Technical and economic conditions for injecting hydrogen into natural gas networks

Final report
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Executive Summary and Recommendations

The work carried out by French operators shows that **it is possible to integrate a significant volume of hydrogen into the gas mix by 2050, with limited infrastructure adaptation costs. This integration involves the coordinated use of solutions including blending, methanation and the deployment of 100% hydrogen clusters in certain subzones by converting current equipment or creating new networks.**

In the short term, hydrogen can be blended in most networks at a rate of 6% in terms of volume, in the absence of sensitive structures or installations on the customer's premises. A pre-identification exercise will be initiated to determine suitable areas for injection project owners. These areas will be extended gradually to align with the results of R&D and equipment replacement actions.

By 2030, operators recommend setting a target capacity for integrating blended hydrogen into the networks of 10%, and 20% thereafter. The goal is to anticipate the need to adapt equipment, in particular downstream. **These rates are achievable with limited changes to the infrastructures.** European partners are currently consulted on this subject.

The work carried out for this report shows additional areas of relevance for the three injection routes by 2050: blending, methanation and 100% hydrogen clusters. **Operators have already launched R&D actions in a concerted, coordinated manner with their European partners.** These actions, which are set to continue, apply to all three options. The aim is to be able to offer the most competitive long-term solution for the development of the hydrogen sector.

The short-term goal is to enable the implementation of the first hydrogen injection projects in the networks and to develop truly competitive hydrogen logistics. To this end, French infrastructure operators have identified **a list of 10 priority levers** that they wish to share with the Minister of State and the Minister for the Ecological and Inclusive Transition:

1. Identify suitable areas in which the 6% blending level is applicable. When these conditions are met, adapt the gas specifications to inject first 10%, then 20%;
2. Invite operators to coordinate and share R&D efforts for all the technical injection routes. Ensure that the corresponding costs are covered in their regulated economic models under the existing processes;
3. Set a specification of 10% blended hydrogen as a sector-wide target by 2030. The aim is to mobilise equipment manufacturers and downstream users, and to manage operators investments on a case-by-case basis;
4. Lead a “hydrogen injection working group” bringing together gas chain stakeholders and government services, in conjunction with hydrogen producers, to facilitate the implementation of the initial injection projects;
5. Ensure coordinated and unified French position with regards to European standardisation work on infrastructure and downstream equipment;
6. Carry out an assessment of the externalities of injecting hydrogen into the networks and of methanation, including a life cycle analysis of these sectors;
7. Integrate the role of gas infrastructures in the development of hydrogen into energy mix forecasting and implement a specific work programme on the coupling of gas and electricity networks;
8. Define and implement a favourable framework for experimenting with the development and operation of the first 100% hydrogen clusters;
9. Create a framework for the development of power-to-gas in the event of market failure;
10. Establish regular work progress reviews between the operators and the State services concerned, and update the report every five years.

Table of Contents

Context

Measure 7 of the "Hydrogen Deployment Plan for the Energy Transition[1]" provides that gas infrastructure operators determine the technical and economic conditions for injecting hydrogen into the networks in order to prepare for the development of power-to-gas – a process that converts renewable electricity into hydrogen. This document is the final report in response to this request. It gives both a short – and medium – term answer, and presents the underlying R&D challenges with a view to enabling gas infrastructures to effectively support the energy transition.

As stated in December's interim report[2], French gas infrastructure operators have been discussing the challenges of integrating hydrogen into the networks for a year. This concerted, integrated work across the entire domestic infrastructure chain has yet to be carried out in other European countries, where stakeholder diversity makes it a more complex undertaking.

This report:

- Recalls the value of natural gas infrastructures in supporting the development of the hydrogen sector,
- Presents a list of 10 levers[3] identified as priorities by operators to prepare gas systems for the integration of hydrogen and synthetic methane,
- Highlights the main conclusions of a technical-economic study conducted by French infrastructure operators on the integration of hydrogen into the networks,
- Presents the key strategic R&D areas selected by the operators,
- Details the main technical issues relating to the integration of hydrogen into the networks.

[1] Hydrogen deployment plan for the energy transition, Press pack, 1 June 2018 (https://www.ecologique-solidaire.gouv.fr/sites/default/files/2018.06.01_dp_plan_déploiement_hydrogene_0.pdf).

[2] Technical and Economic Conditions for Injecting Hydrogen into Natural Gas Networks, Interim Report, December 2018.

[3] See Appendix A

Value of natural gas infrastructures for the hydrogen sector

I. Key features of natural gas infrastructures: a summary

Natural gas infrastructures have five features that make them strategic allies in the development of the hydrogen sector. These features reflect the efficient nature of the infrastructure as an energy carrier. They also demonstrate a structural complementarity with the electricity network in the development of "*sector coupling"* – something that is currently being explored at the European level as a lever for optimising the integration of renewable energies. Numerous studies (see, e.g., those by Navant [1] and Pöyry [2]) have also measured the significant additional costs generated by a decarbonisation strategy based on a single energy vector and hence on a single network, leading to massive investments in the latter to integrate the services of the other networks it replaces.

1. Gas infrastructures are capable of **transporting energy over long distances** with very low losses (0.7% vs. 2 to 6% for electricity[4]),
2. They can also **transport and deliver very large quantities of energy at a given time,** and are now key allies in managing the winter spike in electricity demand. By way of illustration, the power at the Germany/France border point at Obergailbach is 28 GW. The transmission capacity on the electrical transmission network (RTE) between France and Germany is 1.5 GW. Underground gas storage tanks are essential tools to cover peak energy demand, allowing for the delivery of an instantaneous power of 90 GW (greater than the French nuclear reactor fleet),
3. The gas network has **intrinsic flexibility** thanks to pressure adjustment that is perfectly controlled by the network operators (linepack). This means that supply and demand do not need to be balanced at all times.
4. Natural gas infrastructures have an unrivalled **mass inter-seasonal storage capacity** (~130 TWh). This makes it the technology of choice for managing intermittent renewable energies when they become predominant in the production mix[5],
5. Finally, the 200,000 km natural gas network **serves a large portion of the national territory, in particular the main urban and industrial areas.** The infrastructure is for the most part buried and not visible, which helps make it acceptable to the public.

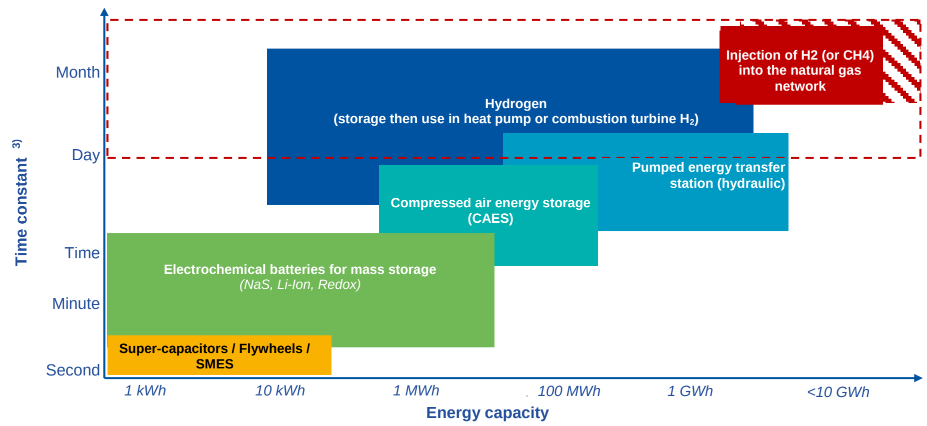

Figure 1 : Overview of the different storage options according to their storage capacity and their time constant (E-CUBE Strategy Consultants analysis)

[4] Loss on the electrical transmission network (RTE) estimated at 2%. Losses on the Enedis network: https://www.enedis.fr/devenir-un-fournisseur-denergie-qualifie#onglet-la-compensation-des-pertes.

[5] Underground hydrogen storage currently appears to be the most suitable means of inter-seasonal storage of very large volumes of energy.
https://www.economie.gouv.fr/files/files/directions_services/cge/Rapports/Rap2019/CGE_stockage_elec_synthese_et_recommandations.pdf

Figure 2 : Mapping of electricity (red) and gas (blue) transmission networks
source: open data energy-networks

To take full advantage of the investments made in natural gas infrastructure, and to make the best use of the complementarity of energy carriers, gas operators, like many other European stakeholders, are convinced that the development of a decarbonised energy system should rely jointly on electricity and gas networks.

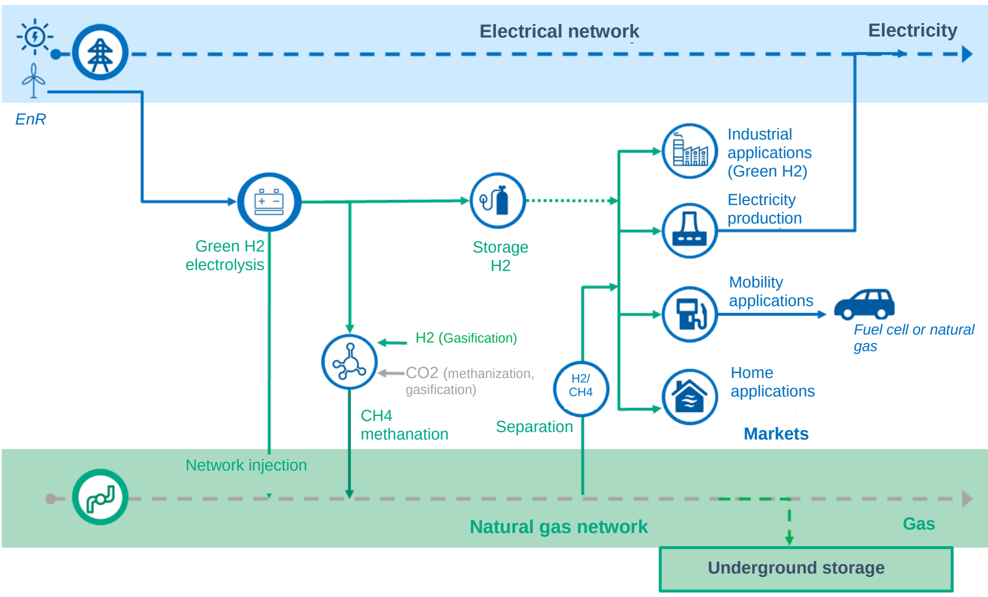

Figure 3: Simplified vision of coupling between electricity and gas networks

II. Hydrogen injection case studies in France

Several economic models involving hydrogen injection into the networks are being investigated. In the short term, there are no mature cases in France. In Germany, however, the massive demand for transport and the storage of renewable energy produced by its northern wind farms cannot be met by the electricity infrastructure, leading to the recently announced installation of 100 MW power-to-gas facilities.

Operators have identified different models in response to requests arising from their participation in different hydrogen sector working groups.

Firstly, the use of gas infrastructures as a lever to develop the production of hydrogen or low-carbon electricity:

- Some project owners want to have an "injection outlet" while dedicated hydrogen uses are being developed locally (e.g. for mobility or industry). They thus seek to benefit from economies of scale for electrolysers and, ultimately, from an optimisation lever (storage/production arbitrage).
- Industry stakeholders want to set up projects of several MWe to optimise nuclear generation *a priori* and avoid forced modulation while promoting the integration of renewable energies. Two projects of this type have already made requests for connection to the transmission network.

Secondly, coupling between electricity and gas systems to optimise the use of energy networks and overall reinforcement costs:

- For example, gas and electricity transmission operators must study the systemic benefits of power-to-gas as an alternative to reinforcements on the single electrical network.
- Some operators of renewable energy production facilities are studying the way that power-to-gas may impact their assets as their purchase obligations come to an end.

Thirdly, injecting hydrogen into the networks as a lever for competitive decarbonisation:

- Some stakeholders are exploring the conversion of local loops backed by hydrogen storage.
- Others are exploring the decarbonisation of mobility uses via synthetic methane injected into the networks.
- The longer-term development of renewable hydrogen import channels (based on different vectors) or synthetic methane, in particular via LNG terminals, is also being examined.
- The structuring of the large-scale transmission of this energy remains a thorny issue, and several solutions for the maritime transmission of renewable energy (via the hydrogen vector) are currently being studied, including:
    - liquefied hydrogen at very low temperature (LH_2),
    - organic molecules carrying hydrogen (Liquid Organic Hydrogen Carriers - LOHC),
    - ammonia (NH_3),
    - SLNG (LNG from green hydrogen methanation with captured or atmospheric CO_2).

  Current analyses still indicate significant costs and do not give any price advantage to one technology over another.

  However, the SLNG scenario has the advantage that it can be gradually implemented through the shared use of existing and partially depreciated infrastructures, without revolutionising mature and controlled uses or technologies.

Given the timescale envisaged for the industrialisation of these cases, French infrastructure operators are working at the right pace to carry out their R&D work. The emergence of these different routes requires the setting up of some initial demonstrators and/or industrial pilot projects.

