Task Force on Smart Gas Grid

Gas Bridges: the natural gas network as key partner of the energy transition

Summary

Executive Summary

The necessity to achieve significant carbon emissions reduction in the coming decades to meet the 2050 target of an 80% reduction in CO_2 compared to 1990 levels presents serious challenges for EU Member States, policy makers, energy companies and infrastructure operators. Member States have committed to deliver on the targets. Policy makers must ensure that a long term regulatory pathway is put in place that supports the range of technologies and networks that are needed to provide for energy production and transportation. Some of these technologies are relatively new and innovative, whereas energy networks have played a key role in the energy mix for decades. Energy companies and infrastructure operators must adapt and move away, over time, from fossil fuels to renewable energy. Ultimately however, the cost of this energy transition will be underwritten by consumers. It is therefore critical that the least-cost pathway is identified to achieve the level of CO_2 reduction required in order to avoid unnecessary, excessive and long term costs on consumers. In order to achieve this, the continued use of gas and gas infrastructure will be necessary to provide a bridge towards achieving an integrated low carbon energy system.

As renewable energy production continues to increase over the coming years and decades, system flexibility will become ever more challenging. On an annual basis there are periods when insufficient wind or sun is available to generate the required electricity to meet demand at peak times. Currently, coal and gas power stations provide this back up. A move from coal to gas would immediately reduce CO_2 emissions. Furthermore, it would provide the necessary signal and support to gas infrastructure operators that gas and gas networks will play a key role in the energy transition. Ultimately renewable gas, created from biogas, power to gas, or emerging technologies for gas in district heating, and smart gas technologies, can fully support the integration of renewables in the long term. Several recent analyses have shown that use of existing gas infrastructure that is underground, safe and secure, will avoid massive investment, disruption and consumer costs compared to what will be required for alternative networks without gas.

This paper sets out to highlight the critical and enduring role that gas and gas infrastructure will play in an integrated low carbon energy system. It outlines a number of emerging gas technologies that are already enabling the energy transition and a least-cost, least disruptive and no-regrets route to 2050, and beyond.

Introduction

The 2015 Paris Agreement demonstrates a strong global ambition in which Europe aspires to be frontrunner in creating a low carbon energy system. Therefore the need for supporting regulation and increased funding for innovation and research initiatives is becoming ever more pressing. Smart grids and smart technologies are key enablers for this transition to a low carbon energy system, particularly to empower the consumer and keep the overall costs under control.

Discarding the potential solutions that the gas sector offers to society will unnecessarily raise the cost of the transition and delay or even threaten a smooth transition. The gas system offers increased stability and flexibility to the energy system and additional opportunities for renewables. The gas system has much to offer in terms of vast quantities of cheap network capacity, storage of energy and relief for the other components of the energy system, heat and electricity.

It is the premise of this report that gas and its infrastructure can and will play an essential role as a "bridge" between sectors in an integrated low carbon energy system.

Scope & report structure

The report addresses the role of gas and the gas network as a bridge for the complete, integrated low carbon energy system. "Bridge" refers to **synergies between gas network and other networks that can enable and optimize the energy transition.**

Some solutions that can be provided by the natural gas network and connected equipment are already identified and currently deployed or tested in demonstrators. The objective of this paper is to describe these gas network services, the underlying technologies, maturity levels and questions that still have to be addressed either to validate these technologies or to further assess value generated and corresponding favorable market conditions (market design, thermal building regulations, etc.).

Following the introduction, the report consists of 5 additional chapters:

- Chapter 1: The role of natural gas in the low-carbon energy system
- Chapter 2: Gas bridges use cases
- Chapter 3: Focus on large scale integration of renewables
- Chapter 4: Focus on services to power system relief
- Chapter 5: Policy recommendations

Chapter 1: The role of natural gas and natural gas infrastructure in a low-carbon energy system

Before we even consider the potential for decarbonisation of the gas network, natural gas as a fuel can already make substantial progress towards achieving the aims of the energy transition:

- Thanks to its carbon content (2,3tCO_2/tep vs. 3,1tCO_2/tep for oil and 4tCO_2/tep for coal[1]) natural gas contributes to reduce GHG emissions for power and heat production as well as in the mobility sector (conversion from

[1] GIEC, 2006

oil or coal to gas) ; its NOx and fine particles content is also much better than other fossil fuels or woody biomass and contributes to improved air quality in the cities;
- The latest generation of gas appliances has further enhanced efficiency and environmental performance; they increasingly integrate smart connected technologies for monitoring and consumer empowerment;
- Gas directly contributes to the European objectives in the field of renewable energies thanks to the development of biomethane that allows the production and use of green gas. Natural gas networks are already available in densely populated areas and thus favor rapid spread of renewable gases;
- In addition to its direct effect on the energy side, biomethane combined with existing transportation infrastructure is a key contributor to the development of a circular economy. This can be derived from waste management by offering many value-added options to the recovery of co-products from agriculture, tertiary and residential activities (wastes) or industrial processes.

Natural gas infrastructure also brings advantages:

- Use of existing infrastructure (no sunk costs) that has proven to be reliable and safe;
- Long term, high capacity storage (underground) and daily balancing (line pack) providing flexibility in both the short and long term for the energy system;
- Further local flexibility thanks to deployment of smart grid technologies such as decentralized monitoring of gas quality, dynamic pressure control, and remote motoring and control of network parameters in real time.

Key challenges to enhance natural gas infrastructure are to:

- Develop cost-efficient “bridge” technologies to give access to gas infrastructure and its storage and flexibility potential;
- Adapt some gas operation and maintenance processes to facilitate energy system integration;
- Develop energy policies to ensure optimal use and yield of various energy carriers.

Chapter 2: Gas bridges use cases

- “Bridge” refers to **synergies between gas network and other networks that can enable and optimize the energy transition.**
- Key applications of gas bridges are garnering increasing interest, especially in the context of avoiding massive investments to adapt the power network to support the energy transition. Bridges toward gas networks can contribute to:
  1. **Facilitating and optimizing large scale integration of renewable energy** thanks to large transportation capability and interseasonal storage capacity;
  2. **Limiting the investment costs** at power network level by promoting and implementing short term gas flexibility options (for example demand-side management solutions).
- Technical demonstrations showing the implementation of these solutions are already underway in Europe. They need to be pursued, promoted and shared to further meet their potential.

- In the next sections we will describe more precisely the value brought by the gas network and its associated technologies, alongside the issues currently addressed by demonstrators and key parameters that still need to be investigated.

Chapter 3: Gas bridges facilitate and optimize large scale integration of renewables

a. Synergies with power network

Maximizing the integration of renewable energies while limiting the corresponding infrastructure cost (storage, grid reinforcement) is one of the key challenges raised by the energy transition. The natural gas network combined with suitable conversion and end user installations can deal with this issue, starting today through to and beyond the 2050 horizon.

