



# Discovering the molecule of the future: Session 1: Hydrogen from production to distribution and storage

Online Briefing Session specially prepared for MEPs and Political Groups Advisers  
in cooperation with the EEF Associate Members



Our event will start soon

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## IN-HOUSE RULES

**Chatham House Rule:** one can mention what is said, but not quote anyone. Please keep it in mind when tweeting (@EEF\_EnergyForum)

**Mute mode:** all participants are on mute mode and not visible during panellists' initial interventions

**Debate time:** all participants are encouraged to ask for the floor to visibly provide their insights or ask their questions: To do so :

- ❖ Use the «Raise Hand» function at the bottom of the participants tab
- ❖ When given the floor, you will be unmuted and have the option to turn on your camera
- ❖ Please introduce yourself and be brief
- ❖ The use of camera while asking a question is advised for a better, livelier interaction
- ❖ We will take 3 questions at a time



# Hydrogen Basics

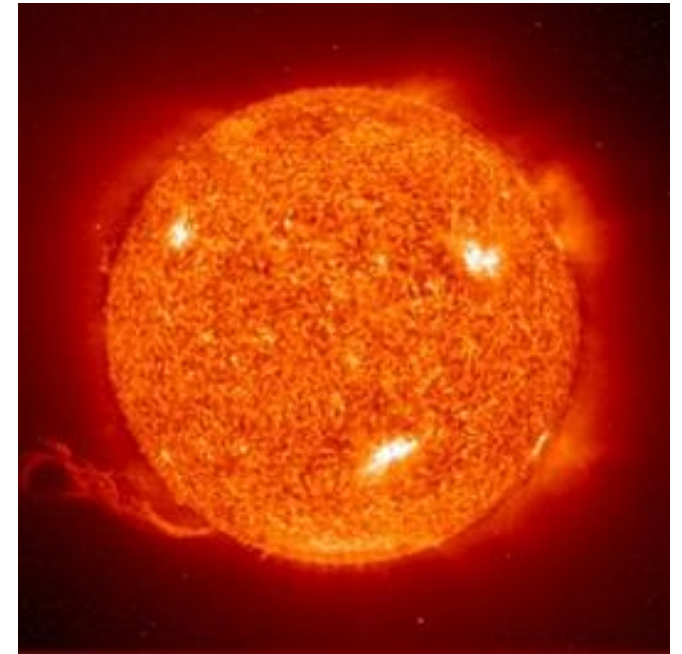
*Presented by*

**Achim Ufert**, Senior Energy Policy Expert, Corporate Communications and Governmental Relations, **Uniper**



# What is $H_2$ ?

- Hydrogen is the simplest and most abundant element in the universe. Stars such as the sun consist mostly of hydrogen.\*  
→ *The sun gets its energy for solar radiation from the fusion of hydrogen into helium. The mass of the sun is  $2 \times 10^{30}$  kg of which 92 % are hydrogen.*
- Hydrogen occurs naturally on earth only in compound form with other elements. Hydrogen combined with:
  - Oxygen forms water ( $H_2O$ ).
  - Carbon forms different compounds found in natural gas, coal, and petroleum.\*→ *Under normal conditions hydrogen appears as  $H_2$ , a colorless and odorless gas.*
- A key characteristic chemical property of hydrogen is its very high flammability



Source: NASA

\*Source: U.S. Energy Information Administration (Jan 2020); <https://www.eia.gov/energyexplained/hydrogen/>



# What is $\text{H}_2$ ? An Energy Carrier

- Hydrogen, like electricity, is an energy carrier that must be produced from another substance.
- Hydrogen can be produced—separated—from a variety of sources including water, fossil fuels, or biomass and used as a source of energy or fuel.\*
  - *Compared with methane, hydrogen has about 30 % of energy per volume but 2.4 times the energy per weight.*
- Hydrogen has a high energy content per unit of weight, which is why it is used as a rocket fuel and in fuel cells to produce electricity on some spacecraft.\*
  - *Like electricity generation with PV, the use of hydrogen as an energy carrier initially comes from applications in space.*



Source: NASA

\*Source: U.S. Energy Information Administration (Jan 2020); <https://www.eia.gov/energyexplained/hydrogen/>

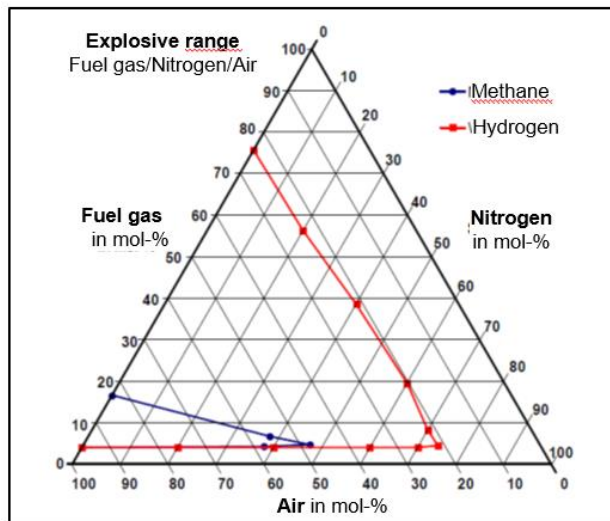


# What is $\text{H}_2$ ? A Safe Element to be Handled with Care

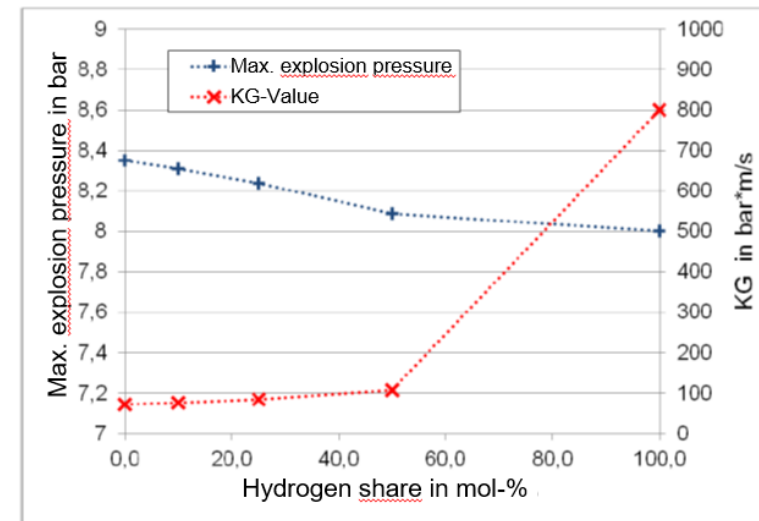
## Technical challenges need to be solved

- Currently the max. share of hydrogen in the European natural gas grid is limited to 0.1 – 12 %.
  - Limiting factors are appliances, gas detectors, the gas grid itself and storages
- Hydrogen in the role of an energy carrier requires further research

### Primary explosion protection



### Secondary explosion protection



Source: BAM – Bundesanstalt für Materialforschung und –prüfung, Sicherheitstechnische Eigenschaften von Erdgas-Wasserstoff-Gemischen; Sept. 2016



# Hydrogen Production

*Presented by*

**Perizat Ybrayeva**, International Hydrogen Business Development Manager, **Uniper**

**Antoine Aslanides**, CEO of Hynamics Deutschland, **EDF group**

**Ton Manders**, Technical & Safety Director, Euro Chlor, **Cefic**



# H<sub>2</sub> Colours

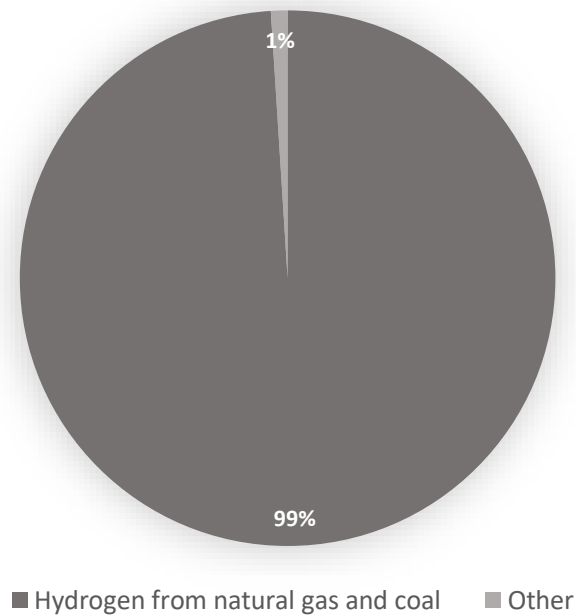
Production Process	Definition in the European Hydrogen Strategy	Associated Colour
Coal gasification	Fossil-based	Grey
Steam Methane Reforming (SMR)	Fossil-based (natural gas) / Renewable (biogas) / Clean (biogas)	Grey Green Green
SMR + CC(U)S	Fossil-based w/ CC Low-carbon	Blue
Pyrolysis / Gas Splitting	Fossil-based w/ CC Low-carbon	Turquoise
Electrolysis powered by renewable electricity	Renewable / Clean / Low-carbon	Green
Electrolysis powered by low-carbon electricity	Electricity based / Low-carbon	N.A.