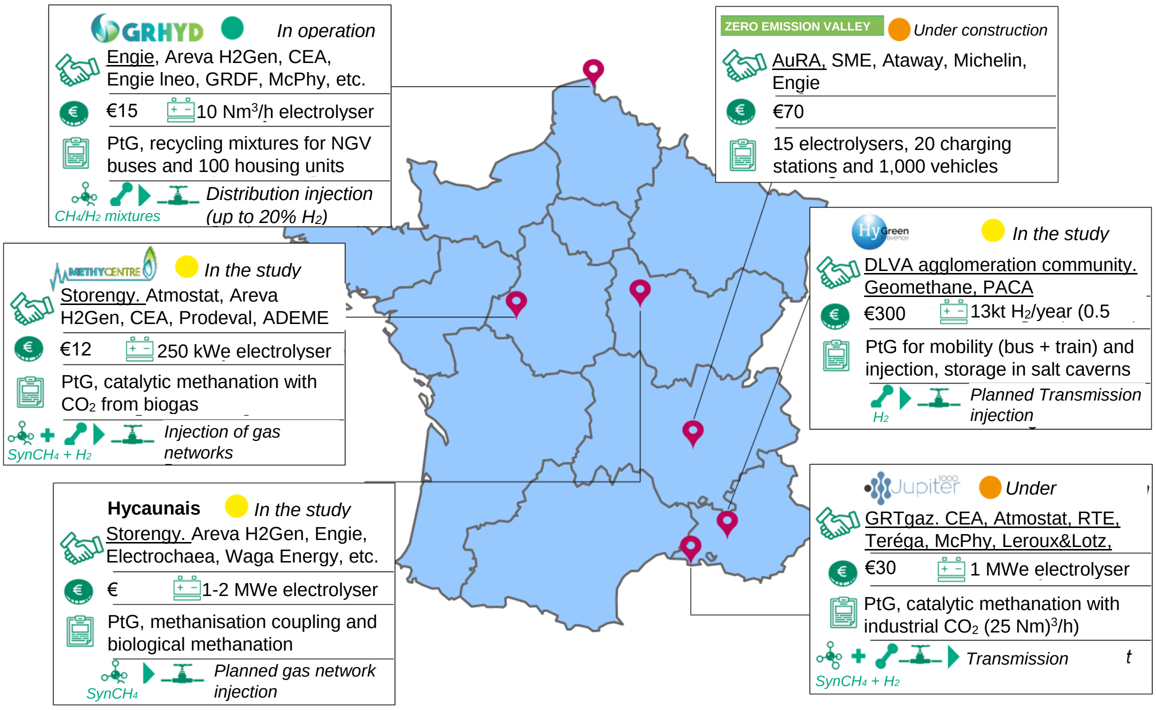

Figure 4: Main power-to-gas projects in France on 1 April 2019

10 priority levers to maximise hydrogen injection into the infrastructures

Requests to connect hydrogen producers, CH_4/H_2 mixtures or synthetic methane have already been sent to some gas infrastructure operators. They demonstrate the timeliness of the issues addressed in this report.

The gas network operators therefore wish to continue their work to prepare gas systems for the integration of hydrogen and synthetic methane to facilitate the development of these new renewable gas value chains.

Gas operators recommend the implementation or pursuit of the following 10 levers:

***Lever* 1.** Identify suitable areas in which the 6% blending rate is applicable. When the conditions are met, adapt the gas specifications to inject first 10%, then 20%
(Contributors: Operators, DGEC/DGPR; action currently underway (6%), with 10% by 2030)

The gas specifications of carriers, storage units and distributors currently provide for a maximum hydrogen level of 6% by volume. The work carried out by the operators shows that this rate can be reached on most of the network's subzones in the short term, with the exception of end-use equipment or sensitive customer installations (e.g. CNG stations or glass manufacturers). Given the characteristics and timeframe envisaged for connecting the projects identified at this stage, the operators do not consider it necessary to adapt the current specifications.

In the coming years, operators will work on identifying more precisely those areas conducive to hydrogen injection into the different subzones, with due consideration given to the technical constraints of infrastructures and downstream end uses.

Looking further to the future, and when the injection sector develops, research work advances, and network and downstream equipment is adapted for hydrogen, the gas specifications will be updated in coordination with State services – to 10% initially, rising to 20%. Specific local contexts aside, this 20% threshold seems to be the upper limit above which significant investment will be needed, in particular for downstream uses. This point is clarified in the chapter on technical-economic conditions.

Lever 2. Invite operators to coordinate and share R&D efforts for all the technical injection routes. Ensure that the corresponding costs are covered in their regulated economic models under the existing processes
(Contributors: DGEC, Operators, CRE; launch date: 2nd half of 2019)

Gas operators made an initial joint effort to identify and prioritise the R&D actions needed to enable the development of the various routes for hydrogen integration into the network. This report contains a chapter dedicated to all of the selected R&D themes.

These themes will be broken down into roadmaps by each operator. In the second half of the year, these will be coordinated to optimise the research efforts. The aim is to achieve the goals as quickly as possible and in the most cost-effective way. This pooling effort between French operators will be coupled with a sharing exercise with the other large-scale operators working on the integration of hydrogen into their networks. The intention is to enhance and enjoy the joint benefits of these R&D efforts. In order to do this, a “technical and strategic experts’ workshop” will be organised with volunteering European stakeholders over the course of the coming year.

The operators will share their consolidated roadmap with the relevant government bodies, , as well as with the French Energy Regulatory Commission (CRE).

It is important that these R&D investments are integrated into the expenditure covered by the tariffs so that natural gas infrastructures can play their full role in the development of the French and European hydrogen sector, and retain their value in the energy transition.

Lever 3. Set a specification of 10% blended hydrogen as a sector-wide target by 2030. The aim is to mobilise equipment manufacturers and downstream users, and to manage operator investments on a case-by-case basis
(Contributors: Operators, DGEC/DGPR, DGE, professional associations; launch date: 2nd half of 2019)

The ability to generalise and scale up the injection of hydrogen into the networks depends on the tolerance of the gas infrastructures' and downstream users' equipment, with customers (in particular, diffuse customers), taken as a whole, representing a significant financial challenge. This acceptability implies, on the one hand, the development and supply of devices compatible with CH_4/H_2 mixtures, and, on the other hand, the acquisition of this equipment by operators and end users in the regions concerned.

Anticipating this adaptability is a real factor in optimising the costs of integrating hydrogen into the gas chain. To facilitate this anticipation, it is recommended that a compatibility target for infrastructure and downstream equipment with a level of 10% hydrogen by volume be set by 2030, under conditions to be defined in consultation with State services. Besides the fact that it is achievable with limited adaptation costs, both on the network and downstream, this target has the advantage of being consistent with that given to the German sector (DVGW[6]) within the same timeframe, thus fostering potential cooperation, the interoperability of European networks, and mass effects on equipment purchases.

Once set, this target will be *de facto* integrated into gas operators' technical specifications. Compatibility with hydrogen is already anticipated for certain equipment, such as chromatographs, in response to the strategies of the stakeholders with links to France.

A specific action by DGE and professional associations aimed at equipment manufacturers and downstream customers could support the coordination of the sector as a whole. For their part, operators are committed to carrying out awareness-raising actions for their stakeholders, including downstream users, as soon as the injection projects are identified in the regions. Where necessary, they will play an active role in the co-construction of equipment adaptation solutions.

***Lever* 4.** Lead a "hydrogen injection working group" bringing together gas chain stakeholders and State services, in conjunction with hydrogen producers, to facilitate the implementation of the initial injection projects
(Contributors: GRTgaz and other operators, DGEC, DGPR, CRE, etc.; launch date: April 2019)

A hydrogen injection working group, led by GRTgaz, was founded in April 2019 to define and frame the different elements (technical and contractual) of the hydrogen injection process, including in the form of synthetic methane, for all stakeholders. This committee must work towards the enabling of pioneer projects and ensure consistency with existing biomethane practices.

The topics currently being studied are:

- Procedures and limits of responsibilities for each of the connection system components,
- Traceability and guarantees of origin of hydrogen,

[6] *Deutscher Verein des Gas und Wasserfaches* is the German gas and water association. https://www.energate-messenger.de/news/190852/dvgw-entwickelt-regeln-fuer-wasserstoff-netzintegration

- Gas quality,
- Future visions for the evolution of energy systems.

Members

Led by GRTgaz

- **Gas operators** (GRTgaz, Teréga, GRDF, Régaz, Storengy, Afgaz)
- **Producers** who have made formalised requests to operators
- **Governments, agencies, public authorities** (DGEC, DGPR, ADEME, CRE)
- **Community** representatives (ARF, FNCCR)
- **Industry professional associations** (AFHYPAC, ATEE Club P2G, Club Pyrogazéification)

+ other sub-group stakeholders according to needs (e.g. sensitive customers, producers)

Regarding the Biomethane injection WG created prior to the launch of the sector, active participation by State services would ensure that regulatory aspects are properly taken into account.

Lever 5. Ensure coordinated and unified French position with regards to European standardisation work on infrastructure and downstream equipment
(Contributors: Operators, professional associations; action currently underway)

Gas operators are actively participating in the work of European standardisation and pre-standardisation groups to support French positions linked to the adaptation of normative benchmarks. The aim is to ensure that these align with the French operators’ vision for the development of the hydrogen sector and the interoperability of the networks. The table in the appendix provides details of the main work in which the gas operators are involved (gas quality, pipelines, metering, compression, delivery points, storage).

***Lever* 6.** Carry out an assessment of the externalities of injecting hydrogen into the networks and of methanation, including a life cycle analysis of these sectors
(Contributors: ADEME, operators, Club P2G ATEE; launch date: 1st half of 2020)

The economic calculations made for this report have so far been limited to an assessment of the adaptation costs related to infrastructures and downstream uses. The relevance of these costs must be assessed with regard to the externalities and services arising from the injection of hydrogen into the networks. This work must be integrated into broader considerations regarding the externalities of the hydrogen sector. In particular, the following must be assessed:

- Greenhouse gas emissions avoided,
- Improvement in the trade balance for the portion of hydrogen produced in France,
- Job creation and other local economic benefits.

An analysis of the hydrogen life cycle according to the different types of production and injection routes must be carried out to assess environmental externalities[7].

***Lever* 7.** Integrate the role of gas infrastructures in the development of hydrogen into energy blend forecasting and implement a specific work programme on the coupling of gas and electricity networks
(Contributors: Gas operators and ADEME, DGEC, Local Authorities, CEA; launch date: 2nd half of 2019)

In connection with both European work on sector coupling and the EU gas market reform, , the public authorities must develop forward-looking visions of the role that hydrogen can play in the energy transition. Their aim should be to jointly mobilise gas and electricity ecosystems by taking advantage of their complementary strengths. Gas operators are already making themselves available to the public authorities to assist with these efforts. They are expected to propose different scenarios for integrating the injected hydrogen in their next gas forecast.

Gas operators are working with industry stakeholders to assess and optimise the role of natural gas infrastructures in the development of decarbonised hydrogen and the various associated uses, with the common goal of helping to achieve carbon neutrality by 2050 at an optimal cost. In the current context, gas operators are committed to the sustainability of the proposed transition pathways. They are convinced that scenarios based on the existing infrastructures can provide a solution without giving rise to massive investments at a given time for end-customers.

If work is being carried out on both sides of the power-to-gas economic models (work by ENEDIS and RTE on Measure 10 of the Hydrogen Deployment Plan for the Energy Transition[8], work by the ATEE P2G Club, etc.), then now is the time to share it. Operators want the public authorities to set up a framework bringing together gas and electricity network operators with a view to achieving a consolidated French vision.

[7] See Measure 3 of the “Hydrogen Deployment Plan for the Energy Transition”
[8] Identification of the value of the services provided to the network by electrolysers and the existing or anticipated means in place to promote this type of service.

The results of this work will feed into other reflections and actions carried out by multi-stakeholder platforms, including:

- The Sector Strategy Committee dedicated to "New Energy Systems Industries"[9],
- The network interconnections working group for Green Growth Commitments Networks[10],
- At European level, work aimed at identifying Important Projects of Common European Interest (IPCEI).

Lever 8. Define and implement a favourable framework for experimenting with the development and operation of the first 100% hydrogen clusters
(Contributors: DGEC, DGPR, CRE, operators; launch date: ~2020)

To go beyond gas operators' R&D work and to anticipate the shape of future technical and regulatory frameworks for the supply, transmission, storage and distribution of hydrogen energy, it would be useful to launch a short-term field experiment to convert a local natural gas loop to hydrogen, or even to implement a new 100% hydrogen loop. Given the downstream conversion costs, the initial target area would be an industrial zone or a limited-size area.

An experiment such as this must be carried out with the support of the State, as part of the National Hydrogen Deployment Plan for the Energy Transition. It will contribute to an improved understanding of the challenges faced by this gas decarbonisation route.

