologies are sufficiently mature for large-scale rollout across all sectors where decarbonisation is problematic. Mention is given to the role of biogas in replacing the natural gas used in hydrogen production facilities with CCS.

The role of infrastructures

The Commission wants to implement a commodities market for hydrogen, with the networks central to its development. It proposes the revision of the TEN-E regulations to integrate hydrogen into the deployment of energy transmission infrastructure, with the support of the European energy networks' TYNDPs. To support mobility demand, revisions to the Infrastructure Directive for alternative fuels and a revision of the Trans-European Transmission Network (TEN-T) Regulations will supplement the regulatory framework.

The Commission acknowledges the need to revise gas market rules to allow operators to finance and operate hydrogen pipelines. Likewise, it views the principle of non-discrimination for access to infrastructure as indispensable.

European Union strategy for energy system integration

The European Commission presented a strategy for an integrated energy system for a climate-neutral Europe as part of the annual work programme followed by the Green Deal. The aim was to propose a series of measures and strategic guidelines to decarbonise the energy system by strengthening sectoral integration.

Insulating the pipes for the Jupiter 1000 blending station zone.

Sectoral integration is defined as the coordinated planning and operation of the entire energy system (energy vectors, infrastructure and consumption). The role of energy infrastructure is stressed, particularly in connection with digitisation and the security of supply, which must now also meet climate targets.

The Commission identifies several major benefits to strengthening sectoral integration, including reducing greenhouse gas emissions, increasing energy efficiency, making the European economy more competitive, improving the flexibility of the network in particular via energy storage, and strengthening the security of supply and resilience.

The strategy is designed around six pillars:

- **a circular energy system:** the "energy efficiency first" principle remains a priority, including for infrastructure planning. This principle involves reusing resources, using more efficient energy vectors, using local energy sources, and applying flexibility solutions to cope with demand and facilitate network management;
- **the importance of electrification:** the Commission forecasts that renewable energy will make up approximately 84% of the electricity mix by 2050. Nevertheless, several barriers to development have been identified, including a lack of energy infrastructure, public acceptance, growth of value chains, administrative barriers, costs linked to immature technologies, etc. Special attention is paid to offshore renewable energy production, in particular for hydrogen production and the reuse of existing gas infrastructures;
- **recognition that renewable gases** will play an important role, in particular H_2 and biomethane, and in specific sectors such as certain industrial processes, aviation and maritime transport. Plans are in place for definitions of renewable and decarbonised gas terminology, as well as a certification system. There is also a particular focus on hydrogen's role in integrating renewable energies into the network and its possible end uses (transport, industrial processes, storage). Finally, CCS technologies and the possibility of producing synthetic gases from CO_2 and renewable hydrogen (CCU) are an integral part of the European Commission's thinking on renewable gases. The RED II directive and the ETS system should hence be revised to include carbon capture, which, combined with gases from biogenic sources (biomethane + CCS) or directly from the atmosphere (renewable H_2 + methanation + CCS) can even offset residual emissions from other sectors;
- **an energy market for decarbonisation:** the creation of a market for renewable and low-carbon gases is anticipated. The European strategy proposes revising the directive on energy taxation and reviewing the legislative framework for gas to include renewable gases. The share of natural gas in gaseous fuels must be reduced to 20%, with the remaining 80% being renewable by 2050. The interoperability of gas systems must therefore be improved;
- **the role of energy infrastructure:** the use of existing infrastructure is essential. Improved coordination and a holistic approach to development plans, particularly between electricity and gas, are key factors. These are the reasons behind the European Commission's desire to give greater priority in the development of new infrastructures to solutions that offer flexibility in handling demand. The conversion of the gas network infrastructure is identified as a cost-efficient solution, in particular to expand the hydrogen infrastructure, with blending (mixing hydrogen with methane in the network) viewed as a transitional phase. Infrastructures dedicated to CO_2 will also be an integral part of the holistic conception of the energy systems of tomorrow;
- **digitisation of the energy system:** cybersecurity and digital services are a key aspect of the energy transition and will be central to the sectoral integration framework.

The energy transition in France: main legislative and regulatory texts relating to gas transmission

The Energy Transition for Green Growth Act

The French Energy Transition for Green Growth Act (LTECV) was published in the Official Journal of 18 August 2015, with supporting action plans. Their aim is to enable France to contribute more effectively to the fight against climate change and protecting the environment, as well as to bolster its energy independence while offering its companies and citizens access to energy at competitive prices.

The Act seeks to provide a framework for joint action by citizens, companies, regions and the State, by setting the following medium- and long-term goals:

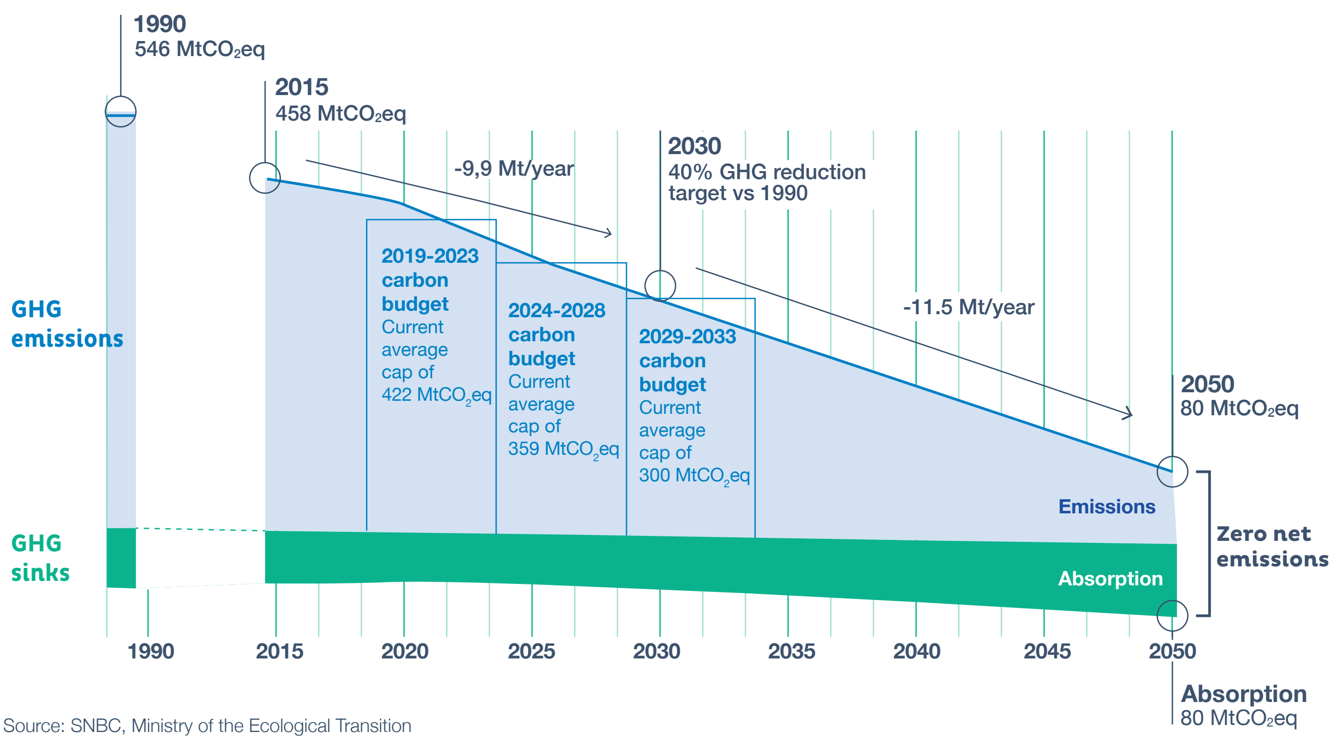
- reduce GHG emissions by 40% between 1990 and 2030 and by a factor of four between 1990 and 2050. The pathway is detailed in the carbon budgets;
- reduce final energy consumption by 50% in 2050 compared to 2012 via the intermediate target of 20% in 2030;
- reduce the primary energy consumption of fossil fuels by 30% in 2030 compared to the 2012 by adjusting this target by fossil energy type, based on the GHG emission factor of each;
- increase the share of renewable energies to 23% of gross final energy consumption in 2020, rising to 32% in 2030 (10% of gas consumption in 2030);
- increase the share of nuclear energy in electricity production to 50% by 2025;
- achieve an energy performance level compliant with "low consumption building" standards for the entire housing stock by 2050;
- give everyone the right of access to energy for household resources at reasonable prices;
- reduce the quantity of landfill waste by 50% by 2025 and gradually dissociate economic growth from the consumption of raw materials.

This law provides for the development of both an SNBC and a PPE.

National Low-Carbon Strategy (SNBC)

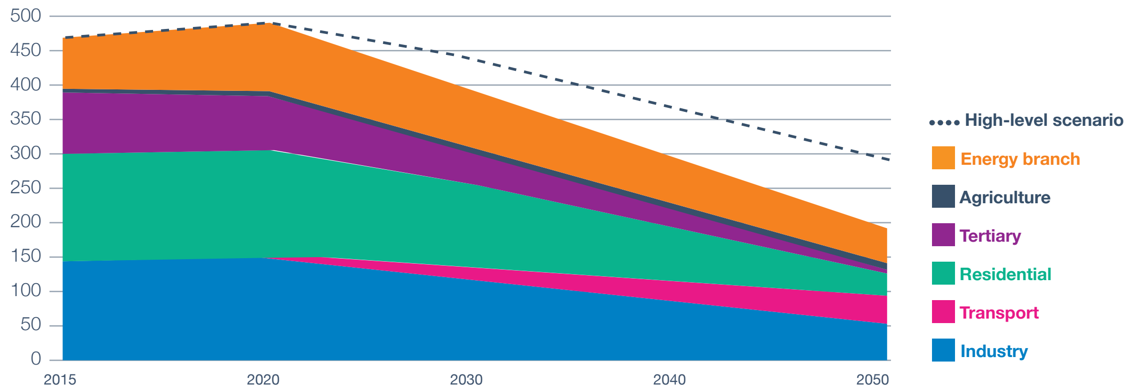
Introduced by the Energy Transition for Green Growth Act (LTECV), France's SNBC was first adopted in 2015 and revised in 2018-2019. The latest version, adopted by Decree on 21 April 2020, is the country's roadmap to fight climate change. It provides guidelines for implementing the transition to a low-carbon, circular and sustainable economy in all business sectors. Likewise, it sets out a path for reducing greenhouse gas emissions up to 2050, including short- to medium-term objectives (carbon budgets). **The LTECV has two main aims: to achieve**

FIGURE 2 | **Changes in GHG emissions and sinks in France between 1990 and 2050 (in $MtCO_2eq$)**



Source: SNBC, Ministry of the Ecological Transition

FIGURE 3 | **Domestic gas consumption including hydrogen (TWh. HHV)**



Source: SNBC

carbon neutrality by 2050 (2018-2019 revision) and to reduce the carbon footprint of French consumption.

The SNBC is centred on a baseline scenario developed during a modelling exercise used also for the PPE. This baseline scenario highlights the need for supplementary public policy measures to those currently in place, which would enable France to meet its short-, medium- and long-term climate and energy objectives.

By 2050, France would thus reach an "absolute minimum" level of emissions, particularly in non-energy sectors (around 80 MtCO_2eq.), which will be offset by carbon sinks.

The SNBC sets French greenhouse gas emission reduction targets (carbon budgets) for the next 15 years based on this target trajectory. These are broken down by business sector and by GHG levels.

The SNBC sets out public policy guidelines concerning:
- governance of the national and regional implementation of the strategy;
- transversal topics such as the economy, research, education and employment;
- each business sector: transport, buildings, agriculture, forest-wood, industry, energy production, waste.

Gas will thus play a key role in achieving these objectives in the majority of these sectors via its infrastructure and greening measures.

Multi-Year Energy Programme (PPE)

The continental metropolitan PPE sets out the public authorities' guidelines and priorities for managing all forms of energy in Mainland France to achieve the energy policy objectives set out in Articles L100-1, L100-2 and L100-4 of the French Energy Code.

It is governed by the provisions of Articles L141-1 to L141-6 of the French Energy Code, amended by the LTECV of 17 August 2015. The PPE must be compatible with the aforementioned SNBC. More broadly, in its objectives and operational actions, the PPE must draw up guidelines and identify means to meet carbon budgets and take into account the guidelines in the SNBC.

The PPE includes the following components:
- **security of supply.** This section defines the energy system's safety criteria, in particular the criterion of electrical system failure;
- **improving energy efficiency and reducing primary energy consumption,** particularly fossil fuels;
- **developing the use of renewable and recovered energies.** The PPE sets out the renewable energy development objectives for the various sectors, for which the Minister for Energy may launch calls for tender;
- **balanced development of networks, storage, energy transformation and energy demand management to promote local energy production,** smart grid development and self-generation;

- **the clean mobility development strategy;**
- **preserving consumer purchasing power and keeping energy prices competitive,** particularly for companies exposed to international competition. This section sets out policies to reduce energy costs;
- **assessing the needs for professional skills** in the energy field and tailoring training courses to these needs.

Published in April 2020, the new version of the PPE sets new objectives for the periods 2019-2023 and 2024-2028, including:

- a 7.6% decrease in final energy consumption in 2023 compared to 2012, rising to 16.5% in 2028;
- a 20% decrease in primary fossil fuel consumption in 2023 compared to 2012, rising to 25% in 2028;
- a 14% reduction in GHG emissions from energy combustion in 2023 compared with 2016, rising to 30% in 2028;
- biogas production of 24 and 32 TWh in 2028 based on the assumption of falling costs (between 4-6 times 2017 production);

The 2023 targets may result, among others, in 10,000 coal-powered heaters and 1 million fuel-oil boilers being replaced by means of renewable heat generation, heat pumps, or very high energy performance gas boilers. Also on the cards are 20,000 gas-powered trucks in circulation, the shutdown of coal-fired power generation, and the shutdown of two nuclear reactors (Fessenheim).

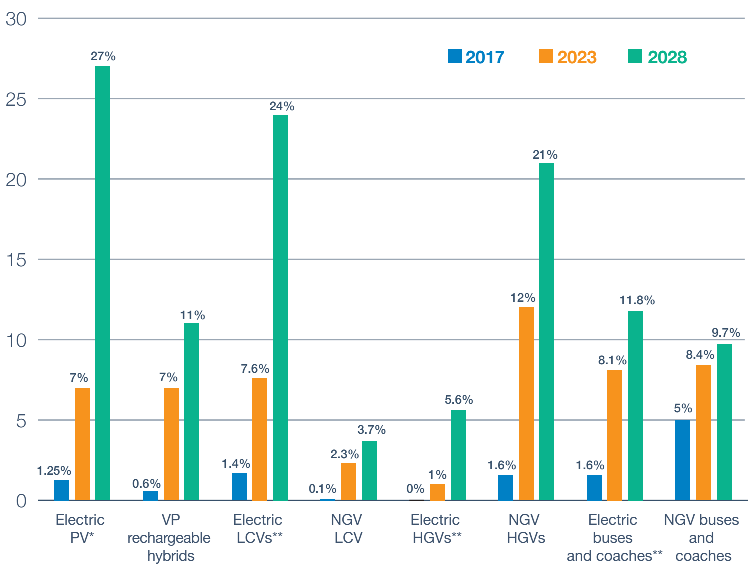
In terms of gas specifically, energy demand control measures are expected to take gas consumption to 470 TWh by 2023 and 420 TWh in 2028 (compared to 470 TWh in 2018). Natural gas is still a fossil energy. As such, it will eventually have to be replaced by biogas or new synthetic gases produced with decarbonised energies (hydrogen or Power-to-Gas). The PPE's objectives are based on the assumption that Biogas will reach 7% of gas consumption by 2030, if the target cost reductions in the baseline trajectory are achieved, and up to 10% if they are exceeded.

2016	2023	2028
5.4 TWh HHV of which 0.4 TWh injected	14 TWh HHV of which 6 TWh injected	24-32 TWh HHV of which 14-22 TWh injected

Natural Gas for Vehicles (NGV) is seen as an alternative solution to fossil fuels that reduces the emission of air pollutants. It can become a completely decarbonised fuel in the form of BioNGV. This new use is expanding for heavy vehicles and is expected to grow further.

The PPE sets out prospective market shares for heavy goods vehicles, buses/coaches and light commercial vehicles (LCVs) of 21%, 9.7% and 3.7%, respectively, i.e. NGV fleets of 54,000, 7,500 and 110,000 vehicles.

FIGURE 4 | **Changes in market share for new vehicle registrations**



Source: PPE

This increase will also require the coordinated rollout of a network of refuelling stations. At the end of 2020, France had 136 public refuelling stations open to heavy goods vehicles. The PPE has set a target of 140-360 stations in 2023 and 330-840 in 2028. The lower range for 2028 is distributed as follows: 83 CNG stations and 41 LNG stations on the motorway network, and 202 CNG stations in urban areas.

French Energy-Climate Law

The French Energy and Climate Law of 8 November 2019 aims to respond to the ecological and climate emergency. It enshrines this emergency into both the French Energy Code and the goal of carbon neutrality by 2050 by reducing GHG emissions by a factor of at least six by this date.

The legislation sets out the framework, ambitions and target of the national climate policy. It covers four main strategic areas.

The law's objectives and measures include:

- a 40% reduction in fossil fuel consumption by 2030 compared to 2012 (versus 30% previously), with an end to using the most GHG-emitting fossil fuels as a priority;
- the end of coal-based electricity production by 2022 (shutdown of the last four coal plants, support for electricity workers and their subcontractors);
- support for the hydrogen sector.

In 2018, the benefits of renewable hydrogen as a contributor to the energy transition were already highlighted by the French public authorities with the launch of a hydrogen development plan - the so-called “Hulot Plan”. The Energy-Climate Law consolidates the 2018 guidelines by providing for 20-40% of French hydrogen consumption being of low-carbon or renewable origin by 2030. On 17 February 2021, the Government published an Order to implement two systems for the traceability of renewable and low-carbon hydrogen, combined with a mechanism to support the production of renewable or low-carbon hydrogen from water electrolysis.

The Energy-Climate Law also amends Article L111-97 of the French Energy Code by giving low-carbon hydrogen producers a right of access to natural gas facilities, as was already the case for biogas producers, provided that the proper functioning and safety levels of natural gas infrastructures are maintained. Many regional projects for the production of renewable or low-carbon hydrogen are likewise emerging, some of which are planning to inject all or part of their production into the natural gas networks, with GRTgaz called on to research their potential connection to the transmission network.

The second part of the law relates to thermal sieves[8], with the aim of renovating them all within ten years.

Lastly, the law provides for a reduced dependence on nuclear power, with the shutdown of the Fessenheim power plant's two reactors in the summer of 2020.

Recovery plans

The European recovery plan

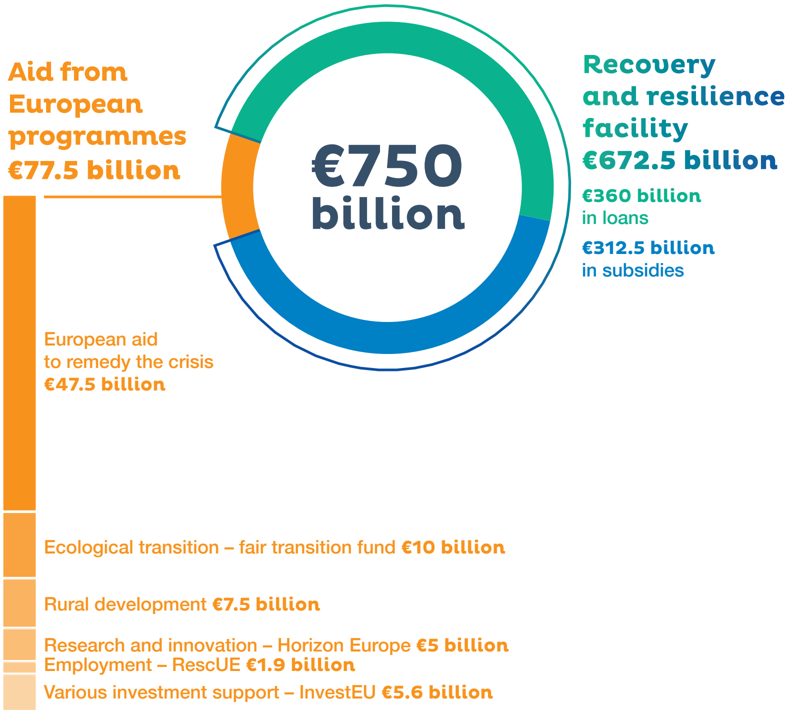
The European Commission has implemented a €750 billion recovery plan called "Next Generation EU" to help repair the economic and social damage caused by the Covid-19 pandemic, and to protect and create jobs. This plan provides for new support mechanisms, while relying mainly on existing funds. The major challenge it faces is its compatibility with the principles and projects of the Green Deal in making climate and environmental issues a key growth driver for the European recovery.

At least 25% of expenditure on climate action is linked to climate goals. The Commission is providing recovery support to Member States in the form of "green conditionality". This is based, first, on the principle of "do no harm" to the environment; and, second, on compatibility between national reform plans, national energy-climate plans, and fair transition plans.

The French recovery plan

For the same reasons, the French government has proposed a recovery plan for the rapid, sustainable restoration of the French economy. The €100 billion plan is based around three components:
- ecology (€30 billion);
- competitiveness and innovation (€35 billion);
- social and regional cohesion (€35 billion).

FIGURE 5 | **European recovery plan financial breakdown**



Source: European Commission

More specifically, the ecological component has the goal of decarbonising the economy via the energy retrofitting of buildings, transport, the agricultural transition and energy. In particular, the government wants to invest in clean sectors and technologies, and to support companies in their quest for solutions that cause less pollution. Hydrogen development has hence been given a specific national strategy.

French hydrogen strategy under the French recovery plan

The 2020 health crisis triggered a plan to revive the economy, and the French hydrogen strategy has an important position in the post-covid world. The strategy was first presented on 8 September 2020. It was jointly conceived by the Ministries of the Ecological Transition, the Economy, Finance and Recovery, Higher Education,

8 | Thermal sieves are homes whose energy consumption are in categories F and G. These are responsible for 20% of France's GHG emissions.

Research and Innovation, and by the General Secretariat for Investment. This is an ambitious €7.2 billion plan covering the next 10 years. It aims to address four key environmental, economic, energy and technological independence challenges by defining three priority strategic areas.

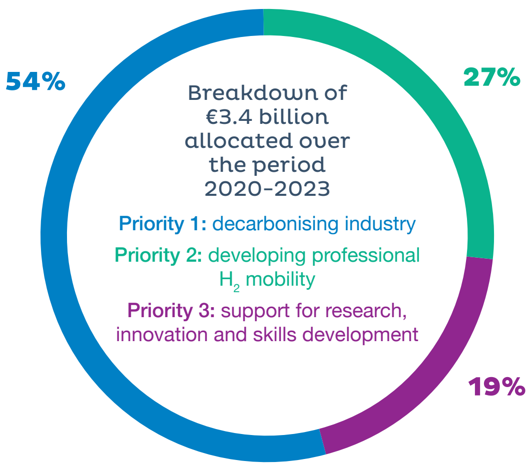
The first of these is decarbonising industry by developing a French electrolysis sector, with a target of 6.5 GW of electrolysers installed by 2030 (i.e. approximately 16% of the aforementioned 40 GW target mentioned in the European hydrogen strategy).

The second involves developing low-carbon hydrogen-intensive mobility for high-power, long-range vehicles, including captive fleets, commercial vehicles and heavy goods vehicles. Maritime mobility is also mentioned, albeit with no stated goal, while air travel seems to be viewed as a long-term bet.

The third strategic area is to support research and innovation, the challenge of which lies in new uses for hydrogen as well as transport infrastructures.

The French state is ready to release these significant resources swiftly, with €3.4 billion already planned for the period 2020-2023 through the Future Investments Programme (PIA – comprising the ecotechnologies fund and the *Société des Projets Industriels* fund), the French Environment and Energy Management Agency (ADEME investment fund) and French sovereign fund BPI (Deeptech fund). A National Steering Committee was set up under the chairmanship of the Minister of Economy, Finance and Recovery. The State has also called on manufacturers to carry out large-scale projects, and two calls for projects were launched on 14 October 2020 on the themes of “Regional hydrogen hubs” and “Technological building blocks and demonstrators”, with planned budgets of €275 million and €350 million, respectively.

FIGURE 6 | **Breakdown of allocations by priority area**



Source: French hydrogen strategy

1.2 | **Gas:** an energy capable of meeting some of these challenges

Natural gas can be a good replacement for other fossil fuels

Even though natural gas emits CO_2 during combustion, it does so less than other fossil energy sources such as fuel oil, petrol or coal. Its use as a substitute for other more carbon-intensive energies can already make a significant contribution to reducing the GHG emissions in our economy.

For this reason, French energy policy's goals of reducing the primary energy consumption of fossil fuels are adjusted for the GHG emission factor of each type of fossil energy.

Transports

In 2019, the French transport sector's energy mix reported 90% of petroleum products.

Transport has been the French sector with the highest GHG emissions since 1998, with 137 Mt CO_2 eq per year. In 2018, it accounted for 31% of French GHG emissions and 25% worldwide. While all other sectors have reduced their emission levels since 1993, GHGs linked to transport have increased by 5.6% (+0.2% per year on average). Road transport alone accounts for 94% of the sector's emissions in France.

TABLE 1 | **CO_2 emission factors for the main fossil fuels**

Lignite (low-energy coal)	4.2 t CO_2/tep
Diesel or crude oil	3.1 t CO_2/tep
Liquefied petroleum gas (LPG)	2.6 t CO_2/tep
Coal (coke, subbitumen or other bitumen)	4 t CO_2/tep
Petrol	2.9 t CO_2/tep
Natural gas (methane)	2.3 t CO_2/tep

Source: Key climate figures for France, Europe and the World, 2021 edition – MTE

FIGURE 7 | **Changes in the French transport sector's energy mix since 1982**

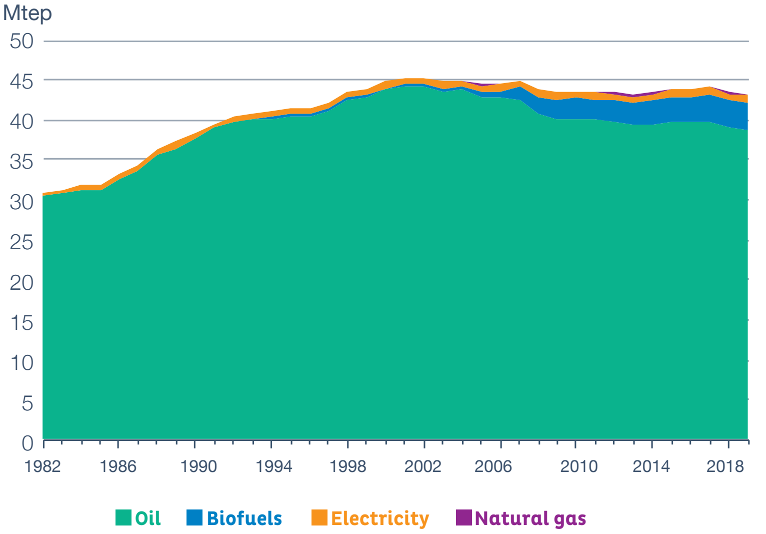
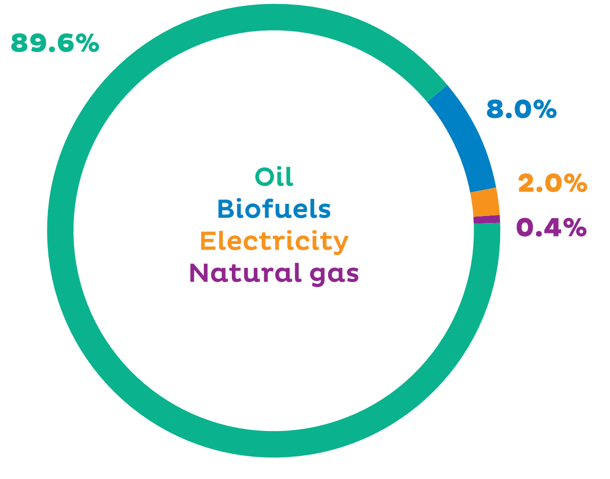


FIGURE 8 | **The French transport sector's energy mix since 2019**



Source: France's energy performance in 2019, Ministry for the Ecological Transition

The regulatory framework of the road transport sector is becoming increasingly restrictive with the so-called "Euro" and CAFE (Corporate Average Fuel Economy) standards. These relate in particular to vehicles' CO_2 emissions that depend mainly on the fuel used.

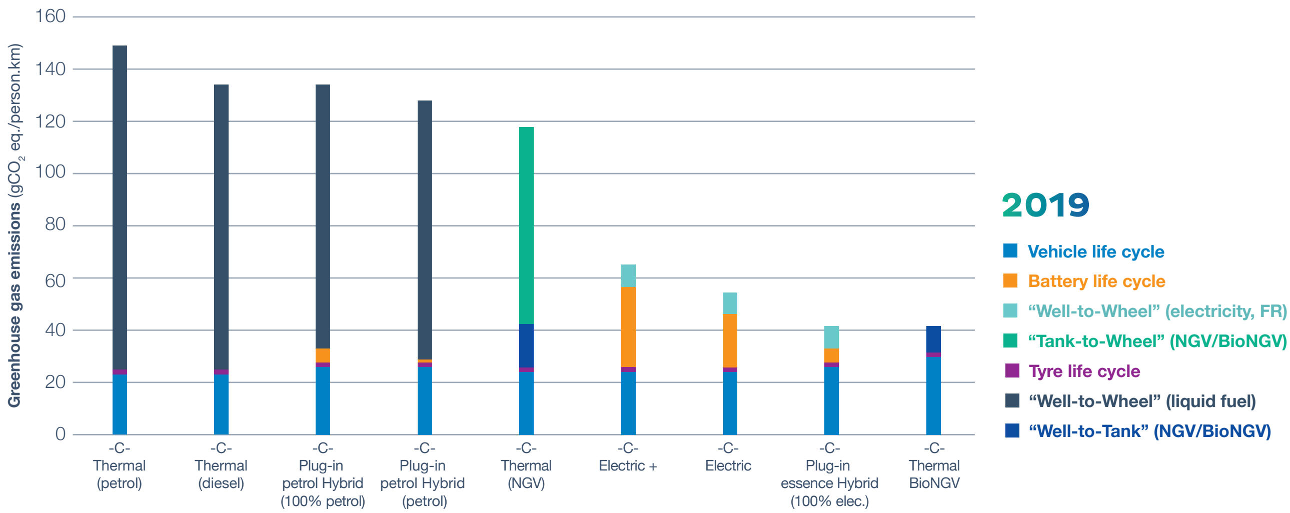
In the short term, natural gas is a useful alternative to petroleum products to decarbonise the mobility sector, in particular as fuel for heavy vehicles or professional fleets. Readily available, with well-understood technology, it has distribution infrastructures that are already present or easy to deploy. It also meets air pollutant emissions criteria for NOx, SOx and fine particles (PM9)[9]. In terms of the "decarbonisation" objective, using fossil-based gas reduces GHG emissions by between 5-15% compared to diesel and petrol engines, depending on the type of use and the vehicle in question.

Renewable gas (BioNGV) likewise shows considerable gains, with reductions of 80% compared to traditional fuels 10.

NGV and BioNGV vehicles are quick decarbonisation solutions for the transport sector.

It should be noted that some studies (such as the one conducted by the French Institute of Petroleum – IFPEN) consider that light vehicles running on renewable gas would have a lower carbon footprint than electric vehicles, taking into account emissions over the vehicles' entire life cycle (i.e. from well-to-wheel).

FIGURE 9 | **2019 climate change impacts for C-segment vehicles (medium-sized cars)**

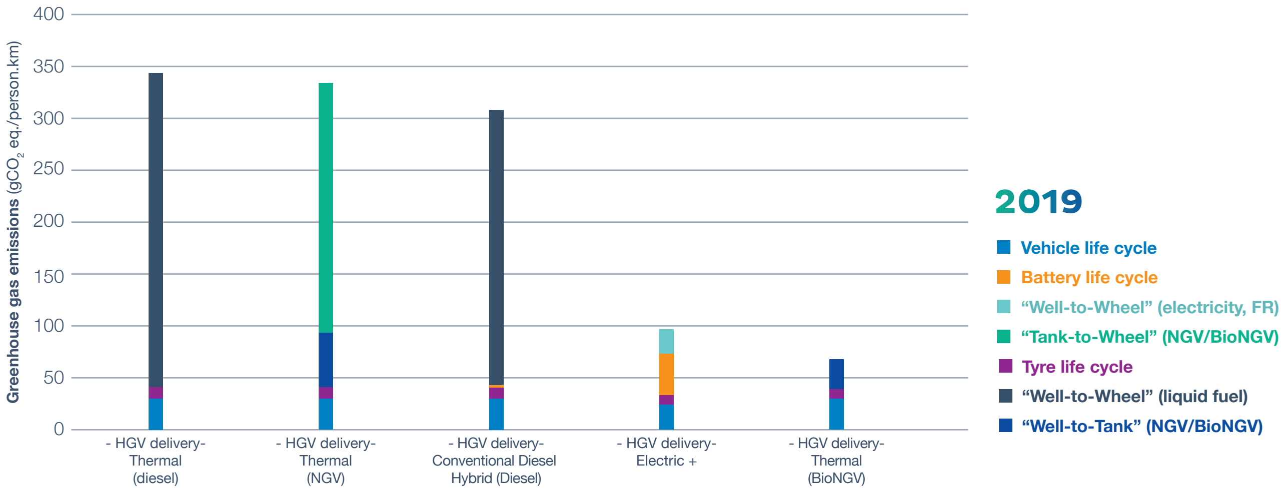


Source: Life cycle analysis (LCA) of NGV and BioNGV vehicles, IFPEN

9 | According to the French national health agency Santé Publique France, fine particles (PM2.5) are responsible for 48,000 deaths per year in France https://www.santepubliquefrance.fr/determinants-de-sante/pollution-et-sante/air/documents/rapport-synthese/impacts-de-l-exposition-chronique-aux-particules-fines-sur-la-mortalite-en-france-continentale-et-analyse-des-gains-en-sante-de-plusieurs-scenarios

10 | CRE Foresight Committee report on the impact of developing clean mobility on the energy mix.

FIGURE 10 | **2019 climate change impacts for 12-tonne HGV deliveries**



Source: Life cycle analysis (LCA) of NGV and BioNGV vehicles, IFPEN

In the long term, hydrogen-powered vehicles could be a driver for decarbonising the sector, in particular for heavy vehicles. This is provided that the hydrogen is of renewable or low-carbon origin, in the same way as BioNGV.

Regarding maritime transport, the International Maritime Organisation's (IMO) new rules set out in the MARPOL convention require a significant reduction in ship emissions, particularly with regard to fine particles, NOx and SOx. From 1 January 2020, the upper limit for sulphur content in the marine fuels of all merchant ships was reduced from 3.5% to 0.5%. In April 2018, the IMO also signed an agreement to reduce marine GHG emissions by at least 50% by 2050.

According to Gaztransport & Technigaz (GTT), LNG emissions compared to heavy fuel oil are reduced by 99% for SOx, 95% for fine particles, 80% for NOx and 25% for CO_2.

Maritime LNG is thus the preferred solution for new naval constructions, as it meets all the criteria set out in Appendix VI of the MARPOL Convention. LNG is also a proven technology. It has been used for a long time in the propulsion of ships transporting raw materials, goods and manufactured goods. The supply chain is open to improvement, but it is based on existing infrastructures and skills that are both easy to develop and energy efficient.

The decarbonisation of air transport leans towards biofuels in the short term, and in the much longer term towards hydrogen by 2050. McKinsey's latest report, published in May 2020, states that hydrogen would eliminate all in-flight CO_2 emissions. Generally, climate impacts would be reduced by 50-75% with H_2 combustion technology, and 75-90% with fuel cell technology. This should be compared with reductions in the climate impacts of synthetic fuels, which are estimated at between 30-60%.

As for rail, 50% of French tracks supporting 20% of rail traffic are not electrified. The use of gas (NGV, LNG) is being studied, in particular in its renewable form in regions with such as Hauts-de-France with large biomethane potential. In the longer term, hydrogen could also be used for rail transport.

Natural gas can therefore be a good replacement for the petroleum-based fuels currently used for most types of mobility, in particular road transport. An increase in gas-powered heavy goods vehicles has also been observed.

Biomethane can replace natural gas without changing the technology (no “lock-in” effect), leading to far greater improvements in CO_2 emissions.

In all transport sectors, the switch to hydrogen is viewed as a long-term decarbonisation solution as it meets the needs of high-powered engines and long-range transport, particularly for captive fleets travelling long distances with just-in-time flows.

Decarbonising industry (excluding electricity generation)

Over the long term, industry is the leading sector contributing to emissions reductions over the past three decades, with direct emissions linked to combustion falling by 36% since 1990. Energy consumption fell by 13% over the same period. The difference is linked to the significant decline in the most emitting energies (oil- and coal-based products down 59% and 47%, respectively) in favour of natural gas and electricity.

GRTgaz vehicles running on NGV.

Industry currently accounts for 19% of French energy consumption and 15% of the country's energy-related emissions.

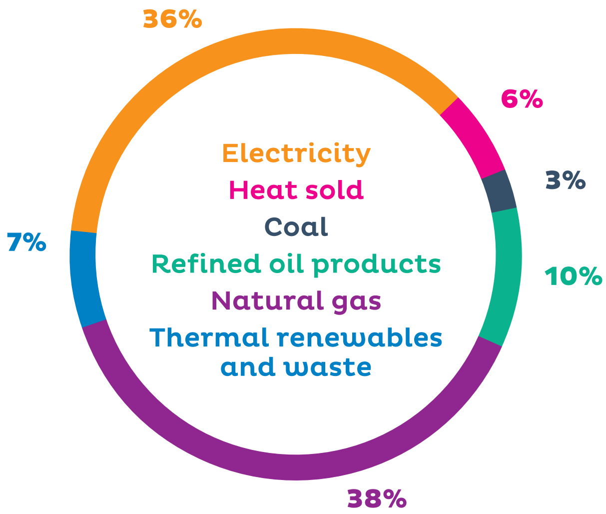
In 2019, refined oil products and coal still accounted for 13% of French industry's final energy consumption at 2.73 Mtep and 0.91 Mtep, respectively (see Figure 11).

For the same reasons as those mentioned for transport, natural gas can contribute to decarbonising industry by replacing other energy vectors with higher CO_2 emissions.

In the longer term, and without any changes to existing natural gas technology, biogas may take over to completely decarbonise the gas sector and its uses.

In addition, CCS/CCUS 11 can also be an avenue for decarbonising the sector by decarbonising industrial processes whose more polluting energy vectors are difficult to replace with other renewable or low-carbon vectors, and by capturing carbon emissions from biogenic sources for industrial companies that use biogas, making them carbon sinks.