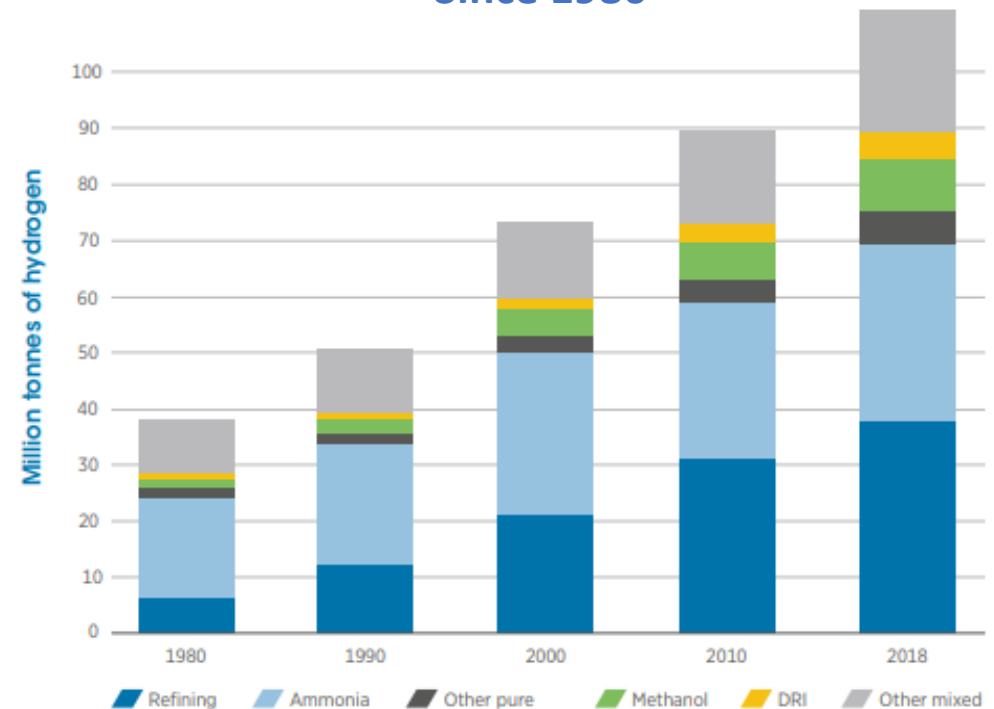
# Production: State of Play

## 2018 Worldwide Hydrogen Production



Source: BloombergNEF, Hydrogen Economy Outlook, March 2020

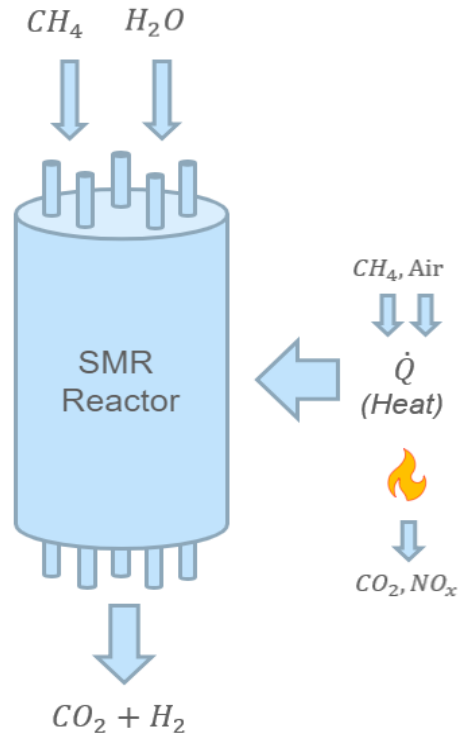
## Global Annual Demand for Hydrogen Since 1980



Source: IEA, 2019



# Steam Methane Reforming + CC(U)S



- Steam Methane Reforming (SMR) uses an external heat source to provide the heat required to sustain the reforming process.
- In the reactor, methane and steam react in a hot and high-pressure environment when they come in contact with the catalyst, most commonly nickel.
- The reaction goes as follows:



2 - 3  
€/kg

TRL 9

Pros

- Low-carbon content
- Possibility to ramp up production more quickly
- More price competitive

Cons

- Not renewable source
- Need for CC(U)S capacity
- Lack of regulatory framework

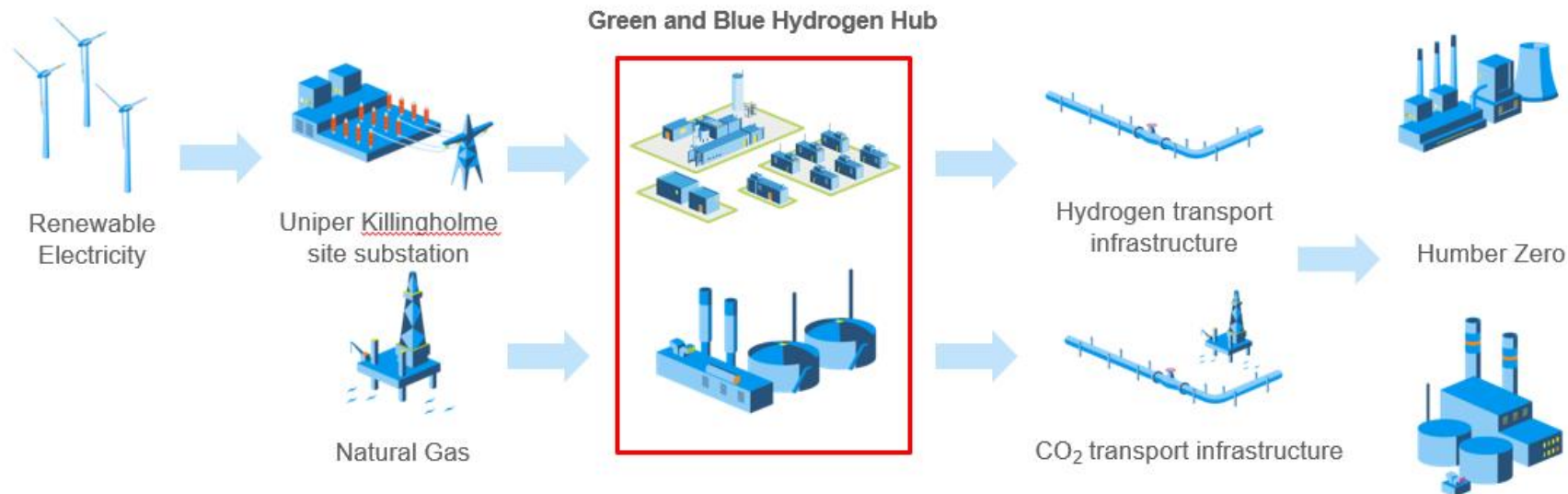


# Steam Methane Reforming + CC(U)S

## Uniper to create a Hydrogen Hub in the Humber region (UK)

### Target

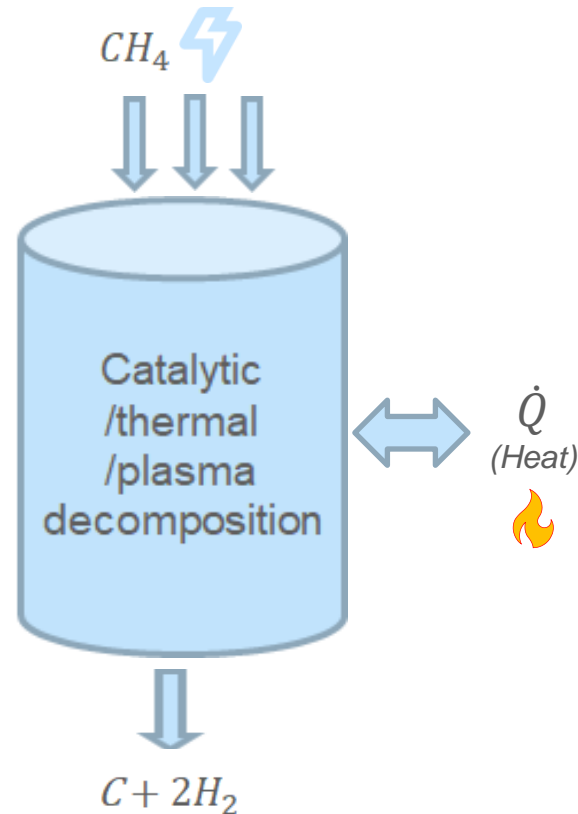
- Creation of a hydrogen hub at the Uniper owned Killingholme location in the Humber region of the UK to deliver green hydrogen from electrolysis and blue hydrogen through SMR with CCS. In partnership with Philips 66 and Vitol through the Humber Zero project.
- Green hydrogen created from renewable electricity and CO<sub>2</sub> from blue hydrogen will be sent offshore by a purpose-built CO<sub>2</sub> network.