Lever 9. Create a framework for the development of power-to-gas in the event of market failure
(Contributors: DGEC, CRE; launch date: ~2020)

Despite clearly identified benefits (see the German example), power-to-gas economic models can be difficult to set up in the absence of mechanisms to compensate services at a value guaranteeing profit. Indeed, there is currently no mechanism to assess the value of coupling, and even less to remunerate it. This point is moreover the subject of numerous European-level discussions. In all likelihood, it underpins the work commissioned to French electricity network operators under the Hydrogen Plan. Identifying this value is a complex task since there are potentially multiple parameters to consider: value in capped renewable energy producers; value in electricity grid flexibility; the more global value of optimising investments in energy infrastructure; value in arbitrage on the cost and therefore the vectors of decarbonisation for different downstream uses (avoidance of euro per tonne of CO_2 calculations), etc.

A temporary transitional framework will be required to enable projects deemed relevant within the country to take shape. This framework will secure their economic model by integrating the long periods linked to this type of investment and the current uncertainties as to the value of the services provided over time. The forms that this framework could take are to be discussed with all stakeholders likely to involve themselves with this type of work. They will be assessed according to the benefits and the anticipated degree of transparency for the initial projects. It is important to be able to capitalise on these initial coupling projects in order to design a sustainable technical-economic framework.

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[9] A committee whose launch was approved by the Executive Committee of the National Industry Council in May 2018. Chaired by Isabelle Kocher, Engie CEO, its priorities include strengthening and consolidating the French industrial offer for the methanisation equipment and solutions market.

[10] Green Growth Commitments (ECV) aim to strengthen the partnership between the State and private project owners. ECV relating to hydrogen are co-managed by AFHYPAC and CEA. The scope of the "Energy Storage" working group includes, in particular, the interconnection between the electricity and gas networks.

Lever 10. Establish regular work progress reviews between the operators and the State services concerned and update the report every five years
(overseen by: Operators, DGEC/DGPR, ADEME, CRE; launch date: 2020)

Operators have decided to maintain their joint working group to continue the dialogue and spin-offs relating to R&D work on injecting hydrogen into the networks. They propose setting up regular exchanges, the frequency of which is yet to be determined, with the State services, ADEME and CRE in order to share the results of their actions. A first meeting should be scheduled for the second half of 2019 to share the operators' consolidated roadmap and present the main milestones.

Operators also propose that the report on the injection of hydrogen into the networks be updated every five years in order to have an official, shareable document to enable discussions with other sector stakeholders, as well as European or international players and the European Commission.

Technical-economic conditions for injecting hydrogen into the networks

The three hydrogen integration routes (blending, 100% H_2 and methanation) are complementary and consistent with the differing dynamics across the regions. They can be developed to allow large quantities of hydrogen to be integrated into the gas system.

I. Work carried out

As the basis for this report, operators carried out technical and economic assessment work aimed at comparing, in an integrated manner (from the points of entry – interconnections, LNG terminals – to end customers), and based on current knowledge, the costs of infrastructure and downstream adaptation for the different hydrogen integration solutions.

The results of the model, presented below, highlight both the different identified injection thresholds and the priority R&D areas, given the financial stakes involved.

This collaborative work was carried out in two stages. First, an analysis of the unit adaptation costs based on the following elements:

- Concatenation of currently available knowledge (internally, but also via bibliographical resources or bilateral contacts with other European operators) on the critical acceptability rates of hydrogen in the main network and downstream of metering equipment. This work is detailed in the technical report presented in the following section of this report,
- Identification of adaptation solutions associated with attaining and going beyond these critical rates and their unit costs. An equipment inventory was also made to identify the main financial sums involved and to target key issues.

The second step consisted of an estimate of the overall costs and network adaptation strategies based on:

- A study of the different types of hydrogen uses and the definition of six different hydrogen injection configurations (case studies) linked to national volumes,
- The construction of a simplified model to simulate the infrastructure and downstream adaptation costs of these six standard configurations for the various envisaged hydrogen integration routes (blending, methanation, 100%),
- A comparative analysis of the three identified hydrogen integration routes.

The operators were supported in their efforts by E-CUBE Strategy Consultants.

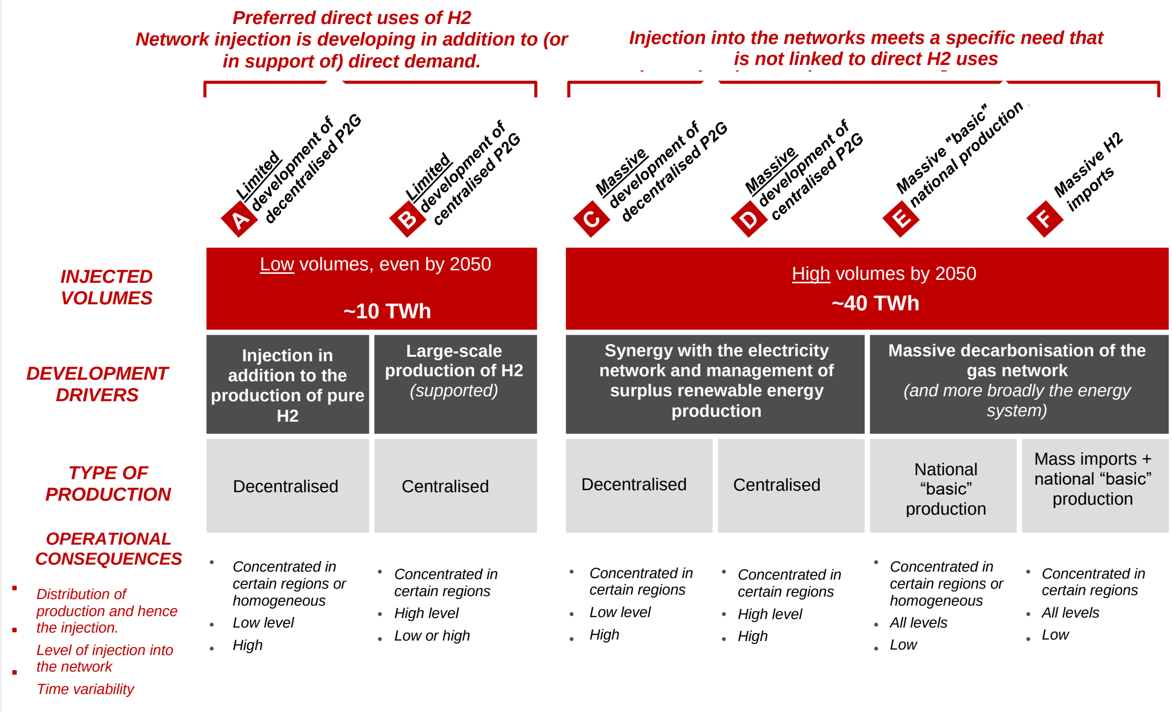
A. Six case studies for a better understanding of all possible use cases

As seen in the chapter "Benefits of injecting hydrogen into the networks", different use cases linked to the process have already been identified. The following features are common to all:

- The mutual strengthening of electricity and gas networks through the production and injection of hydrogen,
- The injection of hydrogen as a means of optimising hydrogen production units initially intended for direct use,
- Direct decarbonisation of the uses by injecting hydrogen into the networks upstream of the consumer.

These use cases display significant variability in the levels and types (fixed/variable) of volumes injected, the network's levels affected (national, regional, distribution) and the foreseeable project development deadlines.

The six injection configurations used to assess adaptation costs for the three technological routes represent the main hydrogen injection classifications anticipated between now and 2050. These highly typical applications combine the massive (40 TWh[11]) / limited (10 TWh) and centralised / decentralised development of injected hydrogen. In reality, several of these configurations will probably operate in combinations that will emerge in due course and according to territorial configurations that are very difficult to understand at this stage.



Source: E-CUBE Strategy Consultants Analysis

Figure 5 : Differentiated case studies used by operators for their cost modelling

The estimated costs of the different cases studied over the period 2025-2050 were related to overall volumes of gas consumed for the upper and lower limits in the SNBC scenario (295 TWh and 195 TWh, respectively).

[11]The 40 TWh are in line with the sector's projections, in particular the AFHYPAC scenario, which foresees an annual hydrogen demand of 220 TWh in 2050. The TWh of study cases only relate to the hydrogen injected into the network. Hydrogen produced for uses is hence deliberately left out.

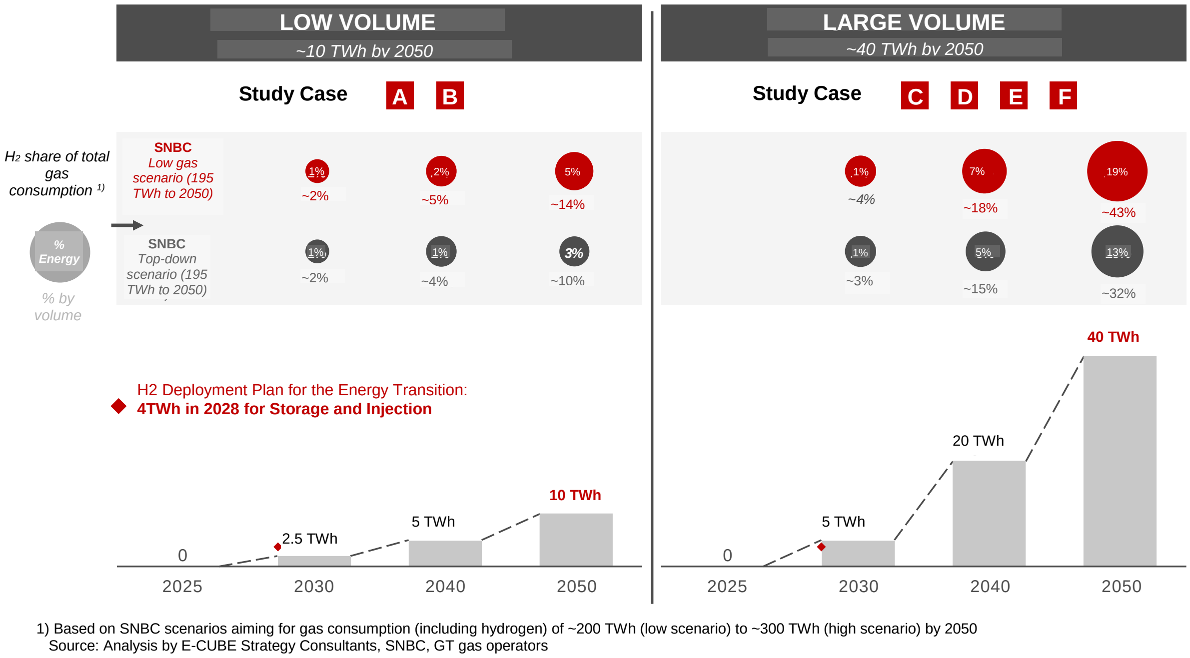


Figure 6 : Predicted pathways for hydrogen injection into the networks by 2050, relative to the volumes of the two SNBC scenarios [in TWh]

B. Modelling the injection of hydrogen into the networks and resulting adaptation costs

In each of the study cases, costs were assessed based on a simplified model of the network. The specific issue of variability has not been addressed as such, and will merit further examination given its impact on network uses, management and operation (leak detection techniques and equipment, invoicing).

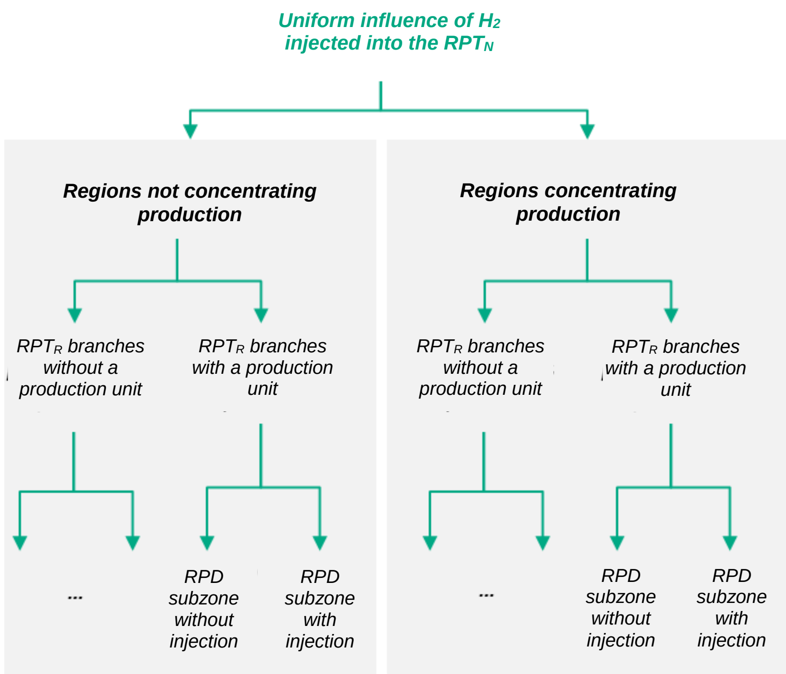


Figure 7: Simplified view of the French gas network

This simplified model has 1 national transmission network, 300 regional subzones and 3,300 distribution subzones. The hydrogen level is assumed to be equal at all points on a given subzone. The gas “descends” throughout the network and “rises” in certain subzones equipped with a reverse flow system (typically 10% of the network).