FIGURE 11 | **Breakdown of final energy consumption by French industry in 2019 by energy type**



Source: France's energy performance in 2019, Ministry for the Ecological Transition

Supporting the removal of coal and fuel oil from the electrical system to reduce GHG emissions

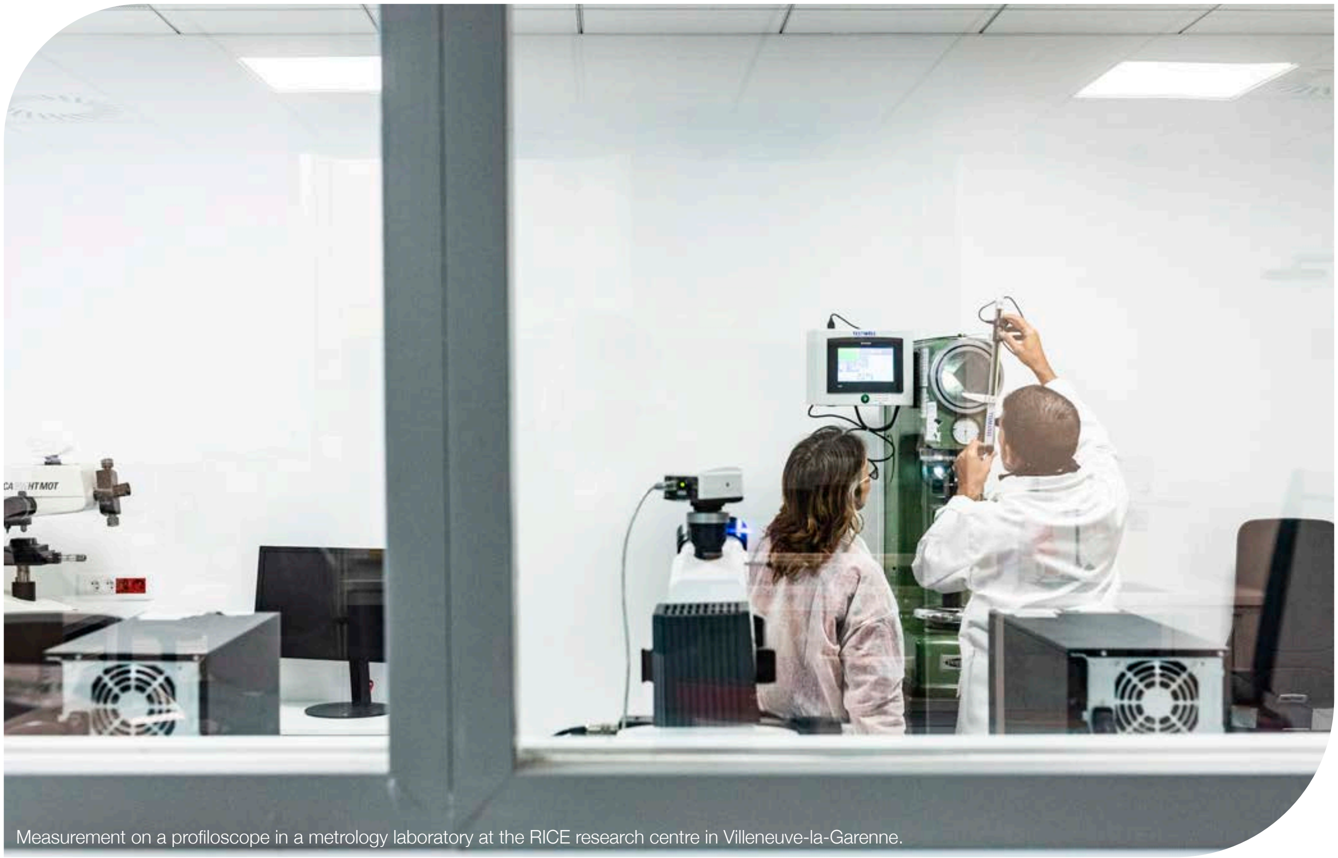
Following the closure of the last heavy fuel oil power plant on 31 March 2018, French the Energy-Climate Law adopted on 8 November 2019 provides for the end of electricity generation from coal by 2022. According to the Ministry of the Ecological and Solidarity Transition, this will cut nearly 10 million tonnes of CO_2 per year. Furthermore, the PPE states that it will no longer authorise new projects to produce electricity exclusively from fossil fuels.

The role of these coal-fired power plants on the electricity grid is similar to that of gas-fired power plants; i.e. flexible plants offering rapid modulation that enable the grid to meet the needs of daily and winter peak demand, among others.

France's remaining four coal-fired power plants have a total capacity of 3,000 MW. Gas-fired power plants will support the removal of coal from the French electricity mix by emitting 60% less GHG for the equivalent function. Over the coming decade, the French electricity network operator does not envisage any additional need for electricity generated from gas.

In the longer term, decarbonisation replacements for state-of-the-art power generation assets may involve the use of biomethane and the addition of CCS/CCUS for current CCPP and cogeneration units, or the development of new low-carbon hydrogen power plants.

11 | *Carbone capture and storage / Carbon capture, utilisation and storage.*



Measurement on a profiloscope in a metrology laboratory at the RICE research centre in Villeneuve-la-Garenne.

Emerging renewable and low-carbon gases that are potentially abundant and competitive

The energy transition involves significant increases in renewable energy production, the associated technologies of which are in many cases part of a decentralised approach. New local initiatives have emerged involving numerous sectors, in particular through the so-called "NOTRe" Law No. 2015-991 of 7 August 2015 on France's new regional organisation. In line with the European Green Deal, developing local circular economies has become a priority for the regions.

Several renewable gas technologies are currently identified (anaerobic digestion, gasification, Power-to-Gas). Not all of these have the same maturity, and they do not always involve the same types of inputs.

Being produced from biomass, these renewable gases have a very low CO_2 content from fossil fuels. Renewable gases from biomass are part of short carbon cycles, and the CO_2 emitted by combustion is offset by the CO_2 generated in producing biomass by photosynthesis.

The so-called "RED II" European Renewable Energy Directive and its incorporation into French law anticipated for the first half of 2021 likewise stresses the sustainability of biomass. The energy produced from it – and in particular green gas – will need to be counted in the Member States' renewable energy goals and to receive public subsidies. In addition to the ban on exploiting non-sustainable biomass, RED II requires compliance with GHG emissions thresholds recorded over the entire life cycle of each technology. These compliance targets will affect green gas facilities becoming operational as of 2021.

The sustainability of resources is therefore a key factor, making it imperative to recognise the primacy of food uses (in particular for biomass for use in anaerobic digestion) and materials (in particular for woody biomass) for energy use.

Anaerobic digestion

Anaerobic digestion is a biological system that uses micro-organisms to break down organic matter and produce biogas composed mainly of methane and carbon dioxide.

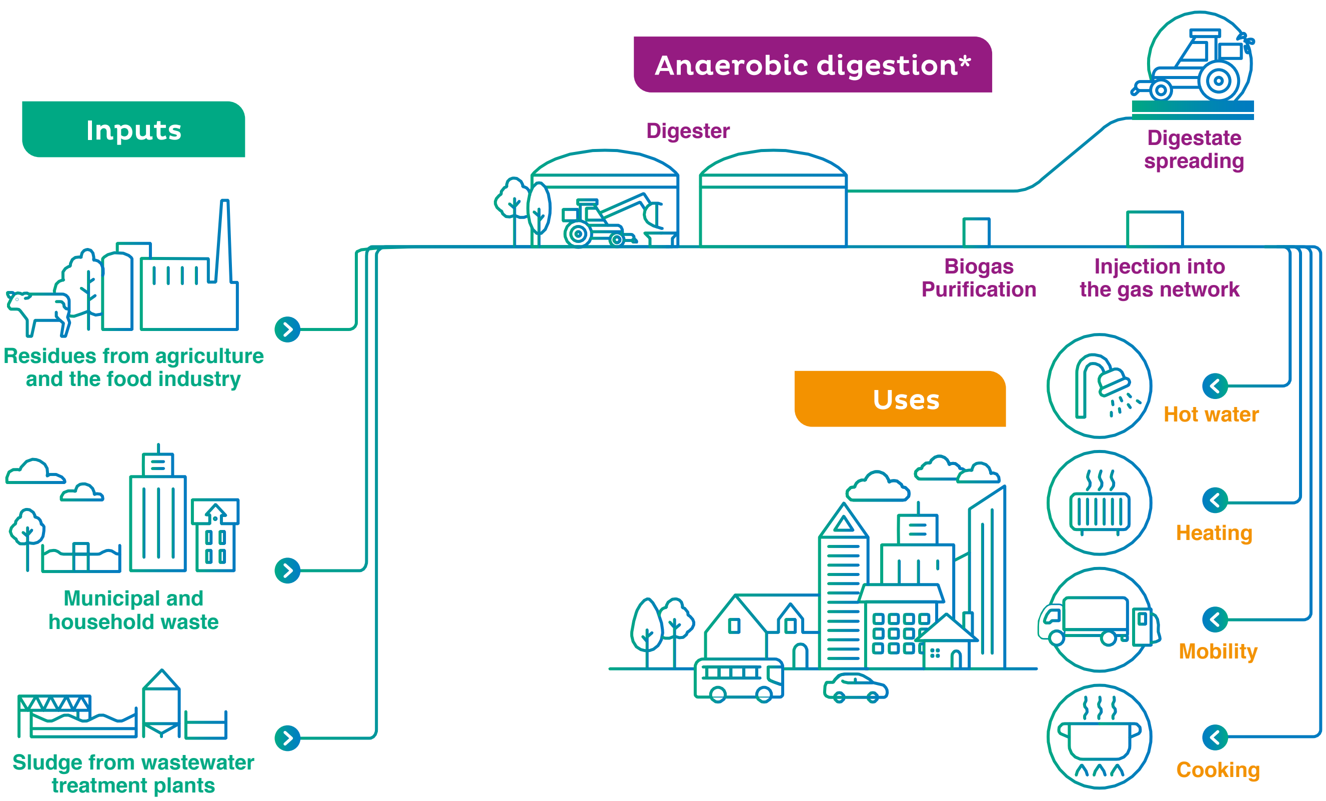
This biogas can either be used directly or purified, and the resulting biomethane can be injected into the gas networks.

Biomethane can be produced by transforming organic materials from various sectors (agriculture, agri-food, catering waste, municipal waste, gas from non-hazardous waste storage facilities (NHWSF), etc.). This sector is the most mature – almost all the renewable gases produced in France and in Europe come from anaerobic digestion.

Taking all potential resources together, ADEME estimated that it would be possible to produce 56 TWh of biomethane in 2030 and 131 TWh in 2050.

The CRE Foresight Committee's "Gas Greening" report produced in collaboration with the French National Institute for Agricultural Research (INRA) concluded that given available resources, the figure set by the Law on

FIGURE 12 | **From anaerobic digestion to injection into the networks: key steps**



* Breakdown of the fermentable part of the inputs used to produce biogas, in the absence of oxygen.

Source: GRDF

the Energy Transition for Green Growth – 10% of gas consumption in 2030, which could amount to between 39-42 TWh – is an achievable target. Likewise, that green gas production could continue to grow in the longer term, in particular with the rise in intermediate biofuel producing crops (CIVE).

This type of production has many benefits.

In addition to its low emissions, its GHG emissions factor is 90% less than that of natural gas. It also improves soil quality and produces a natural fertilizer to replace chemical fertilizers. Produced locally, it creates jobs and generates extra business for farmers. It offers a new way of recovering waste for industries and the regions.

TABLE 2 | **ADEME assessment of usable deposits (in TWh)**

	2030	2050
Livestock manure	22	27
Intermediate crops	6,5	51
Grass and fodder	0	13
Crop residues	23	31
Biowaste (agri-food industries and household)	5	8
TOTAL	56	131

Source: ADEME 2018 study: the 100% renewable gas mix in 2050

To date, the capacity register for anaerobic digestion projects awaiting connection is nearly 26 TWh for 1,164 projects. This already exceeds the target set by the PPE of 24 and 32 TWh by 2028, with between 14-22 TWh injected.

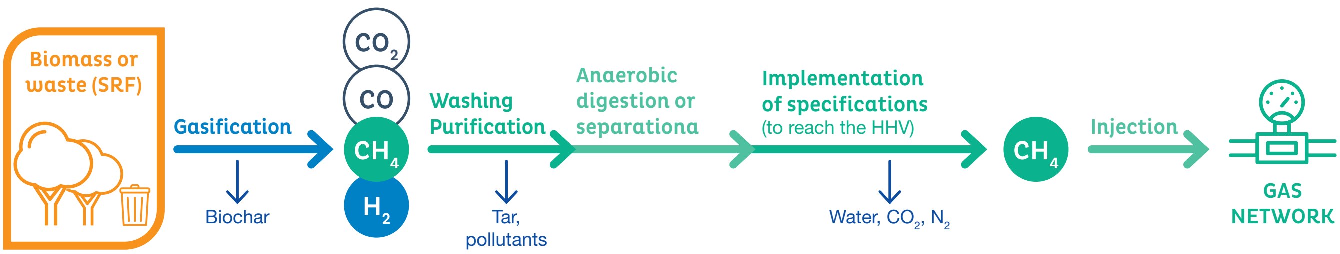
The cost of producing biomethane in France remains high at around €100/MWh compared with the notably low price of natural gas from fossil fuels (~€11/MWh at end-September 2020). However, the sector can be expected to become more competitive, and the PPE sets a target of €67/MWh in 2023 and €60/MWh in 2030.

It should also be recalled that producers can enjoy a regulated purchase price that is guaranteed over 15 years if they inject their biomethane into the networks.

Pyrogasification

Pyrogasification is based on dry biomass, i.e. a wide variety of resources that are difficult to recover including wood residues, non-hazardous demolition wood (doors, windows, old furniture, industrial panels, etc.) and solid recovered fuel (SRF).

FIGURE 13 | **The pyrogasification process**




Connection of the shelter for the commissioning of the MD Biogaz site.

It is based on pyrolysis and gasification processes that involve heating relatively dry carbon material at high temperatures (400-1,500°C) in the absence of oxygen. This material is then transformed into gas (syngas).

Pyrogasification allows for dry biomass to be included in the range of recoverable waste. It offers an alternative solution to burying or incinerating these materials, both of which are frequently expensive for local authorities.

Hydrothermal gasification

Hydrothermal gasification is a technology for converting wet biomass to treat residues and organic waste. It uses the water contained in biomass in its supercritical phase as the reaction environment to produce a synthetic gas that is rich in methane. The renewable gas produced is still under high pressure at the end of the process. It can hence be injected and stored in the gas network (in particular the transmission network to get maximum value from the residual pressure), or used in an NGV station or for any other use that consumes natural gas (cogeneration units, heating, electricity generation). In addition to the renewable gas produced, the process recovers mineral salts, nitrogen and water from the input, which can be used to produce fertilisers.

By isolating the various elements of the biomass, the process allows for the recycling and recovery of the material's separate chemical components (fertilisers, phosphorus, etc.). Unburdening the material of its residues facilitates its return to the soil and offers a solution for the treatment of agricultural waste. Hydrothermal gasification is an alternative to incineration, which is prohibited in certain areas and a source of CO_2 emissions.

Several input groups, such as organic liquid biomass with a dry matter level of less than or equal to 25%, are significant sources of production in metropolitan France. These include sewage sludge, livestock effluent and other residues from agricultural activity, residues and co-products from agri-food industries, industrial organic effluent and urban organic waste.

As well as a very high organic carbon conversion rate (> 90%), the technology is able to recover all mineral salts and nitrogen contained in the input biomass at high levels of purity (> 80%).

Looking forward, GRTgaz estimates potential methane production via this technology of at least 58 TWh[12].

Power-to-Gas

Power-to-Gas is a process for converting electricity into syngas. Electricity must be of renewable or low-carbon origin for the gas produced to be considered as renewable or low-carbon energy, respectively.

The first step consists of an electrolyser producing hydrogen. The second step involves converting hydrogen into methane using a methanation reaction, which requires a source of CO_2.

The ADEME study "A 100% renewable gas mix in 2050?" estimates the theoretical synthetic gas potential derived from Power-to-Gas at 140 TWh, as part of a 100% renewable electricity mix.

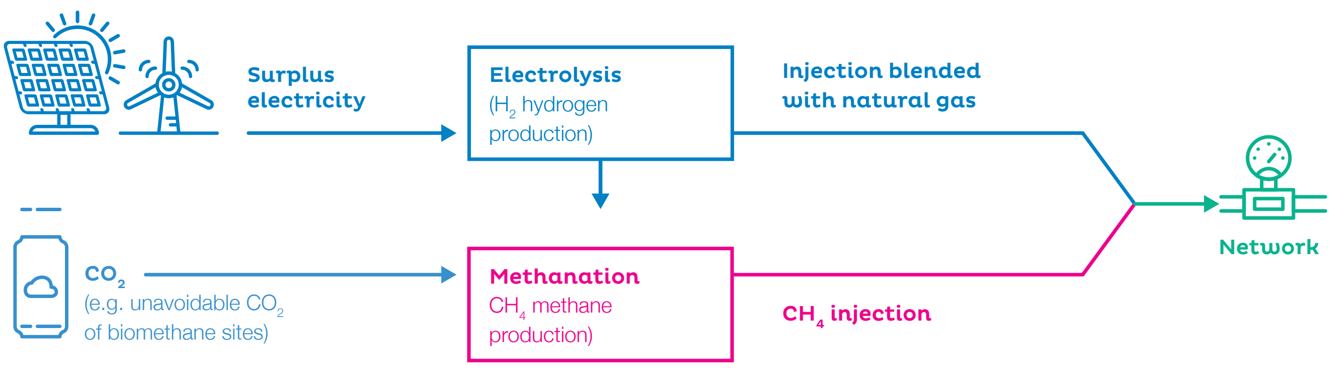
Other low-carbon technologies

Thoughts and ideas about decarbonising gas can also be extended to the question of the capture and geological storage of CO_2 (CCS), as the goal of carbon neutrality cannot be achieved by energy savings and renewable energies alone. The SNBC therefore plans to develop carbon sinks to offset emissions that cannot be reduced any further. CCS technology can contribute significantly to reducing CO_2 emissions, particularly in the industrial sector.

One of the difficulties observed in some industrial companies is the fact that the processes are closely linked to the energy vector/raw material used, making fossil fuel substitution a costly process that can be difficult to implement. Unless other chemical processes are found that produce the same results, emissions capture (CCS/CCUS) seems like a useful solution, particularly for the steel industry, refining, the cement industry or electricity generation from gas.

CCS technology is mature in terms of capture, transport and storage. Its cost remains high compared to the price of CO_2 quotas. European carbon tax targets may be a determining factor in the development of this technology, if investment in CCS becomes more economically attractive than purchasing CO_2 quotas.

FIGURE 14 | **Principles of Power-to-Gas**



12 | GRTgaz report: "Hydrothermal gasification potential in France", October 2019.

Capture costs vary greatly from one emitter to another, in particular due to the makeup of the emissions (concentration, composition, etc.). In its report on the geological capture and storage of CO_2, ADEME gives cost estimates for the different types of emitter. This same report also estimates the CO_2 transport and storage costs, leading to a cost estimate for the CCS chain (Tables 2 and 3).

Furthermore, CCS/CCUS combined with the gas greening used in the processes results in negative CO_2 emissions.

TABLE 3 | **Cost estimate for a CCS chain with offshore storage (in €/t CO_2)**

	Cost of capture (1)	Cost of preparing CO_2 for transport (LNG train)	Cost of onshore pipeline transport 300 km	Cost of offshore pipeline transport 200 km	Cost of offshore transport by boat 1,500 km	Cost of offshore storage	Total €/tCO_2
Hauts-de-France Offshore pipeline	55	9	-	4	-	9 (2)	77
Hauts-de-France Offshore boat	55	9	-	-	23 (3)	20	107
Normandy Offshore pipeline	85	9	6	4	-	9	113
Normandy Offshore boat	85	9	6	-	23	20	143

(1) Estimated for the most suitable technology based on the largest emitter in the area.
(2) Estimated based on a volume of 10 Mt2/year for storage in a depleted reservoir.
(3) Estimated based on a volume of 2.5 Mt2/year and not 10 Mt2/year, as for pipeline transport for North Sea storage in a saline aquifer.

TABLE 4 | **Estimated costs for a CCS chain with onshore storage (in €/t CO_2)**

	Cost of capture (1)	CO_2 preparation for transport (LNG train)	Onshore pipeline transport cost distance km(2)	Onshore storage cost	Total cost
New Aquitaine	51	9	6	3	69
Grand Est	51	9	6	12	78
Île-de-France	82	9	6	12	109
Hauts-de-France	55	9	3.5	5	72,5
Normandy	85	9	9.5	5	108.5

(1) Estimated using the most suitable technology based on the largest emitter in the area.
(2) The distance varies according to the area concerned (e.g. for Dunkirk, the transport distance is 500 km while the transport distance is < 200 km for Lacq).

Source: *Le captage et stockage géologique du CO_2 (CSC)*, ADEME, 2020

1.3 | Infrastructures central to these challenges

Production located far away from consumption

In France, gas is imported almost entirely by a few high-power facilities located at the country's borders in the case of pipelines, or in large ports for LNG terminals. For example, it can enter France at Taisnières (Franco-Belgian border) for an hourly energy power equivalent to approximately 12 nuclear reactor units [13].

Consumption areas are mainly located in Île-de-France, the north and east of the country, and in the river valleys.

The geographical location of renewable gas production potential depends greatly on the technology and type of input. For example, anaerobic digestion has significant potential in the west and north-east of France, while Power-to-Gas will likely be near to sunny or windy areas, particularly in the west or south-east.

With the exception of urban waste, which is produced near major urban centres, most renewable gas production will be located far away from high consumption areas.

The decentralisation of gas production resources should lead to a significant change in gas flows that are historically directed from the borders to the cities. However, it should still generate flows from where the gas is produced to where it is consumed.

Flexibility and modulation

Natural gas is widely used for heating buildings due to the fact it can be easily stored. This use requires significant seasonal modulation. A high degree of intra-day modulation is also necessary, as for electricity, both to meet residential and tertiary consumption demand and to generate electricity from gas.

France's gas storage facilities are highly developed. The country has nearly 130 TWh of storage capacity in underground cavities (aquifers or salt cavities), allowing it to meet seasonal modulation requirements. LNG tanks in the LNG terminals and the gas stored in large-diameter pipelines laid during the last decade (linepack) can meet wide daily variations in consumption.

The need for flexibility should remain high over the coming decade.

In the long term, the energy efficiency of buildings and boilers should reduce heating requirements and hence also the seasonal modulations in gas consumption.

On the other hand, the large-scale expansion in renewable electricity generation will lead to increased needs for controllable electricity generation, and thus potentially for gas-based electricity generation units.

Production from anaerobic digestion and gasification should be relatively stable over the year. While control over their production levels is minimal, this is not required to give the gas system any special flexibility.

However, the production of hydrogen or synthetic methane from electricity electrolysis in France could drastically increase the variability of gas injections on the network.

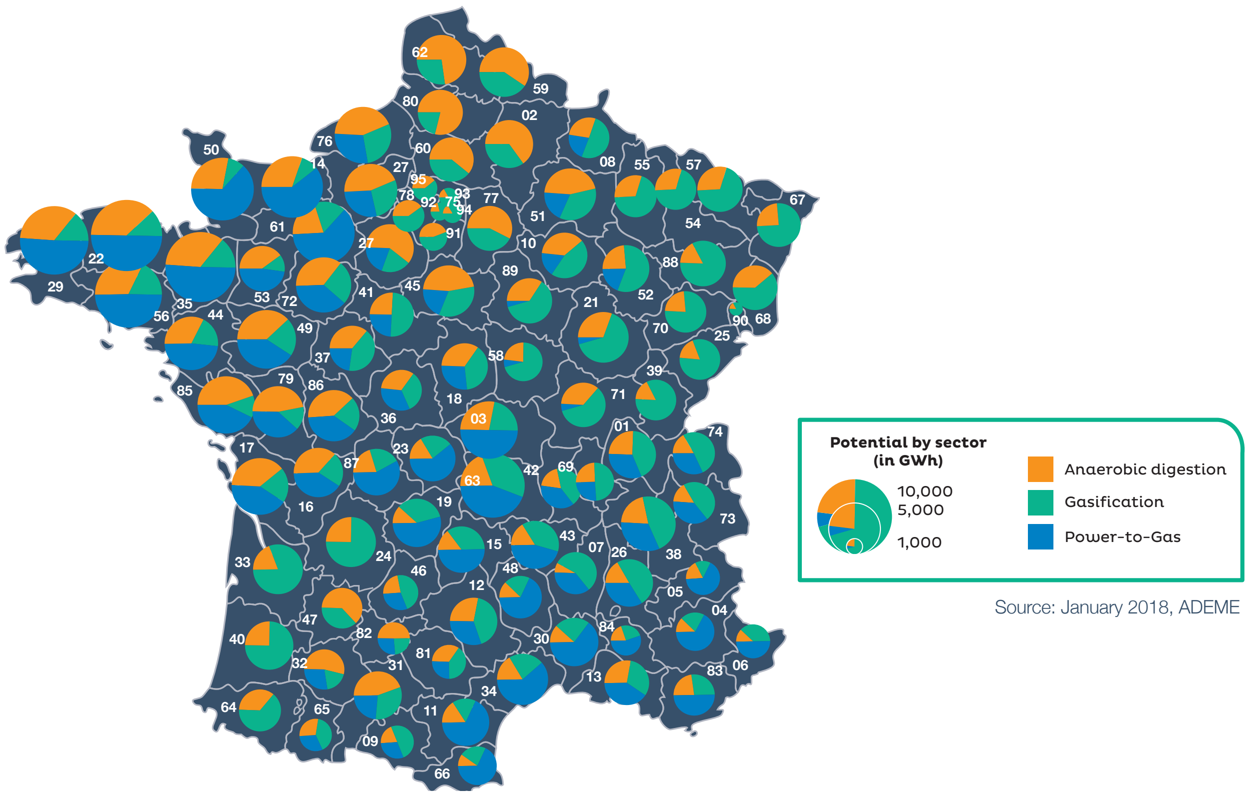
There will hence be an ongoing long-term need to use resilient storage to manage variations and modulation. Likewise, as is currently the case, the need to transport gas to these storage facilities will continue to be a key factor in the sizing of the network.

Coupling of gas/electrical systems

The demand for energy from different vectors results from a system driven mainly by controllable means of production. Power plants fuelled by natural gas are currently the main tools for coupling the gas, electricity and even heat networks.

13 | One nuclear reactor unit is equivalent to 1,000 MW.

FIGURE 15 | **Breakdown of injectable gas potential by French department and main sector in 2050**



Source: January 2018, ADEME

It should be noted that other couplings also exist. While much more limited, these are very important in operational terms (e.g. the electrical compressor stations needed to move gas within the transmission network).

Gas remains a means of support for the electricity system, particularly for controllable production. A recent RTE-ADEME study highlights a possible increase in peak consumption of around +2 to +6% by 2035. Gas-fired power plants or Gas-to-Power more generally will be able to meet this additional flexibility requirement.

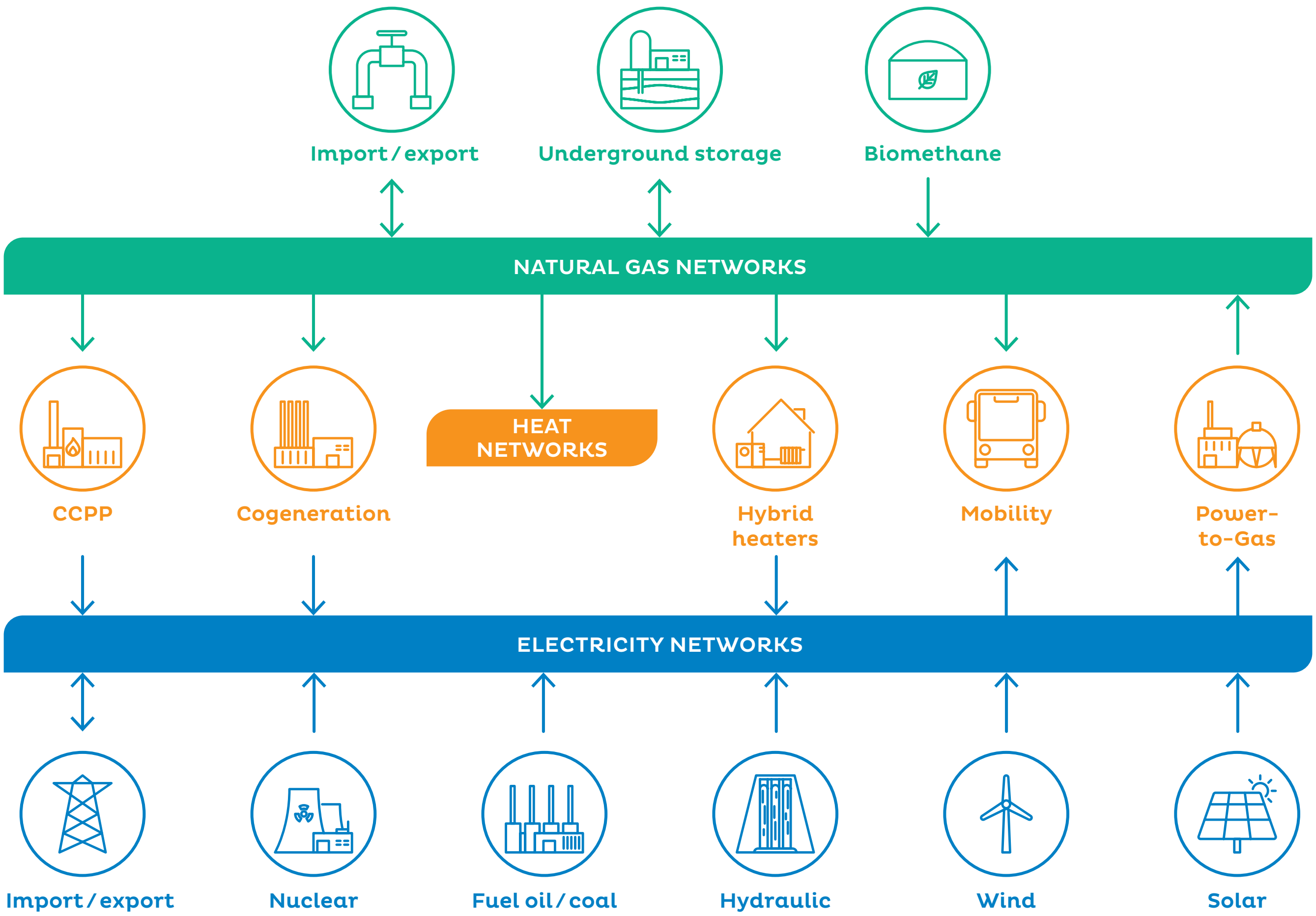
New industrial equipment means we can look forward to a much stronger coupling of the two energy vectors in the coming years. New electrolysers make it possible to produce a gas energy vector from electricity (Power-to-Gas) and hybrid heater systems, and in particular hybrid heat pumps (HHP).

Power-to-Gas is currently the only technology considered capable of storing and transferring large volumes (i.e. TWh of energy) over several weeks or months while making use of existing gas storage infrastructures, which can now store the equivalent of several months of consumption. If necessary, it can help optimise the way congestion is managed on the networks, thereby reducing costs by avoiding the need for strengthening.

Hybrid heat pumps consist of an electric heat pump fitted with a gas boiler for use during cold periods, when the heat pump has much lower yields. This option also lowers the demand for power on the electrical network, which is already high during these times of weather-related stress.

The energy transition towards a less carbon-intensive world involves getting the most from each region's renewable energy potential, and employing the most efficient energy vector for each use. However, the proper functioning of any energy system requires a balance of supply and demand at all times and at all geographical locations. Clear information about the operation and location of this new equipment is needed to more accurately identify any necessary network adaptations in the longer term.

FIGURE 16 | **Current and future interactions between networks**



Source: GRTgaz

Focus on the Smart Grid

Developing the circular economy leads to changes in the way the networks are used, either to maximise and circulate locally produced renewable gas, to couple energy networks, or to share data in real time with network users.

Ways to manage the balance between supply and demand, and thus manage the country's network, must be rethought in terms of decentralisation and the spread of energy production, hybrid uses that link the balances of the different energy systems, and the intermittency of non-programmable yields.

These conditions require an even smarter network. The "smartgrid" (or smart network) can be seen as the marrying of digital technology and energy infrastructure, and more generally as the convergence of the digital and energy transitions.

In 2016, GRTgaz launched a SmartGrid programme with four strategic pillars:

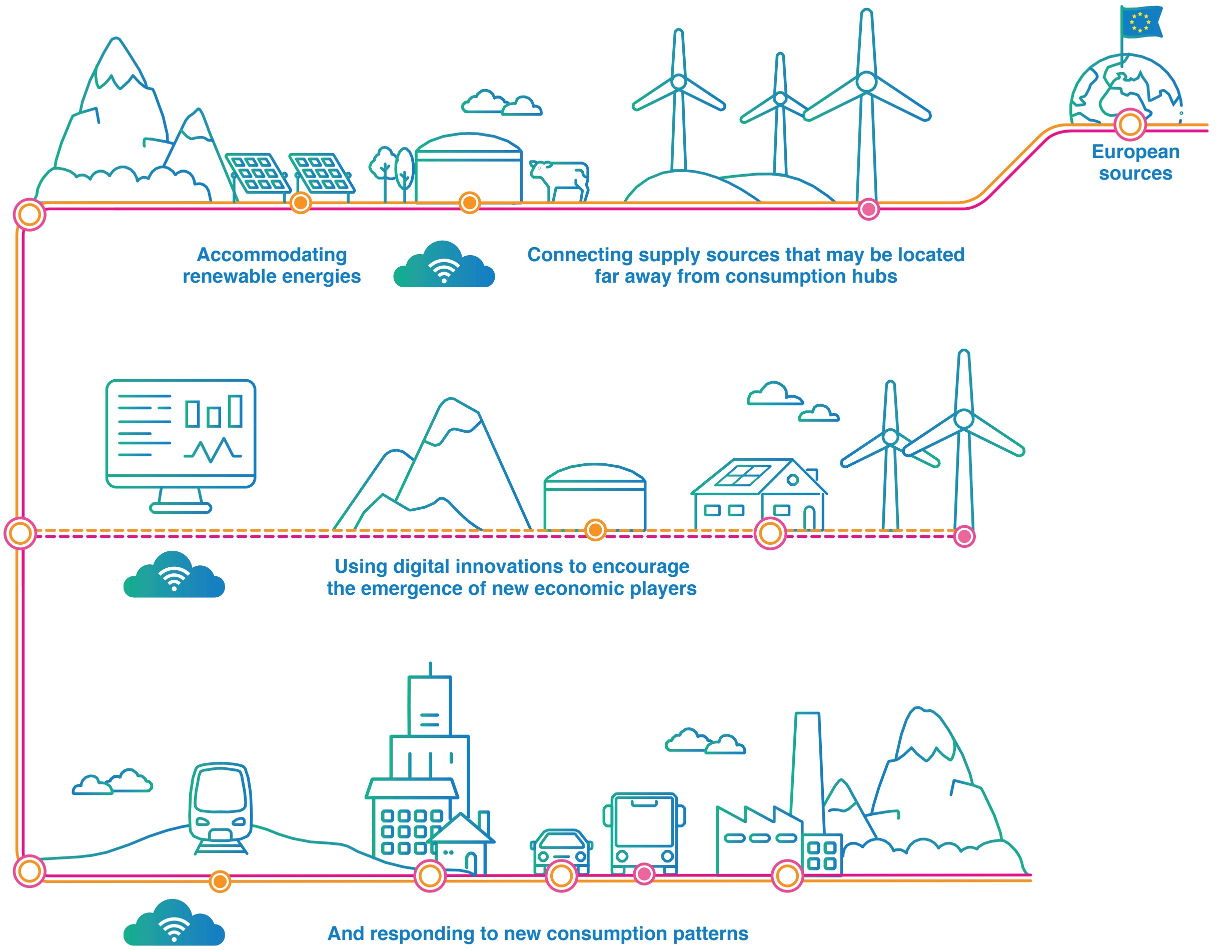
→ **maximising the integration of renewable energies in France at the lowest cost,**

→ **coupling the different networks,**

→ **improving the efficiency of the gas networks,**

→ **providing information that enables our stakeholders to be more efficient.**

These strategic pillars were presented to the CRE as part of a roadmap, and have been integrated into the GRTgaz business plan (GRTgaz 2020).



Nationwide optimisation, which requires solidarity between the regions and a deep, liquid market accessible to all

Gas transmission networks have been significantly strengthened over the past two decades to build a French market that is secure, liquid and competitive. All consumers enjoy constant access to all sources available in France, and suppliers can sell and exchange their gas anywhere in the country (virtual single trading area). This structure limits marketing risks and therefore any hedging costs. It also promotes security of supply, benefiting consumers.

Unlocking the energy potential of each region is a key challenge for the energy transition. Many local initiatives have emerged involving local authorities, local companies or even citizens. Both the regions and the local authorities benefit from these new drivers. They see their roles as enhanced by the energy transition, and in particular by the significant growth of local energy production from renewable sources. The regions use the French Regional Plan for Land Use and Sustainable Development (SRADDET) to find an optimum local or regional solution that favours short supply chains.

However, not all regions enjoy the same renewable gas potential. Some have access to large volumes of renewable gas that can be easily mobilised, while others, where supply is lower than demand, are probably in deficit.

Transmission networks play a key role here. They must ensure the quality of supply, guarantee the security of supply, regulate imbalances between production and consumption, and guarantee universal access to the market under equal conditions for all connected stakeholders. As production is decentralised, all French stakeholders must still enjoy access to a single marketplace.

Furthermore, as local energy production and consumption continues to expand, the national network's role as "guarantor" will grow in importance.

1.4 | Challenges for infrastructures

A capital-intensive structure with long maturities

Transport infrastructure for energy vectors such as gas, electricity or hydrogen have service lives (amortisation period of around 50 years) far longer than those of usual industrial assets, and require heavy investments.

In the past decade, investments in the gas transmission network have been substantial, resulting in an efficient industrial tool for many years to come.

These infrastructures also have increasing yields that result, on the one hand, in very low marginal construction capacity costs, and, on the other, in economies of scale that are conducive to natural monopolies.

To make use of these economies of scale, it is hence more cost-efficient to size the new infrastructures based on a medium-term projected need, provided it is sufficiently robust, and not on an immediate need. Infrastructure planning a long time in advance allows for needs to be anticipated as accurately as possible, and avoids additional capacity increase costs.

Necessary optimisation in times of financial austerity

Logistics are a significant part of the cost of delivering energy vectors to consumers. This fact will be exacerbated by the gradual disappearance of oil products and coal, which have relatively low transport costs compared to gas and electricity.

The post-covid-19 environment is both an opportunity for recovery but also a pivotal moment for the economic stability of our society. In these times, it is all the more important to optimise the energy infrastructure - and by taking a holistic rather than a silo approach.

Of course, the optimal integration is between natural gas infrastructures and those needed to develop biomethane. This has been identified and is the subject of a network adaptation optimisation process, the terms of which are subject to regulations and laws.

A second optimisation process will be necessary to minimise the development costs of hydrogen from biomass.

The vast majority of scenarios predict reduced gas consumption in France and Europe. This would free up capacity on the existing network, which could then be used for the transmission of pure hydrogen.

At the same time, current technologies allow for the conversion of natural gas pipes to hydrogen transmission pipes at a much lower cost than that of building new ones. Likewise, energy vectors can be converted through methanation and vapour reforming.

With these different types of gas, the network plays a specific role in optimising the gas system by offering a deep outlet market for hydrogen through injection.

Pressure gauge on a compressor station in Fontenay-Mauvision (78).


Aerial view of the reverse flow station in Pouzauges (85).

The gas sector as a whole therefore has all the tools needed to optimise these interchangeable gas vectors. Beyond natural gas, the hydrogen needs of French and trans-European consumers must be gathered and assessed before planning work can begin on the national hydrogen network.

Lastly, there is another, broader optimisation process between the electricity, gas and heat vectors. For maximum economic efficiency, the substitutability of these energy vectors in a specific time or place requires us to let go of our silo mentality and start thinking about infrastructural change holistically. In some cases, congestion on the electricity grid can be avoided at lower cost by using hydrogen, which could be transported in adapted gas pipes.

Coordination with other energy infrastructures thus seems vital in terms of geographical and temporal planning, particularly with the electrical system.

Decentralised injections in contrast to the current high-power import points

The growth in renewable gases through the "Right to Injection" changes the gas networks' operating conditions and balances. Operators are forced to rethink their systems. While the production or supply points of yesterday were high power and few in number, they are now multiple, low power, and spread throughout the country.

Distribution networks in particular are expected to join forces with the collection and transmission networks to supply other consumption hubs with non-local surplus production.

To do this, gas flows must be "reversed" from the distribution networks to the transmission networks. The interfaces between these two networks hence need to be adapted. This reversal of flows is made possible by specific technical facilities known as "reverse flow stations".

The network is structured to accommodate this national green gas production via a mapping and zoning process that identifies the potential for anaerobic digestion. This optimises the costs of developing infrastructures, and in particular reverse flow stations.

New gases with different specifications to be integrated at the lowest cost

Gas from anaerobic digestion has specifications that are very close to those of natural gas. Gases potentially derived from biomass or waste by gasification may, however, be composed of higher levels of hydrogen. Furthermore, hydrogen injection, which is more complex to implement, is seen as a transitional solution prior to a dedicated hydrogen network, particularly given the risk of market fragmentation it may generate. The European Commission therefore stresses the need to update gas quality standards at a European level.

The treatment and upgrading of these gases may require costly facilities. Working with the sector to define the most cost-effective solutions to integrate these new gases into the networks is a significant challenge. This may involve treating these new renewable gases prior to injection into the network, or adapting the network at a local level to make it compatible with more detailed specifications.

