

Development of Business Cases for Fuel Cells and Hydrogen Applications for Regions and Cities

Hydrogen injection into the
natural gas grid





This compilation of application-specific information forms part of the study ***"Development of Business Cases for Fuel Cells and Hydrogen Applications for European Regions and Cities"*** commissioned by the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH2 JU), N° FCH/OP/contract 180, Reference Number FCH JU 2017 D4259 .

The study aims to **support a coalition of currently more than 90 European regions and cities** in their assessment of fuel cells and hydrogen applications to support project development. Roland Berger GmbH coordinated the study work of the coalition and provided analytical support.

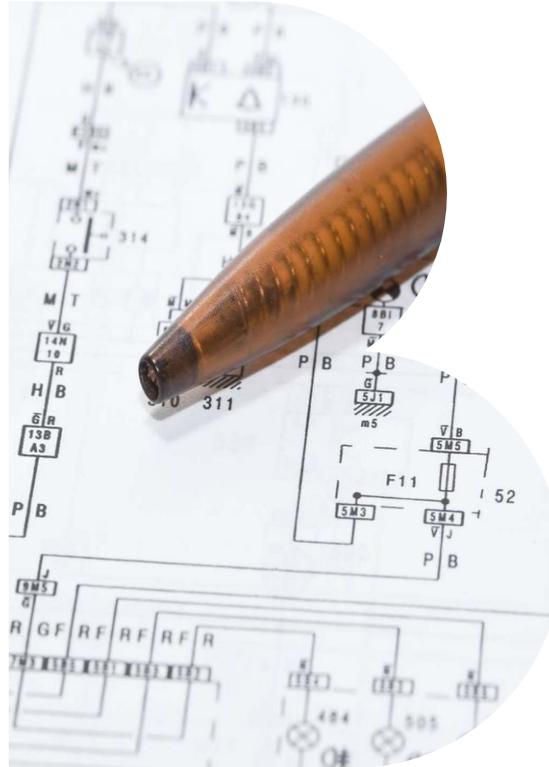
All information provided within this document **is based on publically available sources** and reflects the **state of knowledge as of August 2017**.



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A. Technology Introduction



Hydrogen into gas grid applications provide a sustainable solution for renewables-based storage and transformation of energy grids

Hydrogen into gas grid

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Brief description: Hydrogen can be converted from renewable energy sources and injected into existing natural gas grids for initial (or long-term) storage and subsequent use in a range of different applications (power generation, heat provision, transport applications such as gas-fuelled urban buses or passenger cars)

Use Case: Cities and regions can inject (or call for / incentivise the injection of) green hydrogen (i.e. from power-to-hydrogen P2H sources) into gas grids to further promote renewable energy sources, decarbonise the gas grid and provide long-term energy storage solutions

Fuel cells in commercial buildings

Key components	Electrolyser, fuel cell, blending/injection system
Electrolysis technology for P2H	Alkaline (ALK), PEM, (Solid Oxide)
H ₂ production efficiencies	50-83 kW _{el} /kg (2013), 36-63 kW _{el} /kg (2030)
Cost of H ₂ production for P2H	<i>dep. on electrolyser size, technology, power input price, etc.</i>
Maximum H ₂ blend level	5 – 20% (potentially even 25%, dep. on gas infrastructure)
Hydrogen provider	E.on, RWE, Thüga
Gas distributors	Private and municipal utilities (e.g. German Stadtwerke), gas TSOs or DSOs
Typical customers	Public and private utilities, public and private TSOs or gas shippers, ultimately e.g. passenger car fleet operators
Competing technologies	Other energy storage (e.g. pump storage, batteries)

Several successful demonstration projects provide a valid foundation, also for the assessment of future commercialisation

Hydrogen into gas grid

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Overall technological readiness: Large scale demonstration and lighthouse projects ongoing and more being commissioned, showcasing technical and economical viability of technology in a relevant operational environment (especially combination of P2H and injection into gas grid)



Demonstration projects / deployment examples (selection)