For each study case, the impact on the simplified network model depends on its specific features:

- Total annual injected volume of hydrogen,
- Volume of hydrogen injected by a production unit,
- Level of injection into the network (national, regional, distribution).

Each year, the model distributes the new production units to enable the overall hydrogen target to be reached, and recalculates the hydrogen level attained for each network subzone.

For each subzone, the cost is the sum of the unit costs needed to achieve the local hydrogen level. The total cost for the scenario is the sum of the costs for each subzone.

II. Volumes of injectable hydrogen in natural gas infrastructures vary according to the unique features of each subzone

The volumes of blended injectable hydrogen in natural gas infrastructures depend on the region concerned and, in particular, the following critical parameters:

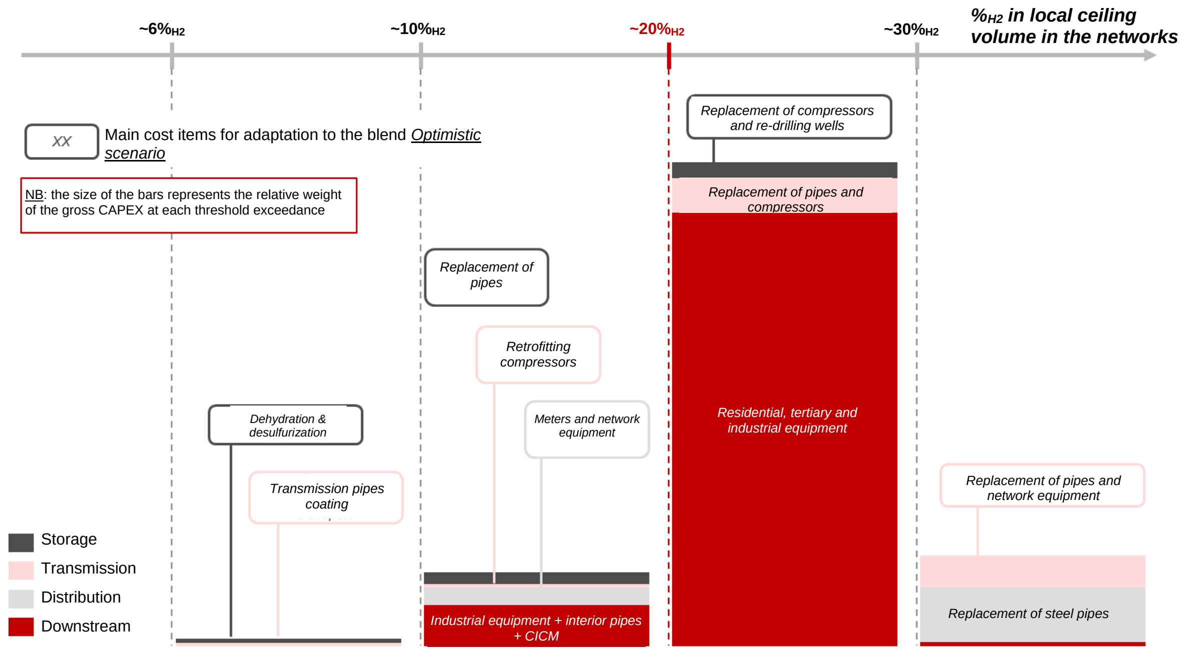
- The nature of the pipelines and the network equipment: some materials are more sensitive to hydrogen than others,
- The presence or absence of aquifer storage tanks (whose hydrogen tolerance is unknown at this time, and which will be specific to each tank),
- The ability to dilute injected quantities: it is easier to plan for dilution on transmission pipes than on distribution antenna,
- The type of customers connected downstream of the injection point: presence or absence of industrial customers who are highly sensitive to gas quality or even NGV refuelling stations (tanks currently certified for a maximum of 2% hydrogen),
- Availability of CO_2 sources if the methanisation route is being considered.

Based on these findings, areas suitable for hydrogen injection in the short term can be identified.

The type of hydrogen production projects will also have an impact on the variability of injected volumes. The latter involves some complexity in terms of connection (sizing of the mobilised network capacity), operation and invoicing. Downstream, variability will likely require protecting sensitive customers (membrane solutions already exist) and properly determining the impact for diffuse customers.

III. In the short term, it may be possible to integrate 6% hydrogen into most structures, in the absence of sensitive uses or installations

Aggregate knowledge to date indicates that **only limited adaptations are required to be able to inject 6% hydrogen into the networks**. The real first investment threshold has been identified at around 10%. **The truly significant threshold is 20%,** in particular given the requirement for downstream uses to be adapted beyond this point.



Note: the operating costs of H2/CH4 separation upstream of NGV stations or groundwater aquifiers take effect from 1%$_{H2}$
Source: E-CUBE Strategy Consultants analysis, Gas operators WG

Figure 8: Summary of adaptation costs (CAPEX) at different hydrogen levels [adaptation costs relative to the volume of equipment concerned]

NB: the graphic view above is maximising as it represents the financial volumes corresponding to the cost of adapting 100% of the fleet at a given time, with no anticipation effect (gradual replacement of equipment by other compatible equipment over time)

By giving preference to suitable areas, it is already possible to inject 6% hydrogen into certain network subzones in the short term. The following actions are underway to this effect:

- Installation of certified chromatographs compatible with the H2/CH4 mixture (for invoicing),
- Identification of leak detectors compatible with the H2/CH4 mixture,
- Meter certification.

A specific inventory of network equipment will also be carried out on a case-by-case basis and depending on the project deployment areas; in particular, for distribution and downstream of the meter.

R&D work should initially extend the zones suitable for the injection of 6% hydrogen mixture, with the threshold eventually increasing to 10%, then 20%.

In the long term, anticipating these different thresholds will have a direct impact on the optimisation of the costs of adapting the infrastructure and downstream equipment.

IV. Regardless of the configurations studied, the associated volumes of hydrogen can be integrated into the gas system at competitive cost by using complementary technical solutions

The modelling shows that it is possible to integrate hydrogen at infrastructure adaptation costs between €1/MWh to €8/MWh by 2050 (according to injection scenarios and total gas volumes consumed in 2050). These 2050 costs are two to three times lower for the enhanced SNBC gas consumption scenario (295 TWh of gas by 2050) than in the low SNBC scenario (critical rates reached later on in the subzones and investments applied to larger total gas volumes).

The three ways of integrating hydrogen into the gas networks – injection blended with natural gas, injection after methanation, and injection of pure hydrogen into converted network sections – **each have their own competitive advantage[12].**

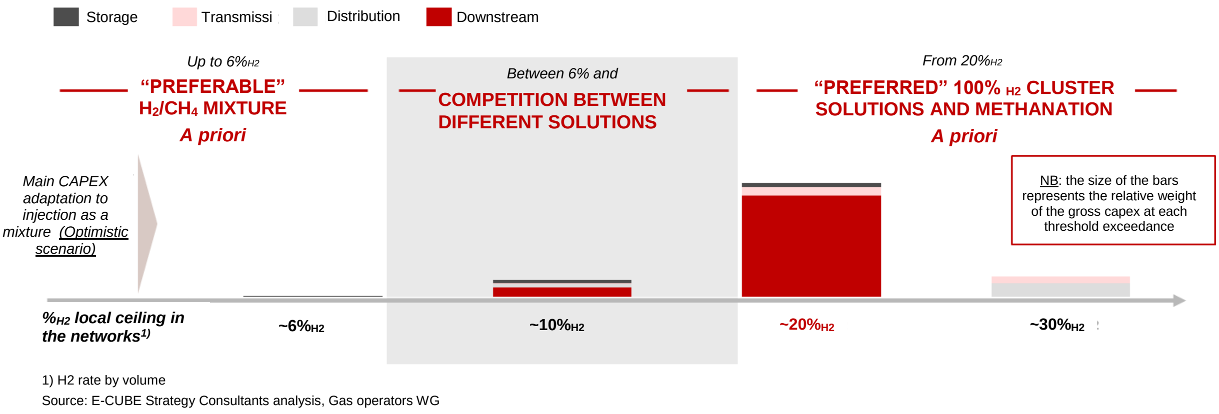


Figure 9 : Competitive advantages of the different H_2 integration solutions in the networks according to the hydrogen level

Combining these technical solutions would make it possible to offer a solution that is adapted to each territory, according to its specific features:

- Blending for the national network (primarily, injection as a mixture at this level or via import) up to a hydrogen content that has yet defined, in favoured configurations that minimise the costs of adapting the network and downstream of the meter,
- CH_4 ecosystems, particularly in places where methanisation has developed significantly, thereby facilitating synergy with methanation through the recycling of biogenic CO_2 from biogas,
- Local 100% H_2 loops (which may be powered by a dedicated transmission network in the long term), in which the conversion will be driven by the conversion of industrial uses and the massive development of other specific uses, such as mobility.

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[12] For methanation, it is the additional costs of methanation compared to an alternative solution (e.g. hydrogen production by electrolysis) that were taken into account to compare the costs of the different integration routes. The volume of injected hydrogen was then adapted to take into account the yields of this additional conversion step.
Three specific cases were assessed for 100% hydrogen clusters: conversion of an industrial zone, conversion of an average city (such as Grenoble) and conversion of a small city (such as Valence).

Major R&D areas identified by French operators and coordination at the European level

A. French operators have identified eight priority R&D areas, including six for infrastructures

The in-depth work carried out highlights the key R&D issues, as things stand today, that would remove the major technical-economic uncertainties and the main identified barriers.

The infrastructure challenges are as follows:

1. The **tolerance** (and adaptability) **of steel pipes** for high hydrogen levels and the ability to treat certain steel pipes, for example using internal coating technology,
2. The **tolerance and performance of network equipment** in the presence of high hydrogen levels:
   - Compressors, dehydration/desulphurisation units, expansion valves, etc.
   - Metering equipment: meters, converters, chromatographs.
3. The **technical capacity to inject hydrogen into aquifer tanks** with no chemical problems (RINGS project),
4. The ability to implement technically and economically **efficient H_2/CH_4 separation units** to “protect” certain “non-tolerant” uses of hydrogen (NGV stations, manufacturing, etc.) and possibly to reproduce hydrogen with a purity required for certain uses (mobility, industry),
5. The **technical-economic performance of the different technological solutions for methanation**,
6. The **ability to capture and transport the CO_2 necessary for the methanation of hydrogen at reasonable costs**

Downstream challenges are as follows:

7. The **tolerance of downstream equipment**, factory pipelines, internal networks and service pipes and risers to **high and variable hydrogen content levels** ,
8. **Manufacturers’ ability to develop new equipment at a reasonable cost** with tolerance for high and variable hydrogen levels.

To date, operators have already undertaken their own respective projects (detailed in the appendix) to prepare the gas networks to receive hydrogen. A more detailed and coordinated vision of the R&D roadmap will be produced in the second half of 2019 by all operators, to be shared as necessary.

For GRTgaz, the R&D roadmap for testing the conditions for injecting hydrogen into gas infrastructures, in particular in the transmission networks, has already been defined by the Research and Innovation Center for Energy (RICE). Sharing and consultation work will be carried out among all French operators. Operators will have recourse to the hydrogen platform currently being developed by RICE (Appendix H – Spotlight on FenHYx).

Unified European research on injecting hydrogen into gas networks will enable France to benefit from all the advances made by other countries involved in this process, such as Germany, the Netherlands, the United Kingdom and Italy. It will also enable Europe to unite its forces with a view to becoming an important hydrogen player, in the same way as other continents such as Asia and Oceania.

B. Multiple European projects and enhanced cooperation

The growing interest of industrial players and public authorities in the role of hydrogen in the energy transition has led European infrastructure operators to step up R&D activities and studies related to the acceptability of hydrogen by gas networks.

Some gas operators have already launched or been involved in studies aimed at assessing the conditions for injecting hydrogen into the current gas networks, or identifying the actions necessary to adapt the networks for the transmission of hydrogen in either blended or pure form. These programmes may cover national or regional networks. For instance:

- Ontras, a German gas carrier, is studying the impacts of blended hydrogen on pipe integrity through the H2-PIMS project[13]. Their goal is to determine the conditions for converting the equipment. This initiative is part of the HYPOS project, which aims to investigate the compatibility of existing gas transmission infrastructures with CH_4/H_2 mixtures with the involvement of around one hundred German partners (universities, research centres, large industrial companies, SMEs, etc.),
- Northern Gas Network, a UK natural gas distributor, has led the H21 Leeds [14]Citygate project to determine the technical and economic feasibility of converting existing gas infrastructures in the Leeds metropolitan area to 100% hydrogen, in order to decarbonise industrial and domestic uses (660,000 inhabitants covered by the study),
- In 2017, DNV GL conducted a study on behalf of the Netherlands Ministry of the Economy to determine the conditions for converting the equipment of Dutch gas carrier Gasunie to transport pure hydrogen.