- **Today**, **innovative and cost-effective gas systems combining PV solar panels and condensing gas boilers** are already deployed in residential units and facilitate renewable power production integration while avoiding power network reinforcement costs or additional investment in storage solutions. These highly performing systems address both the question of facilitating integration of renewable power production (based on self-consumption) and the one of managing the energy demand (improved energy efficiency of recent gas solutions).
- Due to the challenges arising from the intermittency of renewable electricity technologies such as wind and solar, **the question of interseasonal storage to manage a large excess of power produced in the summer time is of increasing importance**. In a number of European countries like Germany and the UK where renewable electricity production is already significant, the threshold is already being reached where renewable electricity grid access is being curtailed.
  For France as an example, models show, at 2050 horizon, surpluses of power during the summer time. The duration of these surpluses exceed 24 hours and thus require specific storage solutions.

Figure 1 - Power supply and demand in 2030 - ADEME Study (2014) - French example

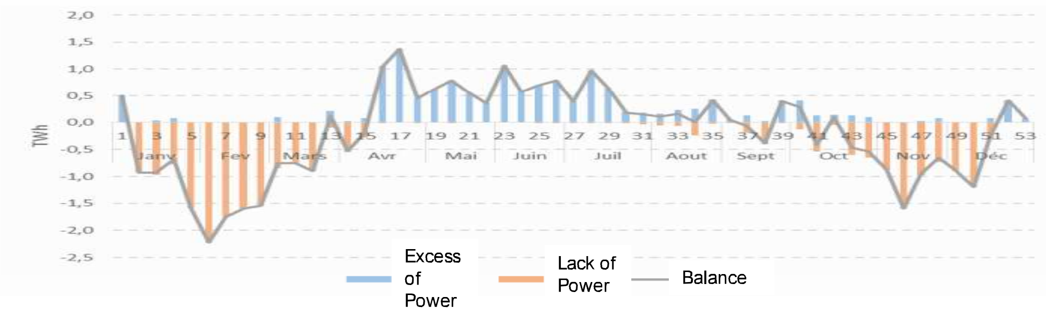
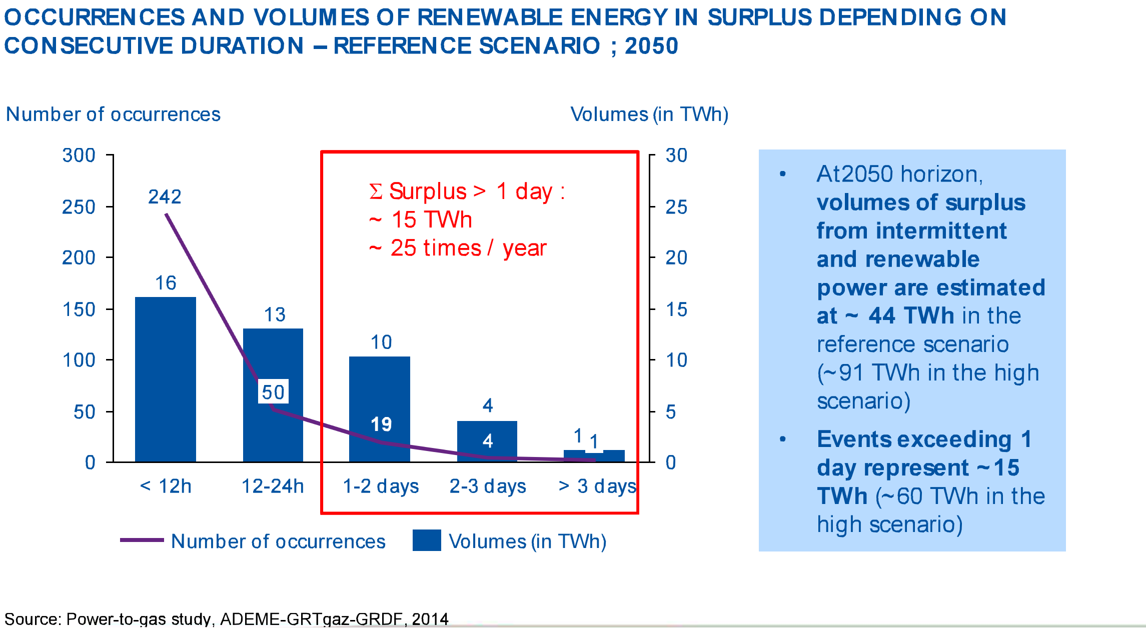
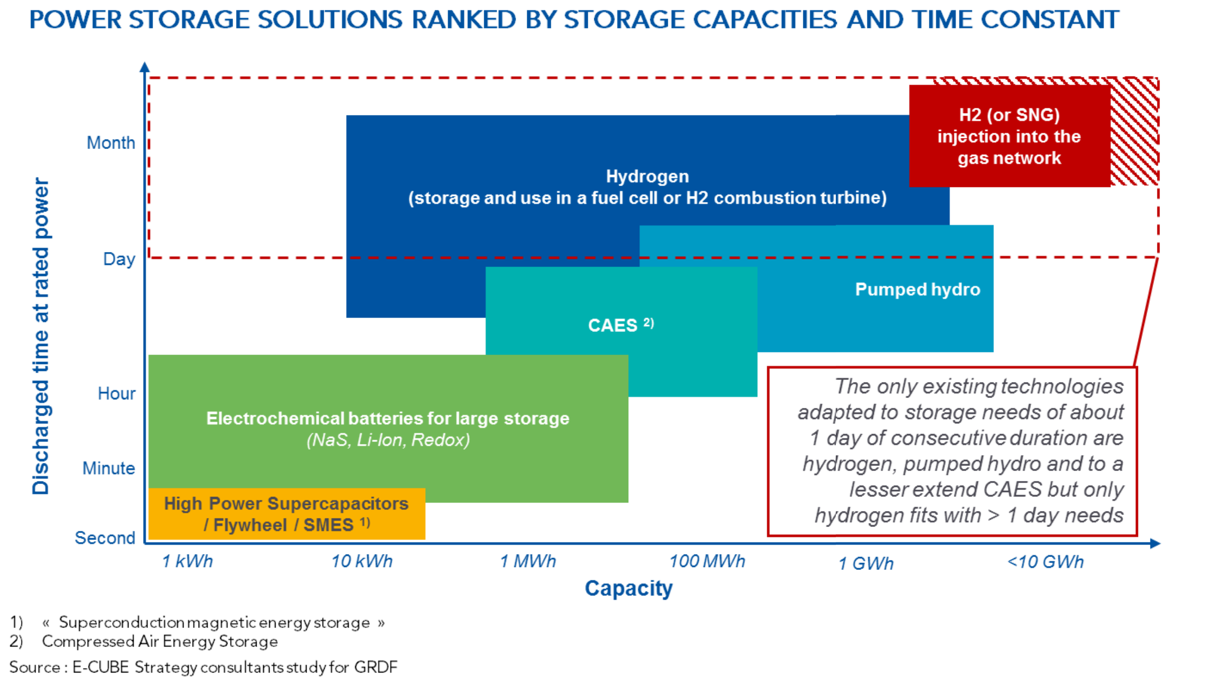