# Pyrolysis

Pyrolysis is the decomposition of methane into hydrogen and solid carbon.



- **Using nickel as catalyst**, methane conversion in the percentage range is observed above approx. 500 °C.
- **Without a suitable catalyst**, the decomposition reaction starts at considerably higher temperature
  - for catalytic processes above 800 °C
  - for thermal processes above 1000 °C
  - when using plasma torches at up to 2000 °C.



The main reaction of methane pyrolysis is endothermic (requires continuous supply of heat).

2 - 3  
€/kg

TRL 5 - 6

## Pros

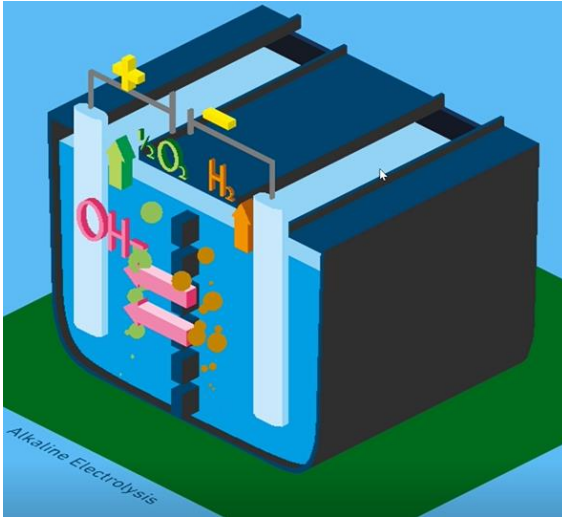
- Requires less energy
- Low-carbon content
- Solid carbon as a by-product

## Cons

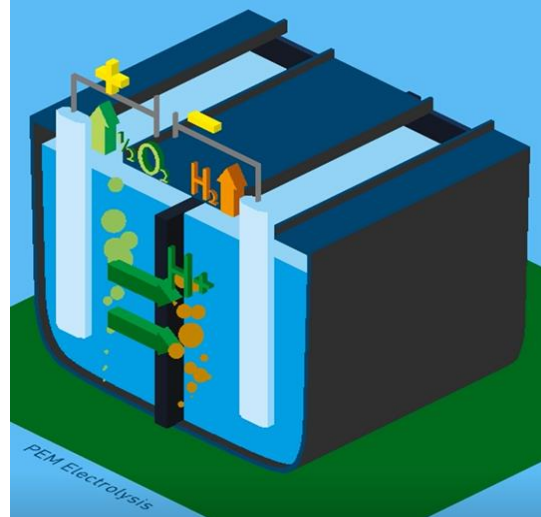
- Not renewable
- Low TRL
- Lack of regulatory framework



# Electrolysis

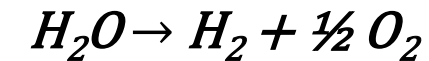


Alkaline Electrolysis



PEM Electrolysis

- The electrolysis technology splits water into hydrogen and oxygen using electricity.
- The hydrogen produced can be renewable / clean / green only when electricity used is itself zero-carbon.



- In Alkaline Electrolysis, water and caustic liquid electrolyte is used for reaction.
- In PEM Electrolysis, the reaction occurs thanks to a Membrane Electrode Assembly.

5 - 6  
€/kg

TRL 9

Pros

- Renewable content
- Seasonal storage solution
- Enabler of sectoral integration

Cons

- High production cost
- Lack of regulatory framework
- Need for renewable electricity



# Power-to-Gas

Power-to-Gas: some concrete examples from **Uniper**

## Power-to-Gas Hamburg



- Power: **1,5 MW<sub>el</sub>**
- Hydrogen production: **290 Nm<sup>3</sup>/h**
- Technology: **PEM Electrolysis**
- Feed into the local distribution gas grid
- Start of operation: **2015**

### Goals:

- Utilization of high efficient "Proton Exchange Membrane" electrolysis (PEM)
- Business development

## Power-to-Gas Falkenhagen



- Power: **2 MW<sub>el</sub>**
- Hydrogen production: **360 Nm<sup>3</sup>/h**
- Technology: **Alkaline Electrolysis**
- Feed into the gas grid of ONTRAS Gastransport
- Start of operation: **2013**

### Goals:

- Demonstration of the process chain
- Optimization of operational concepts

## STORE&GO Methanation plant



- Input: Renewable H<sub>2</sub>: **210 Nm<sup>3</sup>/h**  
Biogenic CO<sub>2</sub>: **52,5 m<sup>3</sup>/h**
- SNG production: **57 m<sup>3</sup>/h**
- Feed into the gas grid of ONTRAS Gastransport
- Start of operation: **2018**

### Goals:

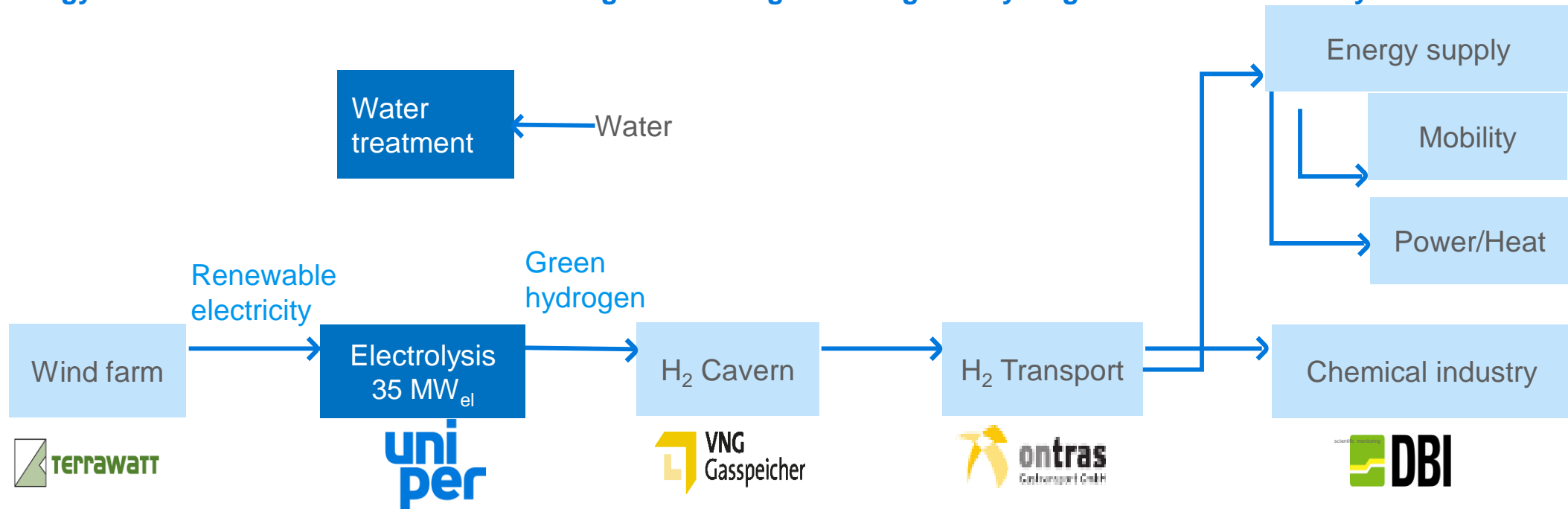
- Testing new methanation technologies
- Gain experience in technology, operation and permitting