These issues are now sufficiently mature to be able to carry out tests under real conditions. In March 2019, 25 European demonstrator projects were identified (pilot pre-industrial projects and industrial deployment projects, either in operation or announced) involving hydrogen injection into the gas networks. Notable projects include:

- The injection of hydrogen into a transmission network serving a pasta manufacturer and a mineral water bottle manufacturer by the Italian operator SNAM. The target hydrogen content for this project is expected to reach 5% by volume,
- HyDeploy, working with the UK distributors Cadent and Northern Gas Networks at the University of Keele campus to test the workings of cooking and heating appliances with gases containing up to 20% hydrogen by volume on the existing network (tests planned to start in summer 2019),
- Hystock[15], overseen by Gasunie and Energystock and initiated in the Netherlands in June 2019, is a 1 MW capacity power-to-gas facility for which the hydrogen produced will be stored in the Zuidwending saline cavity. It can be used either to supply industrial customers or be injected into the gas network as a mixture,
- The French projects GRHYD, Jupiter 1000, Methycentre, Hycaunais, Hygreen and FenHYx are presented in the appendix.

European infrastructure managers are actively involved in the work of CEN - CENELEC Sector Forum Energy Management (SFEM)/Working Group Hydrogen. The aim of this platform is to establish a state-of-the-art for technologies and normative activities linked to the hydrogen sector, and to strengthen cooperation between industrial and public stakeholders and standardisation bodies. A report published in 2016 by SFEM made it possible to identify R&D priorities on different components of the hydrogen sector, including network infrastructures. A review of this report is currently underway and will become public in 2019.

European gas operators are also working together to develop the hydrogen injection sector through European technical groups. Many of them are members of standardisation groups carrying out work related to the challenges faced by the sector (e.g.: CEN/TC 234 – Gas infrastructure). Operators also participate in Marcogaz' work aimed at providing technical support to the European Commission on gas infrastructures. Finally, the Hyready project involving European gas carriers and distributors has set itself the goal of developing common good practices between its members for the preparation of their networks to hydrogen injection.

Cooperation between European gas operators is also increasing through the pooling of R&D actions and budgets. Several significant R&D partnerships are currently under discussion and could be announced in the coming year.

The provision of European funding for joint R&D actions plays a role in these mergers. In its 2019 call for projects, for example, the Fuel Cells and Hydrogen Joint Undertaking (FCHJU)[16] is offering two million euros to support projects addressing the following subject: "Systematic validation of the ability to inject hydrogen at various admixture levels into high-pressure gas networks in operational conditions".

[13] https://www.dbi-gruppe.de/h2-pims.html
[14] https://www.northerngasnetworks.co.uk/event/h21-launches-national/
[15] https://www.energystock.com/about-energystock/the-hydrogen-project-hystock
[16] The FCH JU is a public-private partnership involving European institutions that is focussed on speeding up the commercialisation of fuel cells and hydrogen technologies.

Increased recognition by European institutions of the role of hydrogen in the energy transition and the development of the industry is likely to further strengthen European support for R&D actions. In January 2019, the High Level Industrial Roundtable, whose role is to advise the European Commission's DG GROW (Directorate-General for Internal Market, Industry, Entrepreneurship and SMEs) on EU industrial policy, recommended coordinating actions and investing in strengthening six strategic value chains, including hydrogen systems and technologies.

Technical conditions related to the injection of hydrogen into the networks

The widespread integration of hydrogen into the networks means continuing R&D efforts on themes identified as priorities. The various activities undertaken by French and European operators will make it possible to refine this technical knowledge in the future.

In this report, the operators have pooled all the problems linked to the injection of hydrogen into natural gas infrastructures. Elements related to uses are outside the remit of the gas operators and must therefore be addressed by the relevant stakeholders, to which operators will provide as much support as possible.

A. Pipeline integrity

Steel pipelines

Hydrogen enters and diffuses more easily into the crystalline mesh of steels generally used for gas pipelines (low-alloy carbon steels). This phenomenon can lead to a weakening of the steel (reduction in ductility) and an increase in the speed of the propagation of defects. This is known as “hydrogen embrittlement”.

The different steel pipes in the networks do not all have the same sensitivity to hydrogen embrittlement. This sensitivity depends on:

- Diameter: the regional networks with smaller steel diameters with a low yield strength are, on initial examination, less sensitive to hydrogen embrittlement than some large transmission backbones, which may be made of technologically advanced steels,
- The year and the method of the tube's manufacture,
- The purity of the steels in which sulphur/phosphor compounds are present,
- Features arising from welding procedures,
- The composition of the gas (in storage, the gas may contain hydrogen sulphide or water in places),
- Operating conditions (pressure, strain amplitude and pressure variation frequency), in particular for very high pressure storage facilities.

It is hence necessary, first and foremost, to arrive at a specific definition of the links between the mechanical characteristics of the steels, the operating conditions and the inspection conditions. In view of the announcements made by other European countries (the Netherlands and Germany), it is likely that a significant part of the network may in fact tolerate certain hydrogen levels, provided that adequate operating conditions are in place. GRTgaz, Teréga and Storengy have begun research to carry out the following series of tests on the materials present in the network:

- A study of the propagation of planar defects under static loading at different hydrogen contents,
- A study of fatigue resistance in an atmosphere under hydrogen pressure (choice of three steels representative of those used in the network, with different percentages: 2%, 10%[17] and 25%),
- A study of steel welds in contact with different CH_4/H_2 mixtures.
- A study of the impact of water and hydrogen sulphide in the presence of hydrogen.

To conduct the tests, the expected results will be spread over a time scale from end-2018 to end-2021. This will include tests carried out in a representative environment on the Jupiter 1000 site[18] (immersion of test pieces in the gaseous pipe containing hydrogen).

Other work has also been carried out at the European level:

[17] Percentage to be confirmed based on results obtained for 2% and 25% hydrogen mixtures, respectively
[18] See Appendix D

- A study by the German carrier Ontras via the H2-PIMS project as part of the HYPOS programme, with the involvement of GRTgaz Deutschland,
- The conversion of an existing pipeline from natural gas into hydrogen by the Dutch operator Gasunie.

Solutions must be explored to reduce the effects of hydrogen on pipeline steel:

- The addition of O_2, CO or CO_2 molecules as an inhibitor of the effects of hydrogen. This solution protects the entire network if the molecules are injected into key areas. Uncertainties remain regarding the effectiveness of these measures and the potential impact on end customers and storage facilities. Investigations on this topic are ongoing.
- The installation of a protective coating inside the pipes preventing the absorption of hydrogen into steel. Similarly, investigations are underway into product development and application methods, in partnership with *Catalyse* and the *Institut des Mines de Paris*.
- Other avenues are also being studied by operators, such as tubing and lining.

Hydrogen injection will probably require the adaptation of pipe inspection methods and tools.

Other pipes (Polyethylene, Cast iron, Copper, etc.)

The initial impression is that polyethylene pipes, which appear predominately in the distribution network (~150,000 km), are not affected by the presence of hydrogen. This assertion is agreed upon by all the various European stakeholders working on hydrogen, and feedback from the GRHYD field experiment[19] should confirm it by 2020.

There is, however, a risk related to the permeability of polyethylene. But this does not pose any particular problem for the levels of hydrogen contemplated in the mix (up to 20%).

Additional studies are required to analyse the reaction to hydrogen of other materials in the network, for example ductile cast iron (4,500 km of pipe). Consideration could also be given to the gradual replacement of these pipes with polyethylene, primarily by targeting the identified injection areas. It should be noted that these pipes are mainly located in city centres (e.g. in Paris) where changes to structures bring their own specific problems.

B. Underground (aquifer tanks and saline cavities)

In France, there are two types of underground storage: aquifer tanks and saline cavities.

Saline cavities seem suitable for storing hydrogen, as pure hydrogen saline cavity storage facilities already exist in Great Britain and the United States. Recently, they have also been used to store helium in Germany, demonstrating salt's impermeability, including for very small molecules.

Regarding storage in porous rock, whether in aquifer tanks or in a depleted reservoir, the dissolution and transport of hydrogen in water, and its confinement in storage, are well known and of the same order of magnitude as for natural gas. Little additional research in this area should be required to address the specificities of French storage facilities. The current literature and studies are reassuring regarding the casing's holding capacity in the presence of hydrogen. However, research work with the BRGM and the University of Pau is about to be launched and should provide additional elements.

The main technical gap is the identification of potential chemical reactions in solution. These could lead to micro-organisms consuming dissolved hydrogen, to the production of hydrogen sulphide, and to the development of biofilms near wells (risk of corrosion).

As storage facilities are directly connected to the national network, consideration could initially be given to limiting the injection of hydrogen into transmission and distribution networks that do not impact underground storage facilities, pending the results of studies carried out by their owners into the tolerance of their aquifer tanks. This is the way it was done for biomethane, the injection of which was only authorised in the storage facilities – and therefore on the main transmission network – in June 2017.

[19] See Appendix C

The joint studies currently being carried out by Storengy and Teréga (in particular via the RINGS project detailed below) will result in an acceptable hydrogen level for each aquifer tank being defined. In the event that certain aquifers are incompatible with hydrogen, two solutions may be considered:

- The installation of hydrogen filtering equipment at the entrance of the storage facility,
- The installation on the transmission network of hydrogen-free routing circuits to these storage facilities.

The RINGS project[20]

The aim of this project is to design and build an experimental reactor in order to identify and describe reactions involving hydrogen in different underground aquifer tanks. This reactor will make it possible to recreate the tank conditions from gas, rock and water samples, and to test different proportions of hydrogen mixed with natural gas. This project started in early 2018 and will continue until 2021. Preliminary results should be available in 2020.

The STOPIL H2 project

The aim of this project is to demonstrate the concept of storing pure hydrogen in a saline cavity in technical, economic and environmental terms. The research is based on a small cavity (8,000 m^3; i.e. 44 tonnes of hydrogen) located in Etrez's underground storage facility.

The first phase is a two-year feasibility study subsidised by GeoEnergie that began in 2019 and which brings together various partners (Storengy, Air Liquide, Geostock, Brouard Consulting, Armines, INERIS and BRGM). Storengy is in charge of designing the tests to check the impermeability and to prepare the cavity cycling. At the end of the feasibility study, a second phase will consist of testing and monitoring the hydrogen cycling of the upper part of the cavity.

C. Gas quality and metering

Given the current state of the metering equipment, the injection of hydrogen into the networks raises the problem of hydrogen metering by volume and conversion into energy (PCS):

- Assessment of variations in the metering of the blend in relation to 100% natural gas and compliance with metrological ranges,
- Installation of analysers and converters certified for measuring PCS in the presence of hydrogen,
- Implementation of *ad hoc* billing solutions for areas with hydrogen injection.

Meters

Regarding meters, the measurement uncertainties must be checked on the turbine meters due to the low density of the CH_4/H_2 mixture. However, other technologies, and in particular ultrasound, accept a hydrogen content of up to 15% with little or no dispersion.

The tests carried out as part of GRHYD (G4 meters: private customers; and G65 meters: small tertiary sector) show that the presence of hydrogen (up to 20% volume) in the gas would lead to a metering difference of between -1% and +2.5%. It should be noted, however, that these tests were not performed on a metrological test bench and that CEN CENELEC[21] has validated the use of turbine meters for a mixture of up to 10% hydrogen.

Additional tests on a metrological test bench and on a wider range of meters remain necessary to come to a decision on the wider deployment of hydrogen injection into natural gas networks. GRDF and GRTgaz are thus co-financing a metering research programme. This three-year Euramet SRTn°03 project[22], entitled NewGasMet, was launched in early June 2019. It aims to better understand the possible impact of new gases, and hydrogen in particular, on the accuracy and lifespan of meters. The research should ensure that the gas meters used with different types of renewable gas, and in particular with gases containing hydrogen, remain compliant with the requirements of the European Measuring Instruments Directive (MID, 2014/32/EU).

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[20] **RINGS =** Research on the Injection of New Gases in Storages. The project conducted jointly by Storengy, Teréga and UPPA (University of Pau and the Pays de l'Adour).
[21] See CEN/TC 237 – N764
[22] https://msu.euramet.org/current_calls/pre_norm_2018/SRTs/SRT-n03.pdf

Meters manufacturers will have to adapt designs and measurement sensors accordingly.

PCS Analysers

The PCS for gas in the presence of hydrogen must be measured by certified analysers.

Like other European carriers, GRTgaz is involved in an analysers' replacement programme, in order to measure accurately the hydrogen content in CH_4/H_2 mixtures. Teréga also plans to replace the equipment on its network.

To prepare for the decentralised injection of hydrogen into the networks, GRDF is planning to assess new analysers capable of measuring the PCS of a gas containing hydrogen.

Invoicing

The injection of hydrogen brings about variations in calorific value, which means new methods must be developed to determine the energy content of the gas at all points of the network. In this context, the operators, via the French Gas Association (AFG), actively contribute to the work of Marcogaz's "Conversion of m^3 into kWh" task force, which will decide on a range of possible solutions over the coming months.

This will be linked to the adaptation of the information system and to the more proactive communication of information about gas quality.