Figure 2 – Renewable energy surplus – 2050 – ADEME Study (2014) – French example



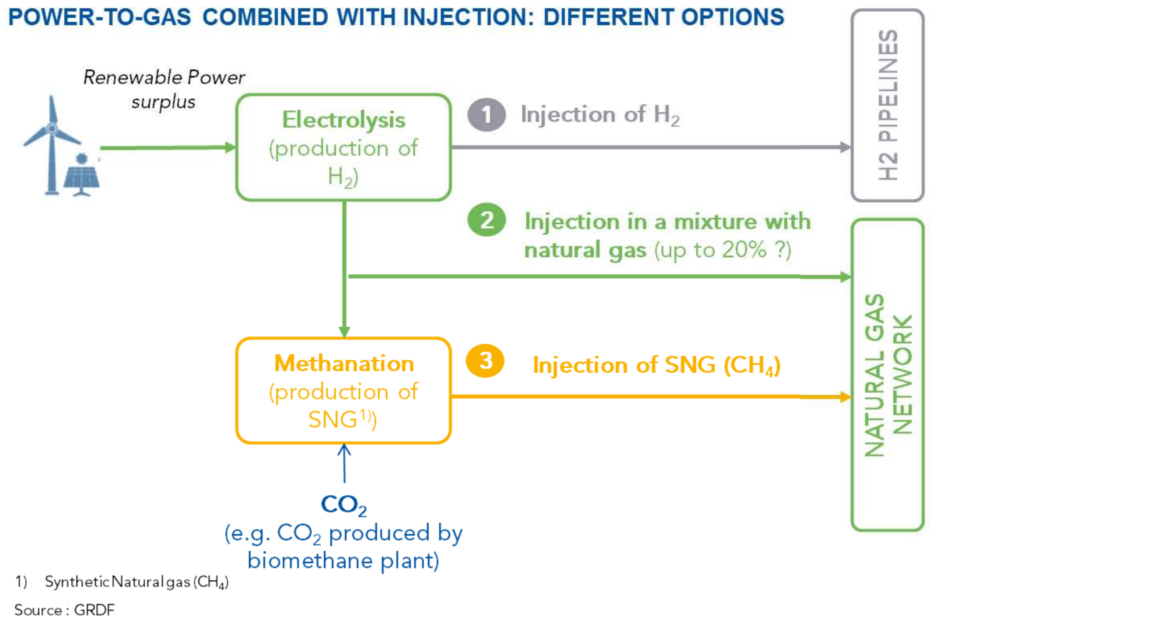
Power-to-Gas combined with injection into the natural gas network is able to respond to these needs with existing technology as the natural gas network has large storage and flexible capacities (underground storage, linepack management).

Figure 3 – power storage technologies landscape



This "storage" solution uses an electrolysis process (production of H2 based on power surplus) combined with injection. Three options for injection can be considered: direct injection of H2 in a mixture with natural gas, the transformation of H2 into synthetic natural gas (SNG) through a methanation process and its injection into the NG network, or direct injection of H2 into existing H2 pipelines (or potentially converted gas lines).

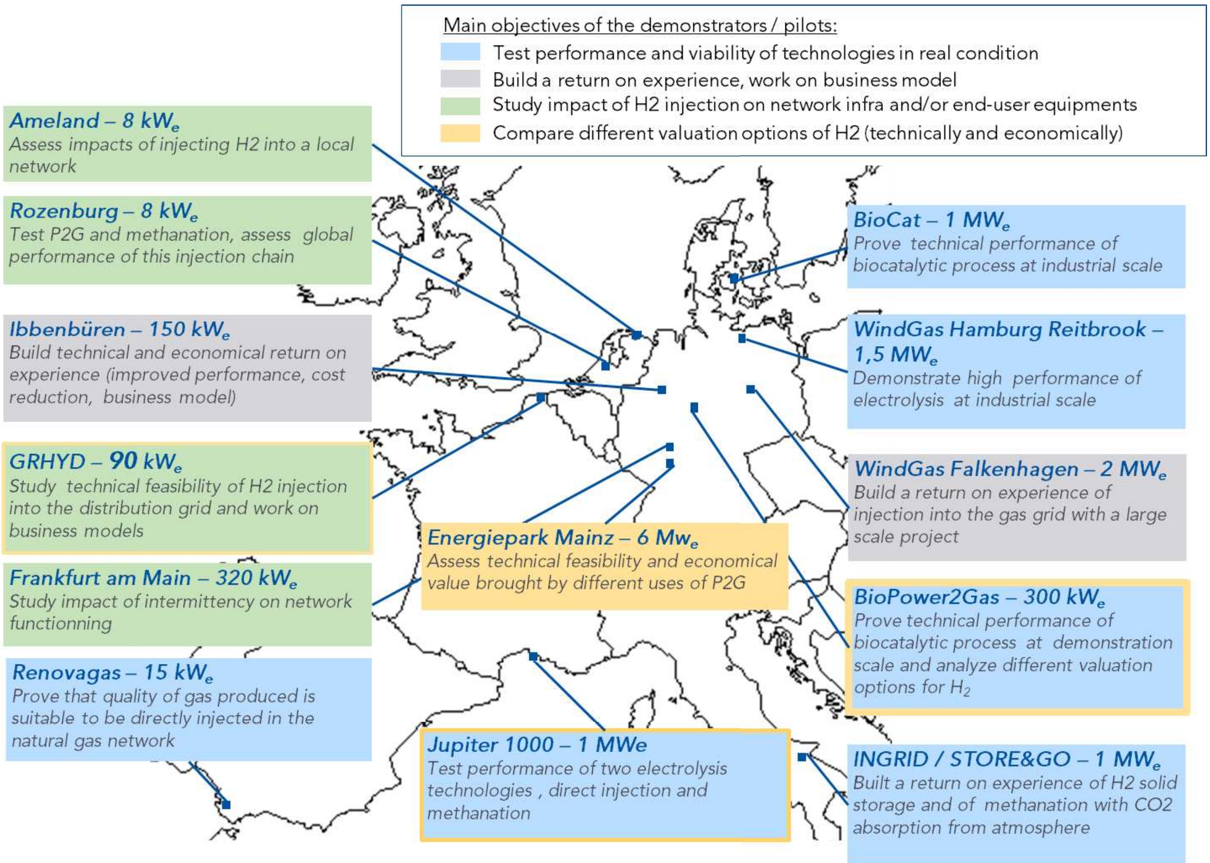
Figure 4 – Power-to-Gas and injection options



Natural gas networks operate well within their design capacity and thus could carry substantial additional volumes without significant investments, contributing to reduction of the overall cost of the energy transition.

About a dozen demonstrators are underway in Europe to test technical feasibility of injecting H2 into the natural gas network or test the performance of methanation processes.

Figure 5 – main European demonstrators combining power-to-gas and injection



Source: Task Force members

Injection of H_2 (or SNG) into the grid is only one of the value-add options for power-to-gas installations. Others are green H_2 for industrial processes or H_2 for mobility cases, expected to be profitable at the 2030 horizon. However, these two last options will not be able to address the question of power surplus management at a reasonable cost (important storage needs). That is why, to improve business cases while optimizing the performance of the overall energy system, demonstrators are working on complementary uses of H_2 (e.g. Mainz project).