## Backup slide

# Energy Park Bad Lauchstädt – Uniper Project

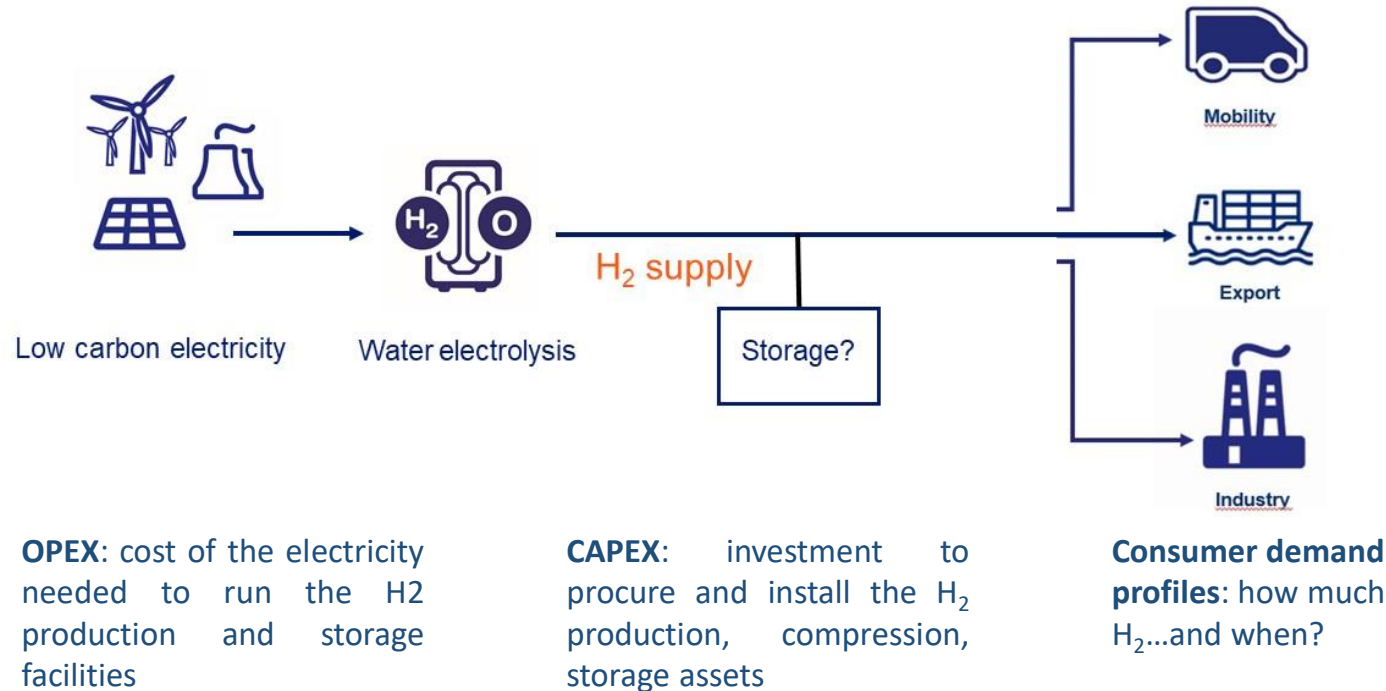
The Energy Park Bad Lauchstädt examines the large scale integration of green hydrogen in central Germany



The initial policy implications for a CO<sub>2</sub>-neutral future via green hydrogen are positive. Although there is still a great deal of political action to be taken to ensure successful implementation.



## Economics of H<sub>2</sub> production by electrolysis: The main cost elements of H<sub>2</sub> production



If I am an investor looking to invest in H<sub>2</sub> production, I will assess very carefully:

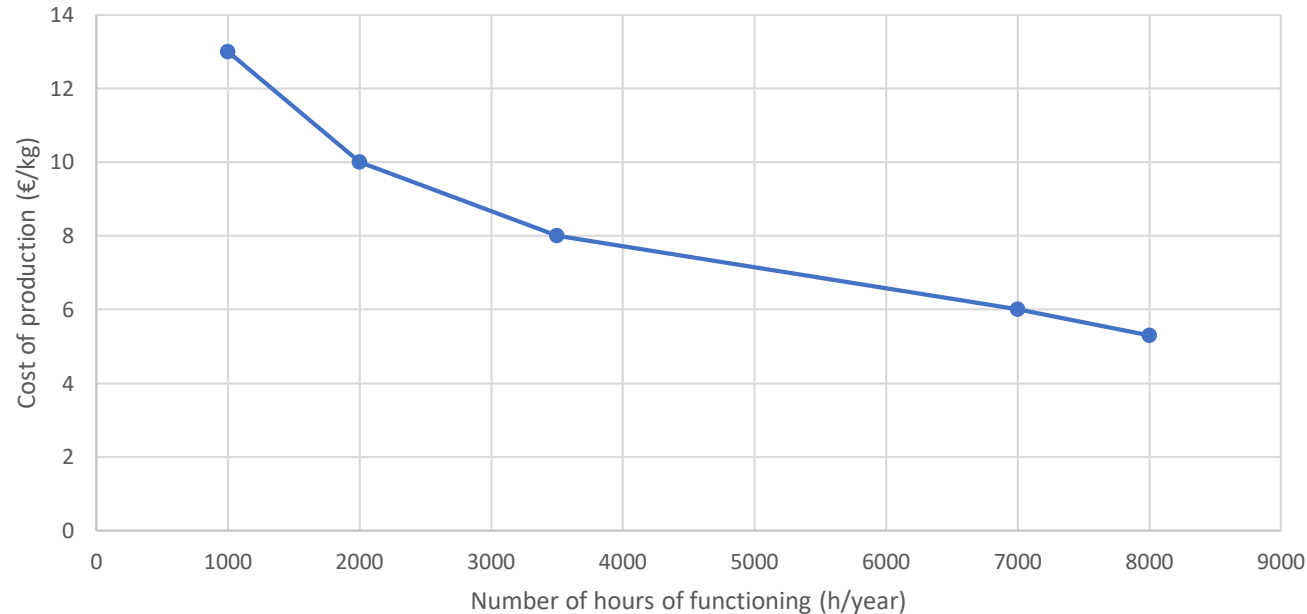
- The needs of my customer: how much hydrogen and when? In industrial processes the answer is usually: all the time!
- The cost of the electrolyser (Capital Expenses - CAPEX): what size of electrolyser (20MW, 100MW, 1GW)?
- The cost of the electricity needed to power my electrolyser (Operating Expenses – OPEX): from the network, or do I need to build dedicated renewables?
- Is there a need to store the hydrogen which is produced to ensure that my customer gets it when needed?





## Number of functioning hours' heavily impacts H<sub>2</sub> production costs

Cost of production of H<sub>2</sub> for a 20 MW electrolyser (€/kg)



After the investment is done (CAPEX),

2 main criteria influence H<sub>2</sub> production costs (OPEX):

- The price of electricity
- Nb of operating hours (how many hours/year the electrolyser runs to produce H<sub>2</sub>)

The business model is about a smart balance between CAPEX and OPEX, for example:

- If the installation is designed to operate 8000 h/year (95% of the time), my investment is very well used, but I will sometimes pay high electricity prices
- If I decide to operate the electrolyser only when electricity prices are low, I may need to invest in a much bigger electrolyser to produce enough H<sub>2</sub> for my customer and to store H<sub>2</sub> for later consumption: I get lower costs of electricity, but increased investment for storage facilities...



## Being connected to the grid enables system integration and improves the business case

- **Safety first and continuity of operations:** It is impossible to design a safe industrial scale system without a 24/7 connection  
⇒ No grid connection brings very high risks
- **Optimising Land use & footprint :** There are very few spots hosting both industrial / transport infrastructure which will need H<sub>2</sub> and showing high renewable potential  
⇒ Imposing systematic direct connection between an electrolysis plant and a RES plant (« off grid ») will drastically limit the potential of H<sub>2</sub> development
- **Integrating more RES :** More renewable electricity means a growing need of flexibility on the demand side, which can be provided by electrolyzers (e.g. producing more H<sub>2</sub> when there is too much RES electricity in the system)  
⇒ Electrolysis is an opportunity to use GWh of RES which are today curtailed from the network: this is only possible with grid connection *(close to the equivalent of ~ 800 MW of electrolysis operating 7000h / year in Germany only)*