D. Network equipment

Network equipment[23] may be affected by the presence of hydrogen. This includes the risk of leaks, integrity risks (a problem similar to that of pipes), and malfunctions. To define the acceptable hydrogen level for each network subzone, it is therefore necessary to establish which of its equipment is most sensitive to hydrogen.

Equipment in the injection zones will have to be classified to provide a precise understanding of both their hydrogen limit levels and the reasons for these limits[24]. Different solutions can then be sought to limit or even eliminate the risks associated with hydrogen.

At the same time, equipment manufacturers must develop, where necessary, new equipment that is compatible with both mixtures and 100% hydrogen. Standardisation work[25] that is starting to identify the affected equipment should help guide R&D developments. Operators will raise awareness among equipment suppliers, whose involvement is limited thus far.

Compressors and turbines can be adjusted (configuration), adapted or replaced to operate at a given hydrogen content. However, variations in hydrogen content over time will require either an adjustment of the settings of the turbines, compressors, and any combustion apparatus with new regulation systems, or the installation of downstream "hydrogen-filtering" membranes in the controlled levels.

E. Monitoring and maintenance plan – human and organizational factors

The design, construction, adaptation and operation of the networks will require training and professionalisation initiatives for employees. To this end, dedicated training programs will be held as hydrogen is developed. Hydrogen has specific features and unique intrinsic characteristics that require a proper understanding in order to guarantee the safety of installations and people.

Professionalisation initiatives have already been implemented in anticipation of the launch of the Jupiter 1000 demonstrator. GRTgaz and Teréga made contact with the ENSOSP test platform for new gases[26] to discuss tailor-

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[23] The term "equipment" is understood in its broadest sense, and includes all items that may be found on the network: valves, taps, expansion valves, flanges, analysers, meters, chromatographs, desulphurisation units, dehydration units, compressors, leak detectors, etc.

[24] There may also be an impact linked to variability (for more detail, consult the Uses section)

[25] Report by SFEM CEN/CENELEC (organisation providing guidelines for the standardisation work to be carried out) that identifies the technical gaps for the transport of a CH_4/H_2 mixture, see [3]

[26] National School of Firefighters

made training courses. GRDF has also implemented specific procedures for its agents and local stakeholders (e.g. firefighters) as part of the GRHYD project.

F. Network capacity

Hydrogen has an energy density three times lower than methane[27]. The volume of hydrogen transported must thus be about three times greater than for natural gas to meet the same energy demand. As pipe pressure is limited by design, the variable parameter will therefore be the flow speed, which is three times higher for hydrogen than for natural gas. Thus, for a 100% hydrogen network, the compression energy will be approximately three times greater for transmission with an equivalent pressure drop.

In the short term and for CH_4/H_2 mixtures with a hydrogen content not exceeding 6 to 10%, the impact will be limited and acceptable within the current gas system.

In the long term, the loss of network capacity should not be a major issue insofar as it would be offset by the structural fall in consumption due in particular to increased energy efficiency among gas consumers.

G. Risk assessment studies and distances of effects

Initial studies carried out as part of the Naturalhy project demonstrated hydrogen's lack of impact on the distances of effects for straight pipelines, with blends reaching up to 25%. Below this threshold, there is no change in the public utility easements to be expected.

However, it will be necessary to recalculate the need to implement additional safety measures on a case-by-case basis. This will be done by jointly assessing the greater volatility of hydrogen and its more flammable nature.

H. Information system and network management

The progress of the renewable gas sectors (hydrogen, biomethane, pyrogasification gas, etc.) will result in the decentralization of gas system injection points. As injected volumes increase, the network operators must coordinate these injections while maintaining gas quality control at all points of the network and controlling the balance between local production and consumption.

Management in areas of high production and low consumption, and/or areas with less hydrogen acceptability, will entail:

- Methanation to manage the hydrogen level,
- The reverse flow of the distribution network to the regional transmission network, or even to the national network,
- Separation of hydrogen and natural gas to protect the most sensitive consumers.

To meet these challenges, the gas network will rely increasingly on new technologies and enhanced data management. GRTgaz, Teréga and GRDF are developing Smart Gas Grid solutions for this purpose. The GRTgaz programme covers four main areas:

1. Maximising the integration of renewable energies at the best cost for the market,
2. Increasing the efficiency of gas networks[28],
3. Coupling of networks (in particular electrical and gas networks)[29],
4. Improving network communication (in particular at the interface between transmission and distribution).

GRDF has added a theme to its programme dedicated to energy control, including the deployment of the Gazpar smart meter.

[27] Approximately 3.6 kWh/Nm3 or 12.8 MJ/Nm3 for hydrogen, compared to 11.8 kWh/Nm3 or 42.3 MJ/Nm3 for natural gas
[28] Tenore and Optimus projects
[29] Project Jupiter 1000

All these solutions being studied will contribute to the optimised integration of hydrogen into the networks.

I. Methanation & CO_2 capture/transport

Producing synthetic methane from hydrogen and CO_2 using a methanation process is a possible alternative to the gradual adaptation of the network to the transport of CH_4/H_2 gas mixtures.

This route has the following advantages:

- It allows the existing infrastructure and downstream equipment to be used in its existing state,
- It makes it possible to increase the carbon performance of renewable gases (carbon capture and utilization - CCU) in synergy with methanisation (capture and recycling of CO_2 biogas from methanisation),
- It provides a solution that is consistent with the short-term development of the renewable hydrogen sector in the regions (medium-sized projects[30] intended primarily for use in mobility and industry, with injection as a means of optimising the economic model).

Two methanation technologies are currently at the demonstration stage:

- Catalytic methanation, involving French stakeholders such as Atmostat,
- Biological methanation, which relies on micro-organisms, involving French stakeholders such as Enosis, or European stakeholders such as Electrochaea.

For work to be carried out on costs, the optimisation of technical parameters, gas quality, and to assess the benefits mentioned above under real conditions, the demonstrators must be supported on French territory.

Experiments in progress

Several experiments are underway to accelerate the technological maturity of different methanation technologies:

- A catalytic methanation unit with a capacity of 25 m^3/h will be tested as part of the Jupiter 1000 demonstrator. The installed equipment is developed by ATMOSTAT from technologies designed by the CEA, which will also be in charge of the demonstrator's technical-economic and environmental study.
- GRTgaz and Teréga also have an interest in combining the pyrogasification and methanisation processes. The partnership signed with ETIA, a specialist in heat treatment processes, aims to design a pilot project for the production of synthetic methane by pyrogasification.
- GRDF supports the structuring of demonstrator projects through its involvement in technical-economic feasibility studies for different production configurations of synthetic methane (on coupling formats between renewable electric energy and methanisation from extreme configurations of hydrogen and CO_2 by manufacturers)
- GRDF also shares its experiences with its partners, Energir (Quebec) and Socalgas (California).
- Storengy's Methycentre and Hycaunais projects experiment with innovative methanisation and methanation couplings to produce renewable synthetic methane according to the specifications of the network gas (for injection into the GRDF distribution network). New regulatory changes may be necessary in regard to this. Finally, it should be noted that Storengy will test each of the two methanation technologies: catalytic, with Atmostat as part of the Methycentre project; and biological, with Electrochaea as part of the Hycaunais project.
- Operators also collaborate with the other power-to-gas sector stakeholders in the ATEE Power To Gas Club[31] to create a power-to-gas installation optimisation model that incorporates methanation, and to assess the necessary support mechanisms and most suitable methods.

Future sources of CO_2 relevant for use in methanation units also need to be accurately identified. In this respect, the combination of methanation and methanisation processes opens the door to some interesting possibilities. The methanation of biogas allows the biomethane flow rate to be increased by around 40%, at an amount similar to the current cost, as the cost of a methanation unit is equivalent to the cost of a purification unit.

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[30] Current projects rarely exceed a few MWe
[31] Energy and Environment Technical Association

J. 100% hydrogen networks

Challenges

In the short to medium term, the conversion or construction of 100% hydrogen pipelines could be an opportunity to deliver decarbonised hydrogen to industrial hydrogen consumers or business districts. This conversion could be driven by the regions' desire to limit local greenhouse gas emissions and by the public authorities' desire to convert a certain number of mobility or industrial uses to hydrogen.

Current and future actions

GRTgaz is in the process of developing a methodology for converting natural gas networks for the transport of hydrogen. GRTgaz is also developing technical guidelines for the design, construction and operation of hydrogen transmission pipelines.

FenHYx test programmes[32] will make it possible to fully identify the technical and operational adaptations needed for the conversion methodology.

GRDF also assesses the impact of converting distribution networks to 100% hydrogen via:

- Monitoring projects of this type being set up in Europe (Leeds in the United Kingdom, potential projects in Germany and the Netherlands),
- An initial assessment of the impacts of this conversion.

It should be noted that this conversion does not seem relevant in areas where biomethane or other types of green gas have already been developed in the interim. In the medium term, it should rather be studied in the context of local loops serving industrial uses.

K. Uses

Both the tests carried out in European projects (Naturalhy, Ameland) and those in GRHYD show that residential customers' equipment can operate with a hydrogen level of 20% (or even 30%), with no loss of production performance and with a reduction in nitrogen oxides and carbon monoxide emissions. However, the experiments at this stage do provide a guarantee as to the long-term (several years, up to a decade) compatibility of this equipment at variable hydrogen levels. The same applies to service sector boilers.

Work has been initiated at the European level, as part of the FCH-JU, to address this specific issue. It is due to start in the second half of 2019.

Some industrial uses may be impacted by the presence of hydrogen at low levels (from 1% for the most critical industrial processes as per current estimations). However, these specific uses are not present on all network subzones. This means that each injection project must carry out a precise inventory of the affected uses to determine a maximum hydrogen injection level.

For industrial equipment, putting a figure on adaptation or replacement costs depends heavily on the sectors concerned and the size of the equipment.

To gain a precise understanding of their maximum hydrogen levels and the reasons for these limits, all these uses must therefore be classified by R&D as a priority. Different solutions can then be sought to limit or even eliminate the risks associated with hydrogen. At the same time, equipment manufacturers will have to offer equipment that can support blended or even 100% hydrogen.

It should be noted that uncertainties still need to be removed on customers' networks downstream of the meter, about which the operators lack information (internal pipes and risers).

The tanks of some of the NGVs on the road in France are not certified for more than 2% hydrogen[33]. For steel tanks, there is a risk of embrittlement that needs further evaluation.

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[32] See Appendix H

[33] The steel NGV tanks that fall under the scope of the Order of 8 December 2017 relating to the features of compressed natural gas (CNG) and liquefied natural gas (LNG) intended for carburation currently allow for a maximum of 2% hydrogen.

For downstream uses, anticipating hydrogen's acceptability is central to foster the gradual adaptation of the fleet and to avoid "change of gas" operations.

Note on the variability of the hydrogen level

Uncertainties exist regarding the tolerance of downstream equipment at variable hydrogen levels. Likewise, few studies have estimated the adaptations or the corresponding costs required to make the equipment compatible with a performance level equivalent to this variability.

This subject is rarely addressed in the literature, and it is hence difficult to pre-empt its impact for all uses. R&D thus needs to provide a more accurate description of the actual impact of this variability on uses, and to develop the tools or means for managing it where possible.

Note on separation

In some specific cases, it may be necessary to use separation solutions to protect sensitives users by providing a gas that does not exceed a few percent hydrogen.

Solutions currently exist, but must mature before they become available at reasonable costs.

Separation could also eventually be used to recover pure hydrogen to supply dedicated uses. This process is still immature. However, research is underway, particularly among manufacturers specialised in polymer membranes.