In 2019, in accordance with a request made in the Hydrogen Deployment Plan for the Energy Transition, gas infrastructure operators[14] submitted a report[15] to the Minister of the Ecological and Inclusive Transition on the technical and economic conditions for injecting hydrogen into natural gas networks.

This study, published in November 2019, shows that it is possible to integrate a significant volume of hydrogen into the gas infrastructure with limited adaptation costs. In the short term, a rate of 6% hydrogen by volume, as defined in GRTgaz's gas specifications, can be achieved in blended form in most networks without the need for sensitive structures or installations on the customer's premises.

To anticipate the adaptation of equipment, particularly downstream, gas infrastructure operators recommend setting a target capacity of 10% blended hydrogen in the networks by 2030, increasing later to 20%. These rates are achievable with limited infrastructure adaptations. A consultation with other European gas operators has been carried out on the subject.

Work for this report also indicates that the three possible network injection routes (blending, methanation, and 100% hydrogen transmission networks) will have areas of complementarity by 2050.

In any event, biomethane and methanation enable compliance with certain technical constraints to avoid disrupting gas use processes that would not support these mixtures. Separation techniques are likewise currently being studied to avoid exposing sensitive consumers to excessive levels of hydrogen.

Options for repurposed infrastructures for hydrogen

Most projected scenarios indicate that methane consumption will be lower by 2050. The suggestion is that its transmission capacity should be made available for other gas energy vectors, in particular hydrogen. It seems that the emergence of the hydrogen market will occur at the same time as the decline of the historic natural gas market. The reduction in gas market supply needs will therefore gradually free up pipes that can be adapted for the transmission of pure hydrogen. This gradual transfer of assets from a mature, developed network to a new hydrogen transmission network will be facilitated by the gas network's existing structure, which in many places has pipes installed in parallel for the supply of both methane and hydrogen.

While most current natural gas pipelines cannot transport pure hydrogen without some adaptation, initial European studies suggest that they could be repurposed at very much lower costs than those of installing a new hydrogen pipeline. On top of the economic benefit, this solution would also have the advantage of reducing the environmental impact linked to installing new linear infrastructures. Likewise, the time needed to make the structures available would definitely be reduced.

While some scenarios envisage very large volumes of hydrogen in Europe (more than 1,500 TWh) by 2050, and thus high levels of transnational flows, work should be carried out to identify the possible ways of repurposing gas pipes to transport hydrogen.

With this aim in mind, several European gas carriers have highlighted the ways a pan-European hydrogen transport infrastructure based partially on existing gas transmission pipes could take shape between 2030 and 2040. This "European Backbone" is detailed in a report[16] published in July 2020 by GRTgaz and ten other European gas carriers.

Uncertainties demanding caution

Beyond the next ten years, the envisaged timeframe for systems planning means that many uncertainties remain for energy market stakeholders.

The SNBC provides a long-term framework for analysing the necessary infrastructure adaptations. However, it does not define the factors underlying the sizing of the networks (power required, in particular for electricity generation; consumption and production locations; transit flows, etc.).

14 | Transmission, distribution and storage network operators.

15 | " Technical and economic conditions for injecting hydrogen into the natural gas networks ", Final Report, June 2019.

16 | https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/

In view of the strategy's ambitious assumptions and the gas infrastructure's central role in the security of energy supply, potential changes to the gas infrastructure over time must also be subject to sensitivity analyses.

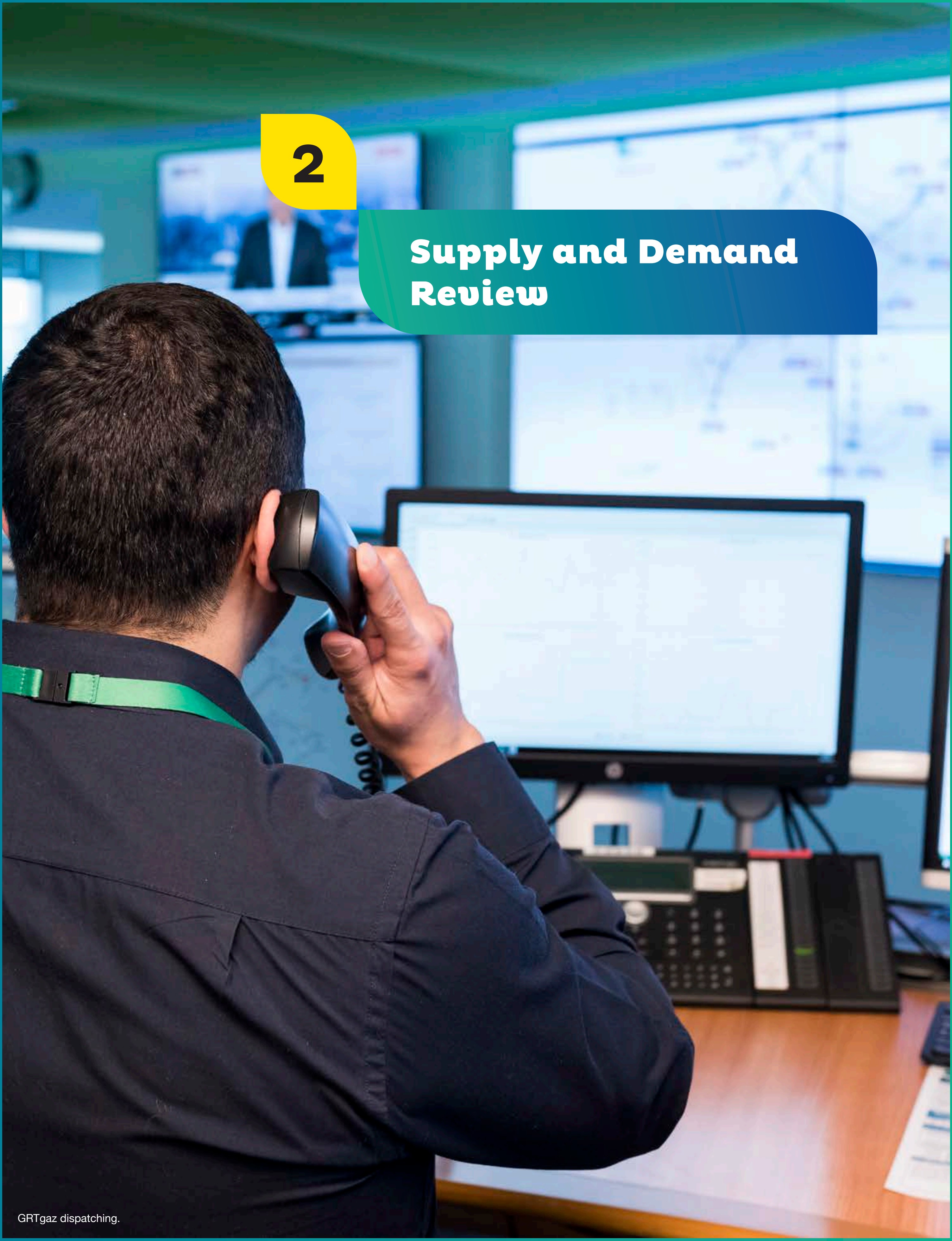
For example, the SNBC contains renewable gas scenarios for which there is energy self-sufficiency. No import of renewable or low-carbon gas is therefore envisaged in the future. Other European countries, however, envisage the import of significant volumes of renewable gas.

Finally, there are still many technical and economic uncertainties relating to technologies, in particular those concerning the production of renewable and low-carbon gas. At this stage, these uncertainties have often justified the fact of their omission from national-level scenarios.

Nevertheless, as decarbonisation issue is now a global issue, technological advances driven by countries betting more heavily on gaseous energies could materialise, leading to a major review of the changes to the French gas mix.

Finally, French gas infrastructures are largely integrated into European infrastructures. The French transmission network transports large quantities of gas each year to Italy and the Iberian peninsula. Changes in these flows are dependent both on changes in the energy mixes of our neighbouring countries and on import flows in Europe. Here as well, significant uncertainties remain.

And these should be considered when determining the best way to develop the gas infrastructure.



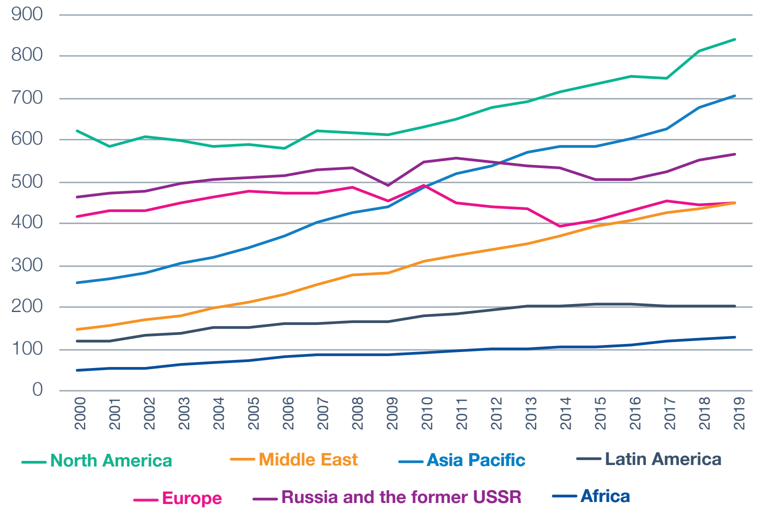
2

Supply and Demand Review

GRTgaz dispatching.

2.1 | Review of 2019

FIGURE 17 | **Primary consumption of natural gas worldwide by region (Mtep)**



Source: Enerdata – Analysis: GRTgaz

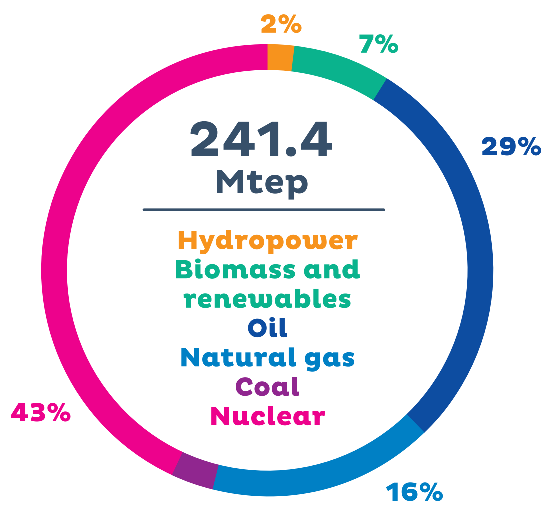
Gas demand on the rise in 2019

Natural gas increases within the global energy mix

Gas is the world's third-largest energy source and the second-largest in Europe, where it accounted for just over a quarter of primary energy consumption in 2019. The share of gas in the global energy mix is increasing, reaching 23.2% in 2019 compared to 22.7% in 2018 and 21.3% in 2010.

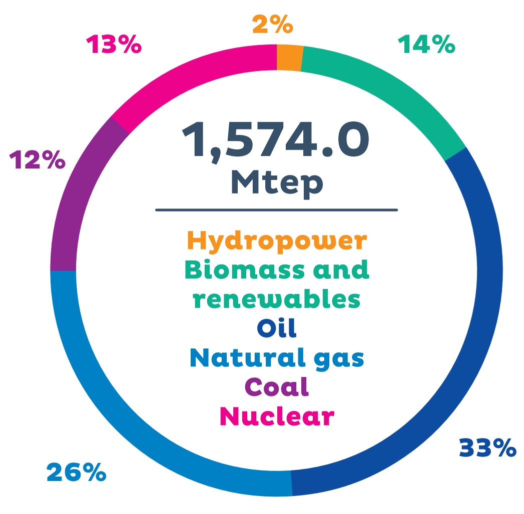
In 2019, primary gas consumption worldwide increased by 2.9% compared to 2018. This was more than three times the rate of increase in global demand for all energy, which was +0.9% over the same period. This increase in global gas consumption is driven in particular by the increase in consumption in the Asia-Pacific (+4.4%) and in North America (+3.4%).

FIGURE 18 | **Primary energy consumption in France in 2019**



Source: Enerdata – Analysis: GRTgaz

FIGURE 19 | **Energy consumption in Europe (EU-28) in 2019**



Source: Enerdata – Analysis: GRTgaz

While primary energy consumption in Europe in 2019 fell by 1.9% compared to 2018, primary gas consumption increased by 2.5%. France is following the same trend, with 2019 primary energy consumption down 2.5% and gross primary gas consumption up 1.8%. Gas accounts for 16% of primary energy consumption in France, and 26% in Europe.

Increasing demand for gas in France, in particular to meet electrical demand

Primary gas demand is the sum of final demand to meet the energy needs of buildings, industry and mobility, and demand for electricity generation and industry.

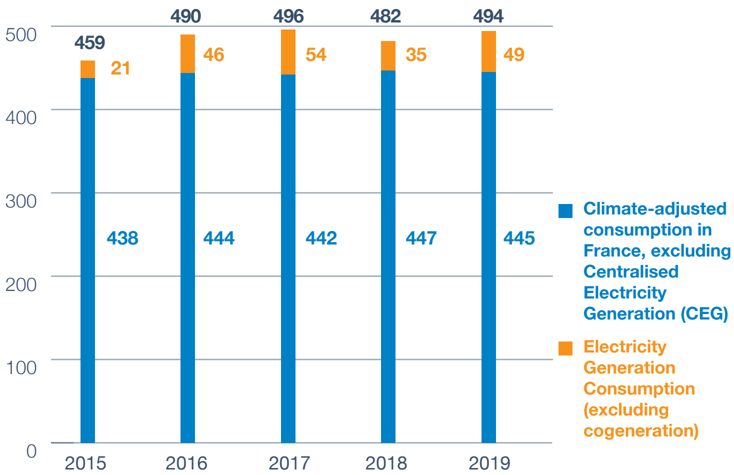
Gas consumption in France increased to 494 TWh in 2019 from 482 TWh in 2018. This change is linked to an increase in gas consumption for electricity generation. For other uses, consumption has remained almost constant in recent years, as illustrated by the change in climate-adjusted consumption.

Demand for gas for CEG, combined gas cycles and gas turbines relates to cyclical effects such as fluctuations in the availability of nuclear power plants and hydraulic power generation. Gas consumption for electricity generation has thus undergone significant fluctuations in recent years.

Breakdown of demand by sector

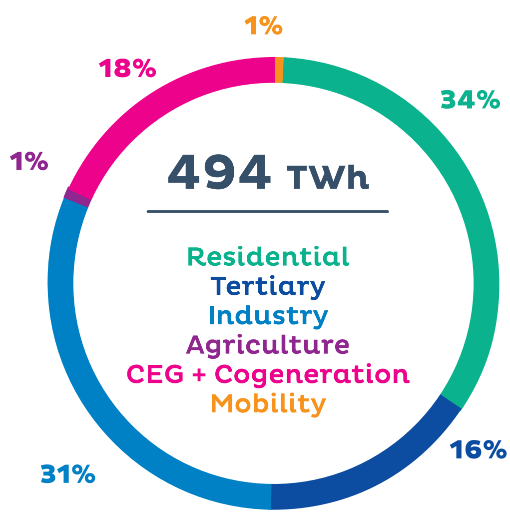
2019 gas consumption in France breaks down as follows:
- 50% for the residential and tertiary sector, for which heating is a key part of gas consumption. Gas consumption in the residential and tertiary sectors has stabilised at around 170 TWh and 78 TWh, respectively, since 2015;
- 31% for industry (excluding CEG and cogeneration), i.e. consumption of 159 TWh;
- 18% for electricity generation (and heat as part of cogeneration). Consumption in this sector fluctuates widely from one year to the next, and explains most of the variations observed in climate-adjusted consumption in recent years;
- 1% for mobility, which, while it currently only represents a minority share of French gas demand, is seeing significant growth.

FIGURE 20 | **Change in climate-adjusted gas consumption in France (TWh HHV)**



Source: 2020 Gas Outlook – Analysis: GRTgaz

FIGURE 21 | **Breakdown of gas consumption by sector in France in 2019**



Source: 2020 Gas Outlook

BIO GNV BIO GNL

BioNGV and BioLNG

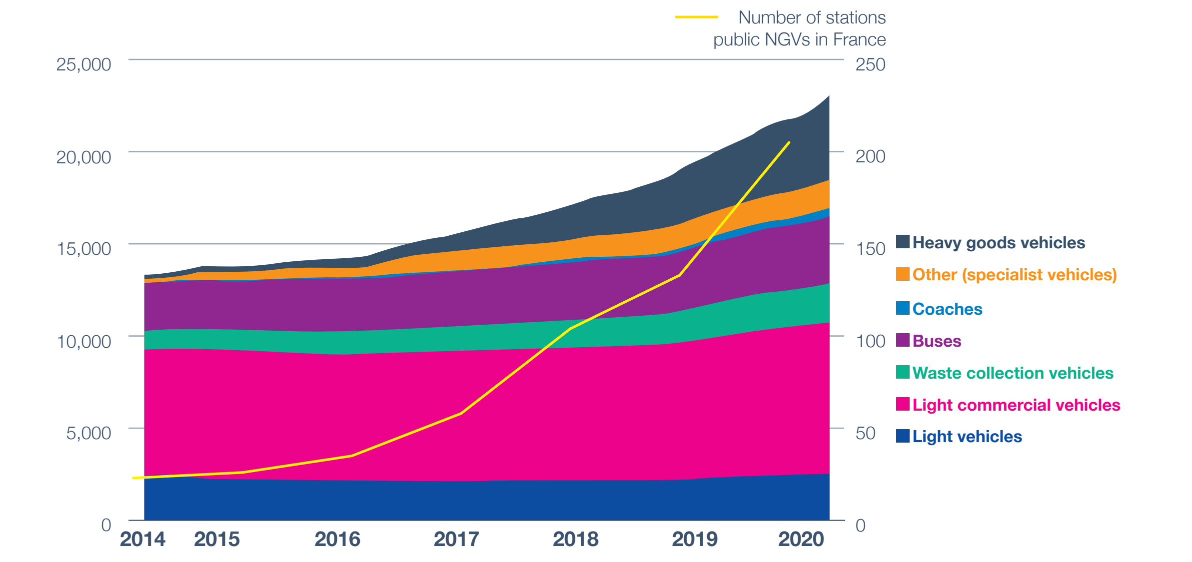
NGV and BioNGV can be used in two forms. The most common of these is the compressed form, which can be found in both heavy goods vehicles and passenger cars. The gas is compressed to between 200-250 bars in specially designed tanks.

For the time being, the liquid form (LNG, BioLNG) is reserved for heavy vehicles. It can store larger quantities of energy, allowing for post-filling ranges approaching those of the diesel versions. This offsets some of its more significant limitations, including the obligation to store it at -163°C.

These fuels should not be confused with LPG (liquefied petroleum gas), which is a gaseous fuel derived from petroleum consisting mainly of butane and propane.

Wissous NGV station.

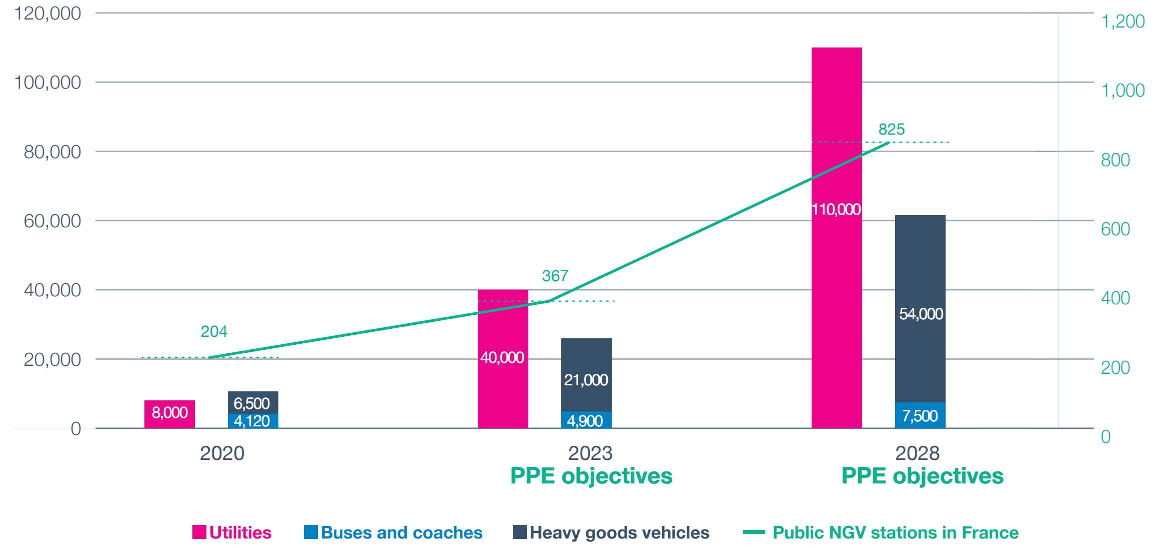
CHANGES TO THE FLEET OF NGV VEHICLES IN CIRCULATION IN FRANCE



Source: opendata AFGNV – GRTgaz, AFGNV, GNV/BioGNV mobility presentation to the CRE Foresight Committee[17], 11 September 2020

FLEET OF COMMERCIAL VEHICLES AND HEAVY VEHICLES USING NGV IN FRANCE

NUMBER OF PUBLIC NGV STATIONS IN FRANCE



Source: AFGNV, GNV/BioGNV mobility presentation to the CRE Foresight Committee[17], 11 September 2020

17 | https://www.afgnv.org/le-comite-prospectif-de-la-cre-sest-informe-sur-la-mobilite-gnv-biognv/

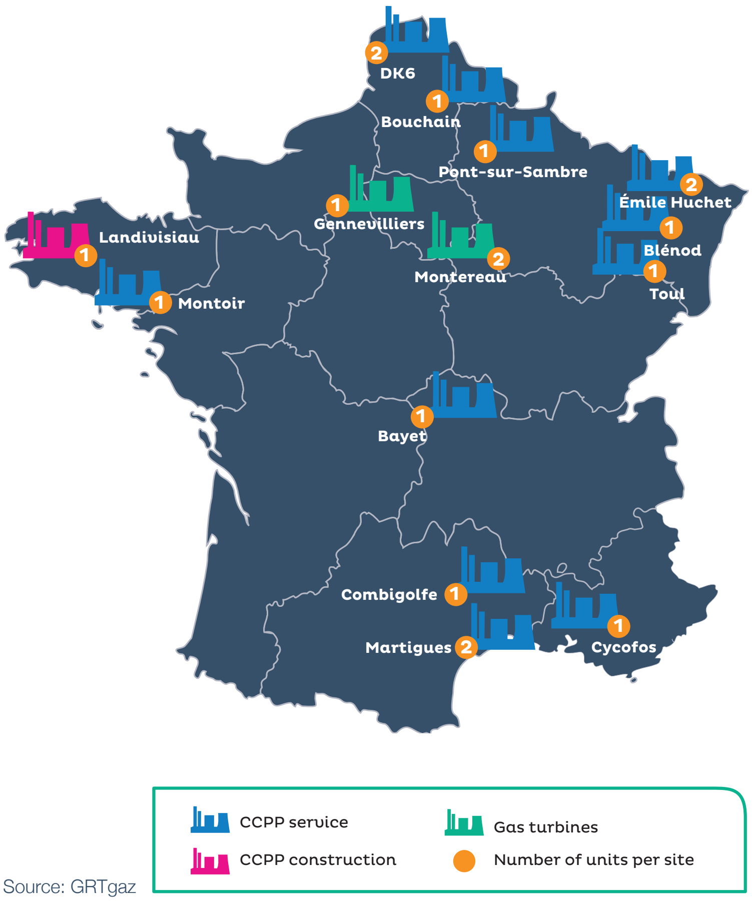
Electricity generation and cogeneration

Gas-based electricity generation is provided by a fleet of 14 gas combined cycle units (GCC) connected to the gas transmission network throughout France, three combustion turbines (CT), and by cogeneration facilities connected to the transmission network for the largest of these (more than 800 units) and all across the distribution network. In 2019, these cogeneration facilities generated 12 TWh of electricity. Electricity generation from gas accounted for 7% of total electricity generation in 2019[18].

Gas demand for CEG reached 50 TWh[19] in 2019 and 44 TWh in 2020, up from 36 TWh in 2018. In 2019, demand for these production units was particularly high due to an increase in the unavailability of nuclear power plants and a fall in hydraulic production. This was against the backdrop of low gas prices, which have become competitive again compared to coal.

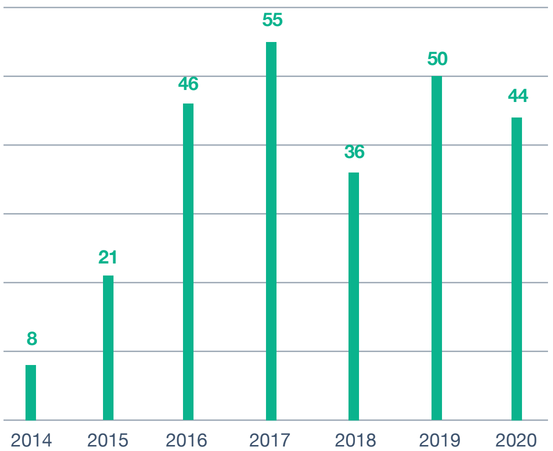
Faced with fluctuations in the availability of nuclear power plants and hydraulic and renewable generation, gas provides a flexible means of production with lower emissions than other thermal sources at increasingly competitive prices.

FIGURE 22 | **Location map for Centralised Electricity Generation from gas**



Source: GRTgaz

FIGURE 23 | **Consumption for Centralised Electricity Generation in TWh**



Source: GRTgaz, 2020 gas review

18 | RTE éco2mix.

19 | Only for gas combined cycle units + gas turbines.

Maximum power demand

Gas consumption is heavily seasonal, with demand in winter four to five times higher than in summer. In 2019, the highest gas consumption was seen on 24 January 2019 (108 GW on the GRTgaz network). By way of comparison, the annual maximum electricity demand on the same day was just 88 GW.

Previous peaks occurred during the cold spell of February 2012, when electricity and gas consumption recorded peaks of 102.1 GW and 176.1 GW, respectively, on 8 February 2012.

TABLE 5 | **Comparison of maximum power demand for the electricity and gas networks**

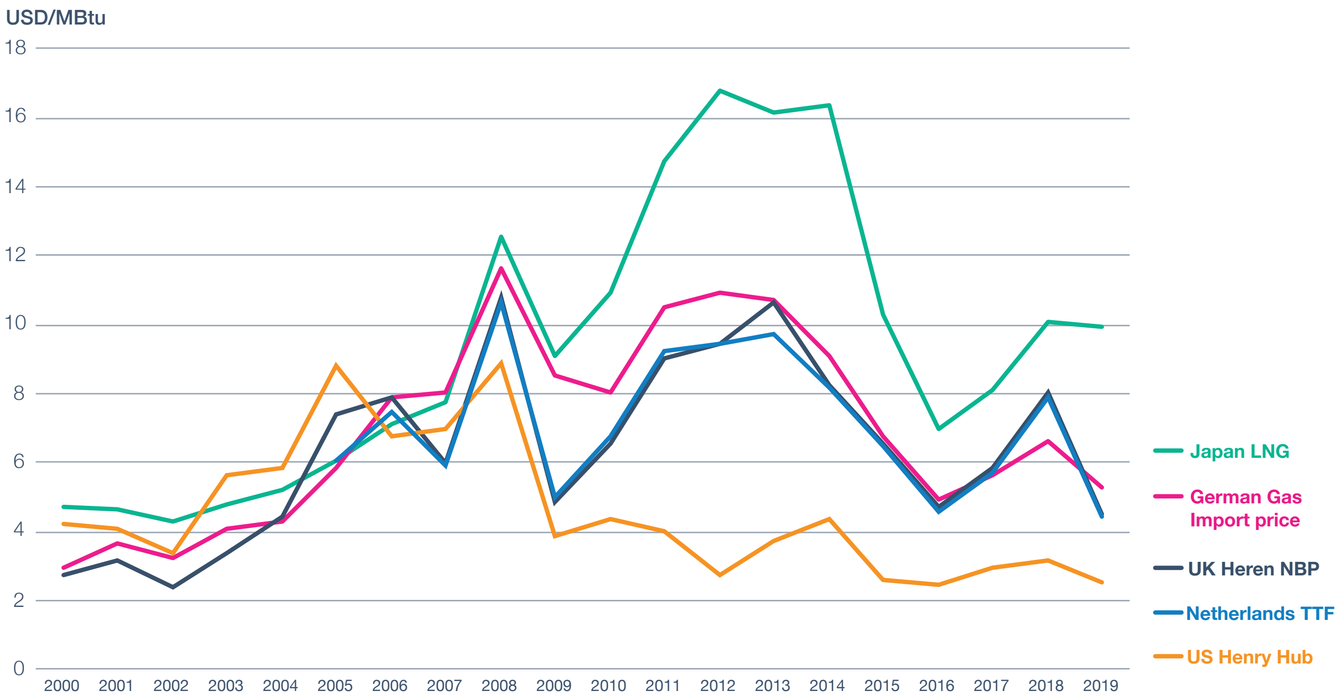
	Gas	Electricity
2019 maximum reached on 24 Jan. 2019 for electricity and gas	108 GW	88 GW
2020 maximum on 22 January 2020 for electricity and gas	103 GW	83 GW
Record high reached on 8 February 2012 for electricity and gas	176 GW	102 GW

A competitive gas offer with a growing share of LNG and the emergence of renewable gas

Global gas prices down in the various markets

Since 2009, the different global markets have seen wide disparities between gas prices. Gas prices in Asia soared from the early 2010s. This was mainly due to the consequences of the Fukushima incident. Since 2014, LNG prices in Asia have fallen sharply due to the indexation of many long-term oil price contracts that lost 50% of their value between 2014 and 2016, and the commissioning of many LNG liquifaction units.

FIGURE 24 | **Changes in worldwide gas prices**



Source: BP Statistical Review of World Energy 2020 – Analysis: GRTgaz

Europe was able to benefit from the high availability of LNG, which drove prices down. The average spot price in the Dutch reference market was €13.60/MWh in 2019.

The year 2019 saw a high degree of price convergence in north-west European market prices. This was the result of a long process aimed at facilitating gas circulation and exchanges within the European Union by strengthening interconnection capacities, harmonising network codes20 and marketplace convergence.

With its numerous LNG-receiving infrastructures and the attractiveness of its market, France has enjoyed broad access to this competitive resource. After major strengthening work on its interconnections with adjacent networks and the virtualisation of interconnection capacity sales with Belgium (Virtualys) and Spain (Pirénéos), the French market's full integration was finalised with the establishment of a single gas exchange point (PEG) in France on 1 December 2018.

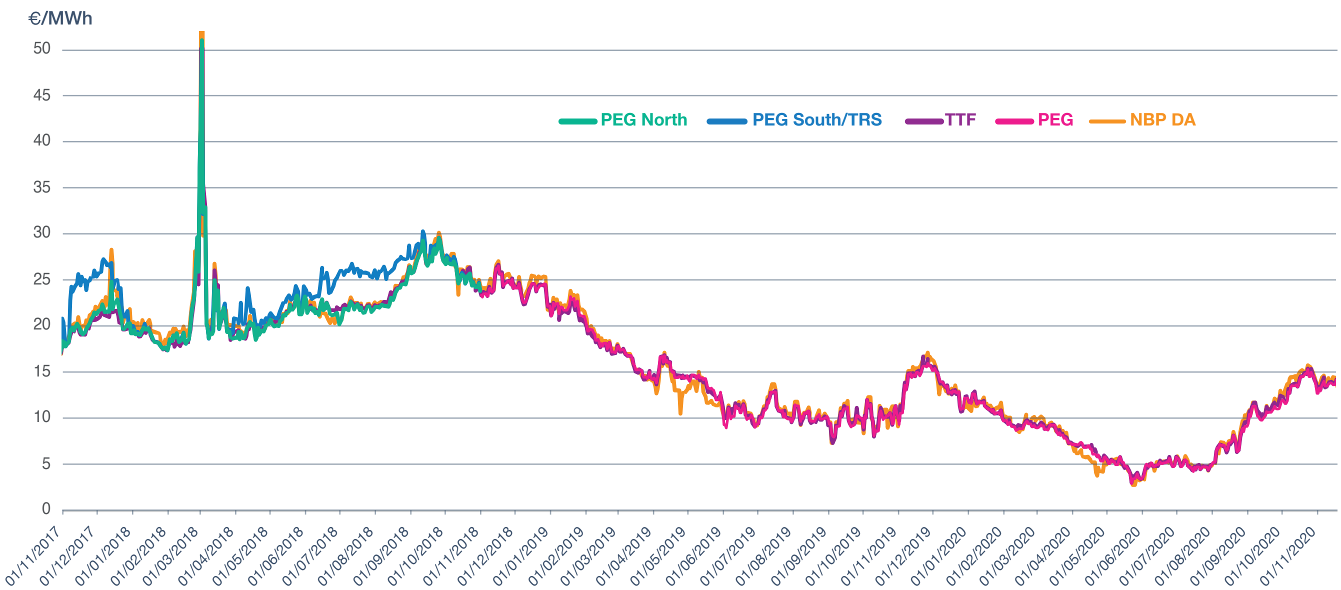
Gas prices on the French wholesale market remained very close to those of other north-west European markets.

The global health crisis caused by covid-19 exacerbated this excess supply, with a slowing economy causing gas prices to fall to historically low levels in H1 2020.

The vitality of the European gas markets (+25% of exchanges) was confirmed in 2019. This was driven in particular by the Dutch market, which has been north-west Europe's reference marketplace since the mid-2010s. The volumes exchanged on the PEG in 2019 came to 95.8 billion m^3 , in a year where French consumption was 43.4 billion m^3 [21].

The volume traded on the stock market is not the only factor defining the liquidity and therefore the performance of a hub. Other indicators must also be taken into account. These include the number of participants in a marketplace and the ratio between the sum of the

FIGURE 25 | **Day-Ahead price history for the French, UK and Dutch marketplaces**

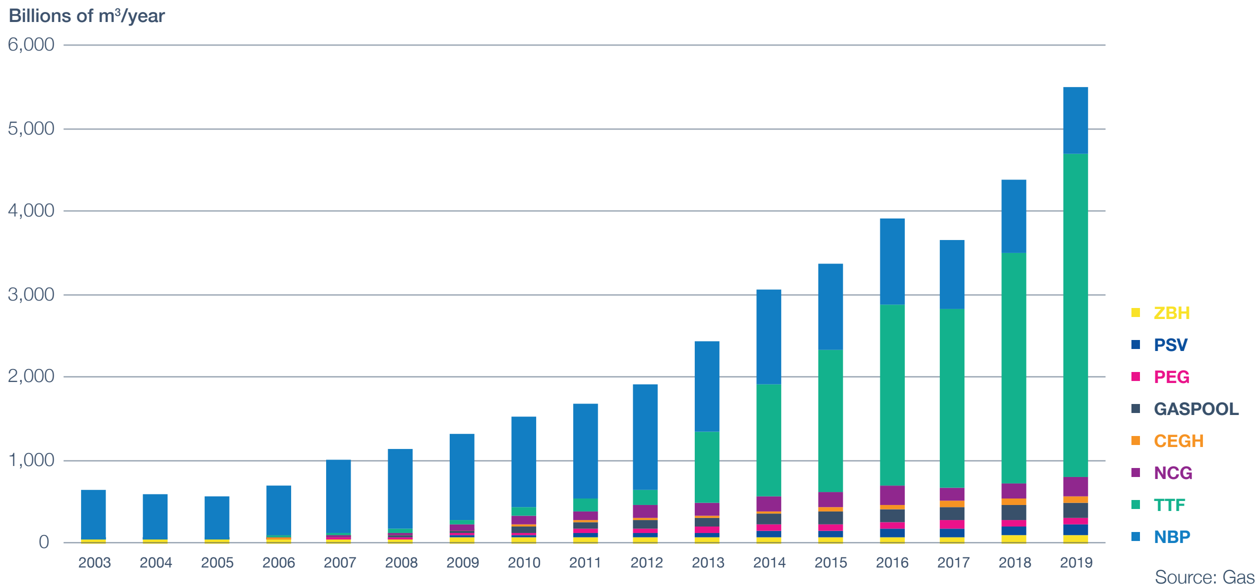


Sources: EEX & Bloomberg

20 | These network codes cover capacity allocation and congestion management, market-oriented balancing, interoperability and price harmonisation.

21 | BP Statistical Review of World Energy 2020.

FIGURE 26 | **Volumes of gas exchanged on European marketplaces**



Source: Gas in Focus

volumes exchanged and the physical volumes consumed for the zone in question. The latter is known as the "churn rate". Table 5 shows its growth for the main European stock exchanges.

In 2019, the PEG's churn ratio improved slightly within Trading Region France (TRF), despite the fall in volumes traded.

With a single gas price in France, TRF achieves the primary goal of eliminating the price differences between a North zone and a South zone that was more dependent on the LNG market. Since the launch of TRF, these differences – €2/MWh on average rising occasionally to €20/MWh – have disappeared. The "France price" is close to the highly competitive price of northern European prices, with price differences of less than €0.30/MWh on average.

The second goal was to create a liquid and attractive marketplace. Once again, this was achieved, with the number of active players in the PEG each month increasing from 107 to 128 between 2018- 2020.

TABLE 6 | ***Churn Ratio* of the European hubs**

Churn rates* for gas marketplaces

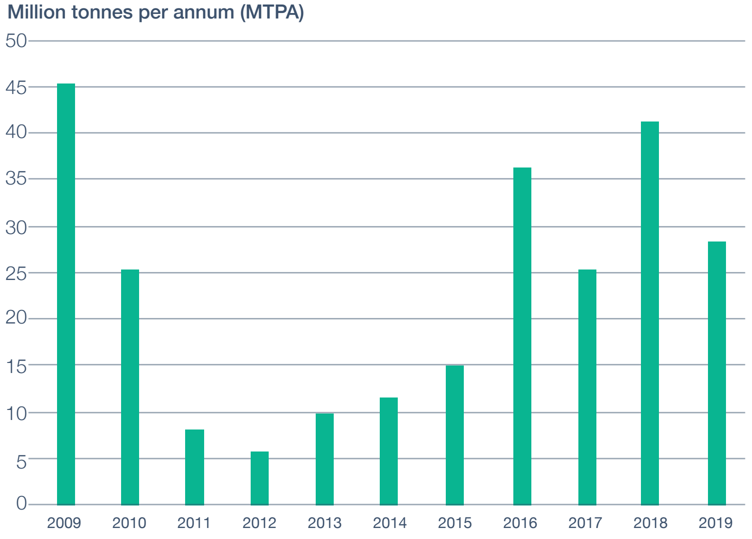
HUB	2008	2011	2017	2018	2019
TTF	3.3	13.9	54.3	70.9	97.1
NBP	14.4	19.8	23.9	17.0	14.3
VTP	CEGH 2.4	CEGH 2.2	5.3	6.9	9.0
NCG	0.4	1.8	3.4	3.8	4.3
GPL		0.8	2.6	2.8	2.9
TRF	France 0.4	France 1.0	PEG N 1.7 TRS 0.6	1.7	2.0
ZEE+ZT	5.1	4.1	2.9	3.3	1.9
PSV	0.2	0.2	1.2	1.4	1.8

*Calculated on the basis of a Net Market Churn, with differing methodologies depending on the year

Source: Oxford Institute for Energy Studies

-0.1 €/MWh average end-of-day spread between the PEG and the Dutch TTF market. A very low and negative spread of 66% for days.