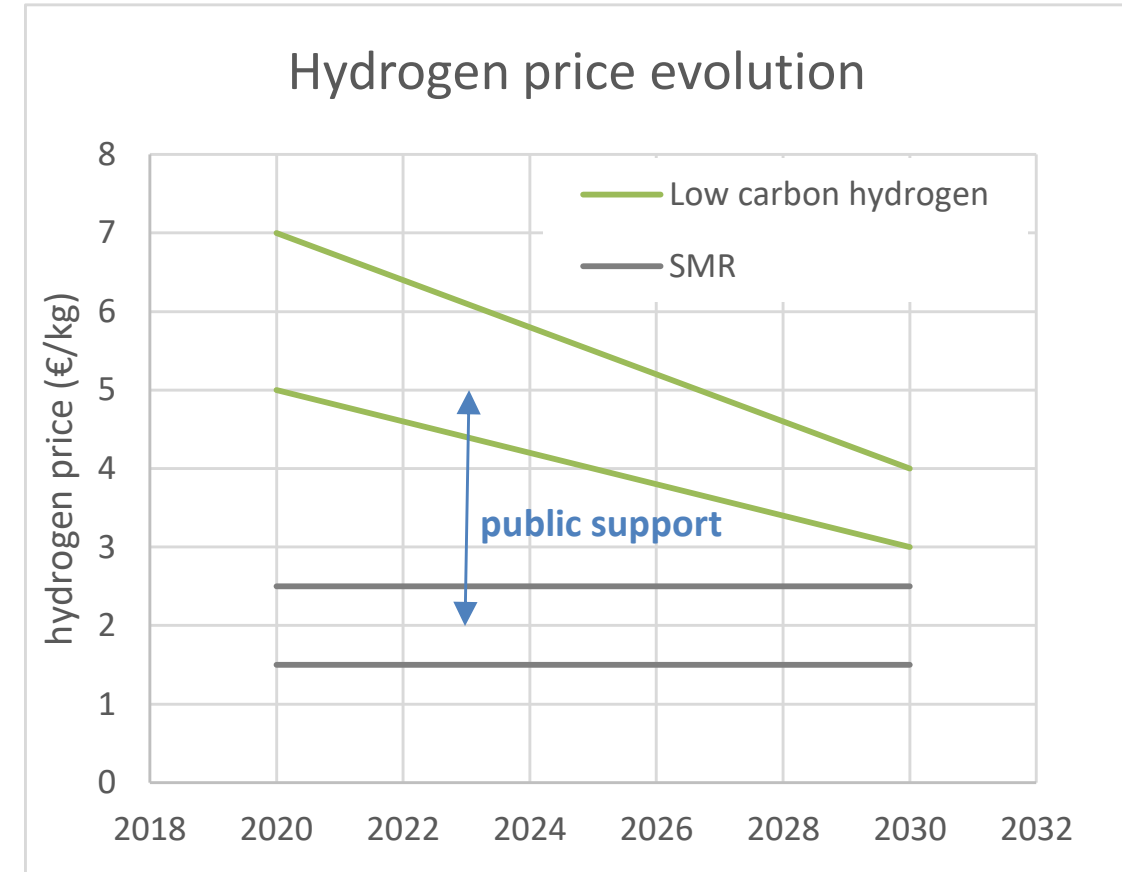
**Being connected to the grid not only ensures safe operation but also improves the business case, it also provides flexibility to the electricity grid to make the best use of more renewables.**



## Decarbonised H<sub>2</sub> by electrolysis price will soon be competitive

Over the next years we foresee:

- **Capex** to decrease by ~60% for the full system driven by larger scale production, learning rate, and technological improvements.
  - Average system size to increase from ~2 MW to ~90MW.
  - **Efficiency** to improve from ~65% to ~70% in 2030.
  - **Other** Operation & Maintenance (OPEX) costs go down following reduction in spare parts cost, increasing lifetime and learning to operate systems.
- ⇒ Production price of low carbon hydrogen should decrease from 5 to 7 €/kg today to 3 to 4 €/kg in 2030 (for an electricity price around 60 €/kWh)
- ⇒ With fossil hydrogen production cost of 1 to 3 €/kg, **public support will be needed** as long as the price of carbon is not high enough





# Hydrogen as by-product from Chlor-Alkali

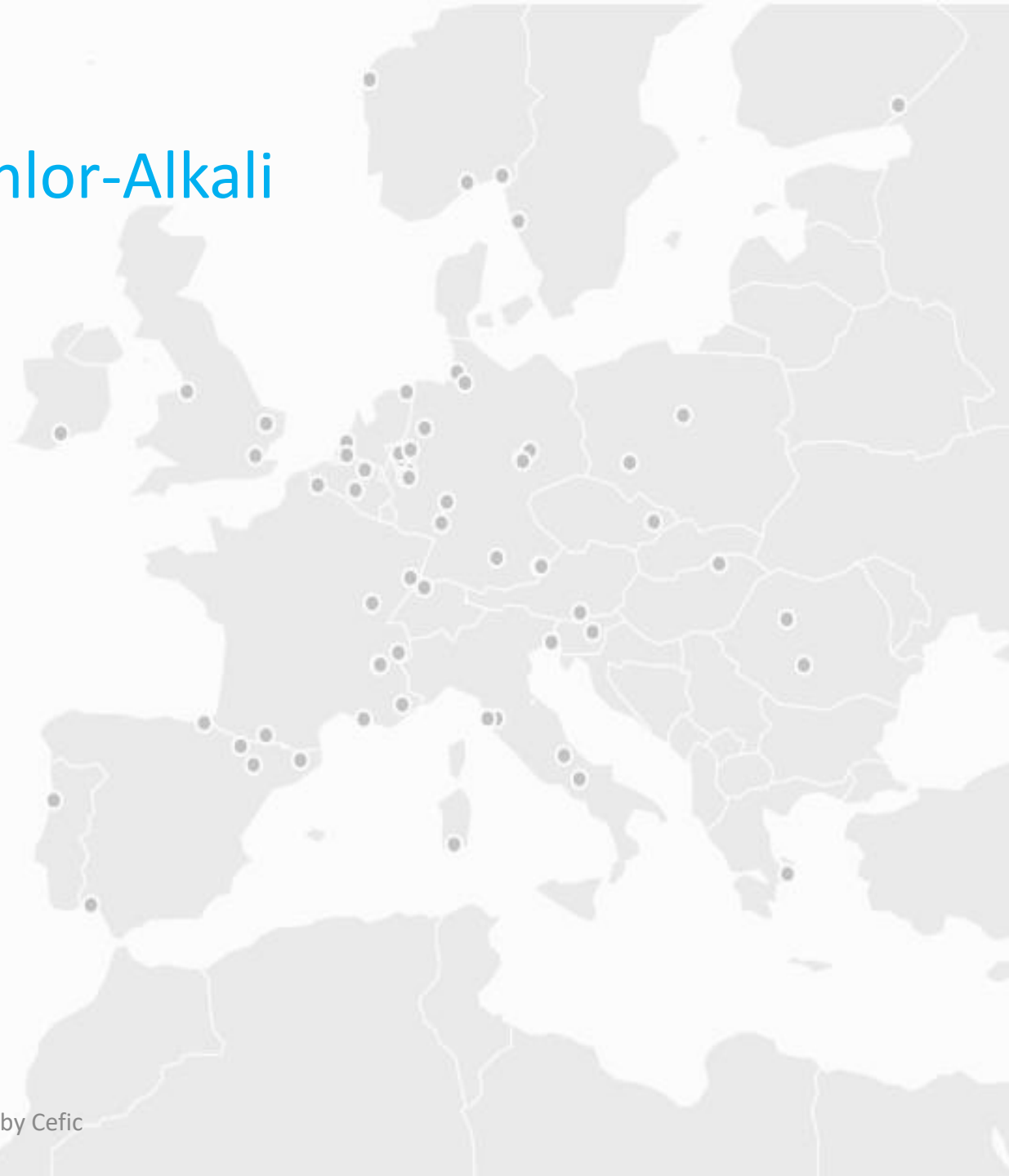
Hydrogen is a by-product of chlor-alkali manufacturing

Production in 2019:

- 9.7 million tonnes of chlorine
- 9.8 million tonnes of caustic soda
- 0.3 million tons of hydrogen  
~ 3% of European hydrogen production
- 67 manufacturing locations in 21 European countries

Input:

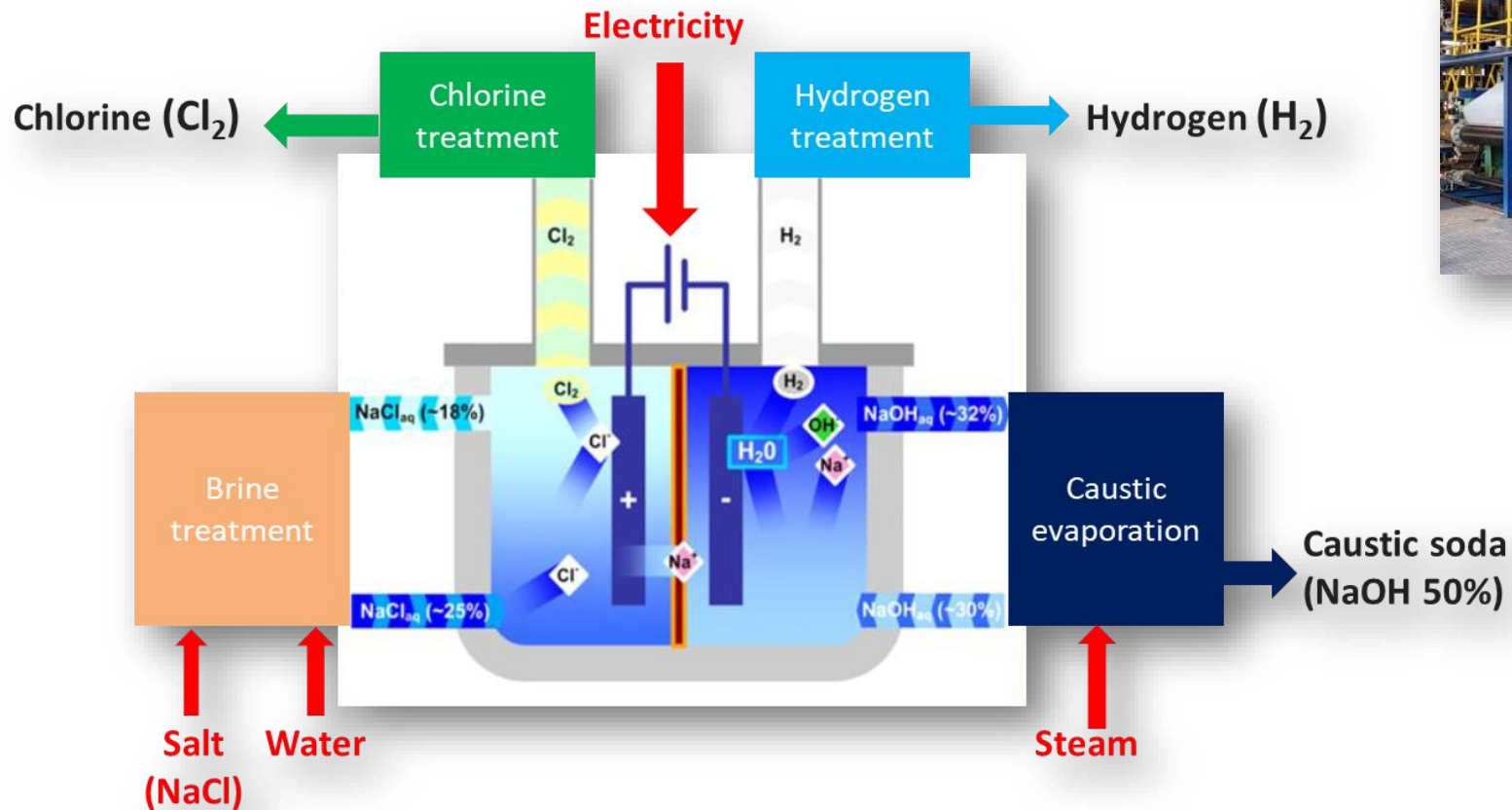
- Salt: 16 million tonnes
- Electricity: 25 million MWh  
~ the use of 6.5 million households





# How chlorine, caustic soda and hydrogen are produced

Basic principles - Schematic representation





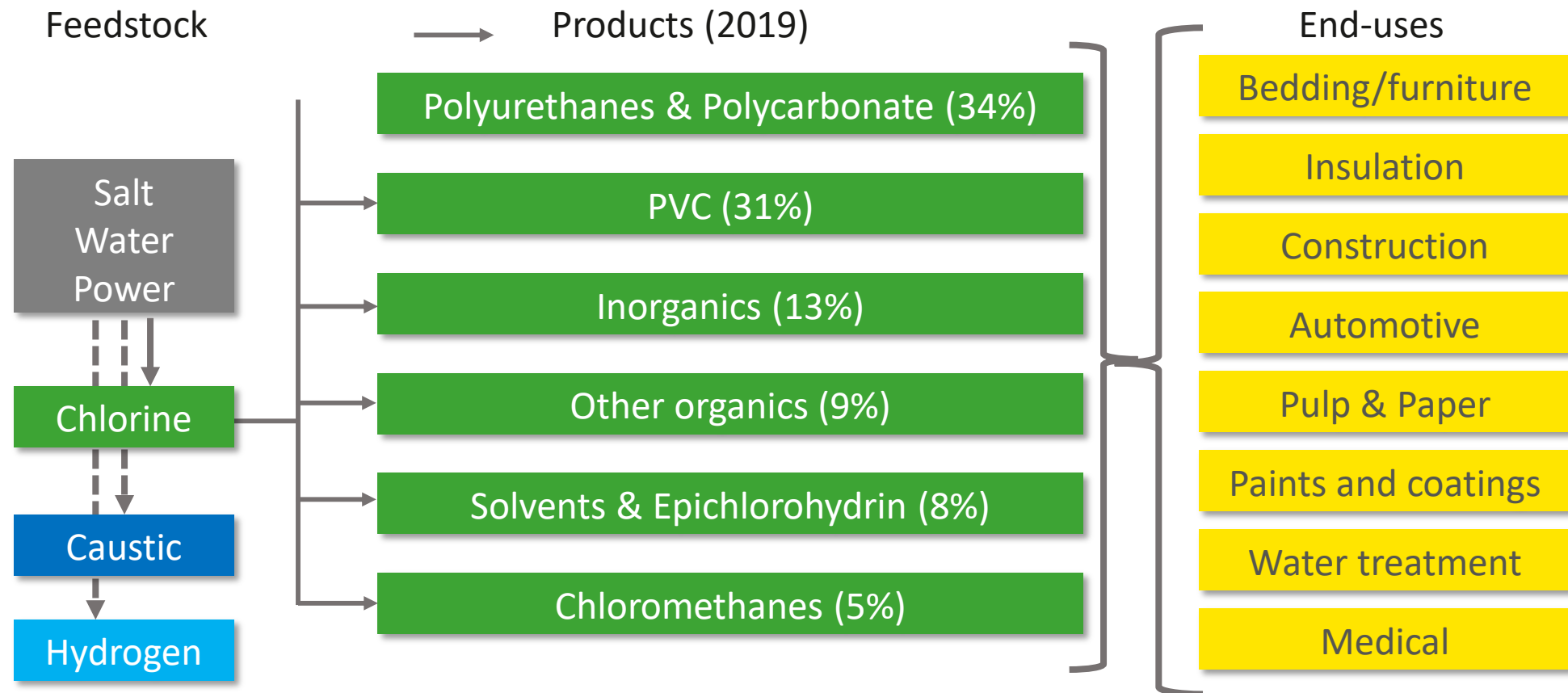
## Hydrogen as a by-product of Chlor-Alkali

- 3 products produced in one step
- Chlorine drives the production
- Process is similar to the hydrogen production of water electrolysis
  - The long-time experience of our industry can be used in the area of water electrolysis