Project	Country	Start	Scope	Project volume
P2G Ibbenbüren demonstration plant (RWE)		2014	Operation of 150 kW P2G demonstration plant producing green hydrogen to be injected into gas distribution network, grid operation by Westnetz GmbH	n.a.
WindGas Falkenhagen (E.ON)		2011	Green hydrogen production from 2 MW wind power to be fed into gas distribution network, grid operation by Ontras Gastransport GmbH	n.a.
Network management by injecting hydrogen to reduce carbon content (GRHYD)		2013	Phase 1: Two-year preliminary study adapting existing natural gas vehicle (NGV) fuelling station with new hydrogen/natural gas mixture (Hythane®) Phase 2: Five-year demonstration phase of hydrogen injection into natural gas distribution network with blend level of up to 20%	n.a.
HyDeploy		2016	0.5 MW electrolyser to demonstrate the use of blended hydrogen in the UK gas grid	GBP 6.8m

*) Technology Readiness Level ≤ 5 6-7 8-9

Besides supporting the integration of renewables, hydrogen-into-gas grids offers an efficient storage solution with existing infrastructure

Hydrogen into gas grid

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Use case characteristics

Stakeholders involved



- > Electricity generating utilities, e.g. operators of wind farms or larger solar PV parks
- > Natural gas transmission system and distribution operators
- > Regulatory and permitting authorities

Demand and user profile



- > Utilisation of excess power from intermittent sources (e.g. PV, wind) to produce "green" hydrogen, on-site electrolyser, e.g. built into container for scalability
- > Maximum H₂ blend level of gas grid as critical framework condition

Deployment requirements



- > Hydrogen production and electrolysis
- > Quality of (local or regional) gas grid infrastructure (e.g. material durability of meters)
- > Adequate downstream infrastructure (e.g. satisfactory connection to H₂ consumer)

Key other aspects



- > Facilitation of hydrogen infrastructure and wider adoption of mobile FC application such as FCEV

Benefit potential for regions and cities

Environmental



- > Reduction of carbon footprint of natural gas grid and ultimately gas-fuelled energy and transport applications
- > Improved flexibility for electricity system supporting the integration of renewable energy

Social



- > Improved stability and security of energy supply, through a viable medium- and long-term storage opportunity
- > Improve social acceptability of hydrogen and fuel cell applications – as larger component of an integrated transition of the energy system

Economic



- > Shift of energy transport to gas pipelines and thus lower intensity of electricity grid expansion
- > Efficient utilisation of existing natural gas infrastructure, especially in parts of Europe with high gas grid densities
- > Short-term, medium-term and seasonal storage opportunities

Other



- > Further promotion of renewable energy sources as a result of converted hydrogen being injected into gas grid and overall higher ability of electricity/gas system to absorb variable electricity generation from renewable sources

Among others, a lack of standardised gas composition, blend concentration and missing incentives inhibit large scale deployment

Hydrogen into gas grid

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Hot topics / critical issues / key challenges:

- > Appropriate hydrogen blend concentration may vary significantly between pipeline network systems and natural gas compositions (e.g. range of 5-25%)
- > Additional pipeline monitoring and maintenance measures will likely be necessary, necessitating investments on the gas TSO/DSO's side
- > Degrading durability of metal pipes and materials when exposed to hydrogen may require necessary infrastructure upgrades
- > Lack of incentives and compensation systems to reward energy storage services is a key element of a commercial business case that is currently not clear enough (e.g. under German Renewable Energy Sources Act (EEG)) – revenue remuneration / monetisation streams have to be defined

Further recommended reading:



- > Study on Early Business Cases for H2 in Energy Storage and More Broadly Power to H2 Applications
<http://www.fch.europa.eu/studies>
- > Blending Hydrogen into Natural Gas Pipelines:
https://energy.gov/sites/prod/files/2014/03/f11/blending_h2_natural_gas_pipeline.pdf
- > Power-to-Gas system solution:
http://www.powertogas.info/fileadmin/content/Downloads/Brosch%C3%BCren/dena_PowertoGas_2015_engl.pdf

Key contacts in the coalition:



Please refer to working group clustering in stakeholder list on the share folder

<https://sharefolder.rolandberger.com/project/P005>

B. Preliminary Business Case



Injecting (green) H₂ into the gas grid promises 4 key benefits: sector coupling, gas decarbonisation, energy storage and H₂ de-risking

Main potential and value propositions

A. Sector coupling

... allowing for environmental benefits of increasingly **green electricity to spill over to other sectors** that are linked to the natural gas infrastructure, e.g. industrial power/heat, mobility

B. Decarbonising the gas grid

... greening the **gas grid by lowering its carbon intensity (with "admixture" of natural gas and green hydrogen)**, improving the environmental performance of efficient gas-based power and heat generation – a "low-hanging fruit" for decarbonisation

Injecting green hydrogen into the natural gas grid

... enabling the **de-coupling of variable energy supply from renewables and energy consumption**, by using the existing natural gas transmission, distribution and storage infrastructure

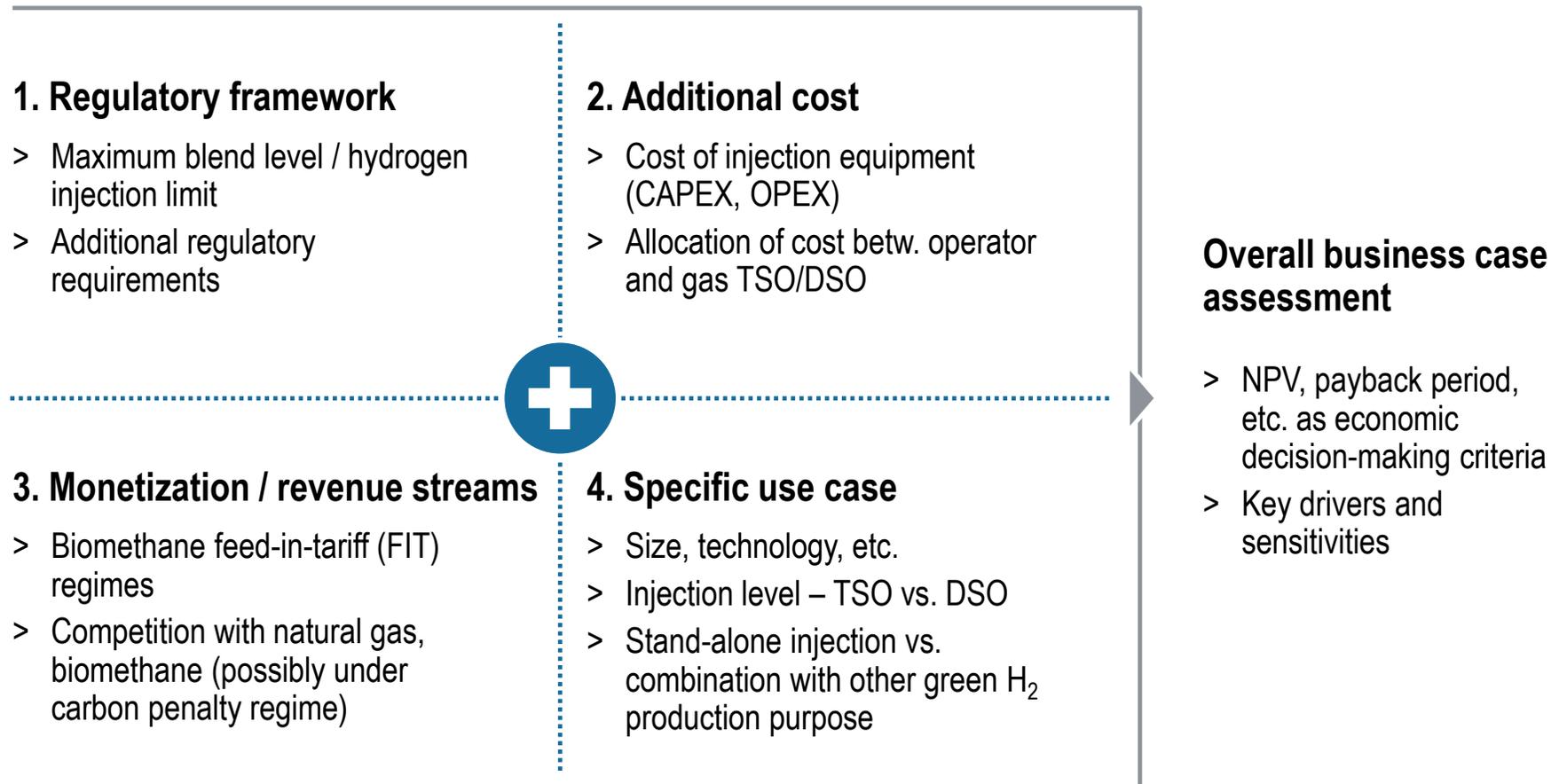
C. Energy storage

> Offering power-to-hydrogen operators a **complementary value stream** to de-risk potential initial demand shortfalls from industrial or mobility off-takers

D. Risk mitigation

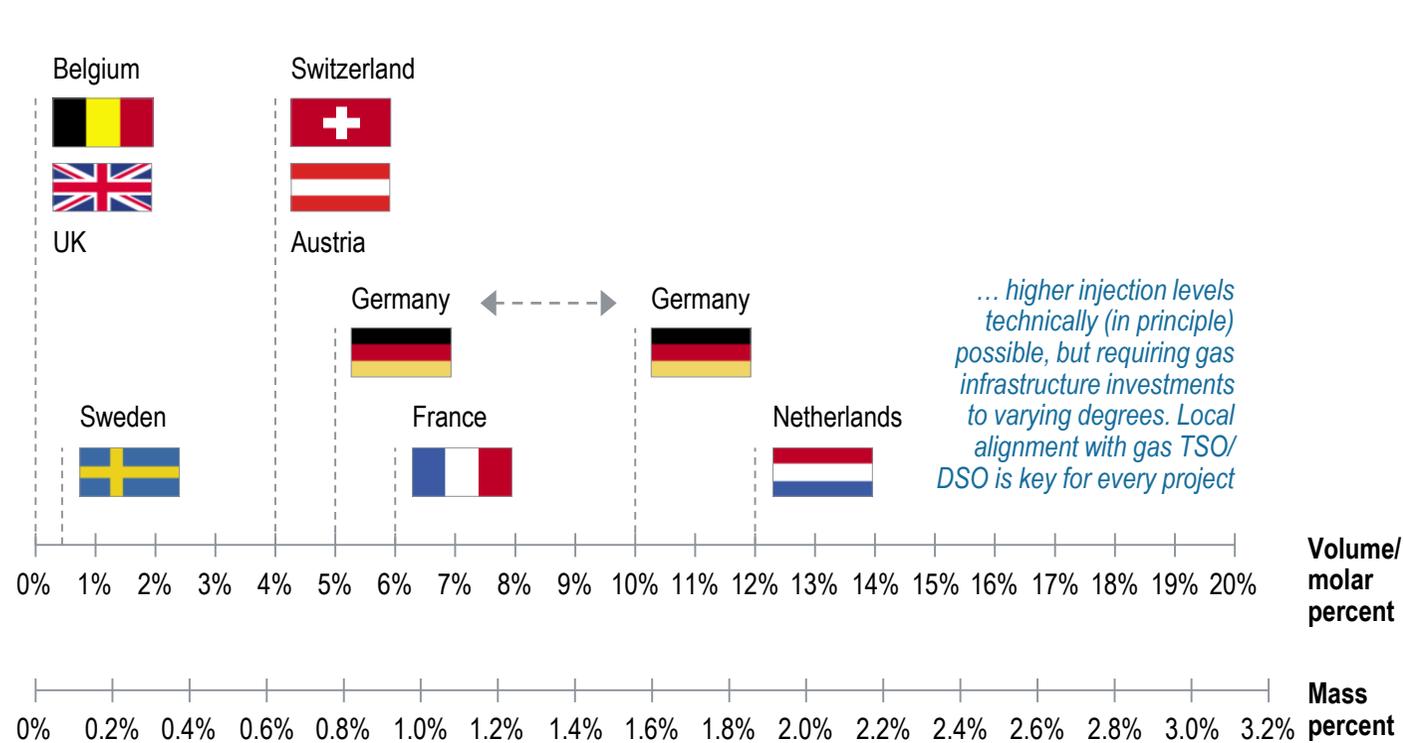
For the business case, regulatory framework, additional cost and monetisation options have to be considered