Figure 6 – Mainz Project (Germany)

2012-2016

Partners

- Project leader, DSO
  STADTWERKE MAINZ AG
- Gas supplier and O&M
  Linde
- OEM
  SIEMENS
- Results and analysis
  Hochschule RheinMain

Key caracteristics

- P2G uses: H2 injection into a local distribution grid, storage and transportation of H2 for industrial processes or mobility stations
- Network pressure: **7 to 9 bars**
- Electrolyser: **6 MWe, PEM technology**
- Project scale: **3×225 Nm³/h of H2 produced**
- Volume of H2 injected into the gas network: **10%**
- Budget : **17 million euros**

- Project supported by the City of Mainz, P2G operations and H2 delivery under Linde's responsibility
- Combination of different H2 valuation options: network injection, mobility, industrial processes, power network balancing
- Up to 10% (in volume) of H2 injected into the gas network (only households supplied)
- Remote monitoring of the P2G installation from Linde's dispatching center
- Continuous functionning of the electrolysis installation
- Switchs have been installed to directly connect the installation to a wind park of 10 MW if relevant in the future
- Patented Innovation from Linde : ionic liquid piston compressor – improved performance
- Main objectives:
  - Test different valuation chains of H2 and build a technical and economical return on experience
  - Assess impact on end-user equipment and network infrastructures

Sources : entretien avec M. DE VOLDER (Siemens) et STILLER (LINDE), documentations des partenaires impliqués dans le projet, communiqués

TO GO FURTHER:

Experience is already being gained from the first injection projects but there are still some parameters to be investigated, shared or consolidated. In particular, work has to continue:

– **on downstream use** to assess potential impact of H_2 on equipment (meters, NGV motorization, gas turbines) and anticipate adaptation needs;
– **on the methanation technologies** at different scales (large scale adapted to transportation network capacities and medium scale adapted to distribution network capacities to develop synergies with biomethane installations);
– **on the business models and especially on the supporting scheme for H_2 / CH_4 injection** as a way to improve and secure the overall energy system performance in the presence of a large share of renewable and intermittent power production;
– **on the relevant combination of (green) gas and power used to achieve the energy transition goal at a sustainable cost** (maintaining gas uses to optimize connection between gas and power network and final use of renewable energy produced).

b. Synergies with district heating

In addition to its synergies with the power network, the natural gas network supports the use of renewable energy for district heating. In the absence of green gas or before sufficient volumes are available, local authorities may decide to deploy district heating networks fueled by renewable energy sources such as woody biomass. As this energy resource suffers from supply tensions and price instability in a context of growing demand in Europe, coupling this energy with natural gas allows to secure sourcing and the control the overall heating cost while optimizing carbon footprint (e.g. versus domestic oil option).

Figure 7 - Netherlands - District heating figures

The Netherlands is known as a Country where all the built-up areas are provided with gas distribution. Nevertheless, 5.5% of the residential buildings are connected to district heating network. Many of the networks are currently heated by gas and almost, all of them use natural gas boilers as back-up system.

Size and heating source of the major Dutch district heating network

Area Name	Owner	Producer	Primary Energy source	Nr customers (x1000)
Almere	Nuon Warmte	Electrabel	Gas	42,9
Tilburg/Breda	Ennatuurlijk	RWE	Coal	31,1
Amsterdam	Nuon Warmte	Nuon ET&W	Gas	7,5
Den Haag (Ypenburg)	Eneco Warmte/Koude	Eneco DEP	Gas	8,9
Duiven	Nuon Warmte	AVR Afvalverwerking	Waste	8,7
Enschede	Ennatuurlijk	Twence	Waste	5,2
Helmond	Ennatuurlijk	Essent Energie Productie	Gas	6,4
Leiden	Nuon Warmte	E.ON	Gas	6,3
Purmerend	SV Purmerend BV	Nuon ET&W	Biomass/Gas	24,3
Rotterdam	Eneco Warmte/Koude	E.ON	Gas	43,5
Utrecht	Eneco Warmte/Koude	Nuon ET&W	Gas	41,7
Utrecht	Eneco Warmte/Koude	Nuon ET&W		
Utrecht	Eneco Warmte/Koude	Nuon ET&W		

source: CE Delft Warmtenetten in Nederland Rapport 2009

Another already existing option is to combine gas-fired CHP with electric boilers. This allows balancing of the electrical grid by shifting loads between the CHP unit and the e-boiler. As the e-boiler converts renewable excess power to heat, a suitable heat sink is necessary. This can be found in the district heating network at a scale where economic efficiencies are achieved. This concept is an example of an interconnection of the power and heating grid, facilitated by a gas-based solution.

TO GO FURTHER:
Assess current volumes secured by the gas network and develop models to compare cost of full switch to district heating + power and the cost and benefits of maintaining and greening the gas networks including positive externalities (e.g. on waste treatment).

Chapter 4: Limiting investment costs at power network level by promoting and implementing short term gas flexibility options

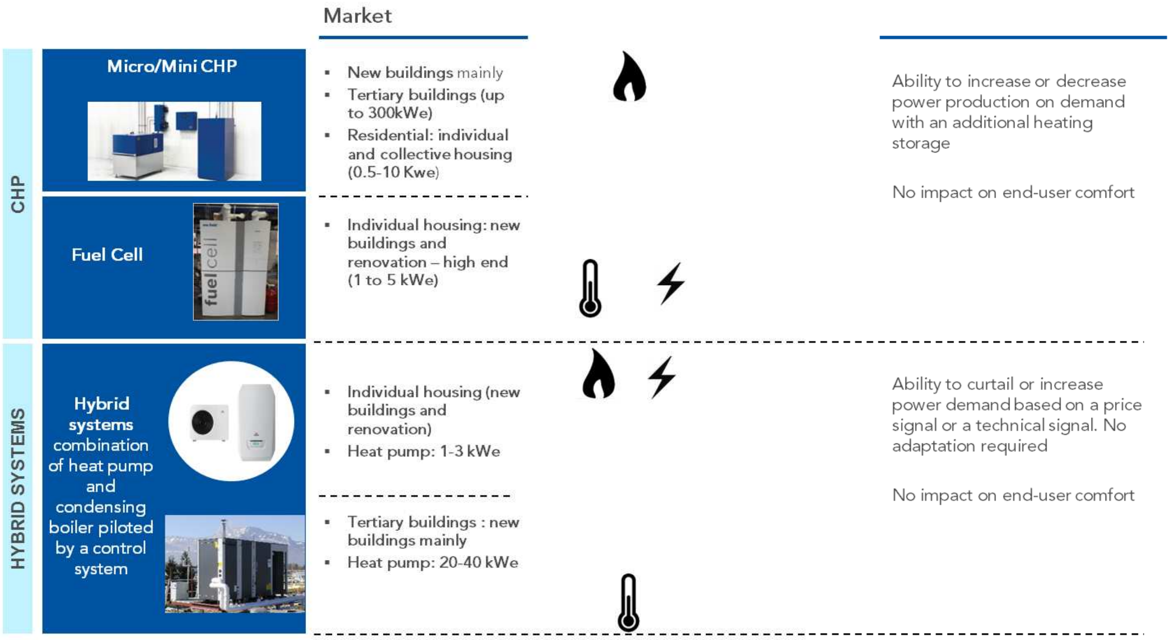
a. Enhancing the potential of smart gas technologies

The deployment of decentralized and intermittent energy production and electrical vehicle charging infrastructure will increase the need to reinforce the power network, in particular at distribution level. To control the costs related to energy transition, power TSOs, DSOs and regulators in Europe favor the development of **flexibility** as a way to minimize reinforcement costs by implementing production and demand-side management.