FIGURE 28 | **Newly LNG train capacities**



Source: HIS Connect Nov. 2020

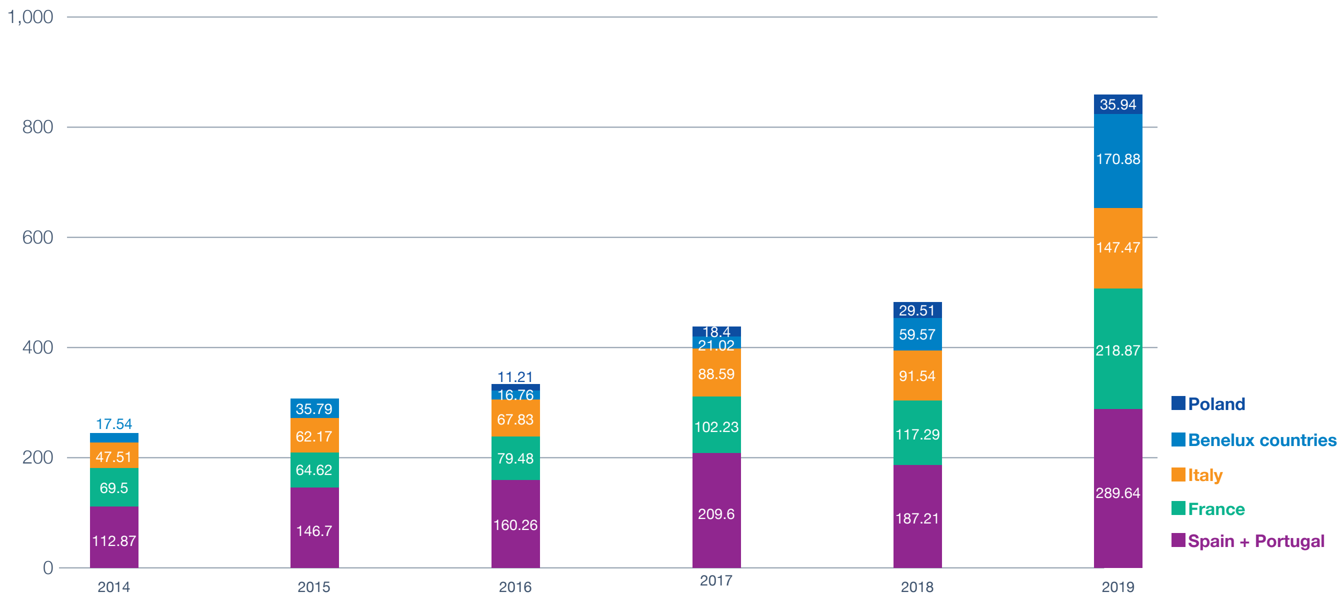
Supply featuring an LNG surplus that benefits Europe and particularly France

As mentioned above, the last three years have seen the commissioning of many liquifaction units around the world. Seven new LNG trains were completed in 2019.

International LNG trade reached 359 million tonnes (Mt) worldwide in 2019, an increase of 11.8% on 2018. Qatar and Australia remain the two largest exporters of liquefied gas in 2019, with 22% and 21% of global exports, respectively.

In Europe, 2019 saw a boom in LNG imports, with an increase of nearly 90% (+465 TWh).

FIGURE 28 | **History of LNG imports in Europe (in TWh)**



Source: ALSI, gie

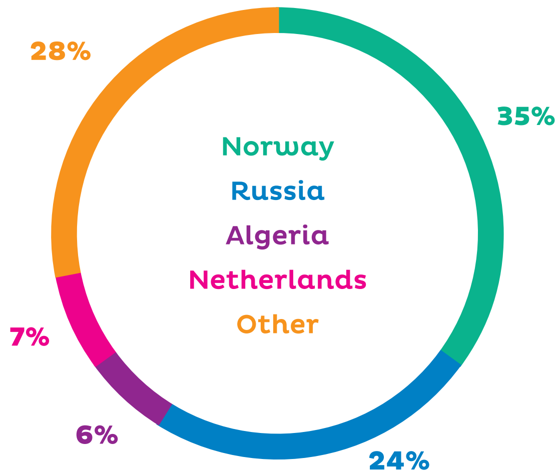
Pipeline supplies have been adjusted to this LNG inflow, declining by 7%, particularly from Algeria, where gas exports to Italy and Spain have fallen by nearly 40% in 2019 compared to 2018. Norwegian and Russian imports are also down. However, Russia have significantly increased their LNG exports at the same time. Russia increased all its exports to Europe by 4% with the commissioning of the two new LNG trains in Yamal in August and December 2018.

European production (excluding Norway) fell by 6.5%. The decrease was greater in the Netherlands (-13%) due to the gradual reduction in production from the Groningen field, which is expected to cease operations in 2022.

The trend in France was similar. Imports by pipeline are decreasing from Norway, Russia and the Netherlands, replaced by sharply increasing LNG imports. Norway and Russia remain France's two main gas suppliers, followed by the Netherlands and Algeria.

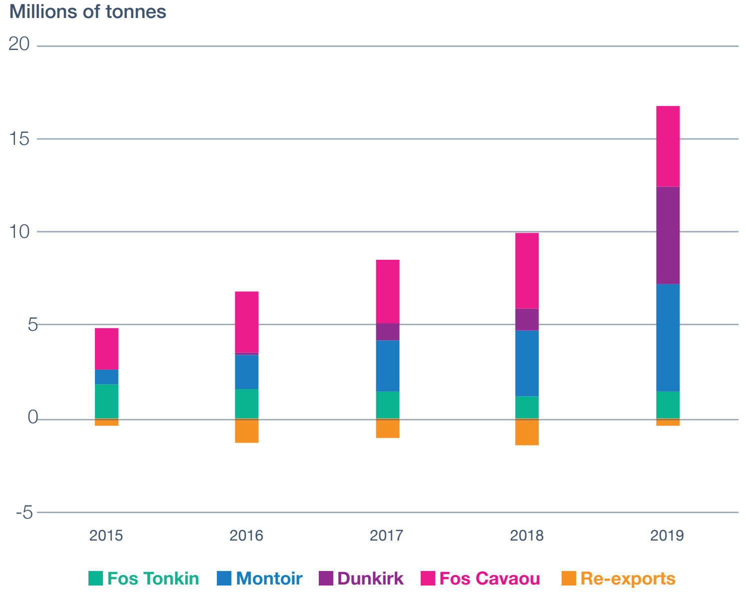
In 2019, France was one of Europe's main LNG entry points due both to its geographical location and the attractiveness of its market. The four LNG terminals saw their entry flows increase in 2019, particularly at the Dunkirk terminal, whose use increased by a factor of almost six. The Fos-sur-Mer and Montoir-de-Bretagne terminals both returned to their early-2010 levels, before the events in Fukushima led to a sharp fall in LNG imports in Europe.

FIGURE 29 | **French supply in 2019**



Source: BP Statistical Review of World Energy 2020

FIGURE 30 | **Volume of LNG imports to France**



Source: IHS Markit 2019

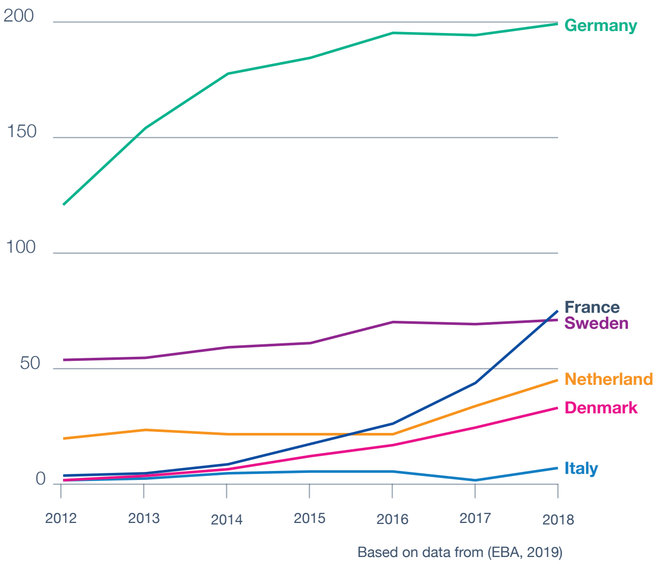

Connection of the shelter for the commissioning of the MD Biogaz site.

National production of renewable gas

France's primary production of biogas in 2019 came to 11 TWh[22] (+11% compared to 2018). The production of biomethane (purified biogas) injected into the transmission and distribution networks is likewise increasing rapidly, even though it currently accounts for only a small share of the country's gas supply (0.25% in 2019).

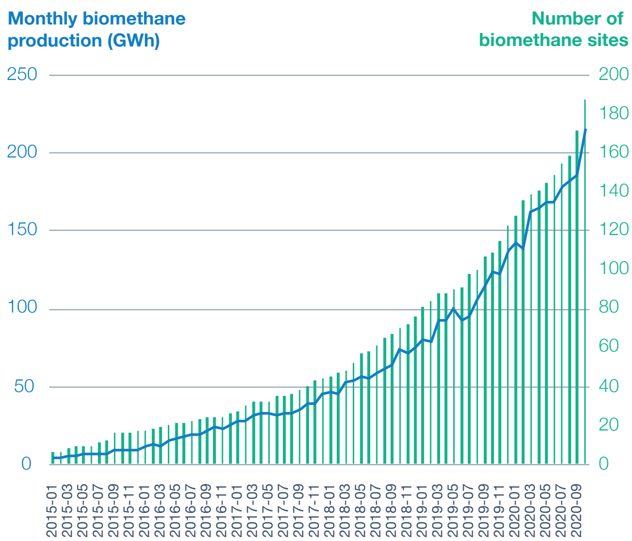
In Europe, biogas and biomethane production are 170 TWh and 23 TWh, respectively.

FIGURE 31 | **Changes in the number of biomethane production facilities**



Source: *Gas for Climate, Market state and trends report 2020*

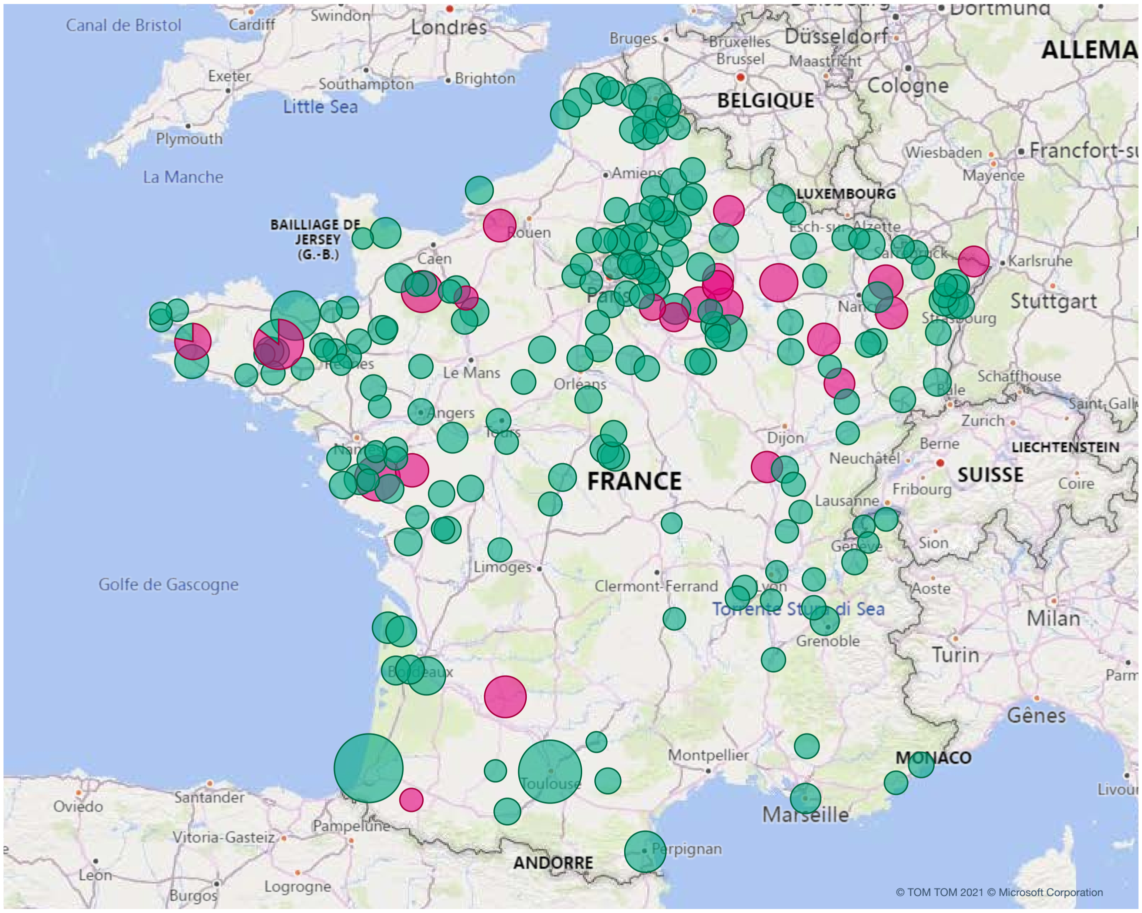
FIGURE 32 | **Monthly production of biomethane injected into French networks**



Source: ODRE (October 2020)

22 | France's Energy Performance in 2019, Ministry of the Ecological Transition

FIGURE 33 | **Capacity mapping of biomethane production sites broken down by type of network injected**



Network type
- Distribution
- Transmission

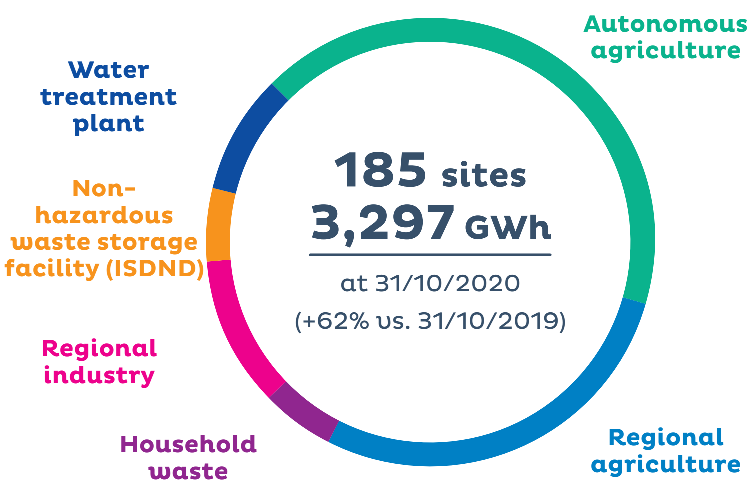
Source: ODRE (to March 2021) – Analysis – GRT gas

The quantities of biomethane injected into the networks hence almost doubled every year (713 GWh in 2018; 1.2 TWh in 2019; 2.2 TWh in 2020).

In 2019, 47 new production sites were connected to the networks and 62 in the first 10 months of 2020. The number of sites injecting into the networks thus rose to 185 at end-October 2020 and their cumulative annual production capacity to 3.3 TWh, of which approximately 15% are connected to the transmission network. The average capacity of the biomethane production facilities injected into the transmission and distribution networks is 34 GWh/year and 16 GWh/year, respectively.

Nearly 70% of biomethane is produced from agricultural waste. The rest comes from household or industrial waste, and from sewage sludge.

FIGURE 34 | **Annual capacities connected by type of site**



Source: ODRE (Oct. 2020)

Routing

French consumption demand in 2019 could be met at all times and anywhere in the country. There was no significant interruption to import flows or the operation of gas infrastructures. Gas storage facilities could be used by suppliers to ensure the security of supply for their customers.

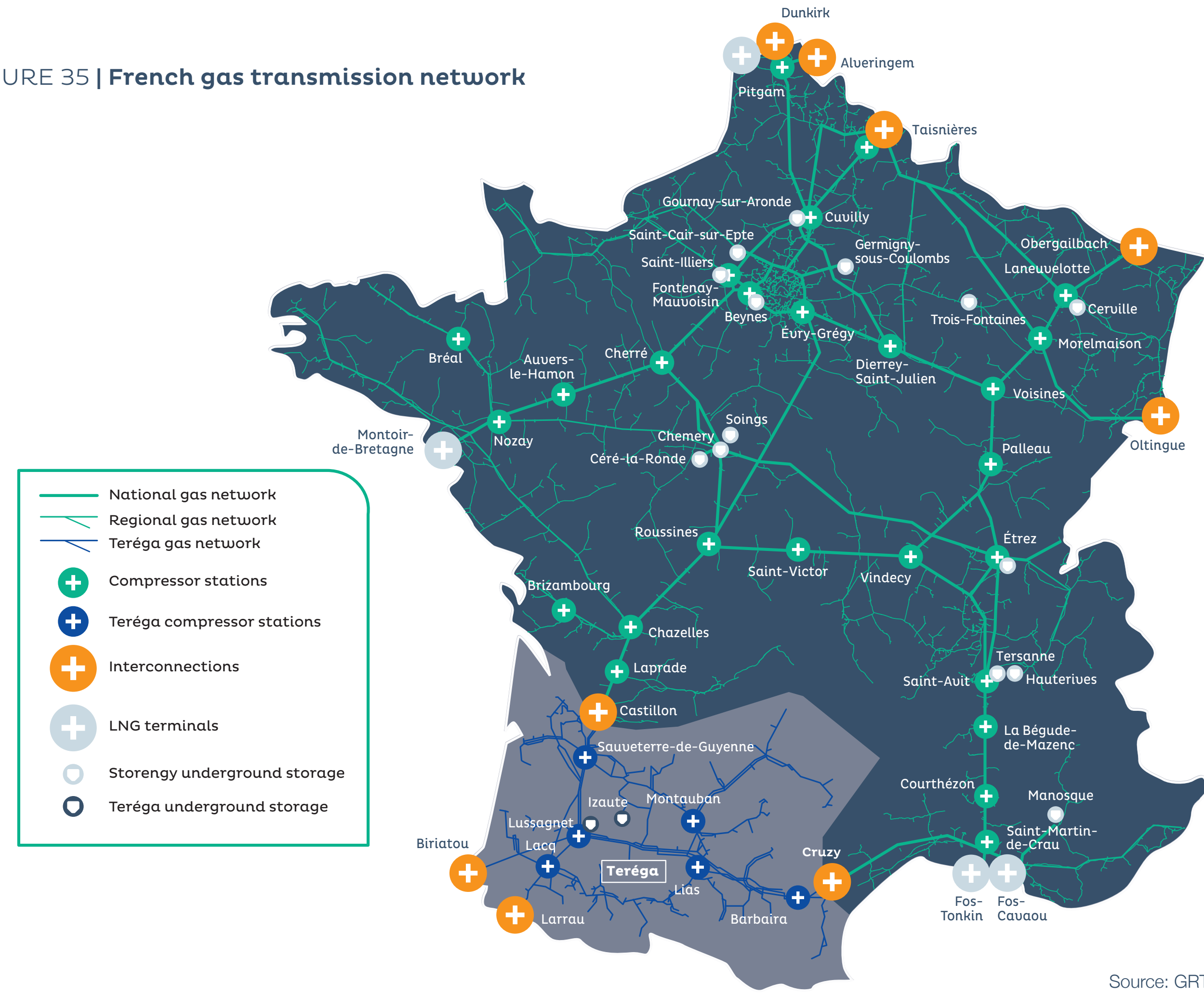
Once again, the gas network was widely in demand. It demonstrated the importance of its sizing in securing access to the most competitive gases, in particular LNG in 2019, in providing transit flows from northern Europe to the Iberian peninsula or Italy via Switzerland, and in accommodating increasing quantities of biomethane.

The French transmission network

The French gas transmission network is a 37,500 km mesh network with extensive interconnections to adjacent countries (Belgium, Germany, Luxembourg, Switzerland and Spain). It is also directly connected to four LNG terminals giving access to the global LNG market, to Norwegian production zones, and to 16 underground storage sites capable of storing one-third of the country's annual consumption. It serves end customers either directly or via its nearly 200,000 km distribution network.

Sales are in the form of capacities rights at the network entry or exit points, as well as at the PEG (gas exchange point).

FIGURE 35 | **French gas transmission network**



Source: GRTgaz

This simplified model allows shippers to:
- supply industrial sites and public distribution stations connected to the transmission network;
- transport gas through France;
- access a virtual exchange point (PEG) authorising gas sales/purchases with other counterparties.

Shippers' only obligation is to balance their gas inputs and outputs over the gas day. This structure provides market flexibility and stimulates competition.

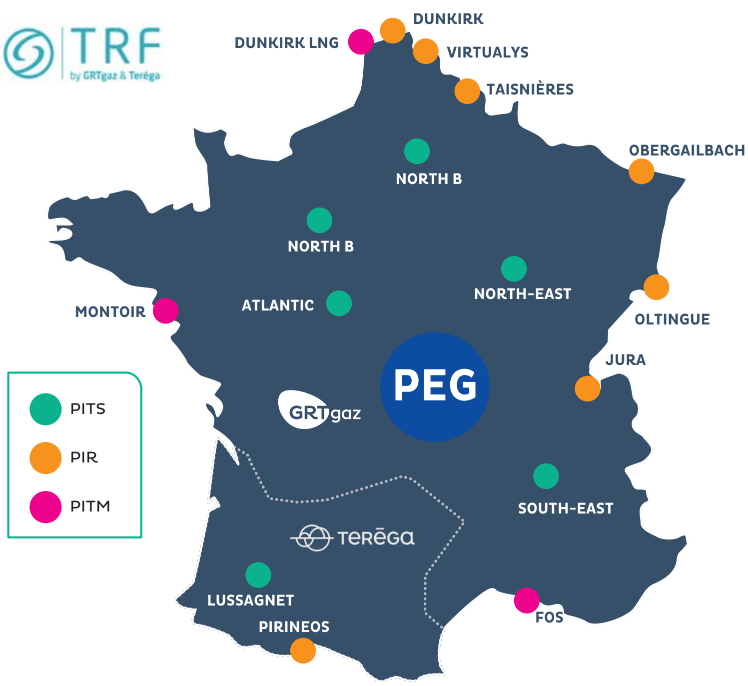
The transmission network thus meets supply and demand through routing and flow management.

Changes to the GRTgaz offer

Trading Region France: a liquid and attractive single marketplace

In line with the CRE's guidance in its deliberation of 19 July 2012, France's single gas marketplace was commissioned on 1 November 2018. Based on an investment plan combining the Val-de-Saône and Gascogne-Midi projects and on contractual mechanisms, this is crucial for meeting flow patterns that cannot be fully addressed by the selected investments.

FIGURE 36 | **TRF: A single market zone in France since 1 November 2018**



Known as Trading Region France (TRF), the single zone comprises a single balancing zone and a single marketplace, the PEG.

The locational spread – the main mechanism for managing residual congestion - was co-constructed with the market. It consists of a call on the market to simultaneously buy and sell gas upstream and downstream of the congestion, respectively. This system has worked well, attracting many players. By end-2020 it had been used 59 times for a total amount of €8.06 million since 1 November 2018, and successfully in most instances (57 times out of 59). Improvements made in 2020 saw this success rate increase to 100%, with reduced associated costs.

Oltingue: increase in firm capacity to Switzerland

To respond in part to Switzerland and Italy's supply issues since the reduction of the Wallbach Interconnection point' capacities (linked to technical problems on one of the TENP pipes), GRTgaz worked together with Swiss operators to optimise operating conditions at the Oltingue interconnection point.

Since 1 December 2018, GRTgaz has confirmed 30 GWh/day of interruptible outgoing capacity at the Oltingue Network Interconnection Point (IP). Firm capacity has thus increased from 223 GWh/day to 253 GWh/day.

This firm capacity was further increased by 7 GWh/day to 260 GWh/day from 1 October 2019 until 31 December 2024.

Dunkirk: increase in firm capacity from Norway

Every winter, GRTgaz renews the "Dunkirk +" offer to meet market demand, with 20 GWh/day of additional monthly firm capacity sold on the Dunkirk IP for the months of November to March. At the same time, additional capacity is available on the Norwegian Gassco network.

The Dunkirk IP's monthly firm capacity thus increases to 590 GWh/day during this period. Interruptible capacity remains unchanged (36 GWh/day).

To guarantee the network's performance while doing this, 20 GWh/day of firm capacity at the Virtualys IP from France to Belgium are offered as interruptible (rather than firm) capacity during the same period. The Virtualys IP monthly firm capacity thus changes from 640 to 620 GWh/day (+ 30 GWh/day in overbooking). The interruptible capacity level increases from 0 to 20 GWh/day.

The offer to switch 20 GWh/day from Virtualys to Dunkirk was discontinued in 2021, as it is no longer required by the market.

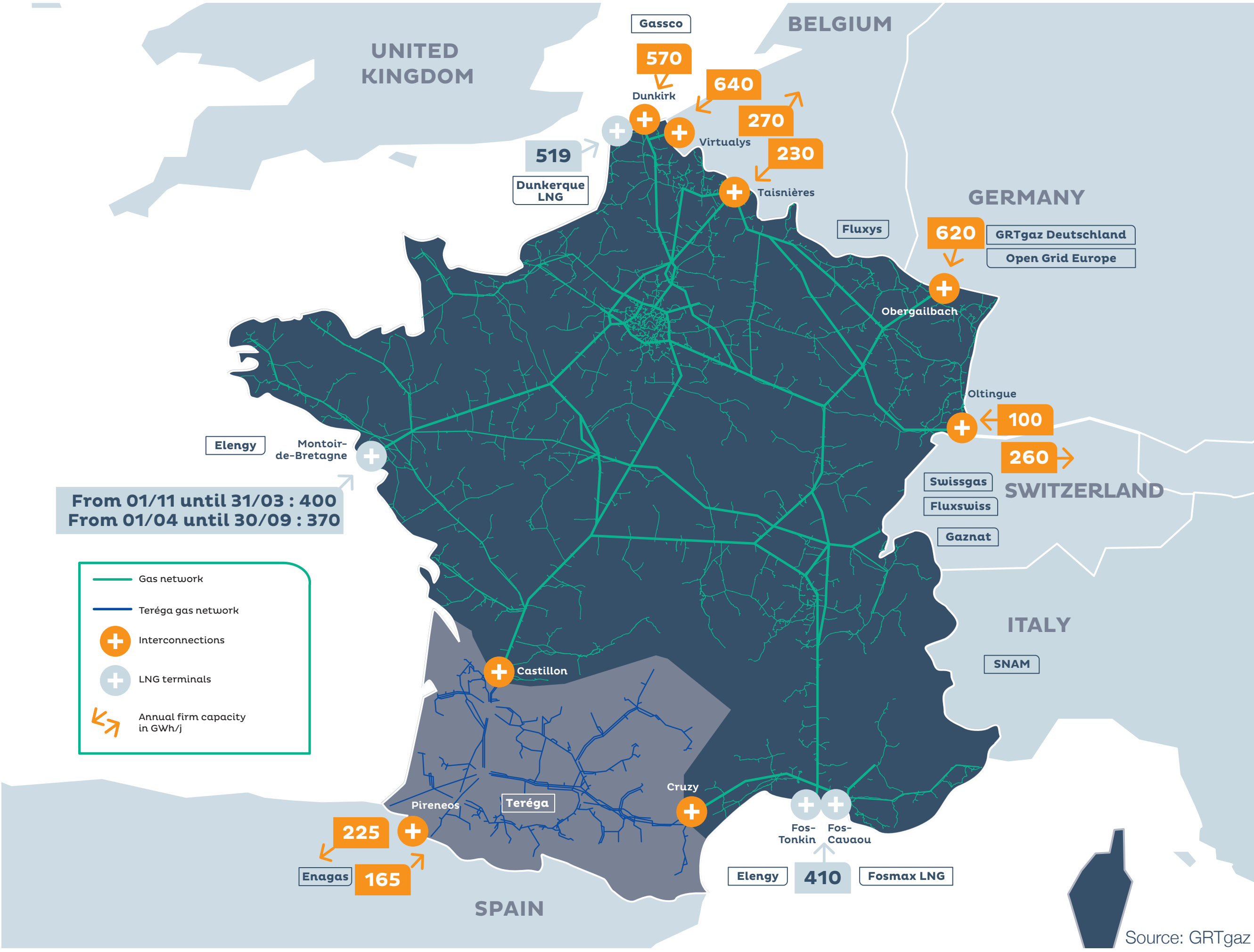
Dunkirk LNG: increase in firm capacity

The interruptible capacity on the Dunkirk LNG terminal was confirmed from 1 October 2020, increasing the firm capacity offer from 300 to 519 GWh/day.

Fos: changes in sold capacity

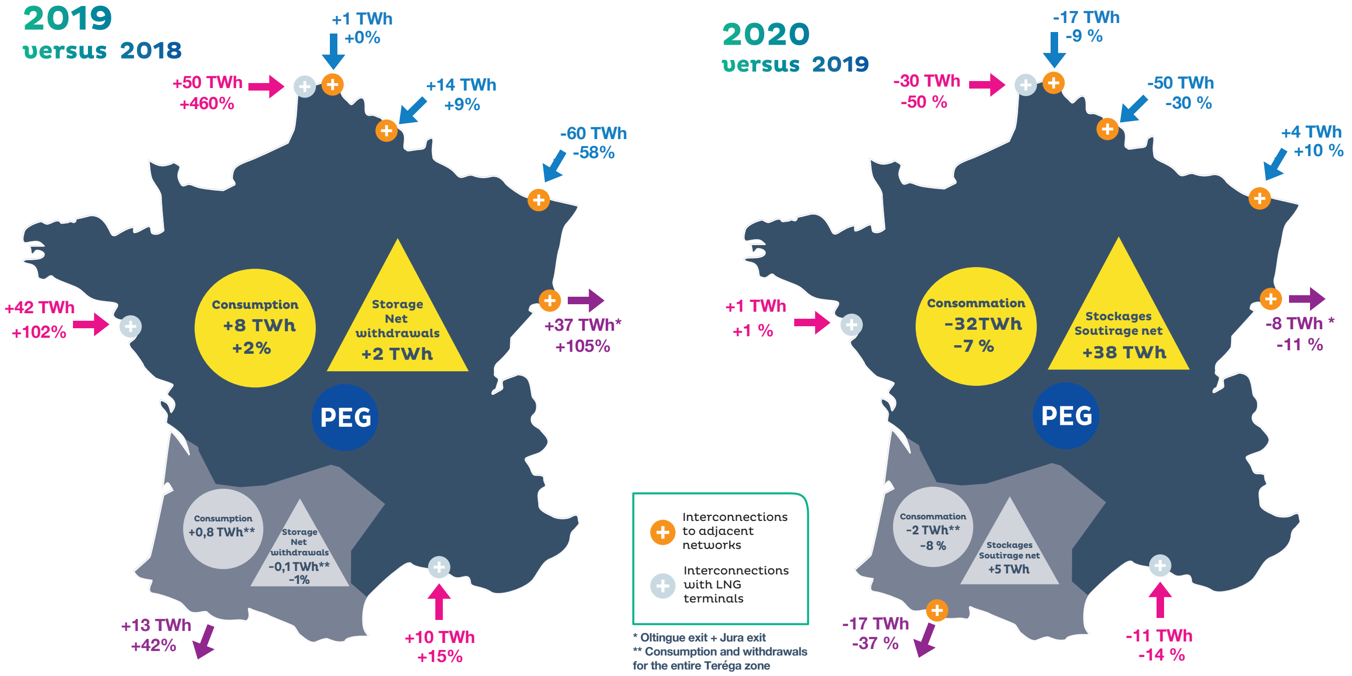
From April 2021, the capacity sold at Fos will be streamlined (higher capacity in winter and lower in summer) to better match the physical capacity.

FIGURE 37 | **Firm capacity as of october 1, 2020**



Source: GRTgaz

FIGURE 38 | **Changes in flows across France**



Source: GRTgaz, Teréga

Flows routed on the network

The year 2019 saw record transits with flows from France to Switzerland and France to Spain up significantly compared to 2018 (+105% and +42%, respectively). This was partly due to the fall in Algerian gas exports during 2019 (-36% to Italy and Spain). Flows from France to Switzerland and Italy also increased. This was due to capacity reductions from Germany to Switzerland (at Wallbach) resulting from technical problems on the German TENP pipeline and joint work with Swiss operators to optimise operating conditions at the Oltingue interconnection point (changes in supply mentioned above). The Oltingue transfer point thus reached its technical maximum on many occasions, doubling the annual transit to Switzerland in 2019.

As stated previously, the four LNG terminals saw their entry flows increase in 2019, particularly at the Dunkirk terminal, whose use increased by a factor of almost six. With 219 TWh of LNG imported, France is one of Europe's main LNG entry points. It was able to meet transit demand to Spain and Italy, which was up by 50 TWh in 2019.

Similar flow levels proportional to consumption were observed in 2020 (see summary). French gas consumption fell by 7% compared to 2019 due to some exceptionally mild weather, with 2020 being the country's hottest year on record since 1900. Except for industry, which was more affected by Covid-19, the health situation ultimately had a lesser impact than the weather on overall changes to French consumption in 2020.

TABLE 7 | **Changes in commercial flows at network interconnection points**

Net flows (TWh)	2019	Change versus 2018
ENTRIES	**743**	**+10%**
Gas pipeline entries	**402**	**-10%**
Dunkirk (Norway)	191	0%
Virtualys (Belgium)	168	+9%
Obergailbach (Germany)	43	-58%
LNG entries	**219**	**+87%**
Montoir	83	+102%
Fos	75	+15%
Dunkirk	61	+460%
Storage withdrawals	**122**	**+2%**
EXITS	**740**	**+100%**
Gas pipeline exits	**119**	**+75%**
Oltingue and Jura (Italy)	72	+105%
Pirineos (Spain)	45	+42%
Other deliveries*	2	+37%
Consumption	**478**	**+2%**
Storage injections	**143**	**-1%**

* Schonenbourg, Ohain, Monaco, Savoie

Source: GRTgaz, Teréga

Capacities use and subscription

Capacities use

By analysing the uses of the transmission infrastructure, operators can measure the occurrence of maximum uses to identify any need to increase the interconnection capacities required by the market.

This analysis shows that the input and output capacities appear correctly sized. The Dunkirk IP is the most popular entry point. The use in both directions of points providing two-way capacities (Virtualys and Oltingue) indicates an interest reverse-flow capacity offers.

Capacity subscriptions

Capacity subscription rates are generally high, with an average 70% of firm capacity reserved for 2020-2023.

To offer additional arbitrage opportunities and enable the entry of new market players, firm capacity subscriptions are kept short term.

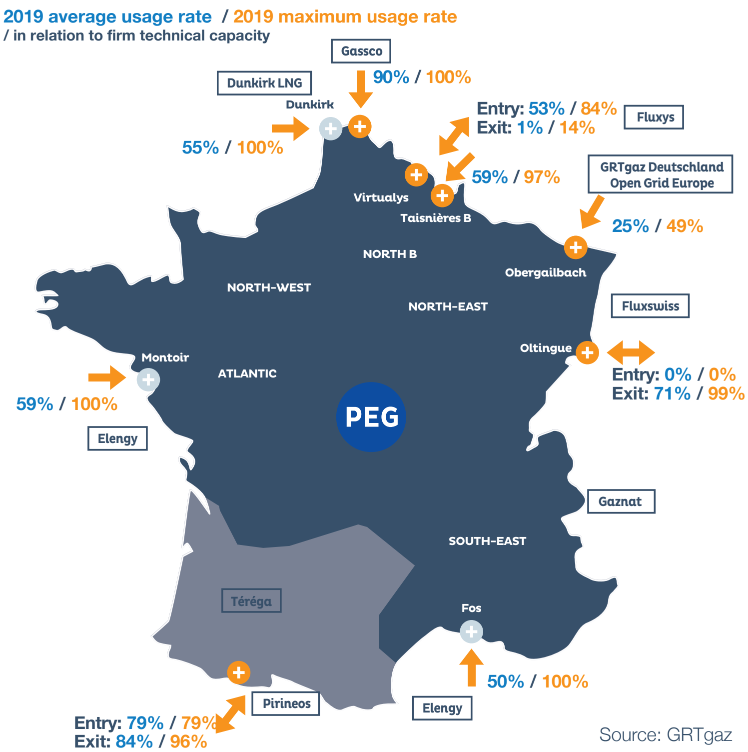
Firm subscriptions at gas entry points

Long-term capacity at Dunkirk is fully subscribed until September 2021. Subscriptions then fall sharply to nearly 55% of long-term capacity sales in 2023.

At Virtualys and Obergailbach, capacity is heavily subscribed up to 2023. There is a sharp fall after this date, bringing the subscription rate down to around 45%.

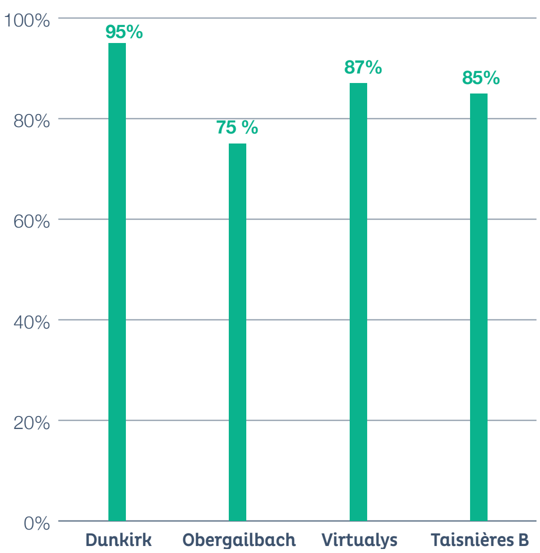
At Taisnières B, long-term subscriptions ended in October 2019. Subscriptions in 2020 were down 30% compared to 2019.

FIGURE 39 | **Use of technical capacities available in 2019**



Source: GRTgaz

FIGURE 40 | **Annual firm capacity subscription rate at gas entry points in 2019**



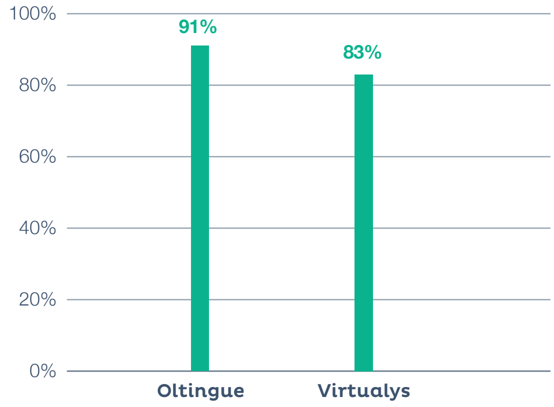
Source: GRTgaz

Firm subscriptions at gas exit points

At Oltingue, long-term capacity is fully subscribed up to 2026.

At Virtualys the overall subscription rate in the France-Belgium direction is around 80% for the period 2020-2023. This rate includes the long-term subscription for capacity dedicated to the transit service from the Dunkirk LNG terminal to Fluxys.

FIGURE 41 | **Annual firm capacity subscription rate at gas exit points in 2019**



Source: GRTgaz

Pitgam interconnection station.

2.2 | Multi-year forecast

The French Energy Code (Article L141-10 updated by Order 2018-1165) provides that transmission system operators (TSOs) produce a multi-year forecast every year, taking into account changes in consumption based on low-carbon actions, efficiency measures and usage substitutions, as well as transmission, distribution, storage, regasification and renewable production capacities, and exchanges with foreign gas networks.

This section presents the forecasts for renewable gas consumption and production according to the four scenarios set out by GRTgaz, Teréga, GRDF and SPEGGN in the 2020 Gas Outlook, forecasts for daily demand at the 2% peak, forecasts for European demand, production and import needs, as well as the main import and interconnection projects that can influence the flow of gas imports to France.

Fontenay-Mauvoisin compressor and interconnection station (78) GRTgaz Val de Seine region.

In summary, the current French gas system benefits from a level of flexibility and resilience that ensures the continuity of supply to France, including at peak cold weather times, within the constraints defined at European level by Regulation 994/2010 relating to the security of supply, as well as the public service obligations set by French legislation and in force until 2030.

This analysis is based in particular on the various complementary tests and analyses carried out by GRTgaz, Teréga and ENTSOG for different geographical areas and timeframes:

- in the short term, each year at the beginning of winter, GRTgaz analyses the coverage of peak demand and, more broadly, the energy balance, taking into account storage levels, the severity of the winter, and the latest import trends. ENTSOG carries out a similar analysis for Europe with its *Winter Supply Outlook*;
- in the longer term, at European level and as part of the TYNDP, ENTSOG analyses the alignment between potential changes in supply, demand and European infrastructures.