# Downstream users

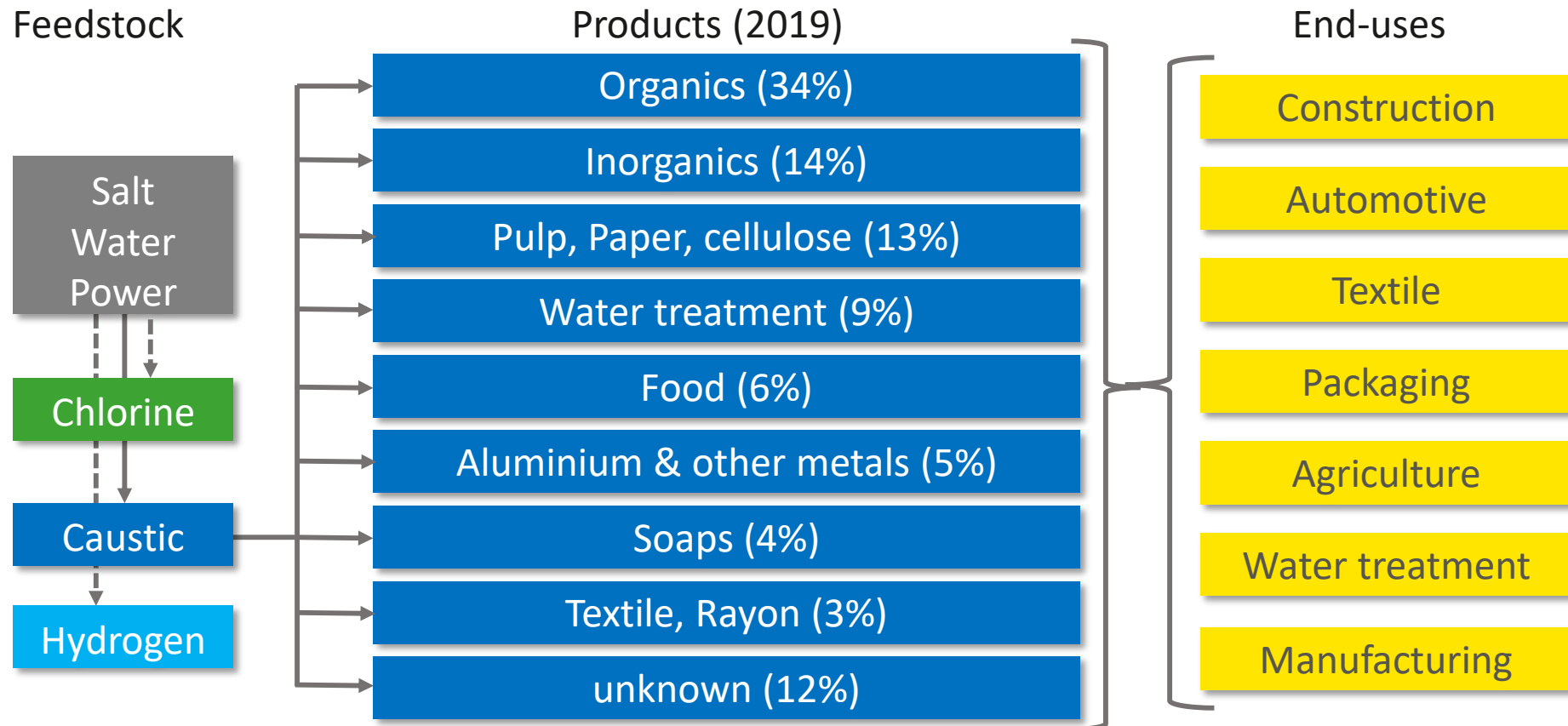
## Chlorine in more details





# Downstream users

## Caustic in more details

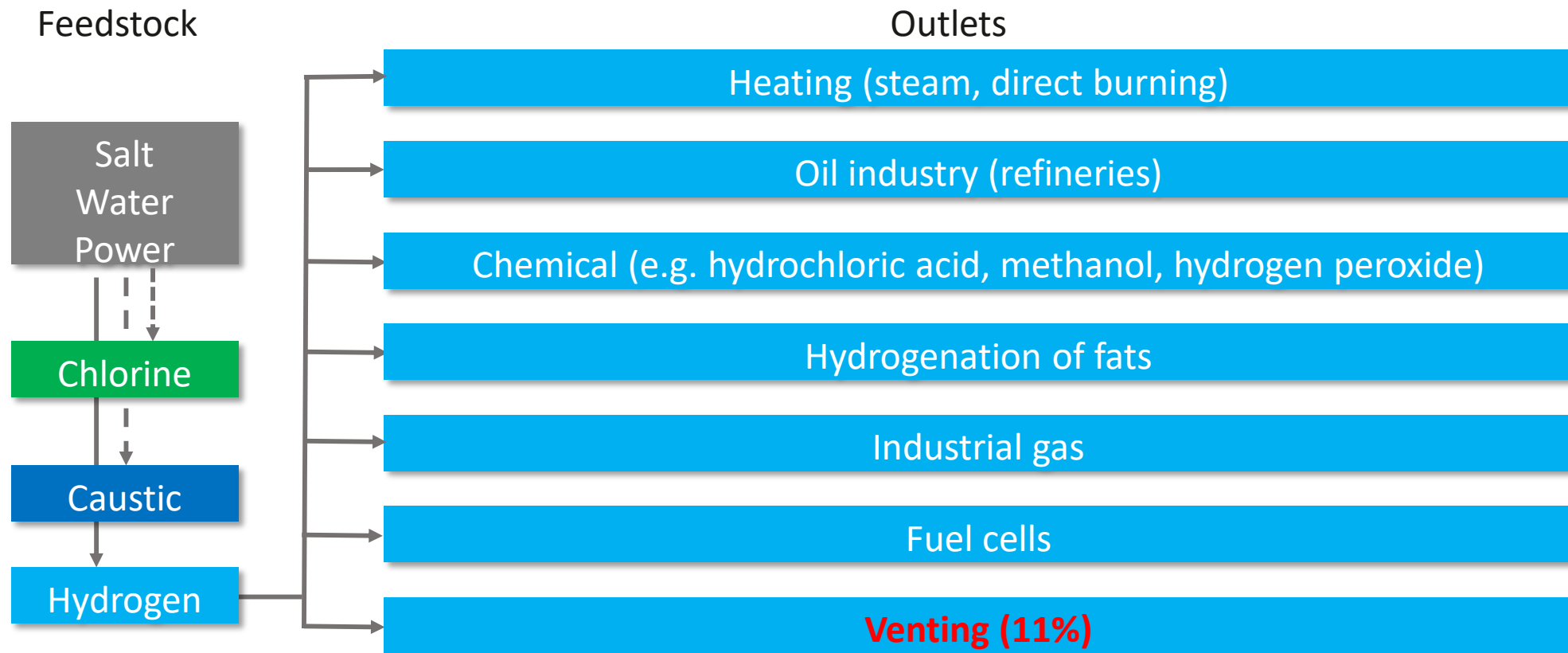






# Downstream users

## Hydrogen in more details



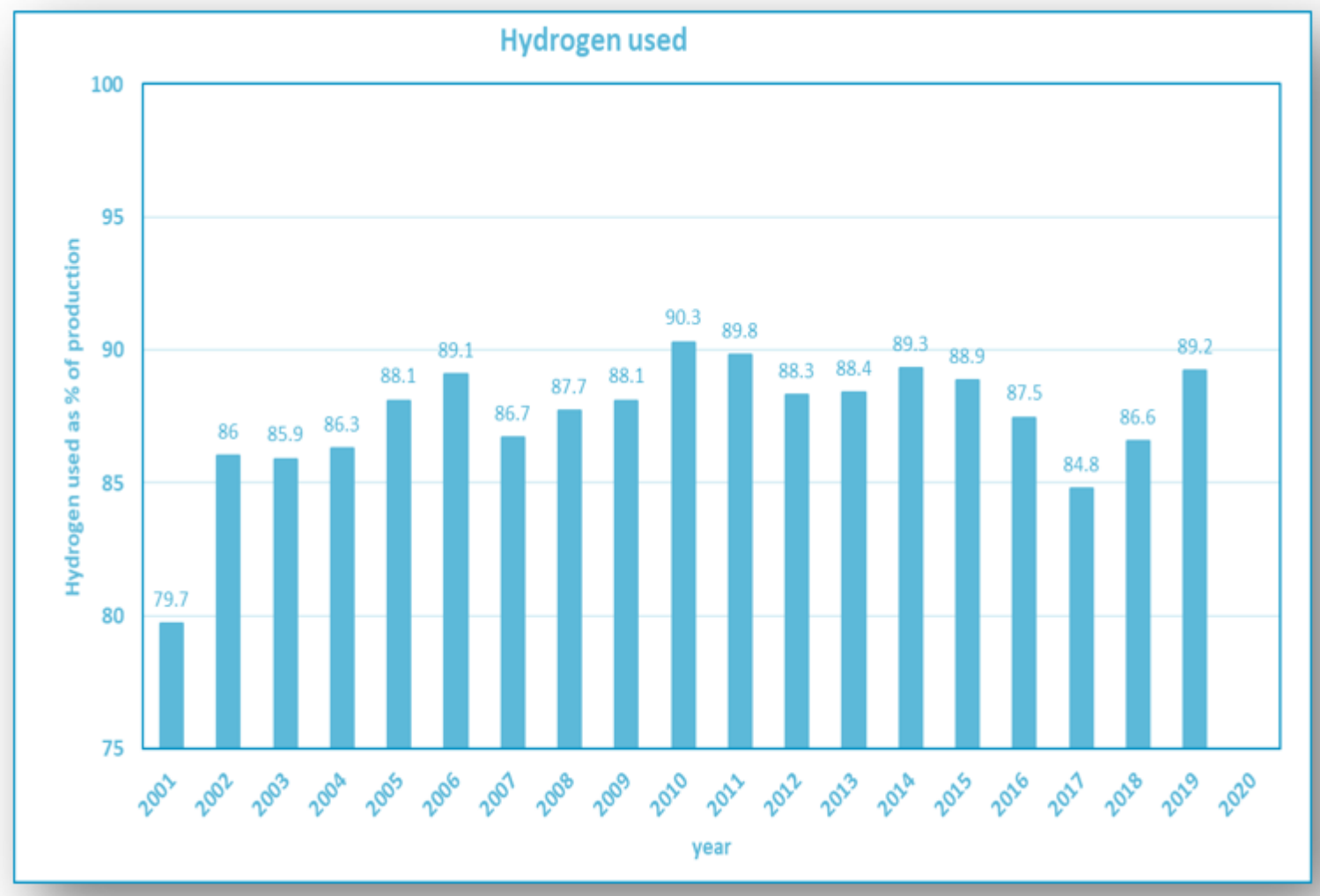


## Backup slide

### Hydrogen utilisation

Why not 100% utilisation?