Historically, large gas solutions (CCGTs, CHPs) connected to the power network already contributes to flexibility at national level (participation to tertiary reserve mechanisms).

In addition to the national flexibility needs, local flexibility needs emerge. Some experiments or market design initiatives have been led in Europe around this flexibility need (UK, France). First experiments on flexibility were focused on power solutions (e.g. batteries and curtailment) but new cases based on gas solutions are currently being investigated. **Smart gas solutions like micro-CHP, hybrid systems or fuel cells can be used to offer flexibility services to the power network**: micro or mini-CHP solutions can be controlled to offer local electricity production - hybrid solutions allowing for trade-off between gas and power consumption depending on technical responses or price signals. The deployment of these solutions is relatively recent in Europe (50 000 micro CHP, mainly Internal Combustion Engine) compared to Japan (around 200 000 fuel cells and 130 000 Internal Combustion Engine already installed).

Figure 8 – smart gas solutions and their flexibility potential



Source: GRDF, E-CUBE

As yet there are just a small number of flexibility experiments with smart gas products and, in most cases they focus on technical aspects. The experiments with fuel cells focus on demonstrating their performance and reliability rather than the integration in the total energy system or the market implications. Other experiments are focused on the ability to combine and remotely controlled gas solutions (e.g. Dresden project testing micro-CHP VPP[2] feasibility - ~20 micro-CHP aggregated or Ameland Island with 45 fuel cells and hybrid systems remotely operated with PV and biomethane supply).
Apart from the technology challenges there is a lack of a regulatory framework for local flexibility (some projects in the UK, experimentation framework recently introduced in France by the energy transition law – LTECV). In that respect, the Interflex[3] project, which will take place in France under the supervision of Enedis, represents a key innovation: ~150kWe of flexibility generated by smart gas solutions will be deployed and managed by aggregators to deal with local distribution flexibility needs. The project will thus advance both technical and economic aspects with an evaluation of the cost and value brought by the different flexibility assets integrated into the demonstration.

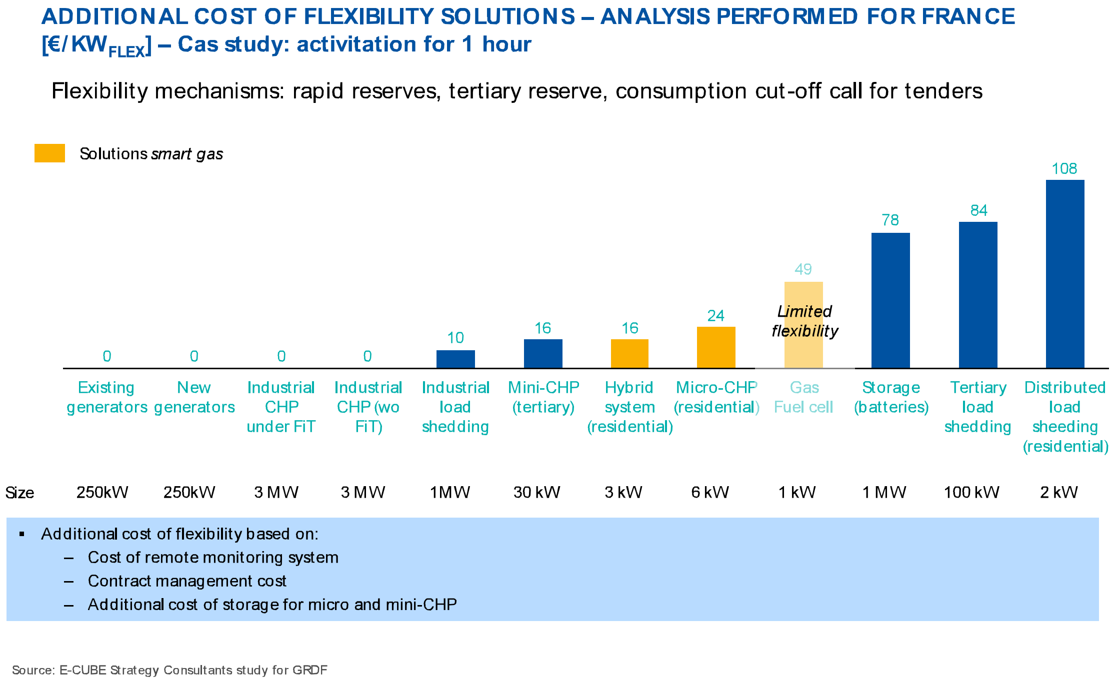
[2] Virtual Power Plant
[3] INTERFLEX = INTERactions between automatic energy systems and FLEXibilities provided by actors of energy markets is a H2020 project aiming at inventing the future DSO – see annex 4. Officially launched in January 2017 for 3 years

Figure 9 - Scope of the French DEMO of Interflex

With prevailing technical and economic conditions, the additional cost of flexibility using smart gas solutions is lower than ones using storage of power or distributed load shedding, as a recent study performed for France shows. In addition, smart gas solutions do not impact end-consumer comfort, and neither do they generate the potential "rebound effect"[4] on the power network. Beyond giving customers choice of energy carriers depending on price signals, including gas-driven flexibility options will give end-consumers access to potential additional revenues and confirm their role as energy system prosumers.

[4] Greenlys experiment REX

Figure 10 – comparative cost of flexibility solutions (additional cost of flexibility) – France case study



TO GO FURTHER:

Given the stake and the current return on experience, it is the key to pursue experiments involving gas technologies and test them in different distribution network contexts. The objectives will be to further assess the economic value of flexibility brought by gas solutions, identify potential evolutions on the equipment side to better serve flexibility needs, an support if relevant new technological developments.

Open existing "flexibility" remuneration scheme to gas solutions.

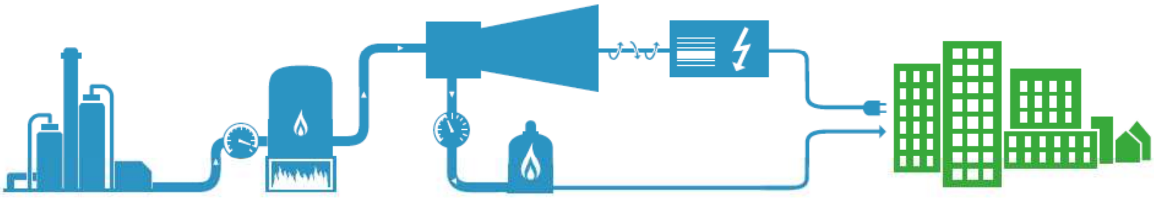
b. Enhance the potential of gas infrastructure equipment

Gas is transported and distributed at high and low pressure. Although the compression energy associated with the transportation of the gas is relatively modest compared to the actual energy content of the gas flow, it is in some case economical to retrieve this energy.