Appendices

A. Priority levers: timeframes and contributors

Lever	Contributors	Launch date
1. Identify suitable areas in which the 6% blending rate is applicable. When the conditions are met, adapt the gas specifications to inject first 10%, then 20%;	Operators + DGEC/DGPR	In progress (6%) By 2030 (10%)
2. Invite operators to coordinate and share R&D efforts for all the technical injection routes. Ensure that the corresponding costs are covered in their regulated economic models under the existing processes;	DGEC + Operators + CRE	2nd half of 2019
3. Set a specification of 10% blended hydrogen as a sector-wide target by 2030. The aim is to mobilise equipment manufacturers and downstream users, and to steer operator investments on a case-by-case basis;	DGEC + Operators + Professional associations (AFG, equipment manufacturer associations similar to Uniclima, etc.) + DGE	2nd half of 2019
4. Lead a "hydrogen injection working group" bringing together gas chain stakeholders and government services, in conjunction with hydrogen producers, to facilitate the implementation of the initial injection projects;	GRTgaz + Other operators + DGEC / DGPR + CRE +…	In progress (initiated in April 2019)
5. Mount a unified defence of the French position in European standardisation work on infrastructure and downstream equipment	Operators + Professional associations (AFG, Marcogaz, etc.)	In progress
6. Carry out an assessment of the externalities of injecting hydrogen into the networks and methanation, including a life cycle analysis of these sectors;	ADEME + Club P2G ATEE + Operators	1st half of 2020
7. Integrate the role of gas infrastructures in the development of hydrogen into energy blend forecasting and implement a specific work programme on the coupling of gas and electricity networks;	Gas and electricity operators + ADEME + DGEC + Local authorities + CEA	2nd half of 2019 (in progress in prospective gas projects)
8. Define and implement a favourable framework for experimenting with the development and operation of the first 100% hydrogen clusters;	DGEC + DGPR + CRE + Operators	~ 2020
9. Create a framework for the development of power-to-gas in the event of market failure	DGEC + CRE	~ 2020
10. Establish regular work progress reviews between the operators and the State services concerned and update the report every 5 years	Operators + DGEC/DGPR + ADEME + CRE	2020

B. Standardisation work

Organisation	Working Group	Participation	Purpose / content	Challenges and risks for the sector
Pre-standardisation activities				
Marcogaz	Hydrogen Task Force	GRTgaz appointed by AFG	State-of-the-art of technical tests conducted on different elements of the gas chain with a hydrogen/natural gas mixture and identification of future research actions. In the process of being finalized	To date, no current projects are being considered. Laboratory tests must be supplemented by field tests (or on test benches under operational conditions). Limiting factors for the injection of hydrogen into transmission networks are mainly gas uses and storage.
	Storage WG	Storengy – AFG (Chairperson)	Contributions to TF H2. Publication of a position paper on the acceptance of hydrogen in storage and pre-normative research requirements. Presentation of this paper at various conferences on behalf of Marcogaz.	Consolidate the vision of European storage providers. Consolidate the vision of European storage providers. Exchange of information on pilot projects Promote and possibly launch pre-normative research programmes on the subject (via GERG), financed by the EC, in particular on the mechanisms at work in porous reservoirs.
CEN CENELEC Sector Forum Energy Management	Hydrogen Working Group	GRTgaz appointed by AFG Storengy represented by ENGIE	Highly detailed identification of the impacts of the hydrogen/natural gas blend both in the gas system and for uses. Identification of research and pre-normative research to be conducted and recommendations regarding standardisation work to be initiated. Report updated in May 2019, for validation within CEN CENELEC (this report has no regulatory value as a standard)	The report recommends setting up test modules for gas system equipment under operational conditions. Infrastructure operators must therefore have either new R&D financial resources for test benches adapted to the H2/CH4 mixture, or be able to test their equipment under operational conditions
CEN Gas Sector Forum	"Pre-normative Gas Quality Study" Working Group/Wobbe Index Task Force	GRTgaz appointed by the AFG (GRDF, Storengy, Elengy also involved via RICE)	The goal of the Sector Forum is to facilitate the exchange of information between the parties and to coordinate and identify the standardisation work to be carried out. Participation in the Task Force dealing with the impact of the injection of hydrogen on the Wobbe Index and the PCS enables exchanges with associations representing downstream stakeholders.	Associations representing industrial customers in European bodies cannot be representative of each industry with a specific hydrogen-sensitive process. Operators therefore have a role to play with regard to their industrial customers. They must be tasked with assessing in detail the impacts on uses, and must have the financial capacity to do so.
Standardisation activities				
CEN TC 234	Group of WG Presidents (convenors)	Storengy mandated by BNG (for WG4)	Contribute to the joint reflection by gas infrastructure stakeholders (CEN TC234) on the acceptance of H_2	Oversee the harmonisation of the analyses and the defence of the French vision. Information flow
CEN TC 234	Working Group 3 (gas pipeline; P > 16 bar)	GRTgaz mandated by BNG	Contribution to the transport pipelines section of the report being prepared on the “consequences of hydrogen in gas infrastructures”	The report also raises the issues of equipment sealing, the adaptation of operational and maintenance procedures, and welding. These issues need to be validated under operational conditions.
CEN TC 234	Working Group 4: Storage	Storengy mandated by the BNG (convenor)	Contribute to the joint reflection by gas infrastructure stakeholders (CEN TC234) on hydrogen storage. Contribution to the storage section of the report being prepared on the “consequences of hydrogen in gas infrastructures”	Consolidate the vision of European storage providers. Communicate to CEN and the Commission on pre-normative storage research needs. The report points out that the major uncertainty regarding the injection of hydrogen into aquifers or depleted gas fields concerns the potential biological reactions of the subsoil that could lead to the disappearance of hydrogen and the generation of H_2S. Furthermore, the problems of corrosion and embrittlement of steel in the presence of hydrogen are yet to be addressed. This is particularly relevant for pipes transporting the untreated gas which are hence loaded with water, and potentially with H_2S with a pressure of up to 250 bar.
CEN TC 234	Working Group 5 (metering chain)	GRTgaz mandated by BNG	Contribution to the transport metering chain section of the report being prepared on the “consequences of hydrogen in gas infrastructures”	WG5 refers to the CEN TC237 WGs to understand the impact of H_2 on the various elements of the metering chain. See below.
CEN TC 234	Working Group 6 (delivery point)	GRTgaz mandated by BNG	Contribution to the regulation section of the report currently being prepared on the "consequences of hydrogen in gas infrastructures” (impact on the functions of the delivery points: safety, regulation, reheating, sizing, internal and external sealing)	In particular, the report identifies the fact that the impacts on the reliability of equipment must be taken into account in maintenance procedures. These impacts are to be validated under simulated operational conditions.
CEN TC 234	Working Group 7 (compression)	GRTgaz mandated by BNG	Contribution to the compression section of the report being prepared on the “consequences of hydrogen in gas infrastructures”	The report identifies adaptation work that is necessary for some compression technologies but takes no position for some others.

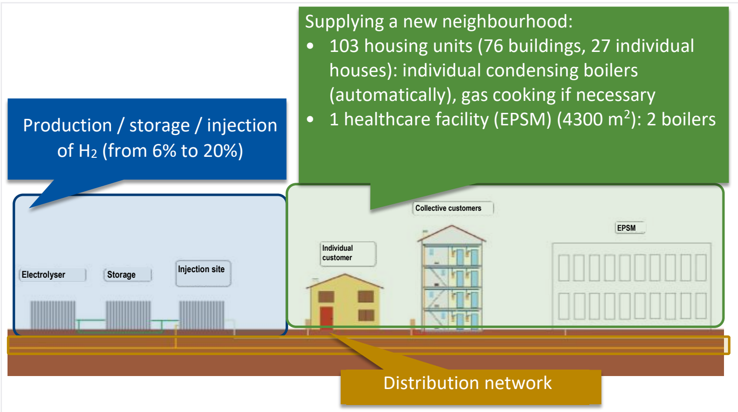
CEN TC 234	Working Group 11 (gas quality)	GRTgaz mandated by the BNG (GRDF, Storengy, Elengy also involved via RICE)	Contribution to the gas quality section of the report being prepared on the "consequences of hydrogen in gas infrastructures"	The report identifies the impacts of hydrogen concentration on standard EN16727:2015 parameters such as density, hydrocarbon dew point, water dew point, methane index, etc. The scope of the standard includes the use of gas, and the working group identifies the need for cooperation with standardisation activities related to uses. Operators must therefore be tasked with playing an active advisory role with downstream gas representatives.
CEN TC 237		GRTgaz mandated by BNG GRDF	TC 237 has produced a joint report with Marcogaz and Facogaz (an association representing meter manufacturers) giving a qualitative assessment of the impact of hydrogen on meters.	The impact on meters and calculation is low (up to 10%). Beyond this, the report states that the specifications for building meters must be adapted to meet the challenges of safety and sustainability. Likewise, parts such as seals or detectors must be subject to testing. Manufacturers must hence be able to test their equipment under simulated operational conditions, having first validated it in the laboratory.

C. Spotlight on GRHYD

Context and challenges

The GRHYD project is the first power-to-gas demonstrator in France on a distribution subzone. It is part of the Investments for the Future programme (launch of the "Hydrogen and Fuel Cells" call for expressions of interest). Its goal is to measure the feasibility and usefulness of green hydrogen production and storage (up to 20% by volume) blended with natural gas. The project is led by the ENGIE Research Centre (ENGIE Lab CRIGEN) and brings together 11 partners covering all the links in the value chain, including laboratories (CRIGEN, CETIAT, CEA, INERIS), equipment manufacturers (ArevaH2Gen, McPhy Energy), operators (ENGIE INEO), GRD (GRDF), and local communities (Dunkirk Urban Community). The total project budget is €15 million, which is co-financed by ADEME to the tune of around 15%. It has also been awarded the Tenerrdis competitiveness cluster label.

The project includes a work package managed by GRDF that tests the injection of hydrogen into natural gas on a fixed and then variable part of a natural gas distribution system in a new district of Cappelle-la-Grande, in the suburbs of Dunkirk.



The challenge for GRDF is to bring to light solutions that enhance the complementarity of the networks and that lead to a greener means of gas transport, while guaranteeing both the quality of the gas and the continuity of supply and security. It must also adapt the operating protocols relating to the distribution of the hydrogen/natural gas mixture.

Schedule

The project was officially launched in January 2014 and is expected to end in June 2020 – not June 2018 as initially planned (as the commissioning of the equipment was delayed, the partners officially requested that ADEME extend the injection tests until March 2020, for a project-end in June 2020, to guarantee two winters of tests). The project was officially launched on 11 June 2018.

A first phase of preliminary studies and laboratory tests was completed at the end of 2017. The equipment (electrolyser, storage, injection site) was built and delivered in 2017 and early 2018. The actual demonstration period began with the injection in June 2018 supplying the hundred housing units in the new district, as well as the boiler unit of a tertiary facility, with variable hydrogen contents of up to 20% (stages of 6%, 10%, 20%, then a stage with variable injection of between 0-20%). The increase to 20% took place on 11 June 2019.

The first tests during the 6% and 10% stages showed the boilers operating normally. Network feedback was also satisfactory.

D. Spotlight on Jupiter 1000

The goal of the Jupiter 1000 project is to design, build and test a power-to-gas pilot installation with the capacity to:

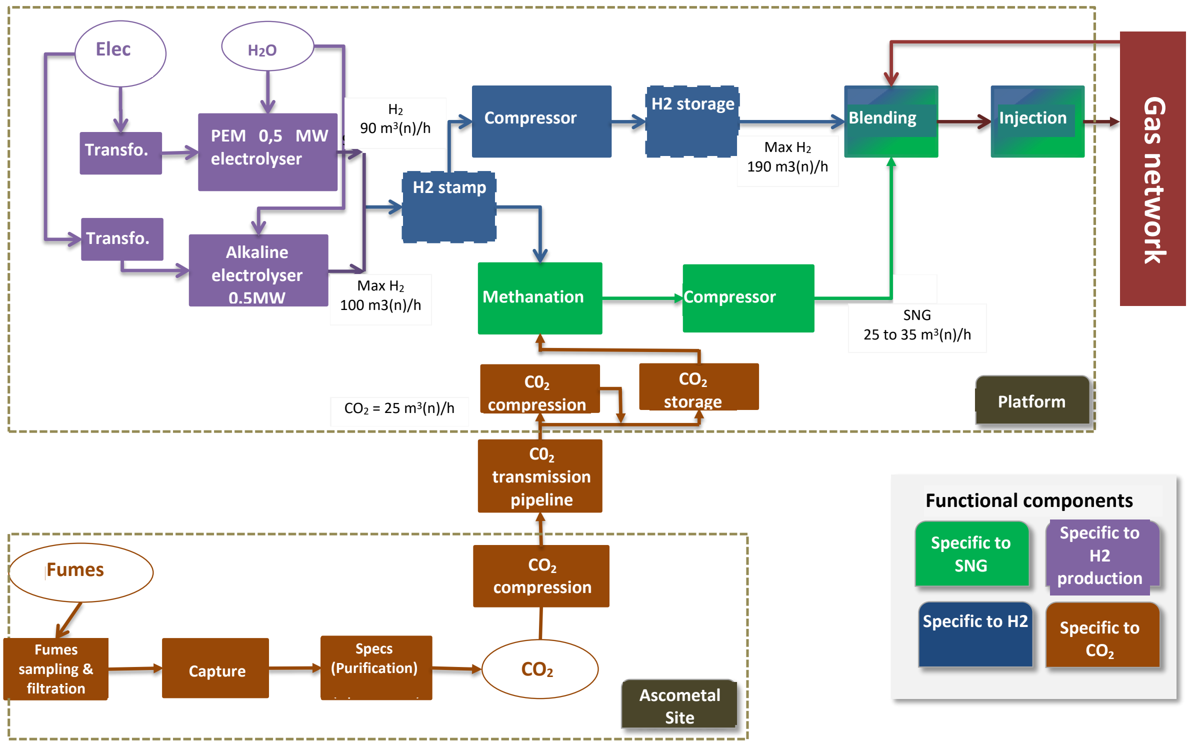
- Produce hydrogen by water electrolysis using renewable electricity available on the electricity network,
- Produce synthetic methane from this hydrogen by reacting it with carbon dioxide from an industrial smoke capture unit,
- Inject these "e-gases" into the natural gas transmission network for storage and to defer the use of this energy.