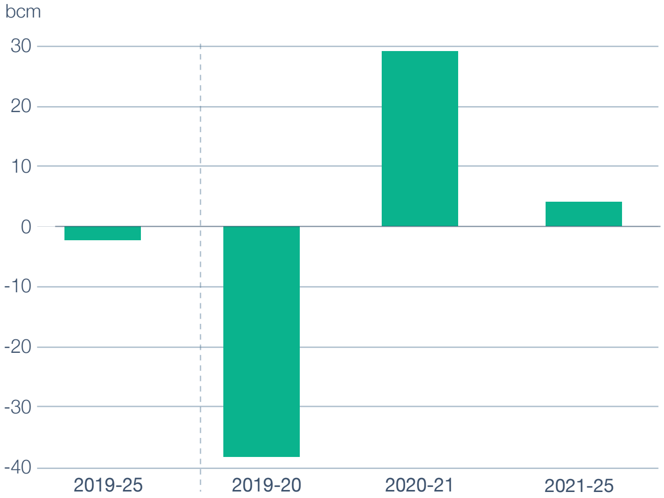
Forecast for 2030

Projected decline in demand

Lower European projections

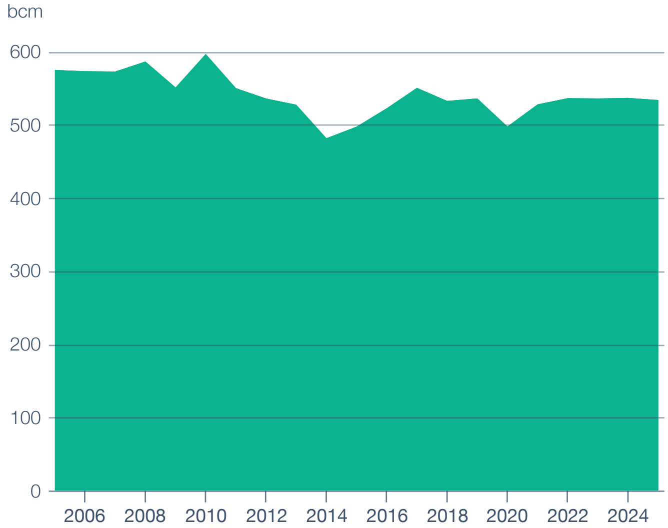
In its GAS 2020 report published in June 2020, the IEA estimates that European gas demand should remain stable until 2025. Gas-fired power stations are expected to be more in demand to offset the gradual 50 GW drop in electricity generation capacity from nuclear, coal and lignite. However, this growth will clearly be limited by the rapid expansion of renewable electricity production, which is expected to increase by nearly 30% in the medium term. Industrial demand for natural gas is expected to return to pre-crisis levels, but with no real growth potential.

FIGURE 42 | **Gas demand growth forecast in Europe between 2019-2025**



Source: IEA, 2020 Gas Report

FIGURE 43 | **Historical and forecast gas demand trends in Europe between 2019-2025**



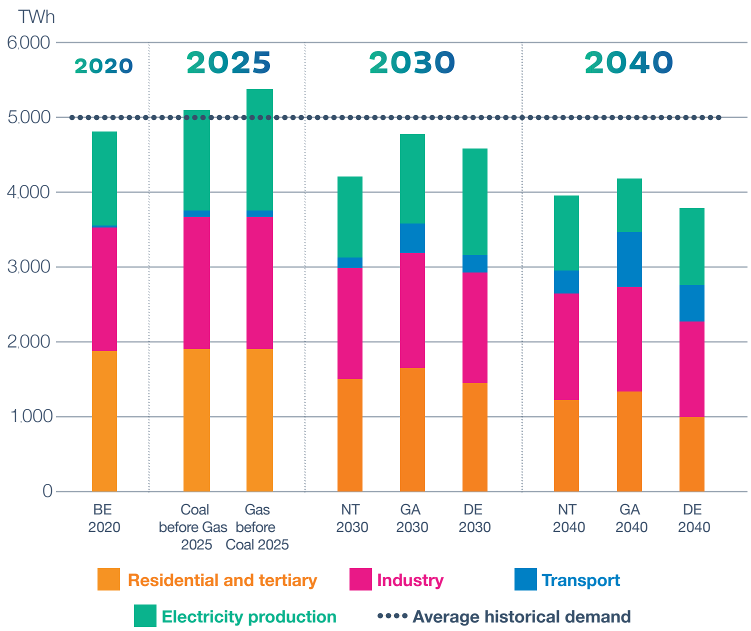
Source: IEA, 2020 Gas Report

The ENTSOG scenarios show a fall in gas demand in Europe by 2030.

The National Trends scenario projects the largest fall in gas demand. Conversely, the Global Ambition and Distributed Energy scenarios feature higher decarbonisation levels by 2030, with higher gas demand. This is linked to the most carbon-intensive energy vectors (oil, coal) being substituted more quickly for gas, as well as a larger share of renewable gas in the gas mix.

All three scenarios include falling demand for gas in the residential and tertiary sectors. This is partially offset by demand for the transport of people and goods. This trend continues across all scenarios, leading to a gas demand level below 4,000 TWh in 2040 (-20% vs 2019).

FIGURE 44 | **Sectoral breakdown of total gas demand in Europe (EU28) by 2025, 2030 and 2040**



Source: TYNDP 2020

The outlook for changes to demand in France is no exception

As every year, the Gas Outlook aims to present realistic and contrasting visions of changes to gas demand and the production of renewable gas in the medium term.

This new 2020 edition[23] puts forward three possible trajectories for gas consumption and renewable gas production by 2030 (data tables for these scenarios can be found in the appendix):

- **NATIONAL low-gas** scenario: this scenario is consistent and compatible with the SNBC "with additional measures" (AMS) scenario published in April 2020. It is based on the significant electrification of uses, in particular in the mobility, industrial and private housing sectors, and on large-scale developments in urban heat networks to supply collective housing and tertiary buildings;
- **NATIONAL high-gas** scenario: this scenario is consistent with the "high gas" version of the SNBC AMS scenario. It reflects the great uncertainty that exists about the changing role of gas in buildings. It also shows that other paths to carbon neutrality in 2050 are possible in France, relying in particular on a larger share of renewable gas to decarbonise the buildings sector;
- **TERRITORIES** scenario: this scenario is designed around the concatenation of regional ambitions and dynamics. It is based on an interpretation of published legislation and elements of SRADDET[24]. Most of these scenarios are based on the complementarity of different energies. It is the most ambitious scenario in terms of gas consumption and renewable gas production.

These three scenarios in the 2020 Gas Outlook form part of the SNBC's ambitious pathway, in particular for energy efficiency and buildings' renovation, involving swift reductions in gas consumption to achieve carbon neutrality targets by 2050 with limited use of renewable gas potential (in France or in connection with imports).

It should also be noted that in drafting these scenarios, it was decided that the health crisis would only affect consumption over the next 3 years. This assumption will require fine-tuning in the coming years to factor in the changing nature of the crisis.

Also, these scenarios assume an increasing population and a decreasing household size, as well as a significant decrease in gas market share both for collective buildings and private housing, in particular in connection with changes to environmental building regulations.

The assumptions used in drawing up these scenarios are detailed in the *2020 Gas Outlook*:

- trajectories of between 381 and 410 TWh/year by 2030. For the first time, these also include the development of renewable and low-carbon hydrogen, for which the public authorities have set ambitious targets for 2030;
- the most significant difference relates to gas mobility, which plays a much more important role in the **TERRITORIES** scenario. Here, the new heavy goods vehicles' market share is estimated at 65% by 2030, compared with around 14% in the two **NATIONAL** scenarios. Gas mobility consumption (NGV and hydrogen) would be around 41 TWh in 2030 for the **TERRITORIES** scenario;
- on the industrial side, the **TERRITORIES** scenario is also the most ambitious, with a gas (methane and hydrogen) market share of around 28% bringing industrial consumption to 137 TWh by 2030. The national scenarios, meanwhile, estimate this market share at 25% for a consumption of 122 TWh in 2030;
- similarly, gas has greater share of the tertiary market in the **TERRITORIES** scenario, where it is estimated at 25% by 2030 for a consumption of 48 TWh. The **NATIONAL high gas** and **NATIONAL low gas** scenarios, meanwhile, estimate it at 20% and 18%, respectively, for consumption levels of 41 TWh and 36 TWh;
- finally, the estimated share of gas consumed for CEG in the *2020 Gas Outlook* is between 45-65 TWh per year by 2030, with cogeneration units down to between 14-25 TWh by 2030. It is important to note that CEG estimates are subject to numerous uncertainties about the means of generation over this timeframe (capacity of nuclear power plants, capacity of variable renewable energies, unavailability of adjustable means, weather conditions). Also, the 2030 RTE forecast published in March 2021 contains a production outlook of 23 to 24 TWh of electricity from gas. This corresponds to a gas consumption of just over 50 TWh, which is consistent with the volumes in the **TERRITORIES** scenario. The **NATIONAL high gas** and **NATIONAL low gas**

23 | https://www.grtgaz.com/sites/default/files/2021-06/Rapport-perspectives-gaz-2020.pdf

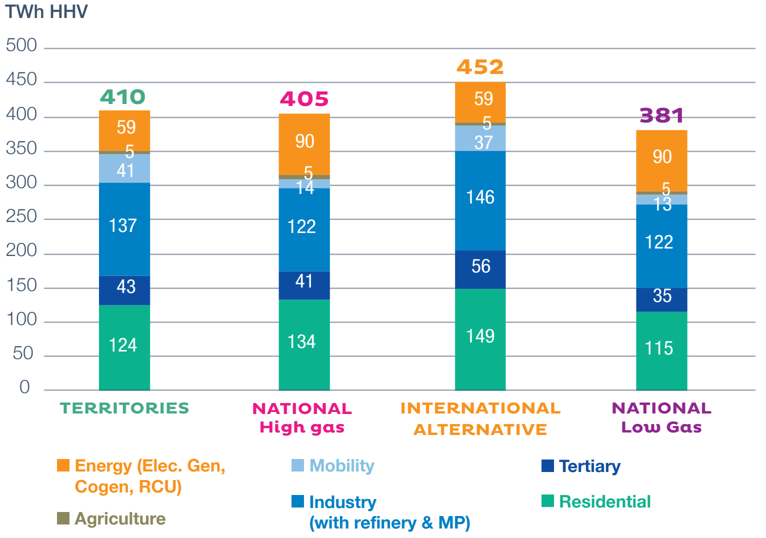
24 | Regional planning, sustainable development and territorial equality scheme.

scenarios, however, are based on volumes at the same level as in recent years. This is different from the RTE scenario, which features the reduced use of gas-fired power plants.

A sensitivity study was carried out alongside these three scenarios to measure the impact on consumption of a slightly less ambitious energy efficiency trend in buildings (development of very high energy performance (VHEP) boilers and pace of renovation).A partial achievement of these targets (70% efficiency compared to the SNBC's benchmark level) would lead to an increase in consumption of 11-13 TWh in 2030, depending on the scenarios. A scenario for renewable gas imports was also outlined. This scenario falls outside the SNBC's strict framework, as it plans to meet additional demand by supplementing national renewable gas production with renewable and/or decarbonised gas imports (hydrogen, synthetic methane or natural gas decarbonised upstream), as planned by many other EU Member States. In this so-called "INTERNATIONAL ALTERNATIVE" scenario, gas consumption could fall less quickly and be at 452 TWh by 2030, while remaining compatible with the carbon neutrality target by 2050 (data tables for this scenario are available in the appendix).

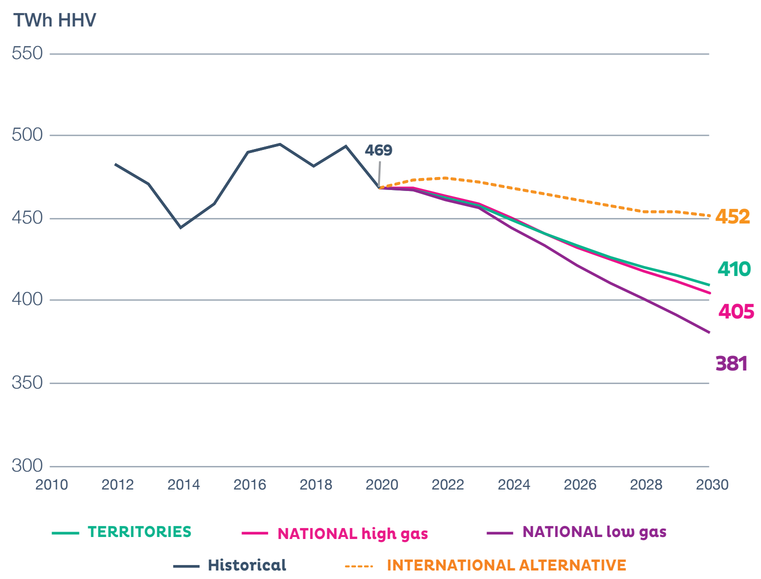
Taking all these factors into account, the fall in the volume of gas consumed in France by 2030 will be between 4-19% compared to 2020.

FIGURE 45 | **Breakdown of consumption by sector in France in 2030 in the three scenarios**



Source: *2020 Gas Outlook*, GRTgaz, Teréga

FIGURE 46 | **Scenarios for total gas demand in France (renewable methane and hydrogen/low carbon) by 2030**



Source: *2020 Gas Outlook*, GRTgaz, Teréga

Peak demand

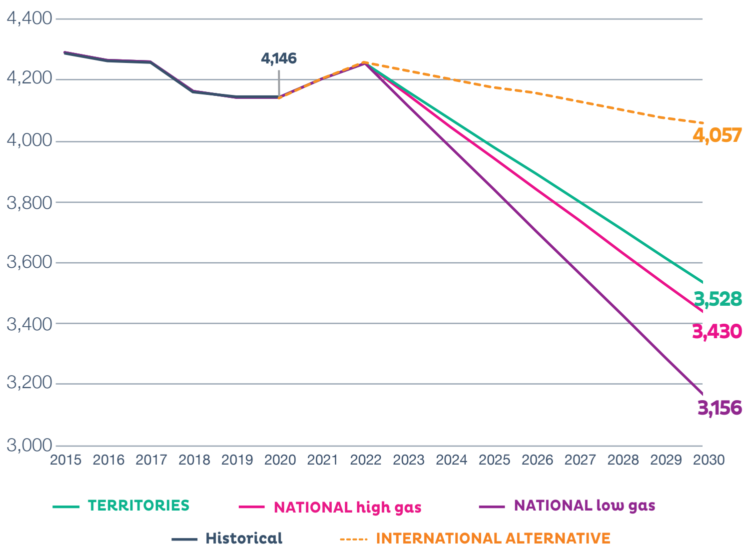
The maximum demand faced by the gas system is during a cold winter or when there are very low temperatures for three consecutive days, as occurs statistically once every 50 years. The sizing of the regional gas transmission networks is based on this peak demand.

Each year, in compliance with the regulations, transmission system operators draw up the cold peak consumption, known as the "2% risk peak". This corresponds to the level of consumption in extreme conditions where the average daily temperature is less than or equal to the lowest temperature with a 2% chance of occurring.

This consumption is calculated for the past year by extrapolating winter consumption for extreme temperatures using a method known as "winter analysis".

The benchmark peak demand is taken from the consumption data for winter 2019-2020 (4,146 GWh/day for all of France, of which 3,824 GWh/day for GRTgaz).

FIGURE 47 | **Scenarios for peak total demand in France in GWh/day**



Source: *2020 Gas Outlook*, GRTgaz, Teréga

Changes in peak demand until 2030 are then modelled using consumption trends. For each of the residential, tertiary and industrial sectors, the same rates of decline in consumption are applied to peak demand in each scenario.

Calculating the residential sector's peak demand is different, however, as some gas customers have switched to a hybrid heat pump system [25] (10% in 2030 in the **TERRITORIES** and **INTERNATIONAL ALTERNATIVE** scenarios). Consequently, the gas consumption of these customers over the year no longer corresponds to 20% of the consumption of a customer with only a gas boiler. However, its peak demand remains essentially the same, as gas boilers are activated during peak cold periods using this system.

With regard to the assumptions for CEG, the stability of the combustion turbines and gas-fired CCPP, including the new Landivisiau plant, is retained. This is in line with the RTE forecast for 2030 published in March 2021.

On the cogeneration side, the assumptions also corroborate those of the recent RTE forecast, with a 20% reduction in installed capacity connected to the gas network by 2030.

Lastly, mobility consumption was considered to be virtually stable throughout the year.

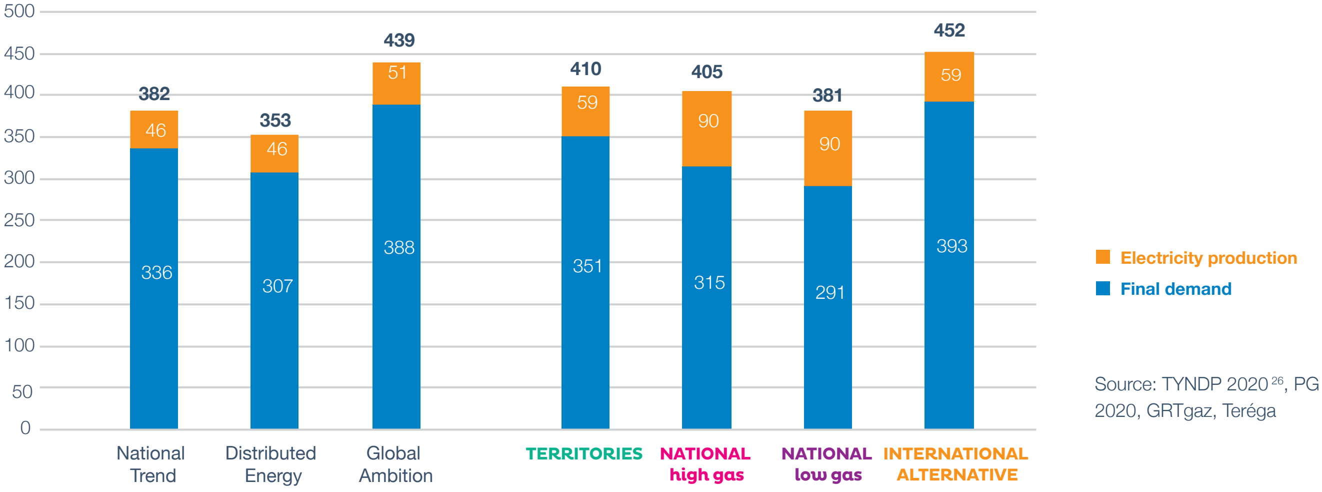
When calculating the peak, only methane gas volumes are taken into account, excluding hydrogen - a very small share of which should enter the network as blended gas by 2030.

Taking all these elements into account, peak needs in 2030 are estimated at between 3,156 and 4,014 GWh/day for winter 2029/2030, down 3% to 24% compared to 2020, according to the scenarios.

Work to calculate the peak is done jointly with Teréga, and some aspects of the methodology still need to be harmonised.

25 | This system consists of an electric heat pump and a gas boiler coupled by a regulation system, getting the most from both technologies and saving energy.

FIGURE 48 | **Comparison by 2030 of the 2020 TYNDP trajectories for France, the scenarios in the 2020 Gas Outlook, and the GRTgaz-Teréga International Alternative scenario**



Source: TYNDP 2020[26], PG 2020, GRTgaz, Teréga

These peak trends cannot be considered as the sole determinants used in sizing the gas infrastructures, as there are many uncertainties surrounding them. They should hence be supplemented by sensitivity studies and risk analyses using different timescales.

Consistency with the TYNDP

These trends follow on from the scenarios proposed for France in the 2020 TYNDP produced by ENTSOG in coordination with ENTSOE.

The scenarios in the 2020 Gas Outlook are within the range of those of the 2020 TYNDP. The INTERNATIONAL ALTERNATIVE scenario, meanwhile, which falls outside the SNBC's self-contained framework, is 3% above the Global Ambition scenario for 2030 in the 2020 TYNDP.

The gas supply is abundant and competitive

Proven natural gas reserves that are accessible under current economic and operational conditions increased in 2019 to 198 trillion m^3 i.e. +0.9% compared to 2018[27]. New reserves were discovered in China, increasing from 6.4 trillion m^3 in 2018 to 8.4 trillion m^3. China now has 4.2% of all global reserves.

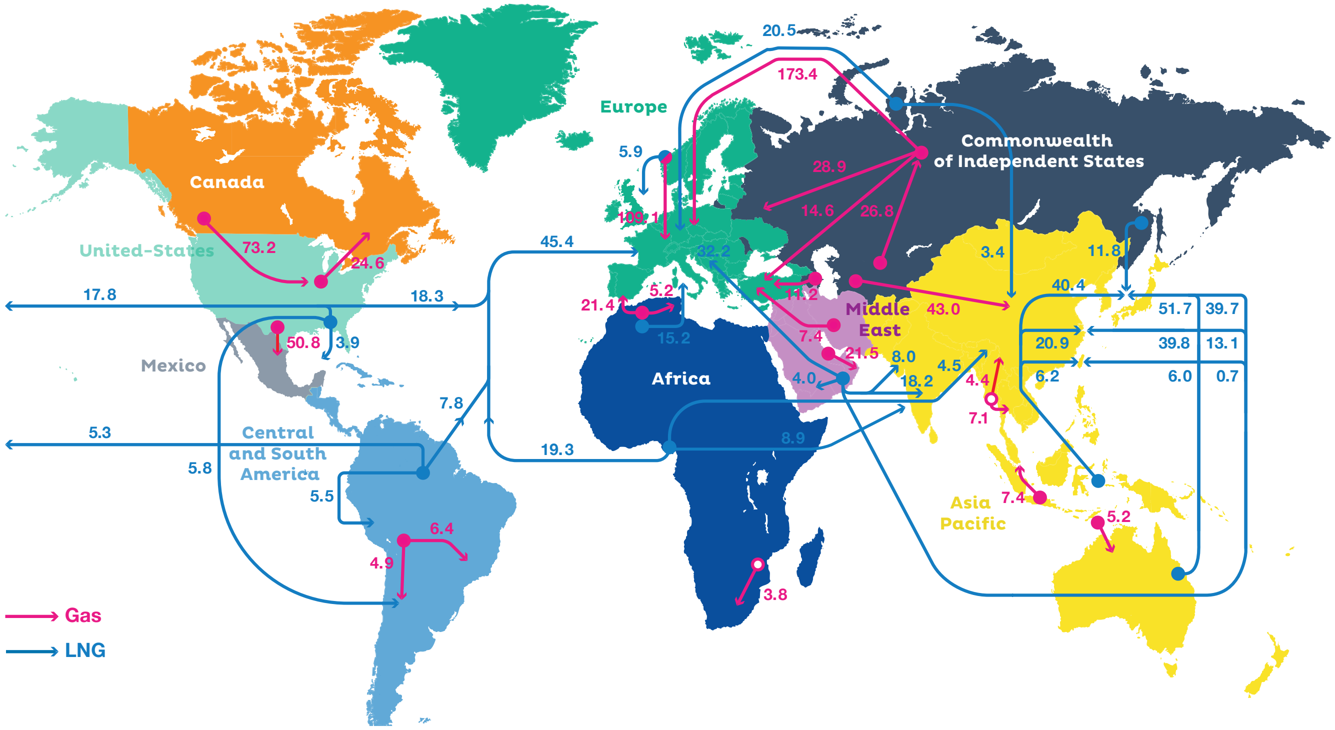
Norway produced approximately 115 Gm^3 of natural gas in 2019, almost all of which goes to Europe. At this rate, its proven reserves would allow Norway to produce for another 13 years. Russia, meanwhile, could still produce at the same pace (679 Gm3 in 2019) for more than 50 years with its proven reserves. EU imports will therefore diversify in the years to come. Reduced production of L-gas from the Dutch gas fields, in the short term, then from North Sea gas (Great Britain, Norway) in the medium term, could increase Europe's import needs. At least, it is likely to change European import flows. LNG, which in 2019 accounted for 20% and 38% of French and European supplies, respectively, is expected to take an increasingly significant share. The same is true for Russian gas, with Russia having the world's largest fossil natural gas reserve (38,000 Gm3). LNG imports in Europe also increased significantly in 2019 (+ 90% | +471 TWh in 2019 compared to 2018) and in early 2020, then fell drastically with the fall in European gas prices due to the Covid-19 health crisis. In France, they increased by 87% in 2019 to 219 TWh, i.e. +102 TWh compared to 2018, half of which was in Dunkirk, which saw a leap in LNG imports.

26 | The differences in volumes allocated to electricity generation come from a different scope, as the figures in the 2020 Gas Outlook also include gas consumed in cogeneration units.

27 | *BP 69th edition Statistical Review of World Energy 2020.*

FIGURE 49 | **Main international gas exchanges in 2019**

International flow exchanges (bcm)



Source: BP 69th edition Statistical Review of World energy 2020, includes data from FGE MENAgas service, IHS

Natural gas therefore remains available, and in large quantities, to support the energy transition in its fossil form by reducing GHG emissions from more carbon-intensive fuels. It should be noted that CO_2 capture and storage technologies and projects enabling low-carbon gas to be obtained from natural gas are still relevant.

Renewable gas is a major challenge for a sector faced with the energy transition, and there are currently four well-established technologies: anaerobic digestion, pyrogasification, Power-to-Gas and hydrothermal gasification.

In the context of the sustainability of resources, the potentials expressed below exclude production that would compete with priority food and material uses.

The IEA [28] estimates current global production at 35 Mtep (42 bcm). This is mainly in Europe (18 Mtep), then in China and the United States. In Europe, the majority of production comes from crops and crop residues. The majority of recovery is through cogeneration, but increasingly aimed at injection. In China, production comes mainly from livestock waste. In the United States, from fermentable household waste.

This production represents a very small proportion of renewable gas potential, which is estimated by the IEA at 730 Mtep/year (880 bcm). Of this, 570 Mtep/year (690 bcm) is for the anaerobic digestion sector, i.e. approximately 20% of global gas needs. The IEA estimates that these potentials could rise to 1,000 Mtep/year in 2040.

28 | https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth (mars 2020)

According to the IEA, the average cost of these current resources is contained at around €55/MWh ($18/Mbtu) worldwide, with the cheapest resources from NHWSF [29] gas estimated at prices comparable to those of current natural gas (estimated 30 Mtep). These estimates exclude the co-benefits provided by renewable gases in terms of waste management, which are far from negligible. By 2040, the IEA estimates that a potential 1,000 Mtep of renewable gas could see its average cost fall to €45/MWh ($15/MBtu).

In its "current policy" scenario, the IEA thus sees the production of renewable gas worldwide increasing from 35 to 150 Mtep (180 bcm) in 2040, i.e. an average annual growth rate of 6.8%. This value rose to 325 Mtep (390 bcm) in its "sustainable development" scenario (+10.7%/year).

For France, ADEME [30] estimated theoretical renewable gas potential at 460 TWh in 2050, 30% of which could be supplied by the mature anaerobic digestion sector; 40% by the pyrogasification sector using wood and its derivatives, solid recovered fuels (SRF); and 30% by Power-to-Gas.

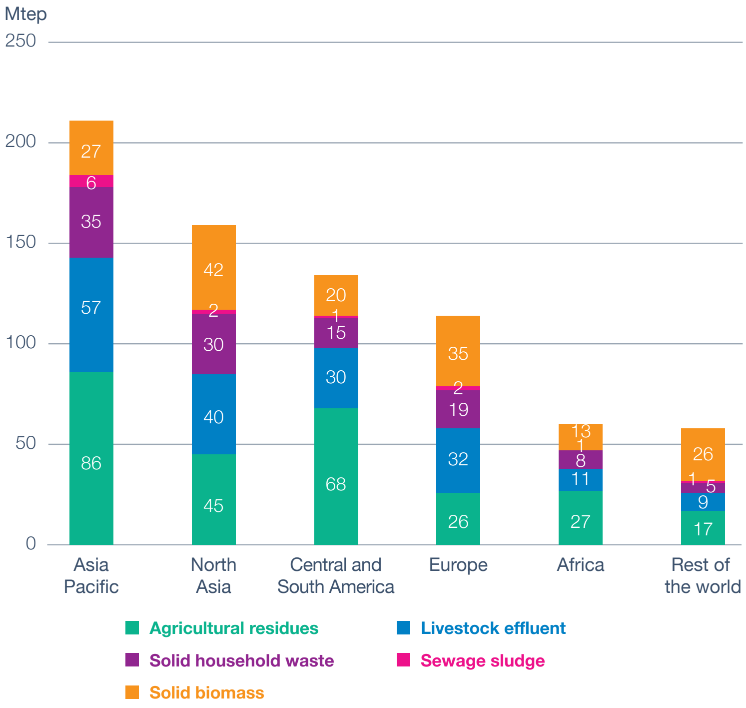
Furthermore, a study carried out by ENEA Consulting published in October 2019 estimated that renewable gases from hydrothermal gasification could have a potential of between 58-138 TWh/year by 2050, according to the assumptions for exploiting deposits.

As a reminder, the PPE sets a target for the production of renewable gas comprising 10% of gas consumption in 2030. This could represent between 39-42 TWh, and a target by 2028 of 14-22 TWh of biogas injected into natural gas networks.

In their joint "Gas Greening" report, the CRE's Foresight Committee and the INRA consider that the PPE's targets are realistic and achievable with the resources available at this time.

In 2019, the capacity register for biomethane projects reached more than 22 TWh. By end-2020, it had risen to more than 26 TWh for 1,164 projects - well beyond the upper limit of the PPE target for injecting biogas

FIGURE 50 | **Biogas or biomethane production potential by input type (2018)**



Source: IEA, *Outlook for biogas and biomethane: Prospects for organic growth*

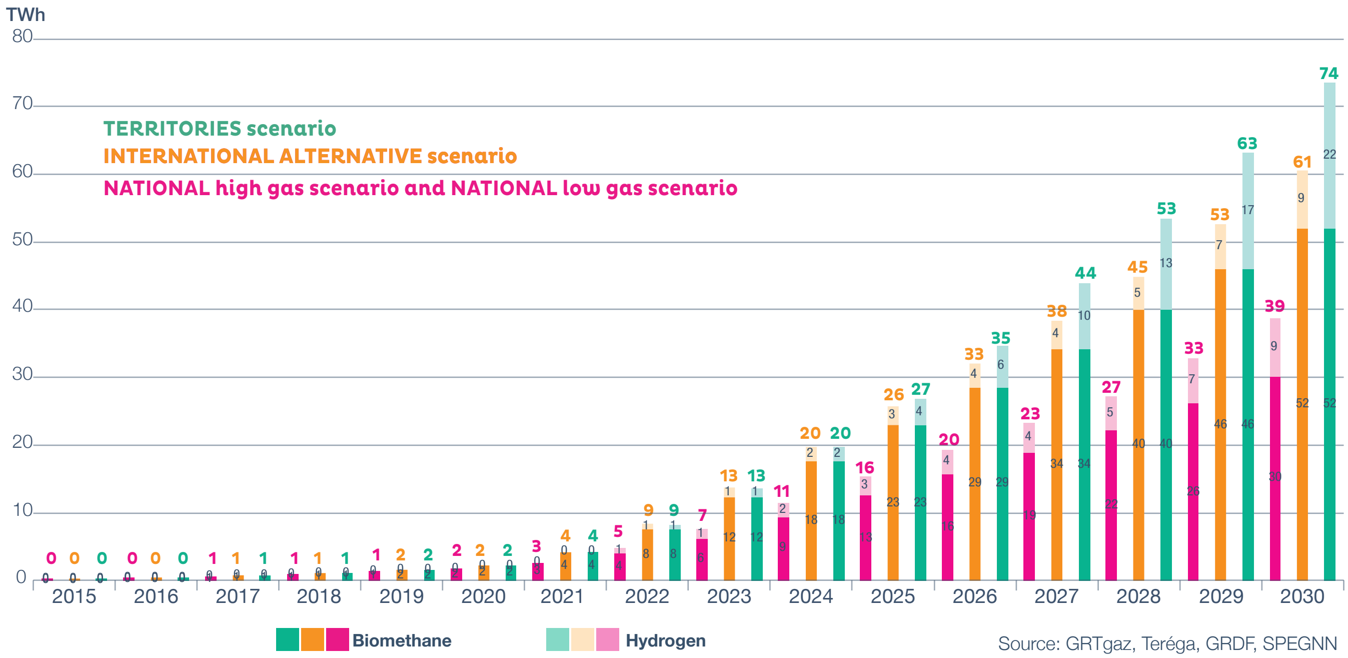
into the networks. To this end, and to increase the rise of biomethane in France, the public authorities, in consultation with market stakeholders, are giving thought to implementing an extra-budgetary support mechanism to sustain the sector's current momentum.

In the *2020 Gas Outlook*, the natural gas network operators estimate renewable gas production as between 39-73 TWh by 2030. This will mainly sustained by the rise of biomethane, as well as by the development of renewable and decarbonised hydrogen.

The **NATIONAL high gas** and **NATIONAL low gas** scenarios retain the PPE's biomethane trajectory, with 22 TWh by 2028 and 30 TWh by 2030. The **TERRITORIES** scenario, meanwhile, uses regional targets that would increase biomethane production to between 42-49 TWh.

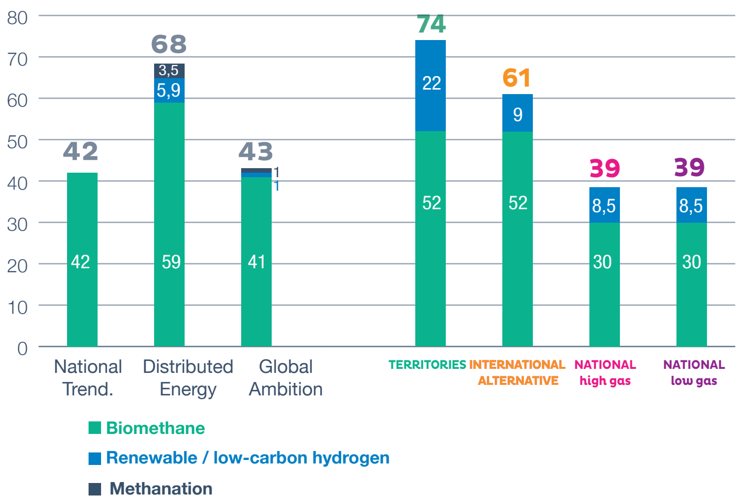
29 | Non-hazardous waste storage facilities.
30 | https://www.ademe.fr/mix-gaz-100-renouvelable-2050

FIGURE 51 | **Scenarios for the growth of renewable and low-carbon gas production in France**



Source: GRTgaz, Teréga, GRDF, SPEGNN

FIGURE 52 | **Comparison by 2030 of the renewable and low-carbon gas production trends in France's 2020 TYNDP, the scenarios in the *2020 Gas Outlook*, and the INTERNATIONAL ALTERNATIVE scenario**



Source: GRTgaz, Teréga, GRDF, SPEGNN, ENTSOG

For the production of renewable and low-carbon hydrogen, the **NATIONAL high gas** and **NATIONAL low gas** scenarios also reflect the targets set out the PPE and the SNBC, prior to the national goals been raised. This corresponds to a projection of approximately 9 TWh by 2030. The national hydrogen strategy has set a new and more ambitious target of 6.5 MW of installed electrolysis capacity, i.e. approximately 20 TWh 31 by 2030. The **TERRITORIES** scenario incorporates this trend by assuming that an additional share of decarbonised hydrogen is produced by means other than electrolysis (e.g. steam reforming followed by carbon capture, or methane pyrolysis). It is also assumed that approximately 2% of the hydrogen produced by 2030 can be injected into the methane network, either by blending, in compliance with regulatory thresholds, or after an additional methanation stage.

Finally, the **TERRITORIES** scenario also shows methane production from pyrogasification of approximately 1 TWh in 2028 and 2 TWh in 2030. Similarly, production from hydrothermal gasification is 0.5 TWh in 2028 and 1 TWh in 2030. The **NATIONAL high gas** and **NATIONAL low gas** scenarios do not foresee the emergence of these sectors before 2030.

31 | With an electrolyser operating at 70% energy efficiency and a 50% use rate, 6.5 GW represents 20 TWh of hydrogen production.

The scenarios developed for the 2020 Gas Outlook slightly widen the range of the 2020 TYNDP scenarios, while generally remaining within the same orders of magnitude. The *2020 Gas Outlook's* **TERRITORIES** scenario includes national hydrogen strategy targets that were still unpublished when the 2020 TYNDP scenarios were drawn up. The territory scenario volumes are therefore 9% above the ENTSOG "Distributed Energy" scenario. However, the "low" scenarios based on the SNBC targets are 7% less.

Supply-demand balance by 2030

In all of these scenarios, French gas demand should be met over the coming decade. Consumption is generally stable or falling, and the availability of natural gas remains high. Supply should also be significantly strengthened by the local production of renewable and decarbonised gas.

As gas is widely imported, the ability of the French gas system to meet demand at a competitive price or under specific conditions must be analysed at the European level. GRTgaz relies on analyses carried out by ENTSOG for this.

The resilience of the gas system is assessed according to the main objectives of the European energy markets: security of supply, competitiveness, market integration and sustainable development. Different scenarios for changing demand, procurement and infrastructure are considered. Several indicators are analysed to assess and identify investment needs. To do this, ENTSOG considers a minimum level of infrastructure - i.e. the current infrastructure - and projects subject to an investment decision ("Low infrastructure scenario").

In the 2020 TYNDP, ENTSOG confirms that most of the European gas network is well connected and on course to meet its assigned European targets. In terms of security of supply, the network is able to cope with contrasting supply mixes and to meet simultaneous peak demand throughout Europe, while maintaining a high level of flexibility, even in the event of disruption to a supply route. Most European countries benefit from diversified supply and market price convergence, especially in Western Europe.

For France more specifically, the various analyses show that the French gas market already enjoys very satisfactory levels of security of supply and access to gas, which is set to continue until 2030. In all the scenarios considered, including those that are relatively harsh in terms of climate, availability of supply routes or prices pressures, the French gas system is able to ensure the balance of gas demand under economic conditions better or comparable to those of other European countries.

Security of supply analysis

European security of supply is examined by modelling the system's ability to respond to extreme weather situations (daily demand at the cold peak simultaneously across Europe; a cold period lasting 15 days), combined with crisis scenarios such as disruption to one of the main European import routes (Ukrainian, Belarusian, Norwegian or Algerian roads) or to the largest infrastructure in each country. ENTSOG measures the remaining flexibility in these scenarios, as well as the share of demand that could not be supplied in each country.

The modelling results show a significant resilience throughout Europe, including in the event of disruption to the main supply routes. The exception is South-East Europe, for which there is a risk of failure to meet demand if supplies from Ukraine are interrupted on an extremely cold day. The European gas system's main flexibility tools are underground storage and LNG terminals. The analysis also shows that the development of renewable gases contributes effectively to the security of supply and reduces the risk of demand restraint.

The so-called "N-1" criterion is one of the main criteria defined by European Regulation 994/2010, which aims to guarantee the security of supply of natural gas. This indicator measures each Member State's available capacity to cover peak demand in the event of its main infrastructure breaking down (single largest infrastructure disruption (SLID) measurement). ENTSOG models this interruption while also taking into account the European-level impacts. In Western Europe, only the Republic of Ireland and Portugal do not meet this criterion.