As mechanical energy is extracted from the pressurized gas, the gas temperature decreases. Therefore the gas needs to be pre-heated to avoid downstream freezing of pipes and soil. This heating is preferably done with (waste) heat from CHP. The combined electricity output of the CHP and of the expansion turbine is then available for distribution into the electricity grid.

A typical installation delivers a few MW_e with a relatively small investment and minor maintenance costs. The Sibelga installation in Belgium is a typical example.

Figure 10 – SIBELGA Gas Pressure Letdown – Belgium



The plant lowers the pressure of incoming natural gas and generates electricity in the process.

The site was chosen because it is at the center of the gas network, has available large volumes of gas at high pressure and can serve a large number of customers. This demonstrates that CHP is not limited to remote regions, such as offshore wind parks or rural solar panels, but can generate 'green' energy right in the middle of the city.
To leverage the large amount of energy released during the pressure reduction from up to 14 bar to about 1.7 bar, the installation has relied on a turboexpander connected to a 2.6 MW alternator.

The gas needs to be pre-heated to avoid downstream freezing of pipes and soil. This heating is done with (waste) heat from 2 CHP connected to 1.2 MW alternators, bringing the overall electrical power to 5 MW.

The combined electricity output of the CHP and of the expansion turbine is then available for distribution into the electricity grid. At peak times, the CHP unit produces 3.3 MW thermal power that is used to preheat gas for the turbine.

The cogeneration process runs for almost three complete seasons of the year: fall, winter and spring. Thanks to the flexible adjustability of the interface, it can work with only one engine running, or with two at limited power, or with both engines running at full power depending on demand.

Over 15 years, the machinery has more than paid off the amount of the initial investment. Considering the whole project with engines and turbines, the returns has been seen after seven to eight years from heat and electricity generation.

Chapter 5: Policy recommendations

1. Promote and inform about the benefits and consumer value of gas infrastructure to achieve least cost decarbonisation scenarios by:
    a. Carrying a critical share of the European energy mix especially at peak time,
    b. Responding to highly varying demand / providing flexibility and reliability for the energy system in the most secure and cost efficient manner,
    c. Integrating renewable and low carbon gases,

   d. Optimizing network operations by implementing the benefits of smart technologies and data management.

2. To ease decision making we recommend developing macro-economic energy modeling including energy and transportation costs at European level and identify least cost decarbonization scenarios.
3. Develop and deploy a favorable and stable regulatory framework for gas bridge technologies.
4. Develop supporting schemes / market mechanisms for gas bridge applications taking into account the value created for the whole energy system
5. Implement Research & Innovation actions supporting the development of cost-effective conversion / bridges technologies. In particular:
   - Support high profile pilot projects for sharing of experience on H2 injection in the gas grid and on methanation technologies
   - Develop cost effective technologies for conversion of electrical energy to storable gaseous fuels (e.g. electrolyser, reverse fuel cell)
   - Develop cost effective technologies and products for efficient conversion of gaseous fuels to heat (e.g. gas fired heat pumps, fuel cell-heat pump combination)
   - Develop cost effective and safe (low-pressure) technologies for local storage of gaseous fuels (e.g. LOHC, methane clathrates)
   - Develop cost effective technologies for quality upgrading of gaseous fuels for sensitive applications
   - Promote a common understanding of gas quality sensitive applications (e.g. gas turbines, underground storage, mobility applications) and identify solutions to ensure harmonization and compatibility.
6. Develop an integrated energy system vision allowing to transport and store green / low carbon energy to (and from) the end consumer and decentralized producers with optimum reliability and cost effectiveness

Annex 1 – Power-to-gas technologies

Technologies	Short description	Capacity range	Yield	Applications	Advantages	Current limits	CAPEX/OPEX	lifespan	Potential flexibility/ Time response	Maturity
P2G : electrolysis + H_2 injection Kind of electrolysis : Alcalin	It converts the surplus electricity from renewable sources of energy into hydrogene by electrolysis of water. 2 kinds of technologies are available for electrolysis (alcalin,PEM) .Then H_2 is directly injected into the gas grid in mixture with GN.	Current demonstrators around 1MWe.	Currently: Almost 70%PCS By 2030 : 79%PCS Electrolyser flow : 4,1 - 4,8 kWh/Nm3	decarbonised mixed gas supply for all uses : mobility, residential buildings, tertiary sector, industry Hydrogen supply (mobility …)	No need of additional investment on existing grid Reduction of the carbon footprint of the gas grid. Almost zero polluter gas rejected.	injection is limited by the ratio of Hydrogen allowed in the grid which varies amongst countries :10% in Germany, 0,1 % in England … research is mandatory to fix the good ratio (-> NaturalHy project) and better assess impacts on end uses	CAPEX Alcalin electrolyser : 800-1500€/kW It is expected to drop to 400€/kW on long-term. OPEX : 5% du CAPEX/an	electrolyser (crucial part): 80.000 - 160.000h	very flexible	On field-test in different demonstrators in Europe (Germany, Netherlands, France)
P2G : electrolysis + H_2 injection Kind of electrolysis : PEM			Currently: Almost 70%PCS By 2030 : 84%PCS Electrolyser flow : 3,9 à 4,1 kWh/Nm3		PEM electrolysers better follow fluctuating power input than alcali electrolysers : Quicker responses to load changes Quicker reach to operating temperature in the startup phase		CAPEX PEM electrolyser : 2000-6000€/kW It is expected to drop to 700€/kW on long-term. OPEX : 3% du CAPEX/an	electrolyser (crucial part): 10.000 - 60.000h	very flexible	On field-test in different demonstrators in Europe (Germany, Netherlands, France)
P2G : electrolysis + methanation + CH_4 injection Thermochemical Methanation	It converts the surplus electricity from renewable sources of energy into hydrogene by electrolysis of water. The hydrogene produced is then associated with CO_2 through a chemical reaction to produce methane then distributed in the network.	Current demonstrators offer around 1MWe. 6 MW in Audi plant in Germany	Overall Yield Currently : Almost 55%PCS By 2030 : 75%PCS Methanation yield : 80%	decarbonised gas supply for all uses : mobility, Residential buildings, Tertiary sector, industry	The gas system is able to absorb huge quantities: solution for massive storage No need of additional investment on existing grid Reduction of the carbon print of the gas grid. Almost zero polluter gas rejected GN of synthesis can be freely injected in the grid (no longer limit rates) Recovery of heat with high temperature	Sensitive to impurity(H_2S<10ppm) Needs CO_2, CO_2 capture Exothermic Not so fast than electrolysers --> interface H_2 storage needed	CAPEX Methanation Reactor : 1500€/kW It is expected to drop to 500€/kW on long-term. OPEX : 10% du capex/an CO_2 capture cost to be added	60 000 h in a continuous cylce of operating. But only 20 000 - 25 000 h in our context (intermittent cycles)	very flexible	Thermochemical Methanation reactor is still on field test but based on well-known CO methanation process.
Methanation Reactor Biologic Methanation			Overall Yield Currently : Almost 55%PCS By 2030 : 75%PCS Methanation yield : 80%		The gas system is able to absorb huge quantities: solution for massive storage No need of additional investment on existing grid Reduction of the carbon print of the gas grid. Almost zero polluter gas rejected GN of synthesis can be freely injected in the grid (no longer limit rates) Recovery of heat with high temperature	Low level of temperature of the rejected heat (the overheat can damage the reactor) Functioning in industrial production still to prove Needs CO_2, CO_2 capture	CAPEX : Methanation Reactor : 1000€/kW By 2030 : 100€/kW OPEX : 12%du capex/an	First results : 3000 hours	NO	Very recent, still at the stage of demonstration