The JUPITER 1000 project is run by GRTgaz. It brings together several partners:

- The Grand Port of Marseille (GPMM) is responsible for providing the project platform, its access and its preparation, as well as constructing the CO_2 pipeline between the capture unit and the site,
- McPhy is responsible for the design and construction of electrolysers,
- The CEA is responsible for the methanation reactor tests, test management and the technical-economic modelling of the demonstrator,
- Leroux & Lotz is responsible for the design and construction of the CO_2 capture unit, which will be installed on the Ascometal site, located less than 2 km from the main site,
- Atmostat is responsible for the design and construction of the methanation unit,
- CNR will provide the electricity required to operate the site. It will also be involved in carrying out the tests.

Teréga and RTE provide mainly funding, as well as their expertise in their field. Finally, GRTgaz is responsible for the overall integration of the project and the design and construction of the platform, including a blending station and an injection site.

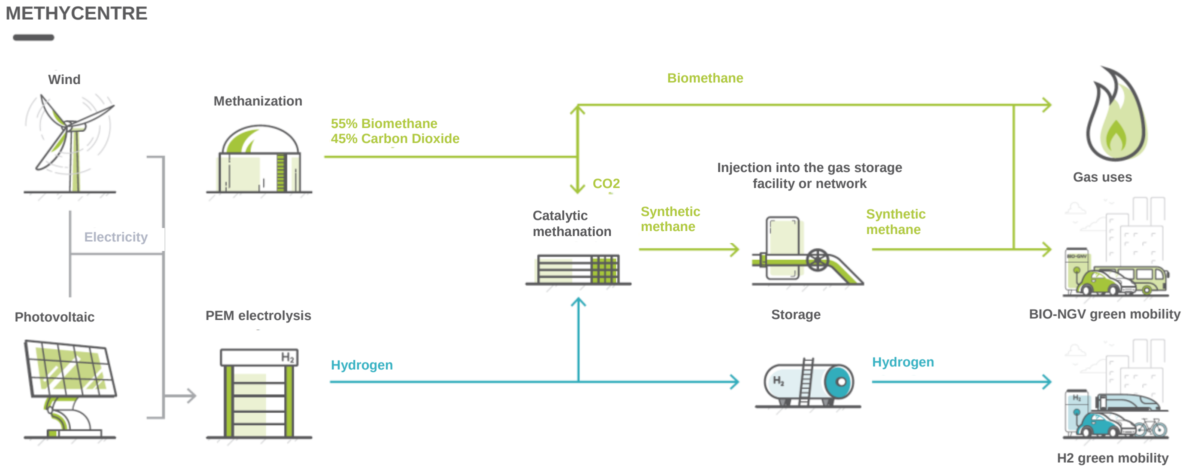
The following diagram shows the project's various features:



Once built, the installation will allow different tests to be carried out over a three-year period. The aim of these tests will be to validate the returns of the different elements, the flexibility provided to the electrical network, the possibility of managing the installation according to electricity market prices, its profitability, etc.

E. Spotlight on Methycentre

The Methycentre project is the first power-to-gas demonstration project in France to be coupled with a methanisation unit. Located near the Céré-la-Ronde natural gas storage site, the demonstrator will be connected to the gas network via a single injection point. It is supported by the Investments for the Future programme run by ADEME, and benefits from financial support from the European Regional Development Fund and the Centre - Val de Loire region itself.



The project consists of the following components:

- Methanisation of agricultural inputs,
- Electrolysis (second-generation PEM technology in partnership with Areva H2GEN and CEA),
- Electro-chemical methanation and membrane separation (in partnership with Atmostat, Prodeval and CEA).

These components are tested using innovative means and in interaction with each other. The challenge is to respond to the intermittent nature of renewable energy by producing high-performance renewable gas at a lower cost. Furthermore, the combination of methanisation and methanation allows for the carbon yield of biogas from methanisation to be almost doubled. Likewise, CO capture$_2$ from expensive fossil fuels, such as industrial fumes, can be removed from the methanation process.

This power-to-gas project is in reality a multi-product and multi-service energy hub that is able to meet its region's specific needs in regard to:

- The production of renewable hydrogen for mobility or manufacturers,
- The production of renewable biomethane and synthetic methane as a substitute for natural gas,
- The provision of services to the electricity grid and to renewable electricity producers,
- CO_2 savings$_2$,
- Waste recovery,
- Resale of heat from the methane producing facility

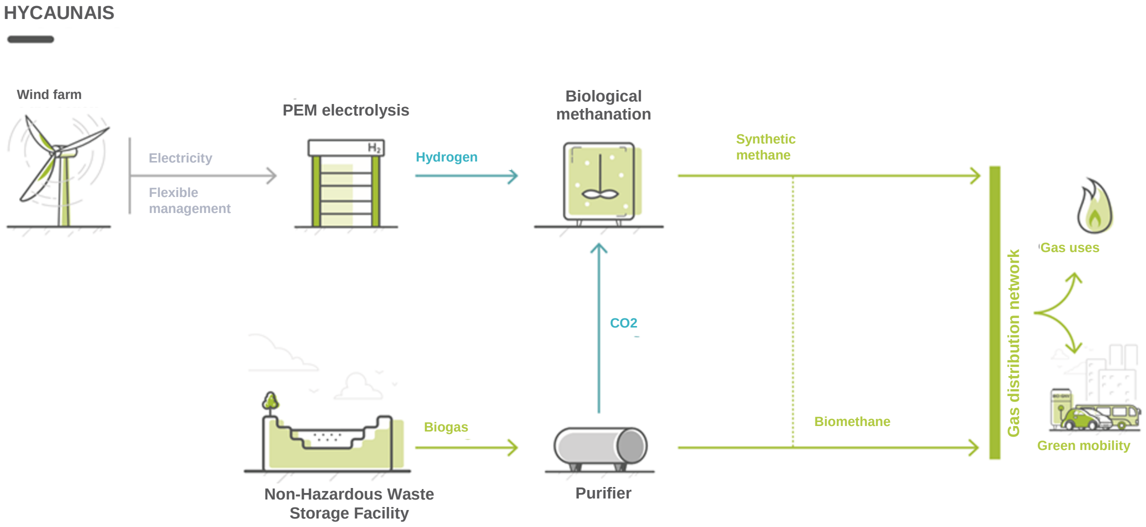
The project is currently in the development and R&D phase. Engineering studies start in 2019 and work commences in 2020 for a planned operational phase between 2021 and 2023.

F. Spotlight on the Hycaunais project

The Hycaunais demonstrator project is technologically complementary to the Methycentre project. It will:

- Be coupled with a unit for producing biomethane from landfill biogas (more restrictive in terms of quality and composition and already in operation in the Yonne region of Burgundy),
- Have a nominal 1MWe electrolysis unit that is optimised for highly flexible operation (up to + /-1 MWe upwards / downwards) to meet the needs of the network, and which can be controlled according to the Engie Green's wind power generation system.
- Use biological methanation (reaction catalysed by bacteria, as for methanisation) and non-electro-chemical methanation.

The Hycaunais collaborative project is managed by Storengy and brings together seven other partners (private, public, SMEs): Engie Lab CRIGEN, Engie Green, Electrochaea, Areva H2GEN, SDEY (Yonne Energy Department Syndicate), the Yonne Energy SEM (*Société d'Economie Mixte* - Joint Energy Company) and FC Lab of the University of Franche-Comté. It includes a 2.5-year technological development and engineering phrase, followed by a 3.5-year operational trial phase from 2021 to 2025.



The Hycaunais project has two economic and commercial goals:

- To demonstrate the feasibility of operating a regional power-to-gas system with strong wind power development,
- To replicate the technological and commercial model developed in HYCAUNAIS in order to present a competitive commercial offer both in France and in Europe.

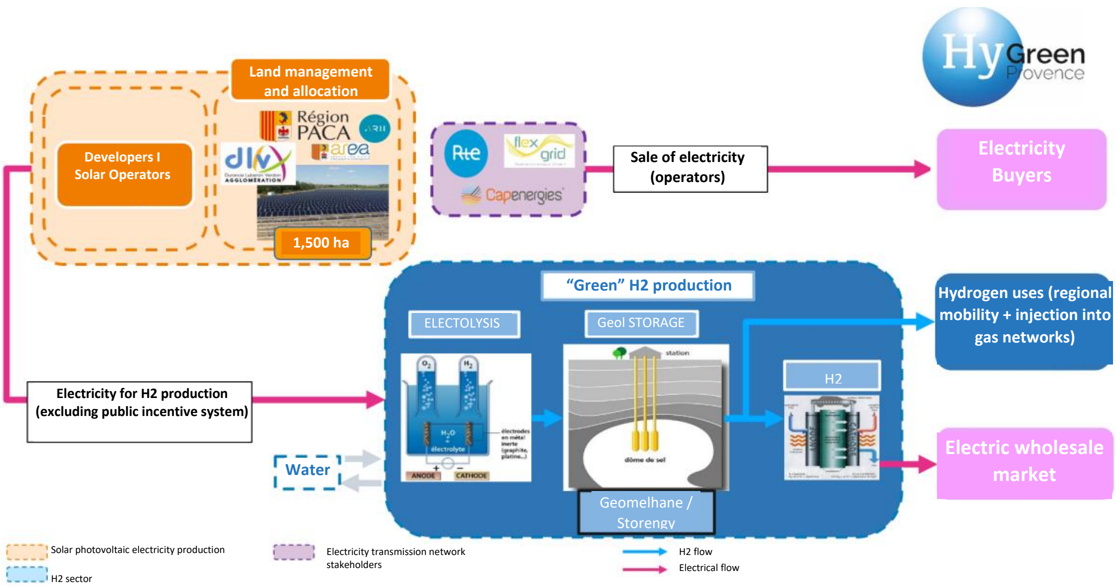
The Hycaunais project was awarded funding as part of ADEME's "Investments for the Future" aid programme on 11 October 2018 (Prime Minister's decision no. 2018-ENR-13). Steps preceding its official launch in early 2019 are underway.

G. Spotlight on the HyGreen project

The HyGreen Provence project aims to implement a "**Solar Power and Green Hydrogen**" project in the Durance Luberon Verdon Agglomération (DLVA) Territory, making a major contribution to the decarbonisation of the Southern region and the economic development of the Territory. It is based on two major potential energy sources in the Territory:

- One of the most competitive solar resources in France (sites located in the Southern Region) enabling the construction of a **local renewable electricity generation system**,
- **The existence of saline cavities** currently used to store natural gas **on the Geomethane site** in Manosque, some of which could be used to store renewable hydrogen and be integrated into a green hydrogen production chain supplying various local energy uses (decarbonised mobility, clean heat, local industrial applications, etc.).

This is an ambitious project involving hydrogen production from renewable energies and massive storage in saline cavities. Launched by the DLVA agglomeration, it is supported by Geomethane, which is studying the feasibility of storing hydrogen in saline cavities (technical-economic aspects, regulatory considerations, etc.).



The project is currently in the pre-development phase and involves three development steps:

- (2022) Electricity production from 730 ha of photovoltaic panels, 10% of which is dedicated to hydrogen production, with centralised hydrogen storage,
- (2025) First extension phase with 840 ha of photovoltaic panels and 3,000 tonnes of hydrogen produced per year. Centralised storage in salt cavities ensuring integration between production and local uses,
- (2027) Extension to the target of 1,500 ha for the solar part, with more than 10,000 tonnes of hydrogen produced per year. This will develop the hydrogen chain with massive storage and downstream uses.

H. Spotlight on FenHYx

In view of the issues raised by the pre-normative R&D needs for hydrogen in the natural gas transmission networks (as identified in the CEN CENELEC Sector Forum Energy Management (SFEM) hydrogen working group report), GRTgaz has designed the future FenHYx collaborative R&D platform[34]. Its purpose is to test the transmission system equipment and materials under real conditions for different CH_4/H_2 mixtures.

The platform will pool European R&D efforts, using FenHYx equipment to design and develop common approaches for carriers across Europe, with a view to increasing the injection of hydrogen into the gas system. FenHYx will improve the understanding both of the impact of hydrogen on the gas networks, and of the adaptation required to ensure their safe and efficient operation. New innovations could also be tested in collaboration with partner manufacturers and research centres. The test results will make it possible to adapt the network maintenance and management procedures. This platform will also act as a training tool for the sector. Its functionalities are being set out in complementarity with the existing test resources at GRTgaz and from a European standpoint.

Goals	**Accelerate scaling and network adaptation** to transport and grow the use of new low-carbon gases **Test/develop new transport equipment or innovative network designs** for hydrogen and synthetic methane Contribute to **equipment standardization** for different levels of natural gas/hydrogen mixture
Project Identity	Project Initiator: GRTgaz Project partners and financiers: Multiple European organisations and gas network operators Location: Definitive location to be established. It could be modular, involving different test centres
Equipment	**An innovative platform bringing together test benches reproducing the real-life operating conditions of the gas transmission networks:** ✓ Gas quality, metering in dynamic conditions, network equipment (valves, taps, compressors, etc.) ✓ Network integrity, corrosion, inspection ✓ New processes: injection, blending and separation technologies
Parameter: tested	Static and dynamic conditions Different levels of natural gas / hydrogen blend, up to 100% hydrogen Different pressure levels

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