FIGURE 54 | **Peak demand coverage with disruption to Ukrainian supply**

Daily cold peak, current infrastructure and Global Ambition scenario by 2030

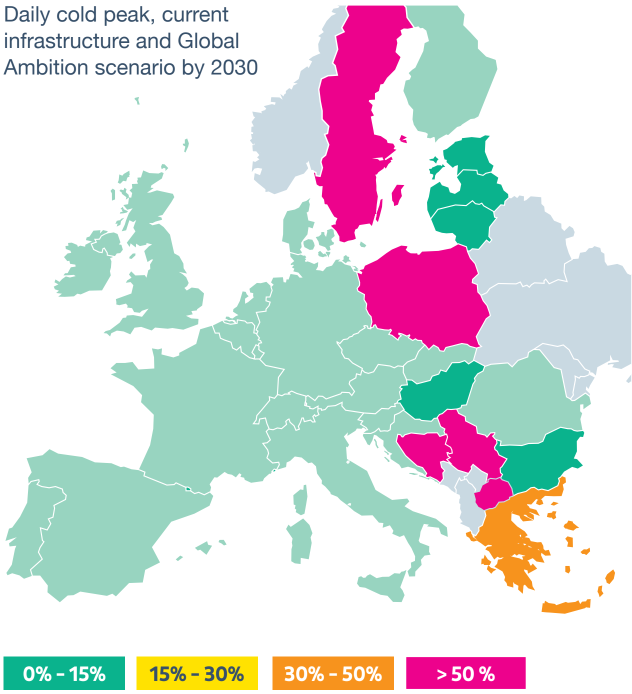


FIGURE 55 | **Peak demand coverage with disruption to Algerian supply**

Daily cold peak, current infrastructure and Global Ambition scenario by 2030

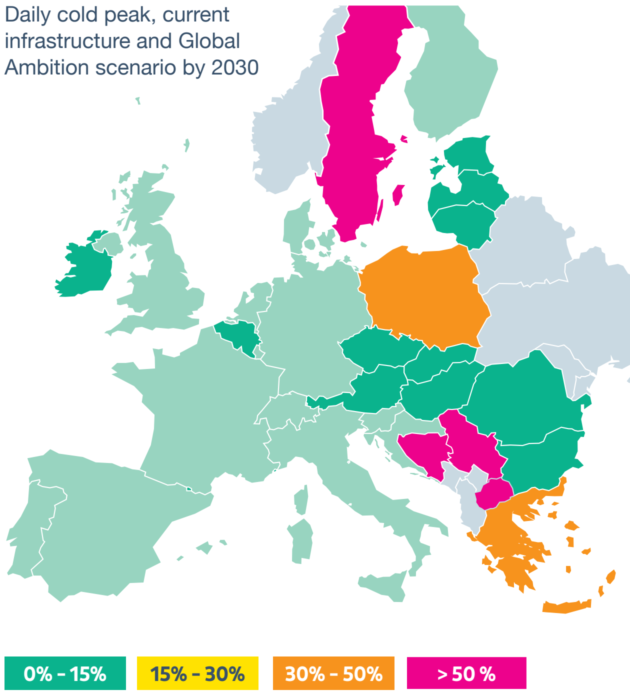
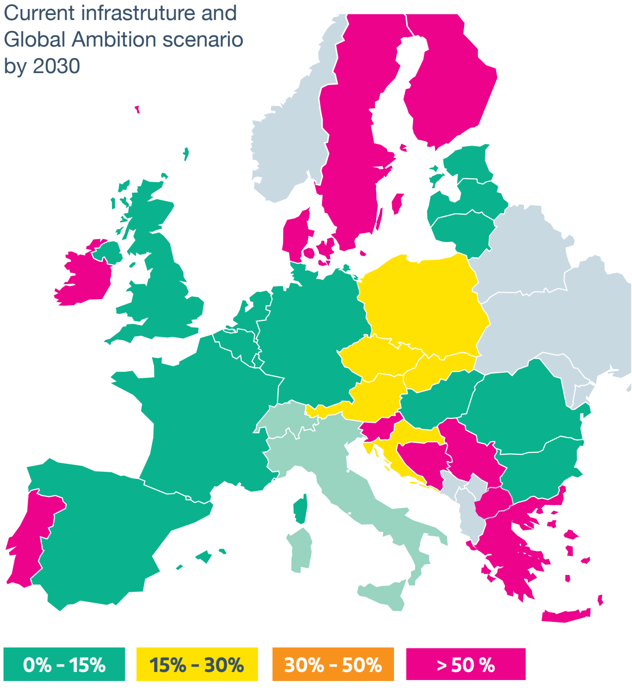


FIGURE 53 | **Peak demand coverage with single largest infrastructure disruption**

Current infrastructure and Global Ambition scenario by 2030



Source: *TYNDP 2020 – System assessment report*

Integration and competitiveness analysis

The 2020 TYNDP measures each country's ability to access a source of supply; or, conversely, its ability to do without a source of supply. From this perspective, France enjoys wide access to Norwegian and Russian gas, to LNG and European production, as well as, to a lesser extent, Algerian gas.

Its dependence on Russian gas is relatively low, as is the case for most Western European countries. The merging of zones means France is also reducing its dependence on LNG, while the Iberian Peninsula remains exposed to fluctuations in LNG prices.

The MASD (minimum annual supply dependence) indicator corresponds to a source's minimum share in the supply mix. It is used to measure a country's dependence on a defined supply.

The LICD (LNG and interconnection capacity diversification) indicator focuses on the capacities of interconnections and LNG terminals. It gives a diversification measurement. France already enjoyed a high level of

FIGURE 56 | **Countries' dependence on LNG indicator (LNG MASD)**

Current infrastructure and Best Estimate scenario (Gas before coal) by 2025

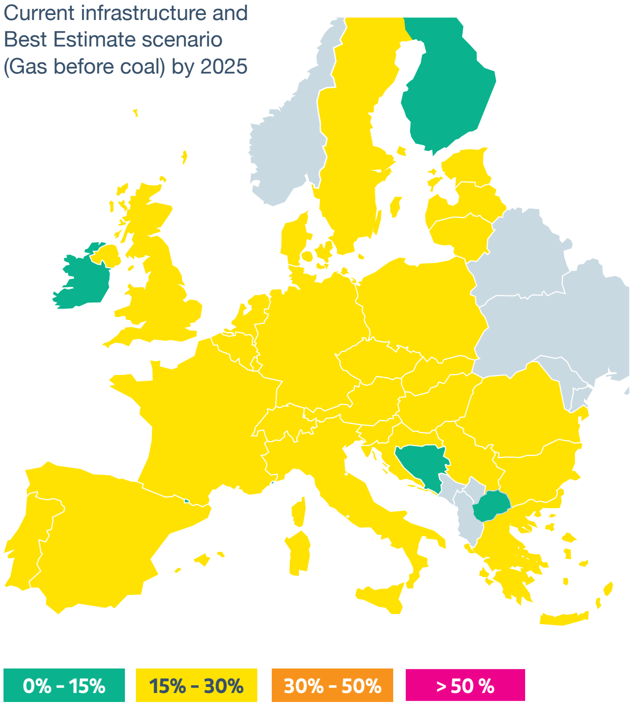


FIGURE 57 | **Countries' dependence on Russian gas indicator (Russian MASD)**

Current infrastructure and Best Estimate scenario (Gas before coal) by 2025

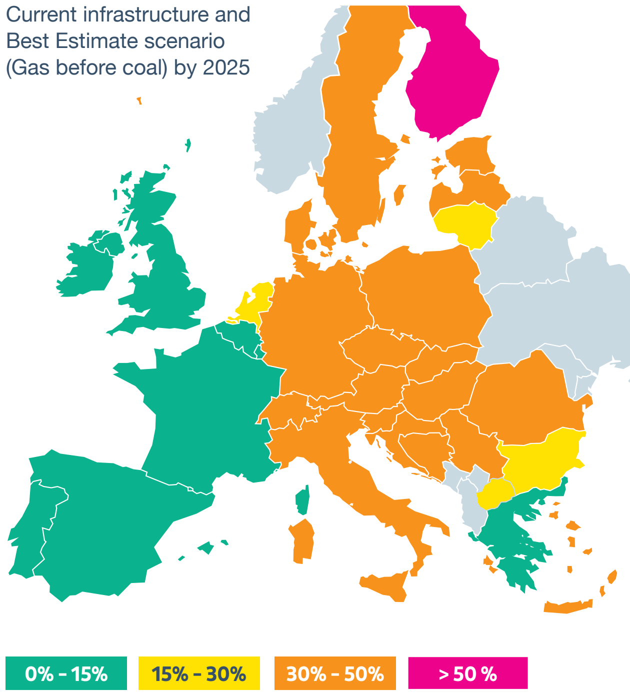


FIGURE 58 | **LNG and Interconnection Capacity Diversification indicator (LICD)**

Current infrastructure

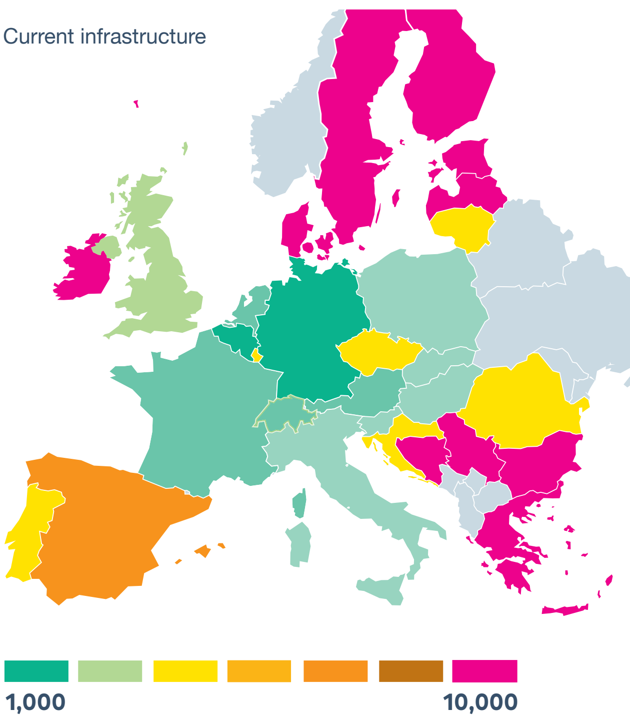
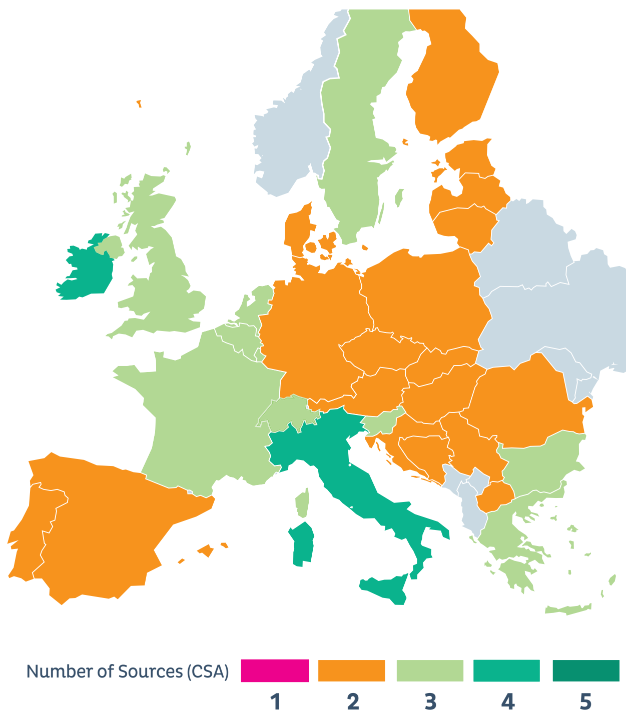


FIGURE 59 | **Commercial Supply Access indicator (CSA)**



Source: TYNDP 2020 – System assessment report diversification in 2020 through the capacities of its interconnections and its LNG terminals. This aspect is never in question, whatever the timeframe and the envisaged consumption or infrastructure development scenarios.

Finally, the CSA (Commercial Supply Access indicator) is an indicator monitored by ENTSOG. It measures the number of supply sources that a consumption zone can access from a commercial perspective. France has three different supply sources: LNG, Norway and Russia.

The state of play in 2050

Changes to the gas infrastructure require a long-term perspective. This section also highlights the longer-term challenges for gas transmission infrastructures, looking beyond the next decade.

The indicative long-term trends outlined for the first time in the Gas Outlook are a particularly useful source.

Consumption trending downwards

By 2050, the downward trend in gas consumption already seen by 2030 is confirmed due to the effects of energy efficiency, especially in the buildings sector. This decrease is partially offset by strong developments in gas-powered mobility (BioNGV and hydrogen), bringing total gas consumption to between 200-330 TWh in 2050, depending on the scenario (i.e. a decrease of between 35-60% compared to the current level).

By this time, demand is met based mainly on France's goal of carbon neutrality.

Prospective studies or scenarios made public by various organisations (ADEME, ENEA, Gas For Climate, France Hydrogen, etc.) indicate that renewable and low-carbon gases could be available in large quantities.

In the Gas Outlook, it appears that the level of demand envisaged by the SNBC or regional projections could be met by making reasonable use of renewable or low-carbon gas.

If the current trend continues, anaerobic digestion logically makes up the largest share of the renewable gas produced (between 130-140 TWh in each of the three scenarios).

In the NATIONAL low gas and NATIONAL high gas scenarios, Power-to-Gas technologies will produce around 40 TWh of hydrogen and synthetic methane in 2050. This level is similar to that in the SNBC. The production of hydrogen and synthetic methane could reach around 100 TWh in the TERRITORIES scenario, reflecting the strong ambitions expressed by the regions.

These strong regional ambitions are likewise seen in the gasification technologies that are also growth drivers for renewable gases in France. By 2050, these technologies will be used in different proportions depending on the scenarios, but especially in the TERRITORIES scenario, whose regional targets for producing syngas from gasification are more ambitious than those in the SNBC.

Many studies consider that renewable or low-carbon gases could be produced and imported in large quantities and at competitive prices in European countries. Hydrogen could thus be produced by large-scale low-cost electrolysis in southern Europe, or in the African or the Middle Eastern countries with long hours of sunshine. Imports could be in the form of hydrogen but also synthetic methane. Similarly, significant carbon storage capacities are envisaged in the North Sea, and some scenarios also consider the widespread use of methane pyrolysis (with solid carbon storage).

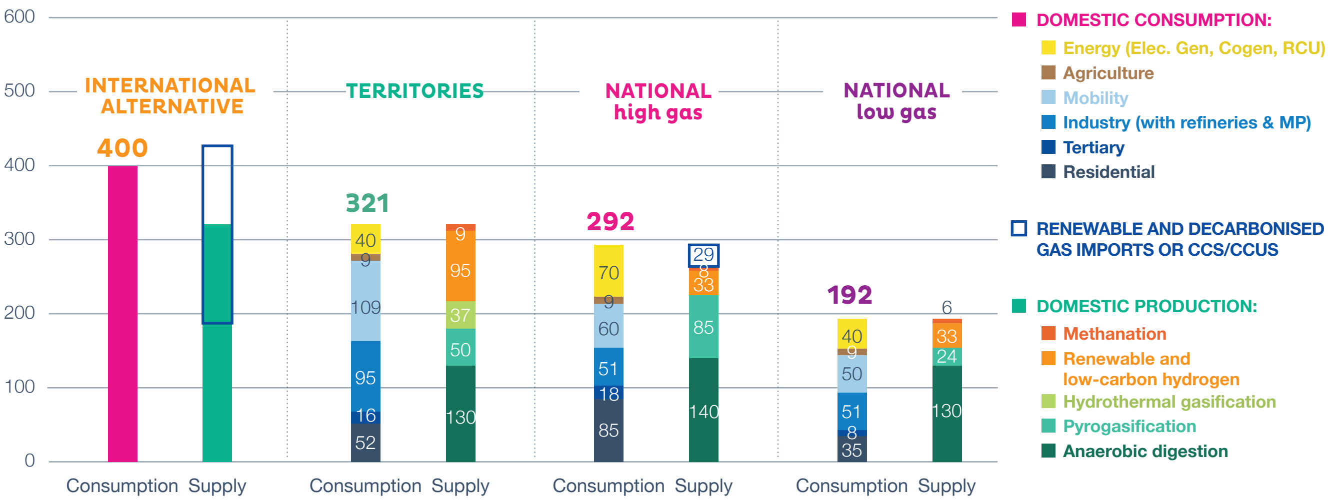
The INTERNATIONAL ALTERNATIVE scenario posits a balance between gas supply and demand that respects carbon neutrality by authorising renewable and low-carbon gas imports and enabling more dynamic consumption. Such a scenario would presumably be accompanied by the transit of renewable gas to neighbouring countries (e.g. Germany).

This drop in consumption is not necessarily synonymous with a corresponding drop in peak demand. The widespread uptake of hybrid equipment such as heat pumps, for example, will reduce annual requirements but not necessarily demand in periods of extreme cold.

High levels of uncertainty

Over this timeframe, large uncertainties remain about both consumption and production in terms of volumes, roles or location.

FIGURE 60 | **Breakdown of consumption by sector, and production by technology, for the three scenarios in the Gas Outlook and the International Alternative scenario, extended to 2050**



Source: *2020 Gas Outlook*, GRTgaz, Teréga

Forecasts for 2050 envisage changes in technology or behaviour whose impact on the resulting daily and yearly consumption is difficult to anticipate.

Regarding heating uses, for example, the behaviour of insulation or the operating specifications of hybrid heat pumps (HHP), beyond their levels of implementation, are all elements that should be studied to better classify the resulting consumption patterns.

The need to produce electricity from gas is still very uncertain and poorly defined in terms of roles. The scenarios drawn up in the SNBC only address annual volumes, and the RTE multi-year forecast, which should give some long-term clarification, is currently being drafted (the published 2021 forecast is limited to 2030-2035).

Nevertheless, the gas system's long-term insurance role appears to be increasingly important for the energy system in general and the electricity system in particular. Storable gas seems to be primarily for uses whose needs electricity struggles to meet, such as heavy mobility, high-temperature thermal uses, controllable electricity generation, and heating during cold periods or when the electrical system is under stress. Also, a network that is required for the widespread connection of decentralized generation will naturally become a means of uniting the different regions enjoying renewable gas resources.

These developments are shaping an energy system in which the links between gas and electricity are strengthened through increasingly hybrid uses and a new channel for producing gas from electricity (Power-to-Gas or Power-to-Hydrogen).

GRTgaz is seeing a significant transit potential for renewable gas take shape, in particular for green hydrogen, with centralised renewable production sources located in Spain and Northern Africa able the meet needs of the Central-Western European consumption areas (Belgium, Germany, the Netherlands, Denmark and England). This transit could be carried out by pipeline via France. The hydrogen transmission network devised by the European Hydrogen Backbone, an initiative bringing together more than 20 European gas transporters, can meet this need, among others.

3

Development and necessary adaptation of the network

MD Biogaz commissioning

The need to strengthen and adapt the network in line with changing transmission needs may result mainly from:
- additional import capacity needs to meet expected demand;
- requests from shippers for additional arbitrage capacities;
- connection requests for new injection or consumption projects
- requests to increase the capacity of operators of adjacent infrastructures.

All these needs and requests are identified and explained in this section.

It should be noted that until now, the TYNDP has focused almost exclusively on providing gas market stakeholders with information about the investments needed to develop an efficient market that is integrated into other European markets. Against the backdrop of the energy transition, decentralisation and the digital revolution, and with the French natural gas market reaching high levels of maturity, this plan increasingly aims to define the changes to the network that are needed to support the energy transition and the increasingly vital role of renewable gases in the gas mix.

Gas transmission infrastructures have long service lives and strong potential for increasing yields. While methane transmission needs could change significantly over time with increasingly cost-sensitive energy logistics, network adaptations should be analysed in view of their usefulness over time and in particular beyond the decade outlined in this plan.

In addition to these adaptations, investments in the network's maintenance and operational readiness are obviously essential to ensure the integrity and performance of the assets over time, and in many cases to minimise reinvestments. These investments must also take into account changes to environmental regulations, societal acceptance, technological advances in information systems, and cybercrime.

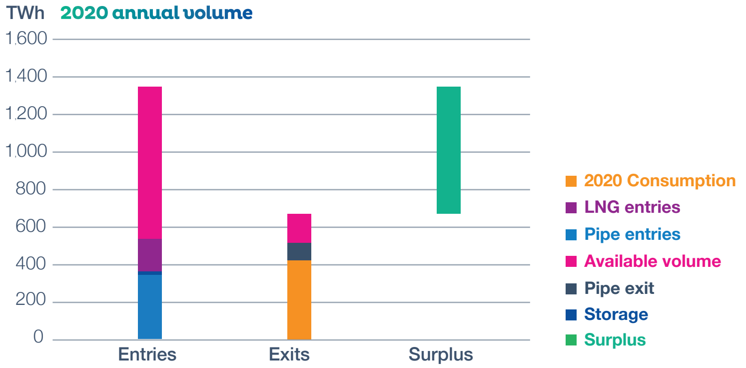
3.1 | Meeting supply and demand in the medium term

Available capacities in 2019

Network entry capacity currently covers annual demand as well as transit to Italy and the Iberian Peninsula, with a significant margin, with network entry and exit capacities sized based on other considerations (peaks, arbitrage, etc.).

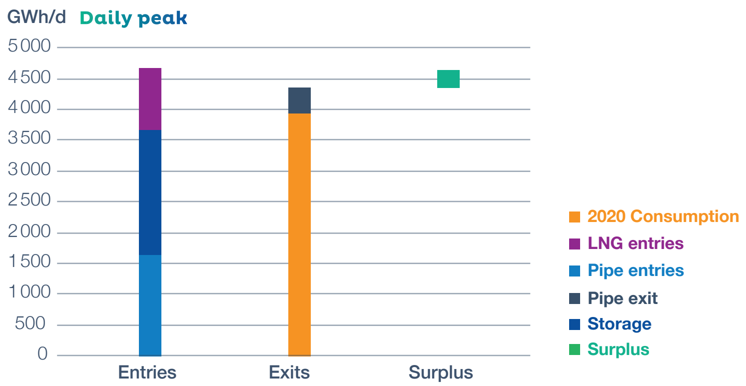
This remains the case at times of peak demand, although with lower margins. Taking the capacities subscribed for winter 2020 as a benchmark, analysis of the firm entry and storage withdrawal capacities compared to peak demand reveals a margin of around 300 GWh/day.

FIGURE 61 | **Network entry and exit capacities to meet demand**



Source: GRTgaz

FIGURE 62 | **Gas system margin at the daily peak**



Source: GRTgaz

As annual and peak gas consumption is expected to fall in the coming decade, the existing transmission infrastructure should meet these needs with a sufficient margin, as indicated by the results from the ENTSOG analyses mentioned in the section Supply and Demand Review.

This margin should be all the more comfortable, at least on an annual basis, as a non-negligible share of gas consumption in 2030 should come from the local production of renewable or low-carbon gas.

The balance of supply and demand is theoretical, and assumes that the capacities sold upon entering the network are used properly. It hence depends on the behaviour of suppliers, who are responsible for balancing their customer portfolio on a day-to-day basis.

For this reason, this forecast is enhanced every year by seasonal publications (The Winter Outlook and The Summer Outlook) to keep market stakeholders informed and up to date.

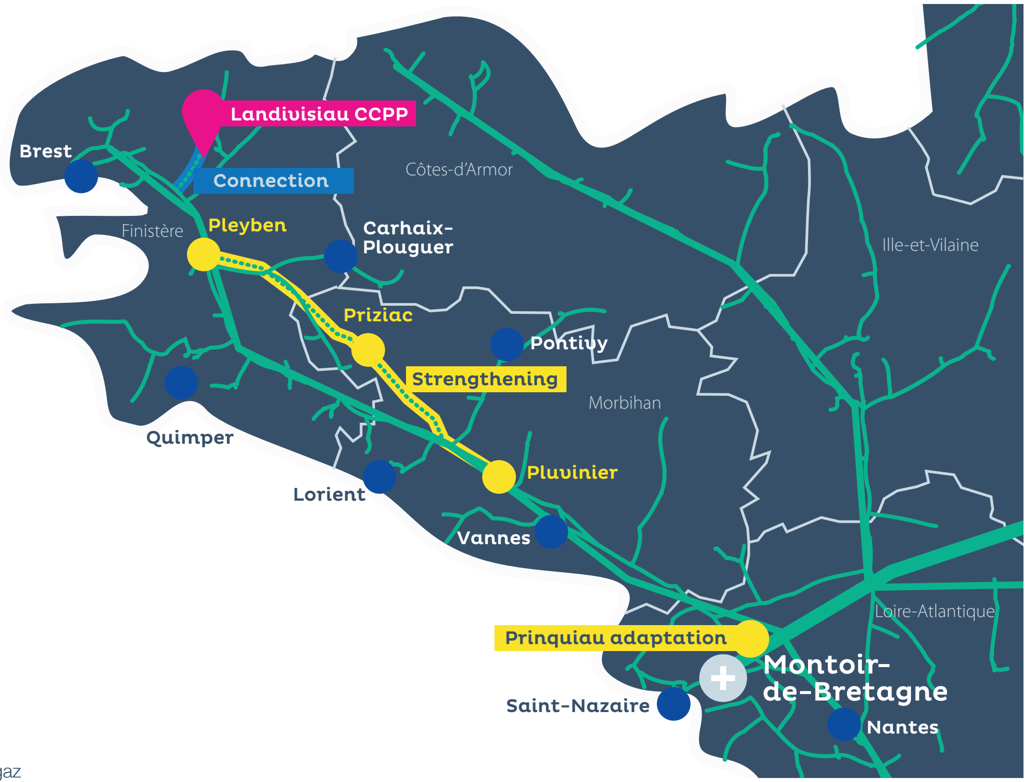
Adaptation requirements for connections

Local capacity increase requirements may be possible (boiler room conversion, new connections) on the distribution network or on the premises of industrial customers connected directly to the transmission network.

GRTgaz carries out work to adjust the flow rates for customers, public distribution systems or industrial customers. The location of these substations can also be changed to secure the power supply to a distribution area, or to support industrial companies in developing their processes. Investments to meet these needs have an annual budget of between €10-15 million.

In addition to these, gas-fired power stations and new gas vehicle refuelling stations are two important types of connection to the network.

FIGURE 63 | **Major works for the commissioning of the CCPP in Landivisiau**



Source: GRTgaz

Gas-fired electricity generation units

At this stage, prospective studies by the electricity transmission system operator do not highlight the need for new gas-fired electricity generation units until 2030, beyond the planned commissioning of an additional plant in Brittany.

Brittany has a fragile electricity supply, while its electricity consumption increases at a faster rate than the national average. This results in a regular stress to the network, particularly during winter cold spells. The decision to construct a new gas-fired CCPP near Landivisiau was made in 2010 as part of the Breton Electricity Pact signed by a number of economic and institutional stakeholders (the State, the Brittany Region, ADEME and RTE).

To supply natural gas to this plant beyond its basic connection to the gas transmission network, the gas network in South Brittany needs to be strengthened.

The South Brittany project consists of strengthening the natural gas transmission network by installing a new 98 km pipe between Pleyben (Finistère) and Pluvignier (Morbihan) and adapting the interconnection station in Prinquiau (Loire-Atlantique) (Figure 63).

On 20 April 2015, the work was the subject of a Declaration of Public Utility, followed by a Ministerial Decree on 16 September 2015 authorising its construction and operation.

Under the investment incentives regulation, the CRE has set a target budget of €137.80 million for the project, based on a cost audit.

The decision to carry out the works was taken by GRTgaz in March 2019, following confirmation of the CCPP project sponsor's commitment, to ensure that the plant in available for winter 2021/2022.

The gas consumption of these plants may vary considerably during the day depending on the use made of these new facilities, intraday semi-base load and peak generation, or generation compensating for the intermittent nature of renewable energies. The flexibility study conducted by GRTgaz shows that the GRTgaz network can meet the needs of intraday flexibility under standard supply and consumption conditions. In the most restrictive scenarios, with the network operating at close to its limit, the Provence region will still require the occasional use of external flexibility sources. The network's intraday flexibility, which has increased with the completion of recent works, has also reduced these needs. It is hence in a position to meet the needs of new changes to consumption patterns, if necessary.

The electricity network operator is performing studies on the possible needs for controllable electricity generation beyond 2030 as part of a long-term forecast. The adaptations that may be necessary if new means of generating electricity from gas were required would depend largely on their location. It should also be noted that these consumptions with high potential to vary throughout the day require the use of the network's compressor stations.

NGV and BioNGV stations

An NGV refuelling station consists mainly of compressors that compress natural gas from the pressure available on the network to the vehicle tank pressure (200 bar). These connections are mostly on the distribution network. In certain cases they may benefit from being connected to the higher pressure transmission network, especially when this is located nearby.

Plans are in place to connect refuelling stations for bus fleets to the network in 2020 and 2021. This will support their transformation towards lower-carbon biogas fuels and improve air quality in urban areas. Public station connections, mainly for heavy goods vehicles, are also expected.

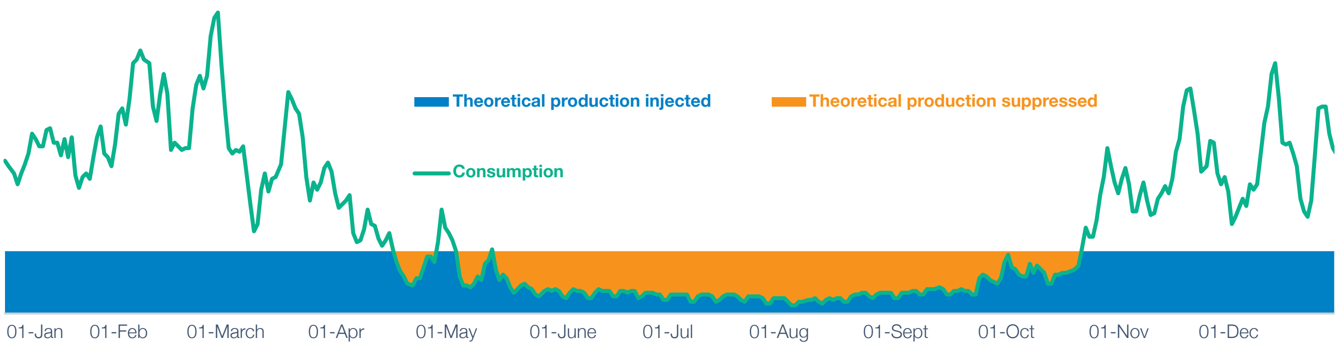
The PPE targets between 330-850 public stations by 2028, of which around 10% could be located on the transmission network. Currently, four station connections per year are planned on the GRTgaz network from 2021, for investments of around €17 million between 2020-2023. Beyond that, assuming a similar connection rate, there will be an estimated 43 public and private stations connected to the transmission network by 2030. This is equivalent to an investment of around €50 million using the same cost assumptions.

Beyond the connections and in the event of restricted power, the GRTgaz transmission network should not require strengthening for these new consumptions.

Renewable gas production units

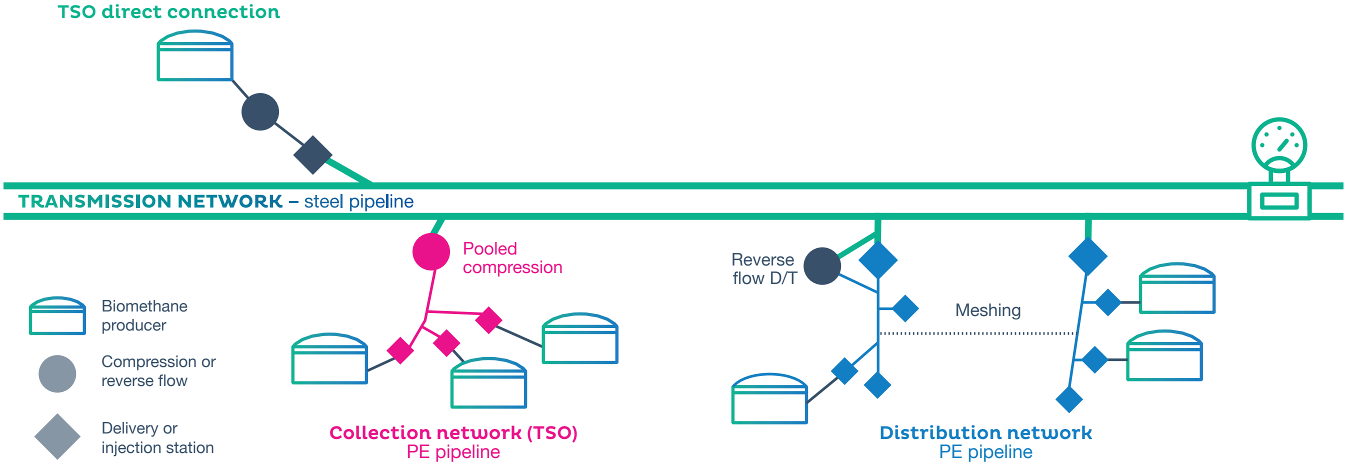
The expansion of biomethane production - the main renewable gas by 2030 - will be supported by these units being connected to the distribution networks. The largest projects will also be connected directly to the transmission network.

FIGURE 64 | **Summer saturation linked to the injection of biomethane into the distribution network**



Source: GRTgaz

FIGURE 65 | **Solutions for integrating surplus biomethane production from the distribution network**



Source: GRTgaz

Beyond these connections, injections into the distribution networks may exceed the area's consumption. This is particularly true in summer, when consumption is at its lowest. Gas that exceeds local consumption should then be transported to other consumption areas, in particular via higher pressure networks.

A defined investment framework

Network operators are considering several solutions to maximise the networks' capacity to accommodate biomethane injection projects. These include:

- connecting producers to unsaturated areas of the distribution network;
- network management with customised pressure settings;
- the meshing of distribution networks;
- compression facilities known as reverse flow stations, which allow gas to reverse its flow direction, moving it upstream towards higher pressure networks and expanding the consumption zone;
- increasing local gas uses, particularly in the form of fuel.

To remove barriers to injection projects, while avoiding over-investment, a "Right to Injection" for biomethane producers was included in the so-called "Egalim" law passed in October 2018. During 2019, the procedures for implementing this Right to Injection were drawn up jointly by network operators, sector stakeholders, the CRE and the Ministry (works involved, technical and economic relevance of the investments, distribution of strengthening costs between sector stakeholders).

Optimising network investments is mainly based on an economic test and works planning (known as "zoning").

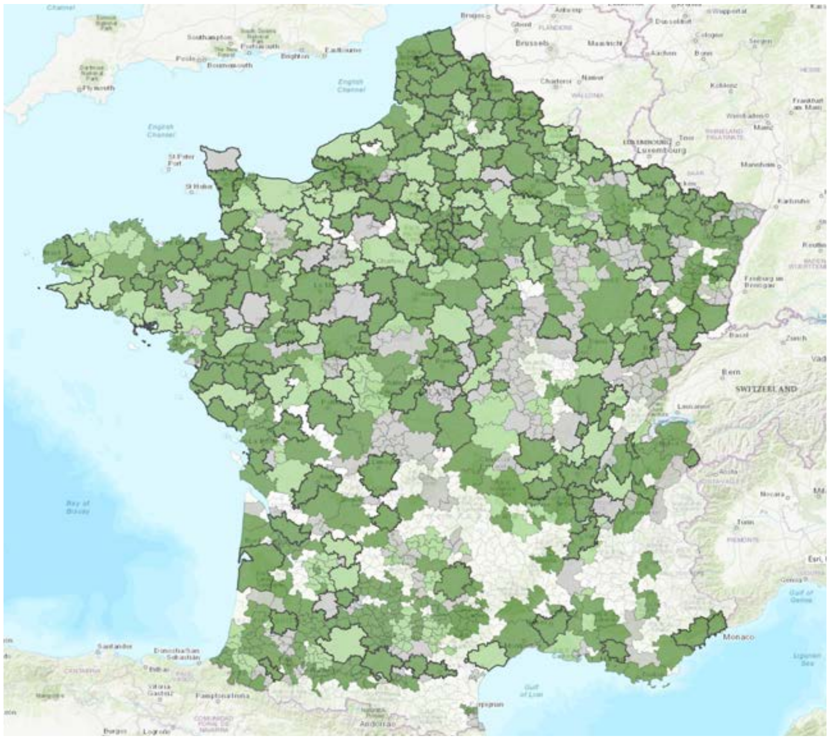
Under the Order of 28 June 2019, the framework for the economic test provides that investment costs can only be pooled if the investments reduced to the volume of injectable biomethane, weighted by a probability linked to the maturity of each production project, do not exceed €4,700/(m3/h). This assessment is carried out based on the PPE's medium-term scenario in which 22 TWh is injected for the whole of France by 2028.

In accordance with the deliberation of the CRE of 14 November 2019, connection zoning must be mapped to identify the network investments required in each zone, their eligibility for pooled investments according to the configuration of the networks, the projects recorded in the capacity register, and the methanisable potential per county based on a statistical distribution of projects.

Connection zonings are carried out jointly by transmission and distribution network operators.

Each zoning:
- includes the counties being studied and their potential methanisable deposits;
- includes the list of projects in the register, their progress, and the elements used to calculate the technical and economic zoning criterion (taking into account connection and strengthening investments);
- presents a map of optimal injection and strengthening projects in terms of the costs expected for the transmission (reverse flow) and distribution (meshed) networks;
- indicates the zone's capacity before and after strengthening;
- calculates the zone's overall technical and economic criterion;
- calculates the Investments-Volume ratio to establish eligibility for pooled strengthening costs.

FIGURE 66 | **Connection zoning map until March 2021**



Technical-economic criterion (€/Nm³/h) (2021)

- Under 3,300 (prescriptive)
- Under 3,300
- Between 3,300 and 4,700 (prescriptive)
- Between 3,300 and 4,700
- Over 4,700 (prescriptive)
- Over 4,700
- Data not available

Source: GRTgaz, Esri, Garmin, FAO, NOAA, USGS

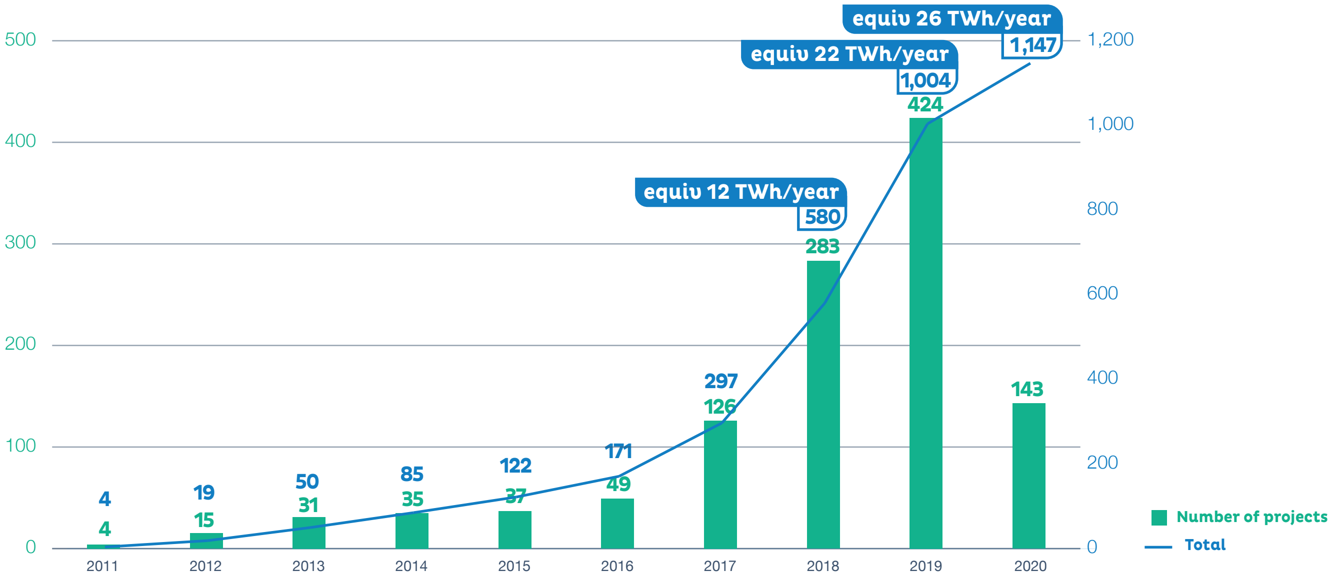
The approved zones meet the criteria for triggering these investments, i.e. an Investments-Volumes ratio below the threshold defined by the Decree (€4,700/Nm3/h), and include biomethane injection projects that have reached a high level of maturity (submission of an ICPE application).

A capacity register has also been set up to manage capacity subscriptions and to monitor the projects. Priority rules have been defined to avoid any possible saturation of the gas networks receiving the produced biomethane. These rules apply when several projects wish to connect to the same zone and are "competing" for the zone's injection capacities.

At the end of October 2020, 1,147 sites were listed in the register, with a production capacity of nearly 26 TWh of biomethane.


Connection of the shelter for the commissioning of the MD Biogaz site.

FIGURE 67 | **Biomethane Injection Capacity Register (October 2020)**



Source: GRTgaz

West Grid Synergy project for 100% green gas regions

WEST GRID SYNERGY

Premier démonstrateur européen de réseaux intelligents pour le gaz

West Grid Synergy's aim is to demonstrate the feasibility of a 100% green gas region by adapting the infrastructure, management and operation of gas networks to maximise biomethane injection capacity. This will include testing the first reverse-flow facilities (distribution network to transmission network).

West Grid Synergy's two main goals are:

- → to prefigure the gas system of tomorrow by implementing a large-scale demonstrator;
- → to analyse stakeholders' expectations and perceptions to support the regions in their energy transformation.

The project includes several partners:

- → network managers: GRTgaz, SOREGIES and GRDF;
- → energy unions: Morbihan Énergies, SIéML, SyDEV.

The demonstrator operates in three French regions [Mauges Communauté (49), Pays de Pouzauges (85) and Pontivy Communauté (56)]. Several biomethane injection projects will gradually be connected to their distribution and transmission networks. In total, nearly 240 GW h/year should be injected by 2022, i.e. the energy needed to run a fleet of nearly 1,000 buses (based on an average consumption of a 256 MWh/year per bus).