Annex 2 – Power-to-gas demonstrators

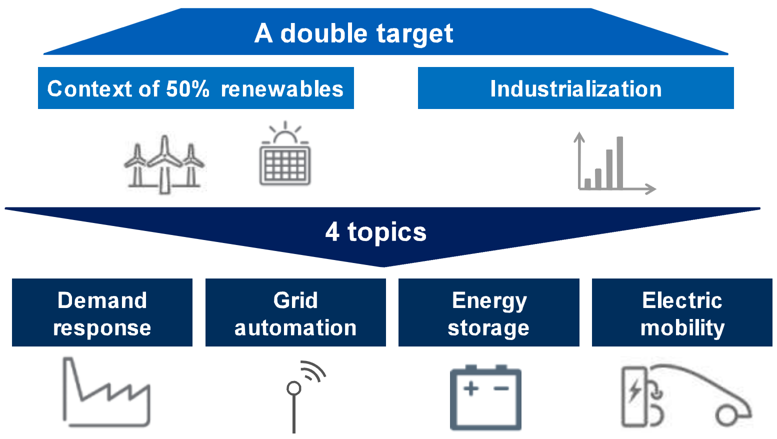
Demonstrators	Location	Objectives	Partners	Budget	Duration
Duurzaam Ameland	Ameland, NL	Long duration test of mixing H2 with natural gas in distrubution system	GasTerra, Stedin, Eneco		2011-2014
Future Billing Methodollogies	UK	Supplementary to the RTN project - looking at how to SMART track new gases and allow introduction of renewable gases in the grid, allowing a move away form FWAC billing. Modelling, new sensors and metering, buiding demand models	SGN, NGN, National Grid, DNVGL	€10M	Beginning
GRHYD	Dunkerque, France	This demonstrator covers 2 aspects: injection of H2 produced by electrolysis into the natural gas distribution grid (new district) and use of hythane as fuel for vehicle. Objective of the injection demonstrator is to to test feasibility of H2 injection up to 20% and work on business models.	Leading :CRIGEN (ENGIE) Others : GRDF,Mac Phy, CETIAT,Cofely ineo , Ineris,CUD,Areva,CEA	€16M	2014-2019
Hydeploy [NationalGrid]	Keele, UK	Hydeploy looks to blend up to 20% h2 in methane. The H2 is generated from an electrolyser. The gas is entering into a private network during the project. There are a number of tests built into the first phase which will include 100% h2 element testing on within building pipework.	Leading National Grid Gas Distribution Others NGN	7.635m£	2017-2020
INGRID & STORE&GO	Troia, Italy (European project)	The INGRID project aims at demonstrating the effective usage of safe, high-density, solid-state hydrogen storage systems for power supply and demand balancing within active power distribution grids with high penetration of intermittent Distributed Generation (Renewable Energy Sources in particular). STORE&GO started to show large scale energy storage by Power-to-Gas is already possible today	Engineering (I), McPhy Energy S.A.(F). Hydrogenics (B), Tecnalia (S), RSE (I), e-distribuzione (I), ARTI (I), Studio Tecnico BFP (I)	€28M	
Jupiter 1000	Fos sur Mer, France	Build a plant of 1 MWe with two technologies of electrolyzers (PEM and Alkaline) ; power will come frome a wind power park located in the area. H2 will then be directly injected in the Transport grid and/or transformed into CH4 thanks to a methanation process (CO2 coming from on industrial), CH4 will then be injected into the transportation network. The objective is firstly to validate technologies and to assess the performance of the unit (dynamic, flexibility, yield), then to build a business model.	Leading : GRT GAZ Others : ATMOSTAT,CEA,CNR,Leroux & Lotz,Marseille Fos Harbour, Mc Phy, TIGF	€30M	2014-2020
MeppelEnergie	Meppel, NL	Demonstration of smart district heating using biogas/biomethane (400 houses)	Gemeente Meppel, I-NRG, Rende Duurzaam, TUD, UT		2013-2016
Real Time Networks	UK	offer new ways to manage the introduction of new gases, while providing more detailed information about our network energy content and the way people use the energy delivered. Modelling and data collection. Developing new SMART demand and supply models https://www.sgn.co.uk/real-time-networks/our-trial/	SGN DNVGL	€7M	Since 2016
Renovagas	Spain	Prove that the quality of gas produced by a synthetic natural gas plant is suitable to be directly injected in the natural gas network	Enagas, CNH2, GNF, CSIC, FCC Aqualia,Tecnalia, Abengoa H2	€2.2M	2014 -2016
Stedin	Rozenburg, NL	Long term assessment of H2/methanisation plant delivering standard kwality gas to building	Ressort Wonen, Gemeente Rotterdam, DNV-GL, RVO		2014 - 2019
Synvalor	Delft, NL	Development of vortex reactor for biomass to methane conversion	TUD		2013-2015
Sysngaschem	Lab of Syncat@Differ, Eindhoven , NL	High temperature co-electrolysis to syngas	Differ, TUE	€1.6M	2016 - …