Key elements of the business case



The maximum (local) blend level of hydrogen into the gas grid varies greatly across (and even within) European countries

#1 – Regulatory framework, esp. maximum blend level / H₂ injection limit



- > Regulatory injection limit varies greatly across Europe and even within countries (e.g. local limits in Germany of 2%_{vol} in case of presence of downstream CNG refuelling stations or storage (e.g. underground))
- > CEN and EASEE-gas are working toward a harmonized standard for gas quality in the EU. Due to the type II vessels for CNG vehicles, 2%_{vol} hydrogen tolerance in the gas mix is the current basis for discussion
- > Higher H₂ blend levels might require add. pipeline monitoring/maintenance measures (gas TSO/DSO); degrading durability of metal pipes and materials when exposed to hydrogen may also necessitate infrastructure upgrades

Direct injection requires add. CAPEX and OPEX on site, dep. on national/local context – Add. cost of injection are relatively small

#2 – Add. cost components of hydrogen injection interface – INDICATIVE

Key add. cost elements

Gas distribution grid	2017	2025
Pressure	10 bar	
CAPEX injection station	EUR 600 k	EUR 480 k
OPEX [% CAPEX]	8%	
Lifetime	35 years	

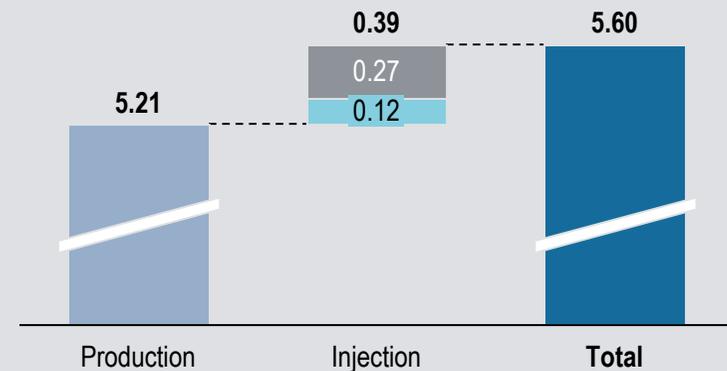
Current focus

Gas transmission grid	2017	2025
Pressure	60 bar	
CAPEX injection station	EUR 700 k	EUR 560 k
OPEX [% CAPEX]	8%	
Lifetime	35 years	
CAPEX H ₂ connection piping	EUR 300 k/km	
CAPEX H ₂ equipment	EUR 200 k	
OPEX [% CAPEX]	EUR 200 k	

Example for effective cost of injection

> **Key assumptions of this example:** 5 MW PEM (at 2017 parameters); 2,500 FTE with full injection; 30 EUR/MWh average electricity cost; DSO-level injection; 250 m piping