This project forms part of a regional drive led by the Brittany and Pays de la Loire regions through the SMILE project, which aims to create a large smart energy network in the west of France. The experiments are closely linked to biomethane production projects and the development of new efficient uses for gas, such as mobility.

A 43 km "biogas backbone" was inaugurated in June 2018 on the Soregies distribution network in Mauges. It will secure up to 120 GWh/year of biomethane injection potential in the region, while meeting the expectations of gas-intensive industrial stakeholders.

France's first two "reverse flow" stations were commissioned at the end of 2019 in Pouzauges and Pontivy. These make it possible to transfer surplus biomethane from the distribution networks to the transmission networks.

In addition to the planned reverse flow experiments, the following new solutions combining gas and digital networks are being tested from 2020:

- → a smart solution for the dynamic regulation of delivery pressure to meet the needs of downstream distribution networks as closely as possible, increasing biomethane injection capacities;
- → optimising biomethane storage in gasometers at injection sites or in NGV stations;
- → distributing a Regional Energy Autonomy indicator to promote renewable gas production in the regions;
- → maintenance synchronisation via the exchange of information between stakeholders; predictive maintenance using equipment instrumentation.

All of these identified use cases require the whole gas system to be modelled, both in advance and at the time of execution. Modelling the system and carrying out simulations will enable the prediction of the network's dynamic behaviour (real-time and predictive consumption and production). Solutions that will maximise the integration of renewable energies into the gas network can then be studied.

Pontivy reverse flow station: compressors, air coolers and piping skids.

Network strengthening

To enable the most advanced projects to be injected, it has already been decided to strengthen the network in zones where these new production capacities exceed local absorption capacities. Initial work to strengthen the transmission network was carried out in the municipalities of Pontivy, Pouzauges and Mareuil-les-Meaux, where reverse-flow facilities have been operational since 2020.

Reverse flow stations make it possible to feed gas from the distribution networks to the transmission networks at a rate of 1,000 to 3,000 m3/hour (i.e. between 0.3-0.8 GWh/day).

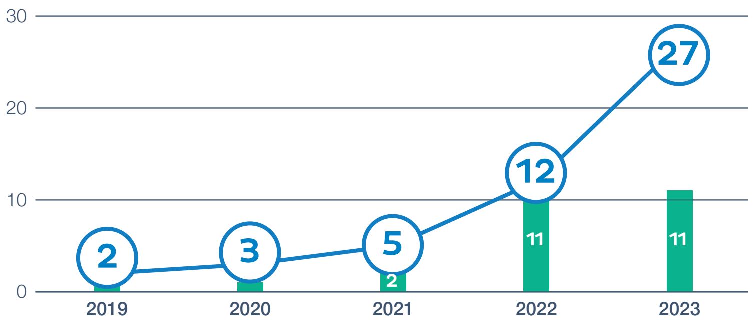
In its deliberations of 23 January 2020, 22 July 2020 and 21 January 2021, the CRE approved the construction of nine new reverse flow stations in the zones of Bourges, Valois (commissioning expected in summer 2021), Soissons, Vouziers, Craon, Laon, Argentan, Troyes and Rennes Ouest for a total investment of €28 million. Approval was likewise given to launch network strengthening studies in the zones of Châlons-en-Champagne, Châtillon-sur-Seine, Rethel, Châteaudun, Corcoué, Montluçon, Étampes, Bressuire, La Ferté-Bernard, Gien and Le Perche for a total potential investment of €32 million. These decisions were taken under the new Right to Injection mechanism.

GRTgaz plans to build and commission some 30 reverse flow stations by 2023. In accordance with the Right to Injection mechanism, each decision will be taken based on co-constructed connection zoning, and approved by the CRE.

As of March 2021, zoning projects already submitted to the CRE represented a production potential of 28 TWh of biomethane. The connections and strengthening projects in these 216 zoning plans cover approximately half of France. The completion of all the investments identified in these local network development plans would result in a total of €950 million split between strengthening works (54 reverse flows stations for €175 million) and network extension works (€275 million for distribution network meshing and €500 million for connections).

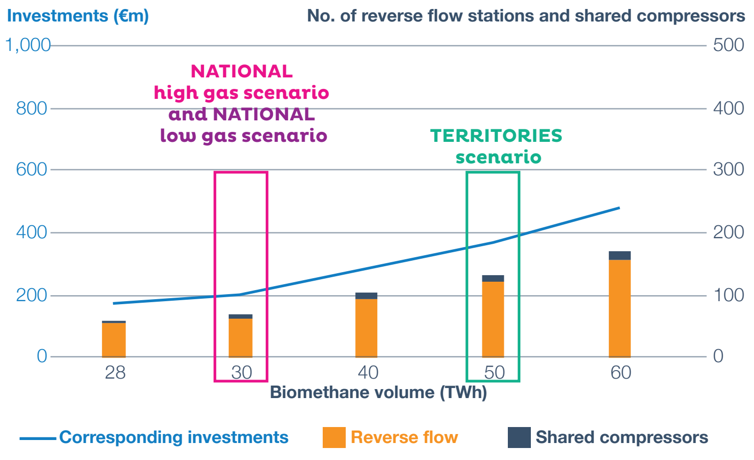
By combining these results with a set of assumptions, we can estimate the investment needs for larger volumes of biomethane injection extended to the whole of France.

FIGURE 68 | **Estimate of the number of reverse flow stations on the GRTgaz network at end-2023**



Source: GRTgaz

FIGURE 69 | **GRTgaz's potential strengthening investments according to France's biomethane injection targets**



Source: GRTgaz

To reach the 30 TWh of biomethane injection for the NATIONAL high gas and NATIONAL low gas scenarios in the 2020 Gas Outlook, the models estimate a need for 63 reverse flow stations and six shared compressors, for an investment of around €200 million by GRTgaz. To reach the 50 TWh of biomethane injection for the TERRITORIES scenario, the models estimate a need for 121 reverse flow stations and 11 shared compressors, for an investment of around €371 million by GRTgaz.

These figures still contain a high level of uncertainty. They should hence be viewed as an initial clarification to assess the potential network adaptations needed to expand the biomethane sector.

Among the assumptions made, notable examples include: the geographical distribution of injection projects is assumed to be random, and their size distribution identical to that seen in the capacity register; the projects are assumed to be sufficiently close to the network for connection to be cost-efficient for the producer; additional meshing of the distribution networks is assumed to be carried out prior to the Distribution-Transmission reverse flow and between different Transmission-Transmission pressure regimes, as it is assumed to be less expensive; once installed, the reverse flow station is assumed to operate for a minimum amount of time during the year; compliance with the I/V threshold for reverse flow facilities was not included in the study. Consumption reduction forecasts were also taken into account.

This method can also be applied to gases produced from technologies other than anaerobic digestion. However, the injection of these new gases may also require some adaptations related to the quality of the gas, which may contain a slightly higher percentage of hydrogen.

Guaranteed arbitrage or transit needs

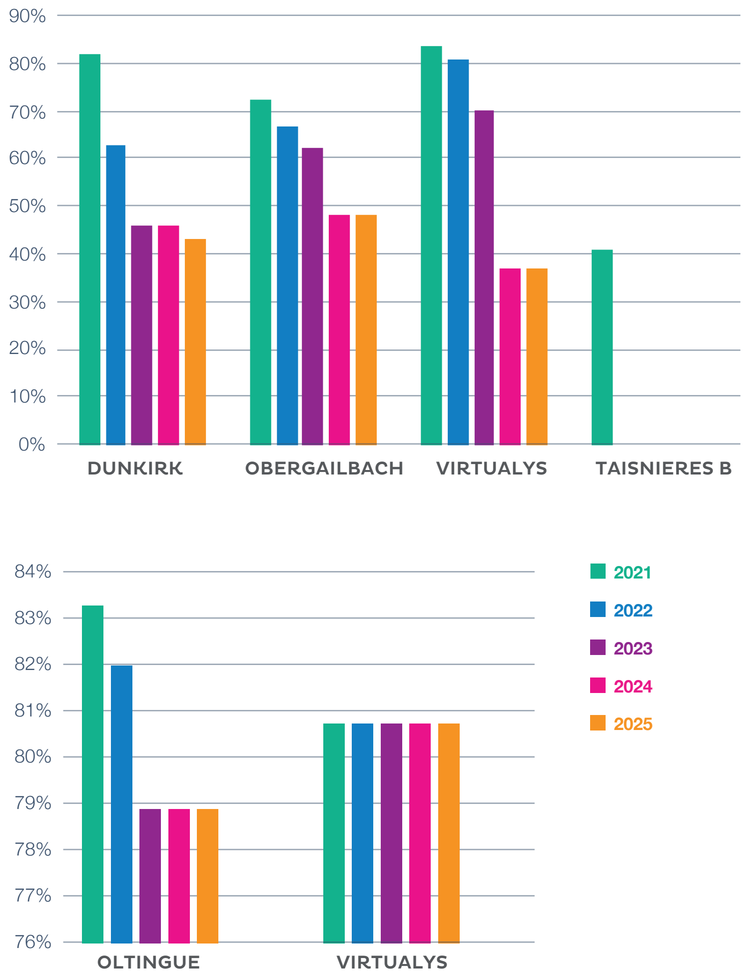
Capacity increases have often resulted from additional capacity requests from network users to increase their access to the most competitive gas in Europe or world-wide. Given the capacity reservations made for the coming years and feedback from the incremental process consultation, the network now seems well-suited to the needs of shippers.

It should be noted that as the energy transition is also underway in the Iberian Peninsula and Italy, gas transit needs are expected to decrease for these countries.

The incremental capacity process was implemented in 2019 in accordance with the network codes for Pricing and Capacity Allocation Mechanisms (CAM). From 1 July to 26 August 2019, transmission network users were able to make non-binding requests for additional capacity on the network interconnection CAM points between European Union countries (Virtualys, Taisnières B, Obergailbach), and also at Oltingue with the TSOs.

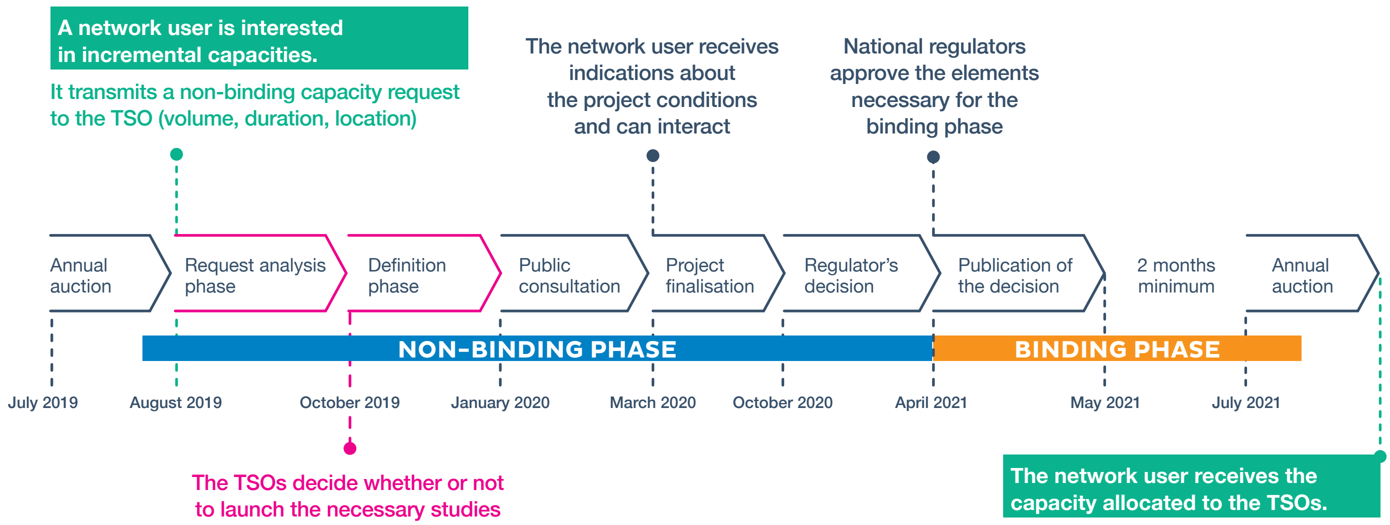
On 21 October 2019, GRTgaz and the adjacent network managers published the result of this consultation in a Demand Assessment Report for each of the points. The reports conclude that current capacity is sufficient to meet demand. The next phase of consultation on this process will take place in H2 2021. In the meantime, network users can freely share their additional capacity requirements with TSOs at any time. In 2020, no *ad hoc* requests were made by network users on French points.

FIGURE 70 | **Reservation of capacity subscriptions at entry-exit IPs 2021-2025**



Source: GRTgaz

FIGURE 71 | **Stages of the Incremental Process**



Source: GRTgaz

With the fall in consumption and import requirements, arbitrage capacities with unchanged marketable capacities will tend to increase. However, the level of capacity at the IP in the longer term must also be analysed in the light of the French market's needs for security of supply, in coordination with the adjacent network operators.

Requests from adjacent operators

In preparation for this plan, GRTgaz interviewed adjacent gas infrastructure operators about their development projects.

The projects below reflect the outcome of this consultation. Feedback from adjacent operators shows that only projects planned for LNG terminals are likely to require network investments.

Adjacent transmission network operators did not report a need to strengthen network interconnection capacities at the borders. GRTgaz therefore proposes that exit capacities to Germany are no longer included the TYNDP.

However, some adjacent operators have indicated a need for improved coordination for potential cross-border exchanges of pure or blended hydrogen. To ensure the integrity of our networks and the safety of our customers, there seems to be a pressing need for convergence in the specifications for the rates of hydrogen injection into the natural gas networks. German gas transmission network operators have nevertheless drawn GRTgaz's attention to the potential need to import renewable gas from France in the long term.

Apart from the conversion of the Gournay storage facility, the storage operators connected to the GRTgaz network have not given notice of any project requiring adaptation of the transmission network.

Support for the development of the Fos and Montoir LNG terminals

France has four LNG terminals: Fos-Tonkin (3 Gm^3/year) commissioned in 1972, Montoir-de-Bretagne (10 Gm^3/year) commissioned in 1980, Fos-Cavaou (8 Gm^3/year) commissioned in 2009, and, since 2016, Dunkirk LNG (13 Gm^3/year). Projects are being considered for the Fos and Montoir terminals.

Nozay compressor station.

Montoir (2026)

Between July and November 2019, Elengy organised a call for subscriptions for existing and available regasification capacities at the Montoir-de-Bretagne LNG terminal. All capacities have been subscribed up to 2035.

Elengy is working with the market to examine the possibilities for extending the terminal, and in particular plans to increase the Montoir-de-Bretagne terminal's capacity from 10 to 12.5 Gm3 by 2026, with the possibility of building a new tank in 2025.

Depending on the injection capacity on the network following the extension of the terminal, it may be necessary to:

- adapt the Auvers-le-Hamon compressor station;
- double the diameter of the Maine artery to DN 900 between Nozay (Loire-Atlantique) and Cherré (Maine-et-Loire);
- and where applicable, install a pipe between Chémery (Loir-et-Cher) and Dierrey (Aube).

The structures identified on the GRTgaz network could be built subject to approval by the regulator, and if Elengy enters into the commercial agreements necessary for its extension project to be completed.

Fos-Tonkin (2021) and Fos-Cavaou (2026)

Following a call for subscriptions in February 2019, Elengy decided to extend the operation of the Fos-Tonkin terminal from 2021 to 2028 at 1.5 Gm^3 per year, i.e. half of the terminal's current capacity. These commitments enabled Elengy to make the necessary investment decision for the work required to extend the site's operational life.

Fosmax LNG is considering expanding the Fos-Cavaou terminal from 8 Gm^3 to 12.5 Gm^3 per year by 2030, with intermediate configurations possible through technical and regulatory bottlenecks.

In view of this, Elengy and its subsidiary Fosmax LNG launched a call for capacity subscriptions in 2021. Along with Teréga, GRTgaz is studying the impacts of these

potential developments on their respective transmission networks. GRTgaz's network investment needs could include:
- adapting the Saint-Martin-de-Crau interconnection;
- renovating and/or rebuilding the La Bégude compressor station;
- a new compressor station in Montpellier;
- doubling the size of the artery in Southern France.

GRTgaz will identify the necessary strengthening measures in light of the injection capacities ultimately requested by the zone's terminals, as well as changes in local consumption.

No specific request from storage operators

France has 12 storage facilities in operation for a total available volume of 137.9 TWh, i.e. one-third of annual gas consumption. Operators of these facilities are considering investment projects aimed at maintaining and securing the performance of the sites.

Storengy is planning to invest in Gournay by 2025 to adapt its facilities for the L-gas to H-gas conversion, in particular to allow low flow rates. These investments are coordinated with the schedule for the L-gas zone conversion.

Géométhane announced the end of its Manosque storage renovation project (Alpes-de-Haute-Provence) to increase its injection and withdrawal capacity.

The project for a new exit to Germany is withdrawn

France and Germany are linked at the Obergailbach/Medelsheim interconnection point, with a capacity of 620 GWh/day going from Germany to France. No firm capacity is currently offered from France to Germany. By making this point physically bidirectional, the project could increase the integration of the two markets, if needed.

Fuel gas station for the Fos-Cavaou interconnection boilers at the Saint-Martin-de-Crau compressor station

This project addresses the following issues:
- contributing to the supply needs of West/South-West Germany, in particular to meet the increased needs of CCPPs;
- providing Germany and neighbouring countries to the east with access to the many LNG terminals in western Europe, at a cost far lower than that of a new LNG terminal;
- offering more arbitrage potential between the two markets where the spread moves in both directions.

In addition to the investments needed to create firm capacities are those needed to offer unodourized gas at the German border.

Unlike in most European countries, natural gas, which is generally odourless, is odourized in France. This occurs by means of an additive (a sulphur compound, THT) when it enters the transmission network. The purpose is to identify any leaks on the distribution networks and interior installations.

As the specifications for gas injected into the German gas networks are not compatible with odourized gas, gas exports from France to Germany are not possible at present.

GRTgaz has examined two solutions to this issue: i) decentralised odourization, based on the European model; and ii) deodourizing gas flows from France to Germany. The first option was abandoned given the significant costs revealed by a series of on-site tests.

The second solution would involve installing a deodourization unit on the North-East artery. Odourized gas would be treated by absorbing the THT using a molecular sieve. This solution has the benefit of being much more cost-effective in terms of investments, with operating expenses proportional to use, making it suitable for intermittent flows. The same solution is also envisaged between Switzerland and Germany.

The contractual tools for creating export capacities from France to Germany were in place, and adapted to low non-structural flows. However, ENTSOG's analysis did not show benefits exceeding costs for an investment-based project. No request has therefore been made by network users or adjacent operators. GRTgaz hence proposes to remove this project from its ten-year plans in the absence of market interest.

Gas quality management

L-gas to H-gas conversion

The low calorific value gas network (known as “L-gas”) supplies natural gas to most of the Hauts-de-France region. L-gas accounts for around 10% of total French consumption and 1.3 million customers, including around 100 that are directly connected to the transmission network.

Historically, it has come from the Groningen deposit in the Netherlands. This deposit has already begun to reduce production, and France is no longer expected to receive L-gas by 2030.

To ensure the continuity of supply to consumers, this network needs to be converted for the high calorific value gas (known as “H-gas”) that supplies the rest of France. As well as modifications to the networks, this large-scale project requires each customer to make an inventory of devices using natural gas (industrial processes, ovens, boilers, gas cookers, etc.), and in some cases their adjustment, modification, or even in a few rare circumstances their replacement.

The project is essential to ensure the continuity of supply for L-gas consumers. Beyond this, it will improve the security of gas supply for this section of the network, which currently has only by a single entry point and a single supply source in Taisnières. The project will create new connections with the rest of the transmission network and provide access to diverse sources of H-gas.

It will also lead to an improvement in transmission efficiency. As the energy content of H-gas is greater than that of L-gas, the volumes of gas to be transported will be lower for the same end-user requirement.

In October 2017, the European Union selected the tender submitted by Fluxys, GRTgaz and Storengy for the conversion in Belgium and France from the list of Projects of Common Interest (PCI).

FIGURE 72 | **L-gas conversion by gas consumption sectors**

Source: GRTgaz

On 4 October 2018, the CRE and the Belgian Federal Commission for Electricity and Gas Regulation (CREG)[32] made a joint decision to allocate the cross-border costs of this project in line with the existing cost allocation for each country.

A European Coordination on L-gas has been set up within the Gas Platform, with regular meetings between the Member States concerned (Netherlands, Germany, Belgium, Luxembourg and France). In 2019, this Coordination was bolstered by a dedicated "Task Force". Under the aegis of the Dutch Ministry of Economic Affairs and Climate Policies, ENTSOG and the IEA, the Task Force will publish a half-yearly report on the progress of the conversion of the L-gas markets in these countries.

A collaboration agreement for the conversion of L-gas to H-gas in Belgium and France was also concluded between Gasunie Transport Services, Fluxys and GRTgaz. Regular technical exchanges between Belgian, German and French operators are also being held to discuss the conversion processes in each country. Finally, the TYNDP and the North-West Gas Regional Investment Plan (GRIP) include the issue of L-gas in their respective reports.

The French legislative and regulatory framework

Implementing a specific legal framework was a key prerequisite to preparing this conversion, in particular to define the schedule of the operation, the responsibilities of the different stakeholders, and the technical procedures used.

This framework is based on the legislation below:

- Article 164 of Law no. 2015-992 of 17 August 2015 on the energy transition for green growth;
- Decree no. 2016-348 of 23 March 2016 detailing the regulatory framework and general organisation of the conversion operation. This Decree provides for the completion of a pilot phase between 2016-2020, the joint development of a draft conversion plan by the network and storage facility managers, and the setting up of a coordination committee;
- the Order of 10 July 2017 detailing the municipalities affected by the pilot phase;
- Law no. 2017-227 of 24 February 2017 expanding the tasks of DSOs to coordinate operations to adapt and adjust the devices of consumers on the distribution network, and introducing provisions relating to the conversion of storage facilities;
- the Order of 31 July 2018 authorising GRDF, GRTgaz and Storengy to convert a portion of the L-gas transmission and distribution networks on an experimental basis;
- and, finally, Article 183 of Law no. 2018-1317 of 28 December 2018 relating to 2019 finance, which provides financial assistance for replacing non-adaptable devices (conversion cheque), the amounts of which are set by Decree no. 2019-114 of 20 February 2019.

Conversion plan

GRDF, Gazélec Péronne, SICAE Somme and SICAE Cambraisis, Storengy and GRTgaz worked closely together to draw up a draft conversion plan. This was sub-

32 | Electricity and Gas Regulatory Commission (Belgium).

mitted to the relevant ministers on 23 September 2016, in accordance with Decree no. 2016-348 of 23 March 2016. The plan was then the subject of an economic and technical assessment by the CRE, the conclusions of which are given in Decision no. 2018-051 of 21 March 2018.

The current L-gas consumption zone's conversion to H-gas is based on the L-gas transmission and distribution networks being split into around 20 geographical sectors. The switch will be carried out independently and successively for each sector, resulting in a gradual conversion of the entire zone by 2029 at latest. This rate is compatible with the operations necessary to adapt the equipment of the 1.3 million affected customers, if necessary.

Pilot phase: conversion of the Doullens, Gravelines, Grande-Synthe and Dunkirk sectors between 2019-2020

Between 2016-2019, GRTgaz made all necessary modifications to the transmission network to implement the pilot phase of the conversion plan, at a cost of approximately €47 million.

The Doullens, Gravelines and Grande-Synthe sectors (i.e. 37,000 customers connected to the distribution network and four connected to the transmission network) were successfully converted to H-gas in April, September and November 2019, respectively.

Despite the health crisis, the pilot phase was successfully completed in autumn of 2020, with the Dunkirk sector fully converted to H-gas for all 80,000 GRDF and seven GRTgaz customers.

FIGURE 73 | **Details of changes made during the pilot phase**

Source: GRTgaz

Adaptations approved for the first part of the deployment phase (2021-2024)

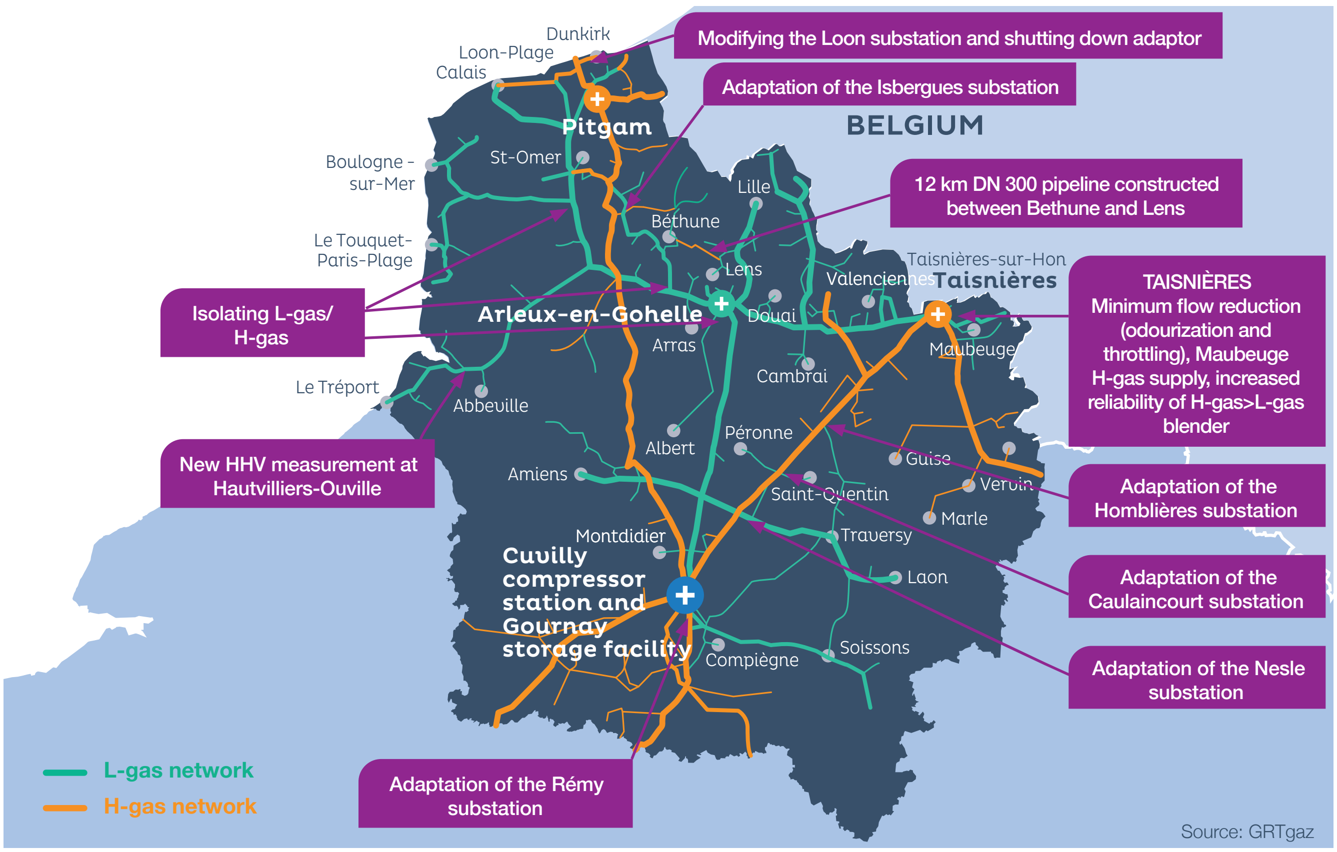
The deployment phase of the conversion was launched in 2021, with a new series of changes to the transmission network to convert 550,000 distribution customers and 54 GRTgaz customers. The deployment phase relating to GRTgaz's investments was split into two parts:

- deployment phase 1 for construction and modification work needed for the planned conversions for the period 2021-2024 (according to the conversion plan of 23 September 2016);
- deployment phase 2 for construction and modification work needed for the planned conversions for the period 2025-2028 (according to the conversion plan of 23 September 2016).

The works required for deployment phase 1 can be grouped into 3 main types:

- an adaptation programme for around 10 existing sites:
  - l- modifying the Loon-Plage substation and shutting down the H-gas>L-gas adapter to ensure the gradual supply of H-gas to the Artois Ouest artery from the North of France,
  - projects to connect the H-gas network to the L-gas network at 5 existing substations,
  - isolating the L-gas and H-gas networks on 4 existing sites,
  - adapting the instrumentation used to monitor and control the quality of the gas transported,
- a project to adapt the Taisnières compressor station, with the reduction of the minimum flow for odourization and throttling, preparations for the H-gas supply in the Maubeuge sector, and increasing the reliability of the H-gas>L-gas enrichment blender;
- a project to build a new 12 km DN 300 pipeline between Béthune and Lens.

FIGURE 74 | **Work required for the deployment phase of the conversion**



Source: GRTgaz

Under the incentive regulation, these projects were audited by the CRE in May-June 2019 to set a target budget. This audit led to CRE deliberation no. 2019-173 of 18 July 2019, which sets a target budget of €30.9 million for this phase. The decision to carry out the works was approved by GRTgaz on 17 September 2019.

Consequences for GRTgaz's offer

Implementing the planned conversion process for customers connected to the distribution network requires the use of a gas known as "L+". This gas complies with L-gas specifications, but with a Wobbe index stabilised within a tighter range at the top of the L-gas range. L+ gas makes it possible to adjust the H-gas configuration of customers' devices, when necessary, prior to the arrival of H-gas.

Since 1 April 2016, L+ gas specifications have been incorporated into the Dutch regulations for gas transported to Belgium and France. The technical requirements of GRDF, Storengy and GRTgaz have also been modified to take these L+ gas requirements into account.

Other consequences for the capacity offer

Consequences for the offer include:

- the disappearance of the "peak" H-gas to L-gas conversion service in spring 2021 following the H-gas conversion of the network to which the Loon-Plage H-gas/L-gas adapter is connected;
- a reduction in the firm entry capacity at Taisnières B from 230 GWh/day to 115 GWh/day in 2025 following the conversion to H-gas of one of the two Artois Est arteries between Taisnières and Arleux (it being specified that the Gournay storage facility should use L-gas until 2026).

These changes correspond to GRTgaz's current vision based on the draft conversion plan submitted to the authorities on 23 September 2016. However, the above deadlines may change if the planned conversion schedule is altered.

To date, GRTgaz has not identified any need for additional capacity for the Virtualys virtual interconnection point by 2025 and beyond. If necessary, all or part of the equipment can hence be reused for the L-gas capacity.

An increase in H-gas capacity would require investments, whose triggering would depend on market demand. Otherwise, the entry capacity at Taisnières B will not be converted into H-gas.

Pure or blended hydrogen

Hydrogen in the gas networks of tomorrow

In an extremely fast-moving environment, GRTgaz is taking steps to safely accommodate hydrogen in its network and thus support the hydrogen market's growth.

Integrating blended hydrogen into the gas networks comes under plans to expand third-party access to the networks to all renewable gas and low-carbon hydrogen producers (Article L111-97 of the French Energy Code amended by the Energy- Climate Law of 2019). This already topical issue is expected to gain weight in the coming years. Support mechanisms for decarbonised hydrogen production, provided for by the recent French Hydrogen Development Strategy, will be implemented, with production projects increasing across the country.

At the request of project leaders, nearly 30 feasibility studies for connection to the network either had been or were currently being examined by GRTgaz at the end of the 2020. These hydrogen injection requests cover a broad range of projects and meet different needs, indicating the salience of this issue. GRTgaz now supports:

- project leaders whose hydrogen production by electrolysis projects are mainly intended to supply new hydrogen uses (e.g. for mobility), but who want to exploit their surplus production via the gas networks until these dedicated hydrogen uses have reached maturity. Even in the medium term, they see the gas network as a driver for optimising their production;
- renewable electricity generation project leaders exploring Power-to-Gas solutions with injection into the gas network to recover electricity that could not be integrated into the electricity network;
- industrial companies that co-produce hydrogen in their processes (e.g. in the chlorine industry) who want to exploit this co-product instead of flaring it;
- synthetic gas production project leaders (pyrogasification from biomass or waste, hydrothermal gasification of effluents, etc.), who can contribute to decarbonising existing uses of natural gas, and whose production may contain a small percentage of hydrogen blended with synthetic methane.

It is hence clear that the gas networks can facilitate the emergence of both a decarbonised hydrogen market and regional ecosystems by offering hydrogen producers a way of extracting value that is complementary to dedicated hydrogen uses (mobility, industry, etc.).

The European hydrogen strategy, published in July this year, has also highlighted the key role that hydrogen blending can play in the existing gas networks as part of a transitional phase before the advent of a mature hydrogen market. Most European countries are thinking along similar lines. It is thus even more important to prepare the French gas networks to integrate hydrogen, as neighbouring countries, with which the gas networks are widely connected, are also taking active steps towards this.

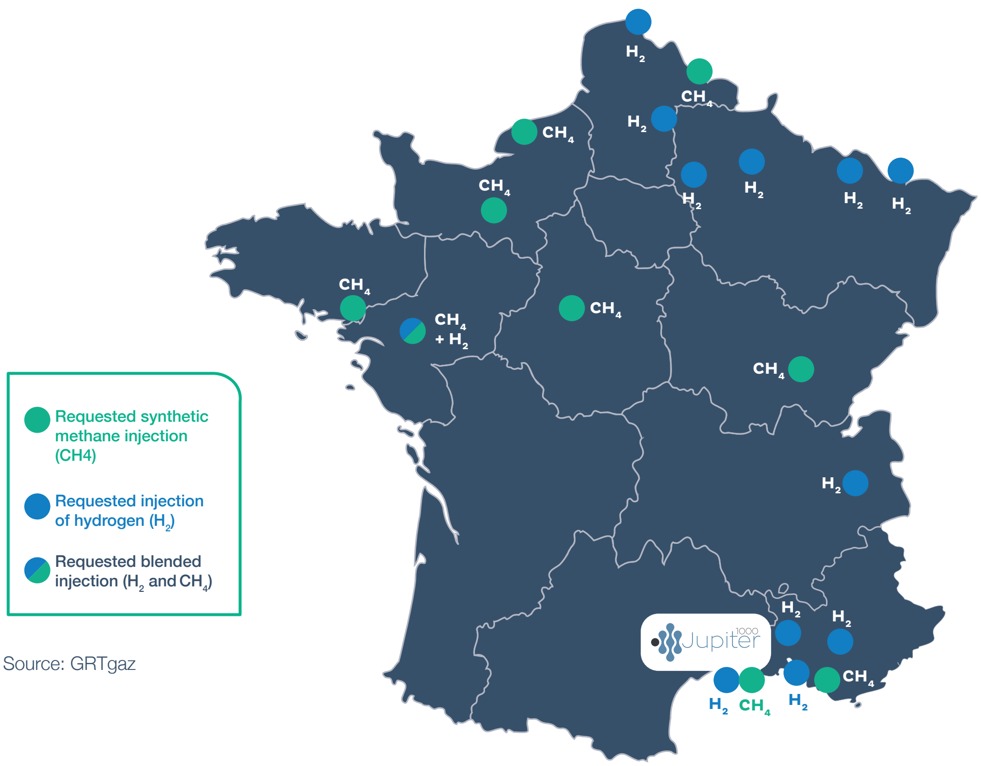
In the medium term, strong growth is expected in intermittent renewable electricity capacity. Having prepared solutions for integrating hydrogen into the gas networks could thus be a key element in guaranteeing the flexibility needs of the energy system and enabling the electricity system to benefit from the gas system's storage capacities.

An R&D programme to anticipate the integration of blended hydrogen into the gas networks

From 2019, in accordance with the provisions of the Hydrogen Deployment Plan for the Energy Transition, gas infrastructure operators have been studying the technical and economic conditions for integrating hydrogen into the gas infrastructure. A report of this research was submitted to the Minister of the Ecological and Solidarity Transition.

Published in November 2019, the study showed that it is possible to integrate a significant volume of hydrogen into

FIGURE 75 | **Map of hydrogen and synthetic gas connection requests**



Source: GRTgaz

the gas mix by 2050, with limited infrastructure adaptation costs, by implementing a coordinated R&D programme to remove the remaining uncertainties and technical obstacles. Gas infrastructure operators recommend setting a target capacity of 10% blended hydrogen integrated into the networks by 2030.

GRTgaz has used the information in this study to organise an R&D programme for integrating hydrogen into its network, to be led by its Energy Research and Innovation Centre (RICE).

It plans to define the safety issues facing facilities (integrity of pipes, network equipment and accessories and associated maintenance procedures) and the management of the network (adaptation of injection technologies, gas analysis equipment, compression equipment, metering equipment, invoicing systems and control tools) to maximise the integration of hydrogen into existing networks under optimal safety conditions and in the most cost-efficient way.

FenHYx: a test platform for injecting hydrogen and decarbonised gas into the gas networks

FenHYx (Future Energy Network for HYdrogen and miX) is a research platform project aimed at defining the technical, economic and regulatory conditions for injecting hydrogen and decarbonised gases into the gas transmission networks and, by extension, into the gas infrastructure.

It forms part of GRTgaz's hydrogen R&D, which has identified needs for test infrastructures taking into account existing European R&D centre projects.

FenHYx aims to reproduce the functionalities of the gas networks, and in particular those of the gas transmission networks, by means of several test modules (compression, expansion, measurement, analysis, injection loop, etc.). At different pressures and concentrations of hydrogen and methane, these will be used to test, assess and certify the resistance of the gas infrastructure equipment to these new gases and to determine the dynamic parameters to be factored in regarding pressure variation and gas quality. In short, it will make it possible to ramp up the network's compatibility with the injection and transmission of hydrogen and other new gases, to rally the sector and bring operators together, and finally to train those using the system.

The first module will be built in 2021 at the GRTgaz research site in Alfortville. This module – "Cluster 1" – will pool the static test benches used to test the integrity of steels, equipment seals, and meters in the presence of both blended and 100% hydrogen.

Cluster 1 is aimed at studying the resistance of network equipment to the presence of hydrogen. It was approved by the CRE in their deliberation of 23 January 2020, amended by that of 22 January 2022, for a budget of €4.4 million (including €0.8 million in third-party financing).

The role of the second module will be to carry out tests on the separation of hydrogen and natural gas. The aim is to come up with protection solutions for customers who may be sensitive to blended hydrogen/methane. The final module will involve dynamic tests (the gas will be compressed and in motion) on the metrology, corrosion and functionality of material and equipment.

Other clusters are also required to perform the full range of tests using dynamic open- and closed-loop testing. These are currently in the definition phase.

GRTgaz's aim is to make FenHYx a genuine platform for research, innovation, and European cooperation for all types of methane blends. It has already given rise to a collaboration agreement with the German carrier, ONTRAS Gastransport GmbH. This platform aligns perfectly with the priorities set out in the French Hydrogen Development Strategy, which plans to support research and innovation, particularly in transport infrastructures.

Initial tests for injecting hydrogen into the network are already underway with Jupiter 1000, an industrial-scale (1 MW) Power-to-Gas demonstrator project located in Fos, overseen by GRTgaz, which has been injecting hydrogen into a transmission network artery since February 2020.

Jupiter 1000: a Power-to-Gas demonstrator

The Jupiter 1000 project is an innovative, industrial-scale (1 MW) facility implemented by GRTgaz to produce hydrogen from electricity, all or part of which is injected into the network. The demonstrator has two electrolysers using two different technologies: Polymer Electrolyte Membrane (PEM) and Alkaline.

The demonstrator will also include a CO_2 capture unit on the chimneys of a neighbouring industrial company, and a methanation unit to convert the hydrogen produced and the recycled CO_2 into synthetic methane. This carbon-neutral gas will then be injected into the transmission network.