Annex 3 – Decentralized innovative smart gas solutions

Technologies	Short description	Capacity range	Yield	Applications	Advantages	Current limits	CAPEX/OPEX	lifespan	Potential flexibility/ Time response	Maturity
Internal combustion engine (Micro and mini cogeneration)	Internal combustion engines use the energy of combustion of a mix air / fuel to put in movement pistons triggering the electric generation of an alternator . the heat energy of gases is recovered by a heat exchanger.	0 -300 kWe	Electricity Yield : 25-45% (mini) Total Yield : 85-105%	Tertiary sector and collective residences	Very wide range of available products (on the whole range of electric power) Relatively low capital cost. Works with low-pressure gas.	High emission of Nox High frequence of maintenance costs. → the stakes are to reduce the investment and maintenance costs	CAPEX : 1000-2000 €/kWe OPEX :1-2 ct€/kWhe	10 years	1-5min	Germany and Japan are the biggest manufacturing countries of internal combustion engine. Japanese companies launched a developpement policy to EU market. The range of available products is wide (but mainly dozens-kW products).
Stirling Micro CHP (Micro and mini cogeneration)	the contribution of external heat allows the movement of goes and comes from the piston, producing of the electric current via an alternator.	1 -10 kWe	Electricity Yield : 15-20% Total Yield : 90-110%	Adapted to the renovation of existing houses, tertiary sector and collective residences.	The system requires few operations of maintenance. Compact product with high total efficiency.	Potential generation of vibrations. Reliability of products (field-test) High investment costs	CAPEX : 2500-4500€/kW	>10 years	10-20min	The high costs of sale make it a niche product whose conception is technologically difficult. There does not seem to be new manufacturers launching on this sector (only 8 currently). 200-300 sales in France
Gas Turbines (Cogeneration)	The combustion of GN and compressed air produces an exhaust gas at high pressure and high temperature which is then relaxed by turbines.The mechanic energy induced is turned into electricity by an alternator while the heat is be recovered by a boiler.	> 1 MWe	Electricity Yield : 22 – 36% Total Yield : 70 – 75%	Residential buildings, Tertiary sector and industry	Electricity supply secured in peak demand especially during the winter. Low maintenance cost regarding competing technologies High flexibility and easy off grid operation	Requires a high-pressure gas or an in-house gas compressor. Mediocre efficiency with low partial loads.	CAPEX : 900-1200€/kWe OPEX :0,5-1ct€/kWe	15-20 years	< 1min total modulation	Mature technology The market is in expansion in Europe with leading countries as netherlands, finland and denmark whose cogeneration part in electricity generation reachs respectively 30%,35% and 40%.
Gas Turbines (micro-turbines)		5-300 kWe								Some facilities in France (Turbomach, Capstone) but more developped in the world (~8000 facilities)
Rankine Cycle (Micro and mini cogeneration)	the principle is to use the heat of an external source, transferred to a fluid during a cyle of compression /relaxation. A turbine is then triggered by the relaxation step and produces electricity trough an alternator.	0.5-10 kWe	Electricity Yield : 6-20% Total Yield : 90-95%	High-power boiler (Tertiary sector and collective residences)	Adapted to low-temperature heat source (80-350°C) Compact size	Lower yield	CAPEX : 1500€/kW	30 years	< 10min	Commercialized, about 10 manufacters compose the market. → this technology presents lower yields but it's worth evaluating its investment and maintenance costs to define its potential .
Fuel cell (SOFC/PEM) (Micro and mini cogeneration)	Fuel cells installation is closed to a floor mounted gas boiler.It integrates a reformer which produces few hydrogen from natural gas. Within the fuel cell stack, hydrogen reacts with oxygen thus producing power and heat.	1 -5 kWe	Electricity Yield : up to 60% (SOFC) 30-40% (PEM) Total Yield : 80-95%	Residential buildings (collective or individual)	Mature technology SOFC can be fuelled with either hydrogene or mix hydrogene/CO in 700-1000 °C process. SOFC fuel cells are more and modular than PEM. PEM : Almost zero Co and Nox rejected Well support the cycles of on/off (~400 cycles per year)	SOFC : Repetion of cycles of on/off can damage the system (Max 5-10 cycles per year) PEM : High initial investment costs Need of additionnal unit to purify then incoming natural gas.	CAPEX : 4500-6000/kWe OPEX :3.2-3.8ct€/kWhe	SOFC : 2-3 years PEM : 4-5 years	not adapted	Due to national regulation, the Japanese market is developped with a total of 43000 sales in 2013. USA, Germany and south-Korea present an increasing fuel cell market. Currently ~50 units on field-test in France
Hybrid systems	Hybrid boiler is the association of heat pump and condensing boiler piloted by an optimised control system. Depending on external temperatures, the pilot chooses the most efficient solution and then provides an optimised energetic perfomance.	PAC : < 4 kW Condensing boiler : 24-30 kW	Condesing boiler : 89-94% PAC : Coefficient of Performances (COP) between 3-5	Residential buildings (collective or individual)	Based on mature technologies Reduce the energetic bills Energetic performances corresponding in the RT 2012 requirements	Hybrids solutions are only well-suited for new houses (not adapted for existing houses)	Not defined	15-20 years	NO	Slight market (estimated to be between 1000 and 5000 sales in 2013)

Annex 4 - Interflex

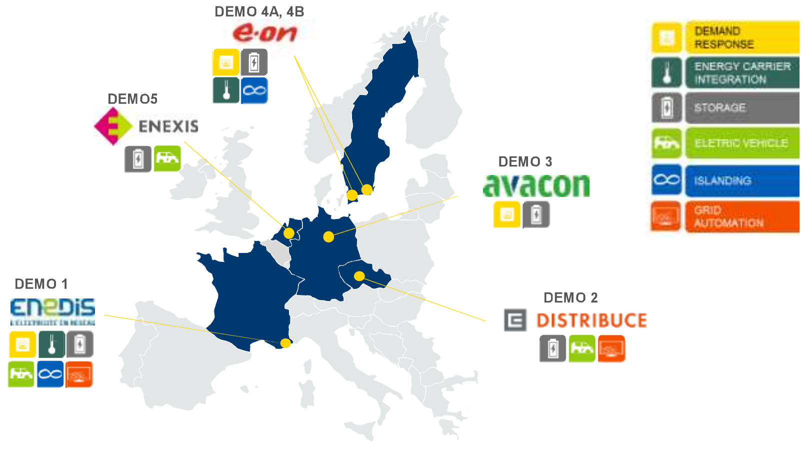
Interflex 1 - Objectives



Interflex 2 - Key figures

Key figures	6 technical focuses	4 cross cutting approaches
22.8 M€ *70% funded by the EC*	Demand response	**Interoperability** of the techical solutions
3 years *Project duration, start 1/1/2017*	Energy carrier integration	**Replicability and scalability** of the solutions
20 *Partners, including 5 DSOs*	Islanding	**Cost benefit analysis** and **business models**
6 *DEMOS in 5 countries*	Storage	**Regulatory** approach
	Grid automation	
	Electric vehicles	

Interflex 3 - Scope



Interflex 4 - French DEMO partners

Partner	Role
Enedis	▪ Implementation and operation of the **local flexibility platform to involve flexibility to solve DSO grid constraints** ▪ **Grid storage assets operation** ▪ **Supervision of technical evaluation** and **deliverables** ▪ **Partners coordination** and **project management** ▪ Responsible for **communication and dissemination** at demonstrator level
GE	▪ Deployment of **the local flexibility mechanism on the area** ▪ Deployment of **innovative functionalities** within this mechanism
Socomec	▪ **Islanding automation** ▪ Development of **innovative functionalities for storage**
Engie	▪ Recruitment of **business customers** ▪ **Deployment of aggregation platform interfaced with DSO mechanism and flexibility valuation** ▪ Contribution to **islanding** ▪ **Grid storage assets operation**
GRDF	▪ Installation **of innovative gas devices** within buildings to **supply electric flexibility to the grid** ▪ Research of **potential sites** and **contracting with clients** ▪ Development of a connection with and aggregators ▪ **100 to 150 kW$_{el}$ of electric flexibility using micro CHP, hybrid boilers…**
EDF	▪ **Recruitment of customers** (350 residential clients and 20 businesses) ▪ Deployment and operation of **aggregation platforms** ▪ Deployment of « [illegible] » (V2H)