> **Cost of injecting H₂ into the gas grid [EUR/kg]:**

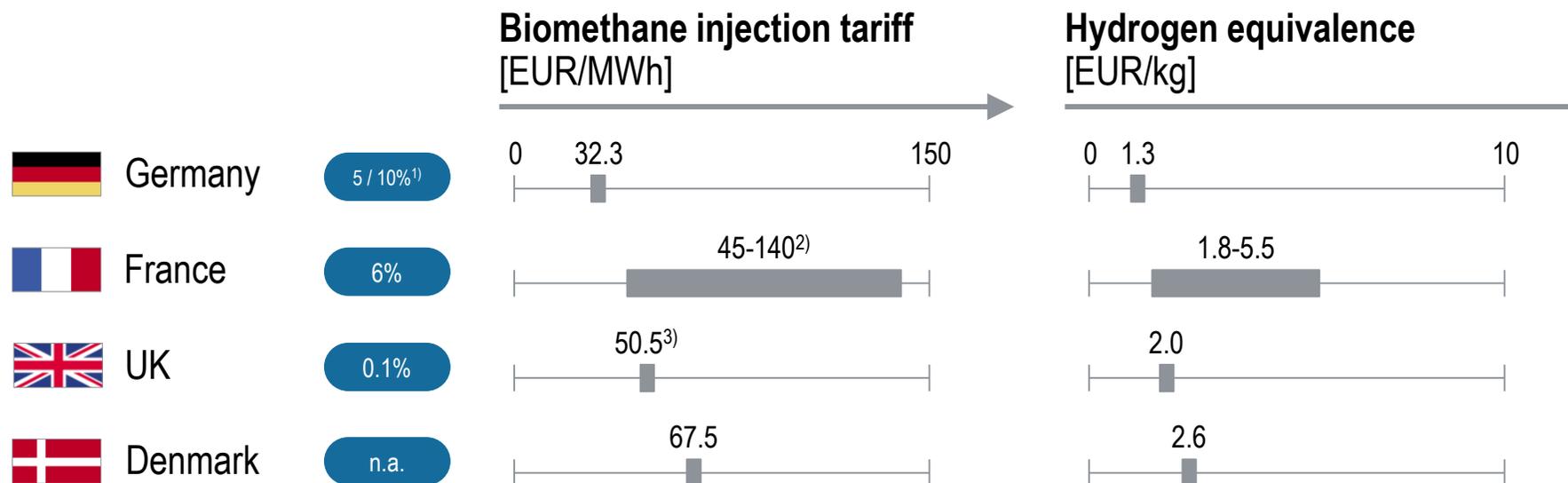


> **Please note:** Cost dynamics change with regards to e.g. size of electrolyzers, technology, operating hours, share of hydrogen injected vs. share that is monetised otherwise

■ OPEX injection ■ CAPEX injection ■ Hydrogen production

Short-term monetisation may come via biomethane FIT, long-term competition with CO₂-penalised natural gas conceivable

#3 – Monetization / revenue streams, esp. equivalence to biomethane injection



- > The injection of green hydrogen into the gas grid decreases the carbon footprint of natural gas and should thus be eligible for feed-in tariffs in line with supporting regimes for biomethane
- > In the long run, it is conceivable that an effective carbon price is introduced that would apply (among others) on natural gas, thereby mechanically reducing the cost gap between green hydrogen, biomethane and natural gas

Hydrogen injection limit

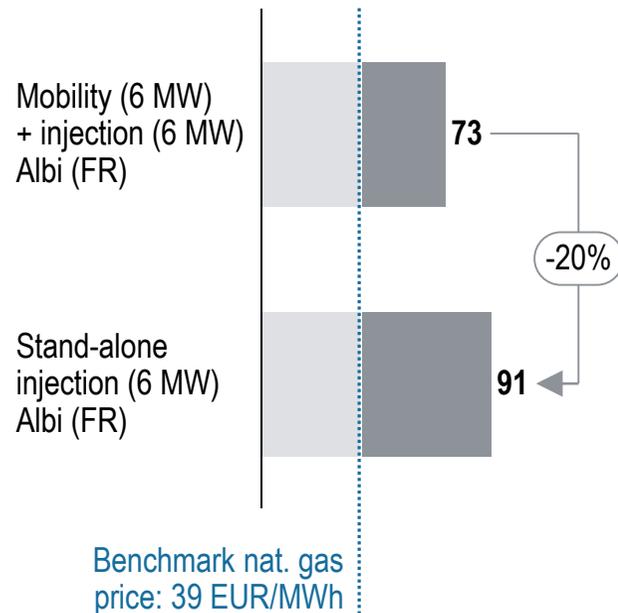
1) <2% vol. in some conditions 2) 2015 3) 2016

Significant feed-in tariffs are necessary to allow for a profitable investment – Stand-alone business cases are generally difficult