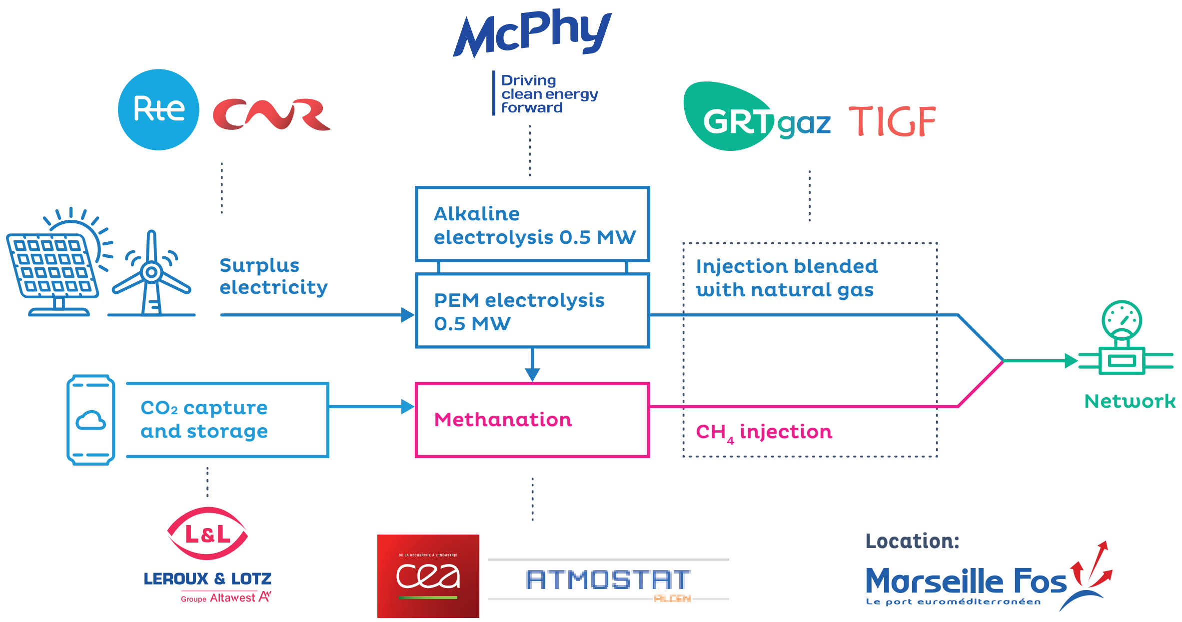
This project is one-of-a-kind in France. It will offer the opportunity to study the technical and economic soundness of the process, and to develop a new renewable gas production sector by 2030.

It is located in Fos-sur-Mer (Bouches-du-Rhône), on the Grand Port Maritime de Marseille's "Innovex" platform dedicated to hosting demonstrators linked to the energy transition.

The project was given the green light in 2015, with the approval of the CRE.

Work is ongoing. Hydrogen injection began in 2020, with synthetic methane scheduled for injection at the end of 2021.

FIGURE 77 |**Jupiter 1000 Power-to-Gas project partners**



The project receives financial support from ADEME, PACA and the European ERDF fund

Source: GRTgaz


View of the blending station. Jupiter 1000.

Alongside the R&D programme, network equipment that needs to be renewed will gradually be replaced by devices that are compatible with the workings of a network integrating hydrogen. This is the case for chromatographs, for instance, which measure and continuously analyse the composition of the gas in the network. These are not currently suitable for analysing a blended gas containing hydrogen. After a "new devices" test phase in 2020, a first pilot phase for the rollout of new hydrogen-compatible chromatographs will be carried out in 2021. The rollout strategy consists mainly of equipping the border entry points to measure the quality of imported gas.

Launch of a consultation process to prepare the regulatory and contractual framework

Finally, beyond the technical aspects, there is a whole regulatory and contractual framework that needs to be constructed, as has happened over time for the integration of biomethane into the gas networks. To this end, GRTgaz launched a hydrogen injection consultation group in spring 2019. Its role is to allow hydrogen production project leaders, gas infrastructure operators, the public authorities and any affected gas customers to work together to define and frame the various technical and contractual aspects of injecting hydrogen into the networks . The "uses" working group, officially launched at a webinar in October 2020, brought together more than 170 representatives of customers and industrial federations, confirming the merits of a consultation that addresses this issue.

Support for the sector also involves the publication in 2021 of a map for hydrogen producers seeking to inject into the GRTgaz network. This enables them to quickly identify zones suitable for injecting hydrogen in the short term, i.e. sections of the network without technical constraints and serving consumer-customers seeking to decarbonise their processes.

The end goal is for GRTgaz to be able to specify the connection and injection conditions for hydrogen or hydrogen-blend producers at the conclusion of the R&D programme and the consultation.

Other adaptation topics related to the transition

Adaptation to lower consumption

In the scenarios envisaged in this plan, the widespread reductions in consumption by 2030 preclude identifying network sections or equipment at this stage that will be rendered useless for transporting methane.

On the other hand, the fall in local consumption may increase the need to transport gas injected into the zone to consumption areas located further away, as it cannot be consumed near the network injection point. To maintain the capacities sold at the network entry points, it may be necessary to plan new equipment to bolster the network's cross-regional capacities (fluidity). Of course, these investments would need be compared to a solution that reduces the network's entry capacity.

The phenomenon was first apparent in the Fos zone, where local network absorption capacities could be reduced by 1 to 2 GW h/year, depending on changes in consumption. Investments may be needed by 2030 to maintain the initial capacities.

More detailed studies will have to be carried out as part of future plans to clarify this issue linked to the local dynamics of observed or anticipated reductions in daily consumption.

Developing the network for transporting hydrogen: H_2 valleys and a European backbone

Beyond injecting pure or blended hydrogen into the network, it may be necessary to transport hydrogen in dedicated networks linking large-scale hydrogen production units with geographically distant consumption hubs. As was the case for natural gas, this solution could also promote the emergence of a competitive market and improve the system's overall security of supply.

The installation of Power-to-Gas units supporting future uses will not necessarily be possible or economically optimal in all consumption zones. For regions without significant sources of renewable electricity or located far away from areas with CO_2 storage potential, it will in some cases be more economical to access competitive renewable hydrogen delivered via hydrogen transmission pipe networks: the most cost-effective way of transporting gas over significant distances.

The European Commission's hydrogen strategy highlights the key role played by pipeline transport infrastructures in creating a developed hydrogen-energy market in Europe.

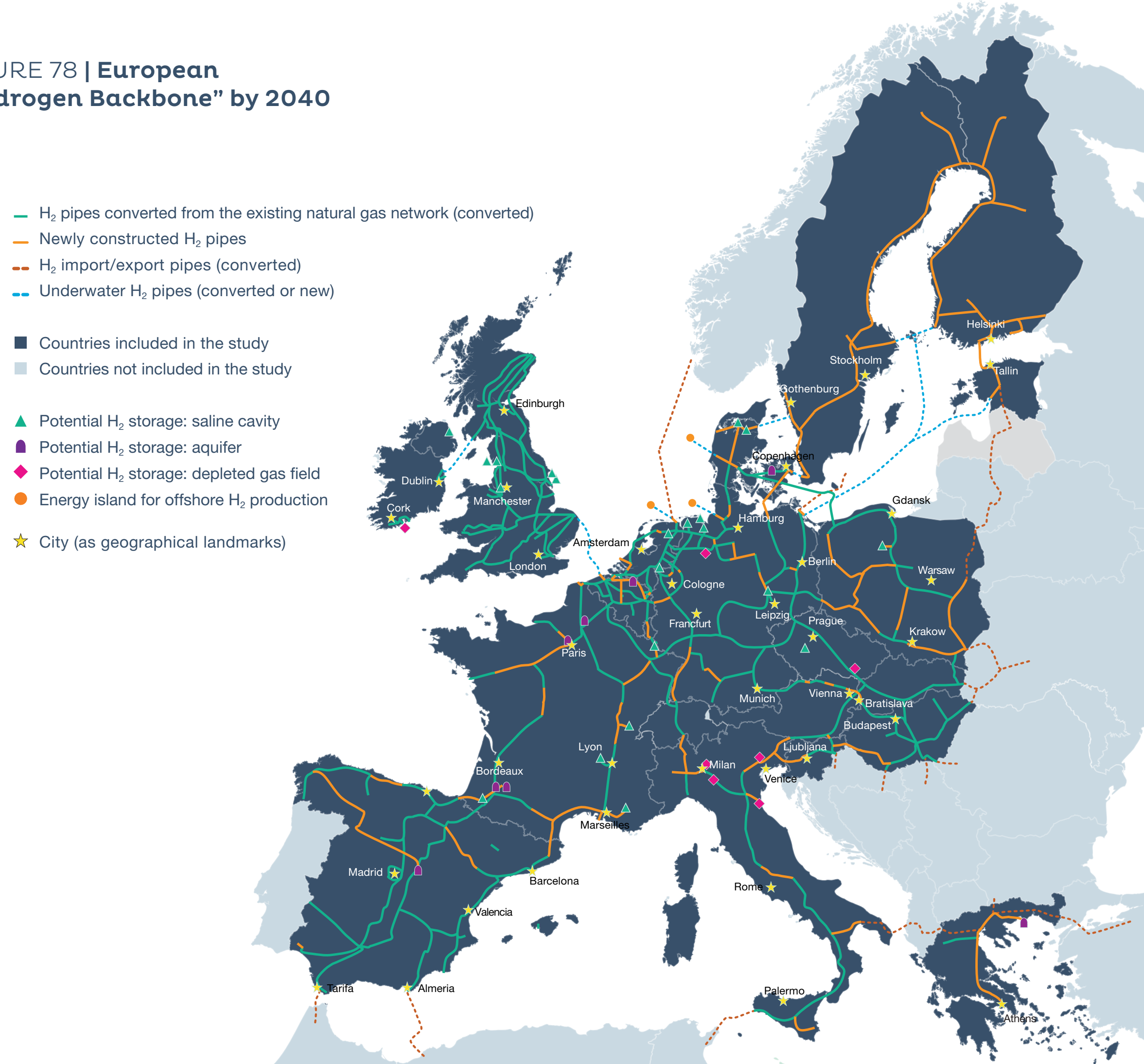
In the long term, the European Commission expects that the production of renewable hydrogen in the EU will, if necessary, be supplemented by renewable hydrogen imports from neighbouring countries (North Africa, Eastern Europe, etc.) to meet decarbonisation targets. This could justify transnational flows within Europe, and hence the need for a long-distance transport infrastructure.

In their responses to the GRTgaz survey, some operators of adjacent networks, especially those in Germany, mentioned the need to study conditions for the import of renewable gases, and in particular hydrogen, from France.

GRTgaz must be mindful of hydrogen development. Hydrogen production currently accounts for a significant percentage of the consumption of methane transported on its network. Any substitution of the hydrogen production methods could lead to a significant and localised reduction in transmission needs. On the other hand, the planned reduction in gas consumption in the years ahead could have a long-term effect of reducing the stress on several sections of the network. These pipes could then be reused, as they would no longer be required to transport methane. This reuse would be much easier for sections with two pipes in parallel.

It was with this in mind that GRTgaz took part in the European Hydrogen Backbone initiative. This initiative brings together TSOs from 21 countries in Europe. Its aim is to highlight what the European hydrogen system could offer as part of an integrated European market. The vision presented by the consortium is for a network of nearly 40,000 km, 69% of which would comprise the existing gas infrastructure in converted form. Cost assessments show that it would be significantly cheaper to reuse these existing structures than to install new pipes, thus minimising the cost of transporting hydrogen over long distances and creating a favourable outlook for hydrogen production in the most suitable areas. Reuse would also

FIGURE 78 | **European "Hydrogen Backbone" by 2040**



Source: *Gas for climate, European Hydrogen Backcbone report*

provide the best solution for adapting the methane transmission network, benefiting its users.

By interacting with and listening to the challenges faced by the regions and their hydrogen projects, GRTgaz has been able to identify some initial options for converting natural gas network arteries into dedicated hydrogen pipes to support the emergence of the first hydrogen valleys. For example, the mosaHYc (Moselle Sarre HYdrogene Conversion) project, which, in partnership with the German network operator Creos Deutschland, aims to convert 70 km of gas pipes between France, Germany and near to the Luxembourg border. This project forms part of an emerging regional hydrogen ecosystem. It will connect sites producing hydrogen by electrolysis with current and future consumption areas, for use in mobility (buses, refuse trucks, heavy good vehicles, trains) and industry. By increasing the overall size of the accessible hydrogen end market, and by strengthening the security of supply of the overall ecosystem, the mosaHYc project makes production and usage development projects more economically viable, facilitating the emergence of this regional hub.

For GRTgaz, the project would also be the first demonstrator in France to convert existing natural gas pipelines for the transmission of pure hydrogen. It would make it possible to develop technical and regulatory provisions enabling the conversion of existing networks to transport hydrogen energy. The cross-border nature of the facilities will also give additional insight into the longer-term development of European hydrogen transmission backbones.

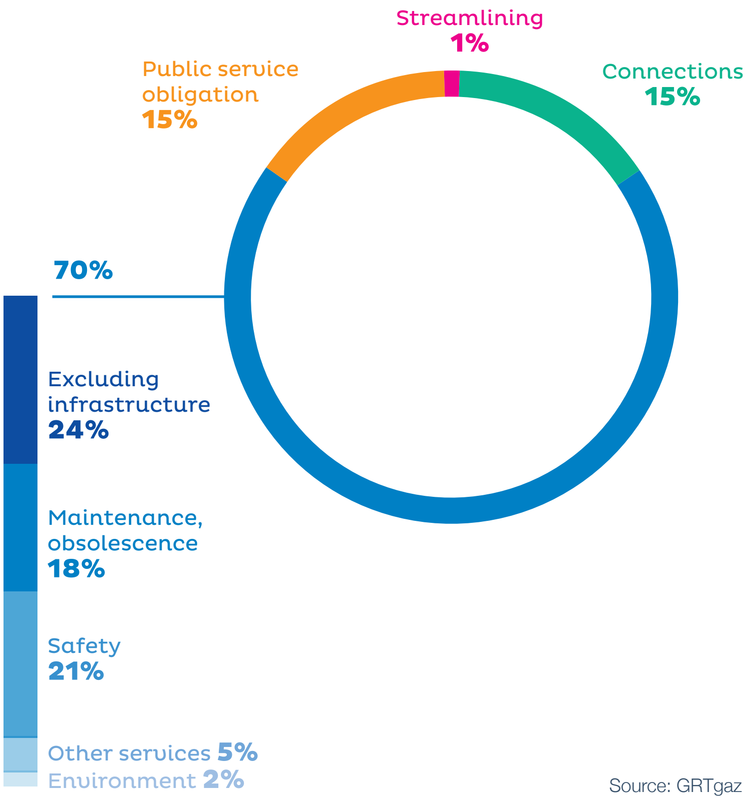
Other investments

Investments needed for the network are not limited to the adaptations mentioned above. In 2020, GRTgaz's investments came to approximately €385 million.

Investments linked to network developments described in this plan came to around €115 million, i.e. approximately 30% of GRTgaz's investments over the year. They relate to projects to streamline the network, meet continuity of supply obligations, and connect new consumers or producers to the transmission network.

The so-called "network streamlining" investments, which consist of strengthening work to the main transmission network to increase entries and integrate the French market, are now negligible. Unless adjacent operators launch projects that have a significant impact on the network, they are expected to remain this way.

FIGURE 79 | **Breakdown of GRTgaz investments in 2020**



Source: GRTgaz

Projects related to gas quality management in Hauts-de-France and the connection of the Landivisiau CCPP account for half of these investments. Connections and adaptations related to biomethane, meanwhile, account for 20% (€20 million for connections and €5 million for reverse flow stations in 2020). The latter investments are expected to increase in the coming years, as are the connection of CNG vehicle refuelling stations. Other development investments concern the connection of industrial customers or the strengthening of public distribution systems. Given the expected changes to consumption, these investments are expected to remain low in the coming years.

The remaining investments (nearly 70%) are those needed for through-life support, in compliance with the regulations in force, and for non-network services (information systems).

The GRTgaz network is made up of several components needed to supply gas:

- pipes (approximately 32,550 kilometres, from 80 cm to 1.20 m in diameter);
- compressor stations (26 stations comprising 78 machines for a total power of more than 600 MW; half of this power is delivered by electric compressors, the rest by turbo compressors);
- substations (nearly 9,500 delivery or pipeline stations) and interconnections (42 on the GRTgaz network, connecting at least 3 pipes);
- an industrial and tertiary information system for monitoring and managing this equipment supplying gas in conjunction with network users.

GRTgaz works on all these structures to maintain their performance under safe operational conditions.

Pursuant to the Multi-Fluids Order, GRTgaz inspects, and where applicable rehabilitates, 10% of its pipes every year. These inspections bolster the continuous monitoring of the network and the preventive pipe protection systems that make up the corrosion protection systems (coating and cathodic protection).

Given the average age of the pipe network, no significant renewal programme linked to ageing is planned in the short term. However, wide-ranging changes have been made to the Multi-fluids Order and its application in the French Oil and Chemical Industry Safety Group (GESIP)

Tomography: an innovative technique for monitoring gas pipelines.

Professional Guides. Major changes that will apply over the coming years include:

- a reduction in the maximum authorised time between two inspections of the same section, leading to more frequent re-inspections;
- stricter inspection methods favouring direct and, where applicable, indirect inspection techniques (in particular the systematic search for leaks);
- rigorous monitoring of pressure cycles to check that they are few in number and of limited intensity.

Sections of pipes can also be specifically treated when they no longer comply with installation standards due to environmental or regulatory changes. The installation of a new pipe under the Durance river following the erosion of the riverbed is an example of this type of adaptation.

The compressor stations have been extensively renovated over the last fifteen years, in particular to make them compliant with nitrogen oxide emission specifications. Overall, the fleet is fairly modern, especially the electric compressors. However, some stations need to be renovated in the short term. The Vindecy station is one of these. Its renovation was sized in view of its contribution to market users (in particular, capacities between the north and south of the network). A cost-benefit analysis kept the investment as low as was strictly necessary. Another compressor station in La Bégude-de-Mazenc (26) will have to be adapted over the coming decade. Work is also being carried out to reduce these stations' methane emissions.

As well as the pipes and compression stations, the network includes a number of ancillary facilities. These are interconnection stations - a kind of "crossroads" of pipes and substations. Substations are generally isolated facilities along the length the network. These include:

- delivery stations, whose function is mainly pressure reduction, pressure safety, filtration and metering. These are located at the end of the network and interface with the customer (public or industrial distribution);
- pressure regulator stations, whose function is mainly pressure reduction, pressure safety, etc. These are located within the network and act as an interface for networks with different operating pressures;

- block valve stations, whose function is mainly to isolate sections of the network or vent a section of the pipeline. These are located at regular intervals along the network;
- valve stations, whose function is mainly to introduce instrumented pigs and scrapers. These are located within the network.

Most of these substations act as safety equipment, and are vital for operating the network. One-third of substation investments are to adapt them to flow variations for consumers connected directly to the network or to public distribution systems. Two-thirds go towards to their maintenance, in particular that of pipeline substations. Planned work is linked to regulatory compliance but also to the obsolescence of some equipment in these substations. The level of investment currently granted for these facilities should allow for a renewal rate consistent with their operational life.


Air surveillance of the network in Rhône-Méditerranée

Finally, GRTgaz works on the network's structures to measure the quantities and quality of the gas delivered to customers (metering, chromatographs, PLCs and remote reading/remote surveillance equipment).

The physical management of flows in the network relies on a large amount of industrial IT equipment. This system includes:

- remote transmission equipment (Remote Terminal Units – RTU) that interface with IS applications to provide ground metering and gas quality data, and also for remote monitoring and remote control of the facilities;
- telecommunications equipment including routers, modems, switches and firewalls enabling data exchanges via the various RTC, GSM and satellite telecommunications networks, etc.;
- control and monitoring systems including Programmable logic controllers (PLC), Programmable safety controllers (PSC), maintenance consoles, communication gateways and man-machine interfaces (MMI);
- industrial supervision stations.

In the coming years, while an RTU renovation programme is being completed, GRTgaz will have to continue to manage the obsolescence of the PLCs on the network. It will also have to adapt its data transmission chain significantly to technological transformations affecting the telecommunications sector. France has decided to replace the switched telephone network with Internet Protocol (IP) technologies from 2023. The copper network that supports ADSL and SDSL services will also end, with a switch to fibre. The oldest generation of mobile communications still in service, 2G (or GSM), is also scheduled to end in 2024.

The commercial information system must also be overhauled to offer network customers secure, adaptable and user-friendly access to all the data they require.

GRTgaz's business operates over a large geographical area. The company must therefore process large amounts of data, whether to manage flows and assets or to provide the necessary commercial information to suppliers or consumers as part of increasingly responsive production processes and energy markets. The information system has become an asset in its own right for network operators. GRTgaz invests nearly €50 million every year to upgrade its commercial and industrial information system.

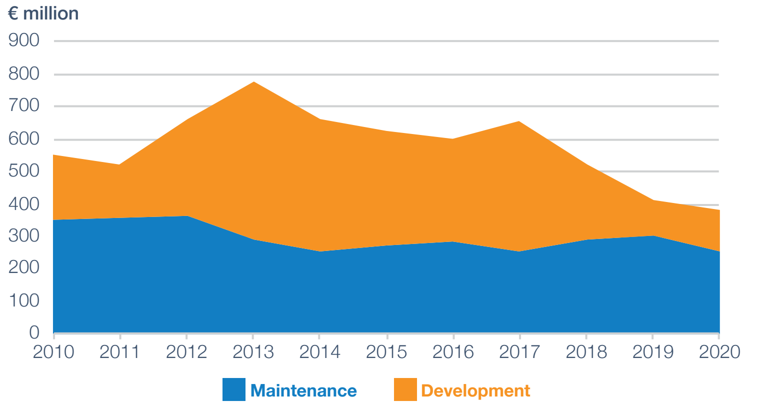
This system will face several challenges over the coming years, including adapting to new network uses and protection against cybercrime. The coupling of energy systems and the emergence of decentralised production will result in different demands being placed on the network. Likewise, there will be a need to provide customers with more information to enable them to participate in the energy system balance. The emergence of industrial IOT 33 solutions should facilitate the increase, and at lower cost, in the number of information and measurement points and their transmission to the GRTgaz IS, while meeting the industrial requirements specific to gas transport (ATEX environment 34, reliability, measurement ranges with the right level of precision, geographic coverage, etc.). The arrival of these new technologies comes alongside a rise in cybercrime. GRTgaz is a company that operates an asset covering a large part of France, which is dedicated to transporting energy of major national importance. Risk management and IT security are therefore two of its focal concerns. This focus has increased in recent years as processes are digitised, cyber threats intensify, and teleworking becomes more widespread in these times of health crisis. Significant investments are being made to protect the information system.

Since 2016, GRTgaz has set itself the goal of reducing its carbon footprint by optimising its energy needs to run the network, and reducing its methane emissions.

The period 2016-2020 saw a threefold reduction in methane emissions.

In October 2020, the European Commission set out a methane strategy that establishes a regulatory framework for reducing methane emissions. Future regulations will cover the obligations to measure, report and verify (MRV) reports, as well as the obligations to carry out leak detection and repair (LDAR) programmes. The European Commission is also considering regulations on venting and burning under so-called “routine” conditions, and could impose targets for reducing methane emissions, as well as new eligibility criteria for European programmes.

FIGURE 80 | **History of GRTgaz investments 2010 - 2020**



Source: GRTgaz

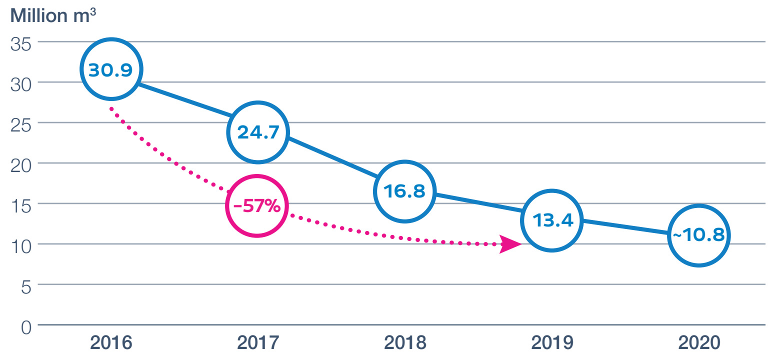
By 2024, GRTgaz is targeting a fivefold decrease in its methane emissions compared to 2016.

Efforts to date have mainly focussed on maintenance procedures. To hit this target, however, these actions must now be supplemented by adapting equipment, particularly for compression.

GRTgaz is therefore considering investments aimed at:
- eliminating vent leaks (from poor sealing of vent and isolation valves);
- recovering gas from depressurization via recompression or cogeneration;
- treating leaks from mechanical seals (nitrogen sealing or recovery);
- reducing defects that could cause accidental safety measures in workshops (Emergency safeguard mechanism – ESM).

33 | *Internet of things.*
34 | *EX-plosive atmosphere*

FIGURE 81 | **Changes in methane emissions since 2016**

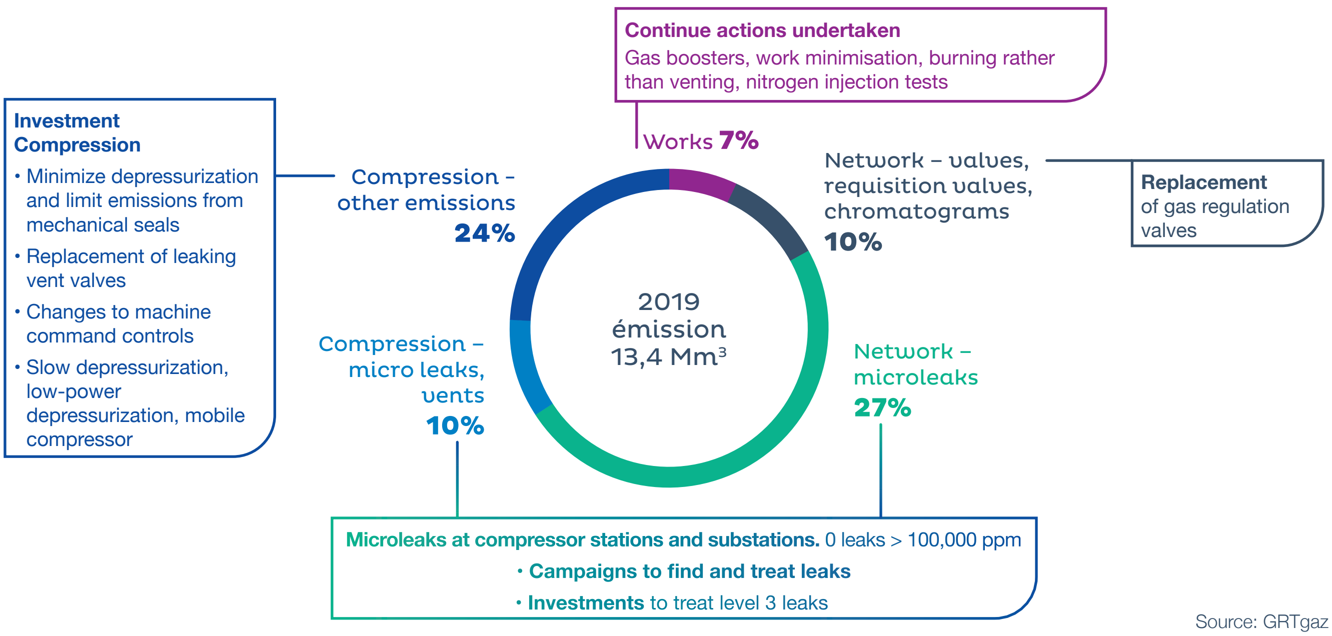


Source: GRTgaz

This programme, which totals around €55 million up to 2030, avoids emissions at a cost significantly lower than the cost of the shadow price of carbon recommended for 2030 by the Quinet report. Investments related to the most mature actions as well as in situ testing of innovative technologies were approved by the CRE in early 2021.

In summary, with the major streamlining investments completed, network maintenance now represent a significant portion of GRTgaz's investments, as illustrated in the graph opposite. In principle, and barring any changes to the regulatory framework, the various aforementioned consumption scenarios ought not lead to significant variations in investments, maintenance, and through-life support over the coming years.

FIGURE 82 | **Breakdown of 2019 expenditure for reducing methane emissions**



Source: GRTgaz

3.2 | Summary of commissioned facilities and changes to capacities

Facilities commissioned between 2019-2023

The facilities expected to be commissioned between 2019-2023 are detailed below. The works have been finalised and are included in the GRTgaz financing plan. Their budget has been approved by the Board of Directors.

Challenges	TYNDP code	Facilities to be adapted or built	Commissioning date	Status	Budget
Pilot phase of the plan to convert L-gas into H-gas	TRA-N-429	Connection of the Doullens, Gravelines, Grande-Synthe and Dunkirk antennas to H-gas	2019	In service	€47 million
Adaptation of the network for biomethane injection		Distribution/transmission reverse flow station in Pontivy (56) and Pouzauges (85)	2019	In service	€6.5 million
Adaptation of the network for biomethane injection		Distribution/transmission reverse flow station in Chessy (77)	2020	In service	€3.6 million
Adaptation of the network for biomethane injection		Distribution/transmission reverse flow station in Marchémoret (Pays de Valois) (77) and Bourges (18)	2021	Work in progress	€6.1 million
South Brittany strengthening work to prepare for the connection of the gas-fired CCPP in Landivisiau		Strengthening of the regional network between Pleyben (29) and Pluvignert (56) (98 km of DN 400 and DN 500 pipes) Adaptation of the Prinquiau substation (44)	January 2022 at the latest	Work in progress	€144 million
Conversion plan from L-gas H-gas (deployment phase 1)	TRA-N-429	Gradual connection of the L-gas transmission network to H-gas	2021/2024	Work in progress	€30.9 million
Adaptation of the network for biomethane injection		Distribution/transmission reverse flow stations in Soissons (02), Rethel (08), Craon (53), Laon (02), Argentan (61) and Troyes (10)	2022	Under study	€16 million

Facilities commissioned from 2024

The decision to build the other facilities will be taken when:

- there is confirmed market interest;
- the decision to build the adjacent infrastructure has been taken, where applicable;
- financing is in place;
- the investment has been approved by the CRE.

In setting a construction schedule for these facilities, GRTgaz factors in indicative information about the desired capacities and commissioning dates given by the operators of adjacent infrastructures. The facilities to be built or adapted, particularly those central to the network, depend on the finishing order and the level of need to increase entry or exit capacities for the market zone in question. The facilities below should therefore be reviewed if there are changes to the capacity requests schedule.

Given this uncertainty, sizing studies were carried out on a preliminary basis for projects with long timeframes. These initial studies will be supplemented by more in-depth analyses when the needs are more clearly established, which could in turn reveal the need to adapt other facilities.

Challenges	TYNDP code	Facilities to be adapted or built	Commissioning date	Status	Change
Adaptation of the network for biomethane injection		Distribution / transmission reverse flow stations, collection networks, shared compression according to zoning plans drawn up jointly by the carrier and the distributor and approved by the CRE	2023 and beyond	Awaiting the emergence of projects	
Increase in entry capacities from the Montoir terminal from 10 to 12.5 Gm³/year	TRA-N-258	Adaptation of the Auvers-le-Hamon compressor station Doubling the Maine artery and strengthening the Cherré compressor station, if necessary Creating of an artery between Chémery and Dierrey, if necessary	2023/2025	Pending the developer's decision	Postponed by the developer
Expansion of the Fos-Cavaou terminal from 8.25 to 11 Gm³/year		Facilities or mechanisms allowing new capacities to be accommodated will be re-examined in view of specified needs	2024	Pending the developer's decision	Postponed by the developer
Expansion of the Fos-Cavaou terminal to 12.5 Gm³/year			2030	Pending the developer's decision	Postponed by the developer
Conversion plan from L-gas H-gas (deployment phase 2)	TRA-N-429	Gradual connection of the L-gas transmission network to H-gas	2023 and beyond	Under study	

Possible changes to annual firm capacities

As at 1 January in GWh/day	2019	2020	In the future
ENTRY CAPACITY	**3,685**	**3,685**	**3,910**
Norway Dunkirk IP	570	570	570
Belgium Taisnières H IP	640	640	640
Belgium Taisnières B IP	230	230	115 [35]
Germany Obergailbach IP	620	620	620
Switzerland/Italy Oltingue IP	100	100	100
LNG Montoir PITTM	370	370	460 [36]
LNG – Dunkirk Dunkirk PITTM to North Zone and Dunkirk to Belgium	520	520	520
LNG Fos PITTM	410	410 [37]	560 [38]
Sapin *via* TERÉGA - PIRINEOS	225	225	225
EXIT CAPACITY	**696**	**696**	**659**
Switzerland/Italy Oltingue IP	260	260	223 [39]
Belgium Alveringem IP and Dunkirk to Belgium	271	271	271
Spain *via* TERÉGA - PIRINEOS	165	165	165

Capacities at 1 January in GWh/day [40]	2019	2020	2021	2027
H-gas to L-gas peak service (interruptible)	57	57	57 [41]	0
L-gas to H-gas (interruptible)	125	125	70	125

35 | From 2025 and 0 after 2029.
36 | Forecast capacity, not approved.
37 | From 1 April 2021, capacity becomes seasonal at 399 GWh/day in summer and 428 GWh/day in winter.
38 | Forecast capacity, not approved.
39 | From 2025.
40 | This corresponds to GRTgaz's current vision based on the draft conversion plan submitted to the authorities on 23 September 2016. These may change, in particular if there are changes to the planned conversion schedule.
41 | Then 0 from 01/04/2021.

Appendices

TERRITORIES

CH_4 consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	169	168	167	169	169	168	163	159	155	151	147	143	138	134	129	124
Tertiary	76	78	79	79	78	75	71	68	66	62	58	55	52	49	46	43
Industry	151	150	156	159	154	144	142	146	146	144	141	137	133	130	126	122
CEG+ Cogeneration	59	90	89	70	88	77	82	80	77	75	72	69	67	64	62	59
Mobility	1	1	2	2	2	2	5	7	8	11	15	18	22	27	32	37
Agriculture	3	3	3	3	3	3	4	4	4	4	4	5	5	5	5	5
TOTAL	459	490	496	482	494	469	466	463	457	447	437	427	417	408	399	390
Natural gas consumption	459	490	495	481	492	467	462	455	444	429	414	398	383	367	351	336
Peak demand for methane in GWh/day	4,291	4,264	4,261	4,164	4,144	4,146	4,204	4,257	4,165	4,074	3,983	3,891	3,800	3,710	3,619	3,528

Renewable and low-carbon hydrogen consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industry	0	0	0	0	0	0	0	1	1	2	3	5	7	10	13	15
Mobility	0	0	0	0	0	0	0	0	0	1	1	1	2	3	3	5
Injected into the CH_4 network	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	2
TOTAL	0	0	0	0	0	0	0	1	1	2	4	6	10	13	18	22

Production of renewable and low-carbon gases in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Anaerobic digestion	0	0	0	1	1	2	4	7	12	17	23	28	33	38	44	49
Pyrogasification	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	2
Hydrothermal gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1
Renewable/low-carbon hydrogen	0	0	0	0	0	0	0	1	1	2	4	6	10	13	17	22
TOTAL GAS CONSUMPTION	459	490	496	482	494	469	466	464	458	449	441	433	426	420	415	410

INTERNATIONAL ALTERNATIVE

CH_4 consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	169	168	167	169	169	168	165	162	160	159	157	156	154	152	151	149
Tertiary	76	78	79	79	78	75	73	72	71	69	66	64	62	60	58	56
Industry	151	150	156	159	154	144	144	149	151	150	149	147	144	142	141	138
CEG+ Cogeneration	59	90	89	70	88	77	82	80	77	75	72	69	67	64	62	59
Mobility	1	1	2	2	2	2	5	7	8	11	15	18	22	27	32	37
Agriculture	3	3	3	3	3	3	4	4	4	4	4	5	5	5	5	5
TOTAL	459	490	496	482	494	469	473	474	472	467	463	458	454	450	447	443
Natural gas consumption	459	490	495	481	492	467	469	467	460	450	440	430	420	410	402	391
Peak demand for methane in GWh/day	4,291	4,264	4,261	4,164	4,144	4,146	4,204	4,257	4,232	4,207	4,182	4,157	4,132	4,107	4,082	4,057

Renewable and low-carbon hydrogen consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industry	0	0	0	0	0	0	0	0	0	1	2	2	4	5	6	9
Mobility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Injected into the CH_4 network	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	1	2	2	4	5	6	9

Production of renewable and low-carbon gases in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Anaerobic digestion	0	0	0	1	1	2	4	7	12	17	23	28	33	38	44	49
Pyrogasification	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	2
Hydrothermal gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1
Renewable/low-carbon hydrogen	0	0	0	0	0	0	0	1	1	2	3	4	4	5	7	9
TOTAL GAS CONSUMPTION	459	490	496	482	494	469	473	474	473	468	465	461	458	455	454	452

NATIONAL high gas

Consommation de CH_4 en TWh PCS

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	169	168	167	169	169	168	162	159	155	152	149	146	143	140	137	134
Tertiary	76	78	79	79	78	75	72	70	68	64	58	54	50	47	43	41
Industry	151	150	156	159	154	144	140	139	139	136	133	129	126	122	118	113
CEG+ Cogeneration	59	90	89	70	88	77	88	88	88	89	89	89	89	90	90	90
Mobility	1	1	2	2	2	2	3	4	4	5	6	7	8	10	12	14
Agriculture	3	3	3	3	3	3	4	4	4	4	4	5	5	5	5	5
TOTAL	459	490	496	482	494	469	469	464	459	449	439	430	422	413	405	397
Natural gas consumption	459	490	495	481	492	468	466	460	452	440	427	414	403	391	379	367
Peak demand for methane in GWh/day	4,291	4,264	4,261	4,164	4,144	4,146	4,204	4,257	4,153	4,049	3,945	3,842	3,739	3,635	3,532	3,430

Renewable and low-carbon hydrogen consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industry	0	0	0	0	0	0	0	0	0	1	2	2	4	5	6	9
Mobility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Injected into the CH_4 network	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	1	2	2	4	5	6	9

Production of renewable and low-carbon gases in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Anaerobic digestion	0	0	0	1	1	2	2	4	6	9	12	16	19	22	26	30
Pyrogasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrothermal gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable/low-carbon hydrogen	0	0	0	0	0	0	0	1	1	2	3	4	4	5	7	9
TOTAL GAS CONSUMPTION	459	490	496	482	494	469	469	464	459	450	441	433	425	418	412	405

NATIONAL low gas

CH_4 consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	169	168	167	169	169	168	162	157	153	148	143	138	133	127	121	115
Tertiary	76	78	79	79	78	75	72	69	67	62	56	51	47	43	39	35
Industry	151	150	156	159	154	144	140	139	139	136	133	129	126	122	118	113
CEG+ Cogeneration	59	90	89	70	88	77	88	88	88	89	89	89	89	90	90	90
Mobility	1	1	2	2	2	2	3	4	4	5	6	7	8	10	11	13
Agriculture	3	3	3	3	3	3	4	4	4	4	4	5	5	5	5	5
TOTAL	459	490	496	482	494	469	468	462	455	444	432	419	408	396	385	373
Natural gas consumption	459	490	495	481	492	468	465	458	449	435	419	404	389	374	359	343
Peak demand for methane in GWh/day	4,291	4,264	4,261	4,164	4,144	4,146	4,204	4,257	4,118	3,980	3,842	3,704	3,566	3,429	3,292	3,156

Renewable and low-carbon hydrogen consumption in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industry	0	0	0	0	0	0	0	0	0	1	2	2	4	5	6	9
Mobility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Injected into the CH_4 network	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	1	2	2	4	5	6	9

Production of renewable and low-carbon gases in TWh HHV

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Anaerobic digestion	0	0	0	1	1	2	2	4	6	9	12	16	19	22	26	30
Pyrogasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrothermal gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable/low-carbon hydrogen	0	0	0	0	0	0	0	1	1	2	3	4	4	5	7	9
TOTAL GAS CONSUMPTION	459	490	496	482	494	469	468	462	456	445	433	422	411	401	391	381

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Design-production: Créapix

GRTgaz is a European leader in gas transmission and a global expert in gas systems. The company operates more than 32,000 km of buried pipes in France to transport gas from suppliers to the consumers connected to its network:

- public distribution system managers serving municipalities;
- power plants;
- industrial sites.

GRTgaz fulfils public service missions to ensure the continuity of natural gas transmission. Alongside its subsidiaries Elengy, the European leader in LNG terminal services, and GRTgaz Deutschland, the operator of the German MEGAL transmission network, GRTgaz plays a key role in the European gas infrastructure scene.

The company exports its know-how internationally, in particular through the services developed by its Research & Innovation Center for Energy (RICE).

As a player in the energy transition, GRTgaz invests in innovative solutions to accommodate as many renewable gases as possible on its network, including hydrogen, to support these new sectors and to help achieve the goal carbon neutrality.

USEFUL LINKS

grtgaz.com
gasinfocus.com
cre.fr
entsog.eu
acer.europa.eu
gie.eu
aie.org
ec.europa.eu
eurogas.org
developpement-durable.gouv.fr
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