Overall preliminary business case assessment – 2 INDICATIVE EXAMPLES¹

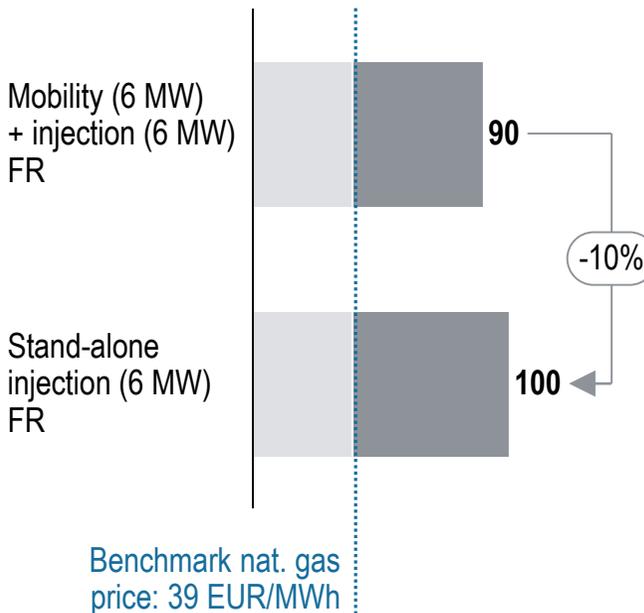
Requ. FIT with pay-back time of 8 years
(with electricity discount)

Injection tariff (EUR/MWh)



Requ. FIT with pay-back time of 8 years
(without electricity discount)

Injection tariff (EUR/MWh)



- > Significant FITs are necessary for profitable investments in hydrogen injection
- > Combining injection with hydrogen sales to mobility or industry users reduces the level of the required FIT
- > Most of the electrolyser capital cost is paid by mobility or industry clients; injection tariff only needs to cover marginal injection costs (and very limited injection-specific CAPEX).
- > Here: in case the stand-alone injection business case only receives a FIT of 73 EUR/MWh, payback time will double to >16 years
- > H₂ injection might thus be best considered as a secondary application

1) Comparing two specific scenarios in France for the target year 2025, with and without access to discounted electricity

Gas grid injection can be a key enabler of other power-to-hydrogen applications – if and when the right policies are in place

Key additional considerations

1 Combined use cases and business cases: "X plus gas grid injection"



- > Gas grid injection can be a complementary application that has the potential to increase the revenues of an electrolyser used e.g. for mobility or industry
- > It could help mitigate the risk of lower-than-expected mobility demand ("valley of death") covering the operation costs and part of asset depreciation towards break-even

2 Key success factor from a policy-making perspective: recognition



- > Power-to-hydrogen electrolyzers can provide gas with low carbon intensity
- > Policy makers can provide a level playing field for the injection of carbon lean gas into gas grid, be it biomethane or green hydrogen
- > Green hydrogen should be recognized as "compliance option" to reduce carbon intensity of conventional fuels

Regions and cities can identify suitable locations for power-to-hydrogen projects with gas grid injection along 4 main criteria

What to look for in identifying power-to-H₂ projects with gas grid injection ...



1. Local grid challenges with growing renewables capacities

- > Increasing wind and solar capacities
- > (Distribution) grid constraints, e.g. due to low interconnectivity – rising congestion challenges, possible needs for curtailment



2. Intersections of gas and electricity distribution grids

- > Urban / suburban areas with RES feeding into MV electricity distribution grid and medium-/low-pressure gas grids for residential/commercial gas supply



3. Sufficiently high hydrogen injection limits for the local gas grid

- > Hydrogen injection levels of e.g. 2%_{vol} or more permitted acc. to local regulation



4. Monetisation options for green hydrogen – in gas grid and otherwise

- > Primary monetisation / value stream, e.g. hydrogen supply to mobility users
- > Plus existing regime for biomethane injection accessible for green H₂ (or bespoke regional remuneration schemes, e.g. green-H₂-gas admixture remuneration)

Please do not hesitate to get in touch with us

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