- Downstream users not always 'available' when required
- Lack of economical outlets
- The vented hydrogen equals to a water electrolysis plant of 200 MW





# Green Hydrogen in Europe

*Presented by*

Aurélie Beauvais, Policy Director at SolarPower Europe



## Where do we stand now in Europe?

**Prior to evaluating the future of green hydrogen, let's look at the situation today**

### **Quick reality check:**

1. Over **99%** of hydrogen produced in Europe now is "grey" (from natural gas without CCS)
2. Emissions from hydrogen from fossil fuels represent **70-100 million tones CO<sub>2</sub> every year**
3. There are 2 plants for "blue" hydrogen (with CCS) accounting for **0.7%** of total production
4. Renewable-based hydrogen production accounts for less than **0.1%** of total production

Almost all hydrogen produced today is based on fossil fuels, which is due to economic reasons:

**€ 1.5-2 per kg** when using **natural gas without and with CCS**

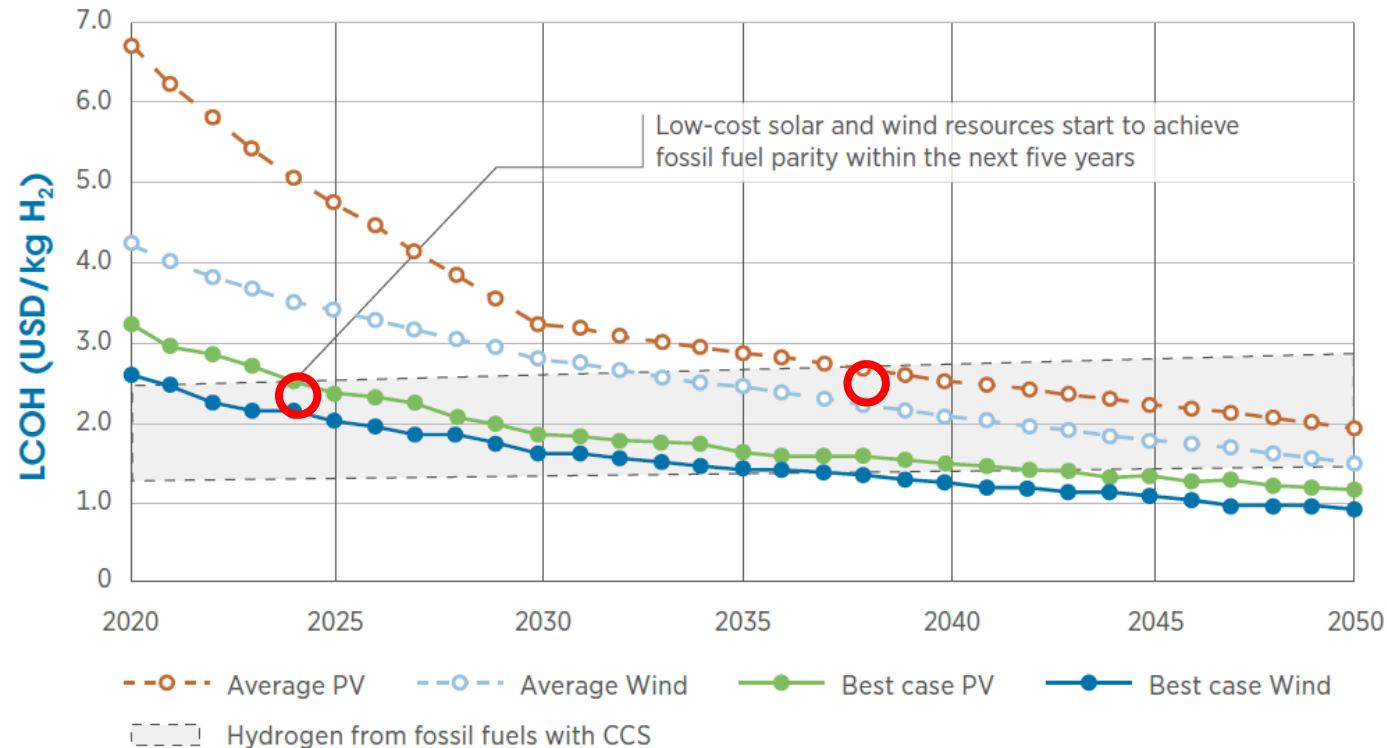
**€ 2.5-5.5 per kg** when using **renewable sources**

**To make hydrogen a relevant pillar of the future energy system and avoid any lock-in in fossil assets, renewable-based hydrogen should be a clear priority.**



# What are the challenges for a renewable-based EU hydrogen economy?

## Hydrogen production costs from solar vs. fossil fuels



Note: Remaining CO<sub>2</sub> emissions are from fossil fuel hydrogen production with CCS.

Electrolyser costs: 770 USD/kW (2020), 540 USD/kW (2030), 435 USD/kW (2040) and 370 USD/kW (2050).

CO<sub>2</sub> prices: USD 50 per tonne (2030), USD 100 per tonne (2040) and USD 200 per tonne (2050).

**In the best locations, solar-based hydrogen is competitive in the next 5 years compared to fossil fuels.**

**After 2035, average-cost solar-based hydrogen also starts to become competitive.**

**Priority: Economies of scale on renewable energy capacity to drive cost reductions in hydrogen production from renewables.**



# How to make the development of green hydrogen at scale in Europe a reality? (1)

1. **Prioritise direct electrification to enable the ambitious roll-out of renewables** in the next decade.
2. **Accelerate the deployment of smart and stronger electricity grid infrastructure** as the cornerstone for a successful renewable hydrogen strategy, allowing for faster and cheaper energy sector integration.
3. **Develop renewable hydrogen on a local basis in Europe first**, to serve the existing demand for hydrogen which already has its local infrastructure.
4. **Support the uptake of a robust European electrolysers industry** to accelerate the competitive production of 100% renewable hydrogen and deliver on Europe's industrial leadership for future-proof energy technologies.



# How to make the development of green hydrogen at scale in Europe a reality? (2)

## Support upscaling of renewable energy projects

1. **Provide the right enabling framework** to ensure the upscaling of solar power plants, at the scale and quantities needed to support the decarbonisation of energy intensive industries.
  - **Implement and enforce** the Clean Energy Package and **remove existing barriers** in EU Member States, to accelerate the deployment of renewable energy and, in doing so, the cost competitiveness of renewable hydrogen.
2. **Revise Energy Taxation Directive** to facilitate cost-competitiveness of solar power across Europe, by removing taxes and levies on electricity that are a barrier to a deep cross-sector electrification and by harmonizing taxation rules.
  - Taxation rules should incentivise hydrogen solutions with the lowest environmental footprint across the entire lifecycle.
3. **Provide a robust certification scheme for solar projects contributing to generate green hydrogen**, to incentivise investments in renewable energy.
  - Renewable-based hydrogen projects should receive GOs, ensuring that hydrogen has been indeed produced from renewable sources (including through PPAs).



# How to make the development of green hydrogen at scale in Europe a reality? (3)

## Support the development of a renewable-based hydrogen industry

1. **Provide clear definition and terminology of all renewable and non-renewable gases and liquids**, in terms of their sustainability and GHG emissions savings.
  - Measuring the environmental footprint and GHG emissions across the entire lifecycle.
2. **Prioritize deployment of climate-resilient dedicated infrastructure projects and logistical network**, compliant with EU's 2030 climate & energy targets and EU Climate Law.
  - **Prioritize deployment of green hydrogen on a local basis** to decarbonize end uses that rely on hydrogen and have their own hydrogen networks, to reduce the investments needs associated to the transport of hydrogen, and to enable **the creation of job and business opportunities locally**.
3. **Create a sustainable industrial value chain to increase production of green hydrogen.**
  - **Support an EU industrial strategy for electrolyzers alongside an EU industrial strategy for renewable energy manufacturing**, for the EU to benefit from a constant and competitive supply of renewable technologies.





# Hydrogen Storage

*Presented by*

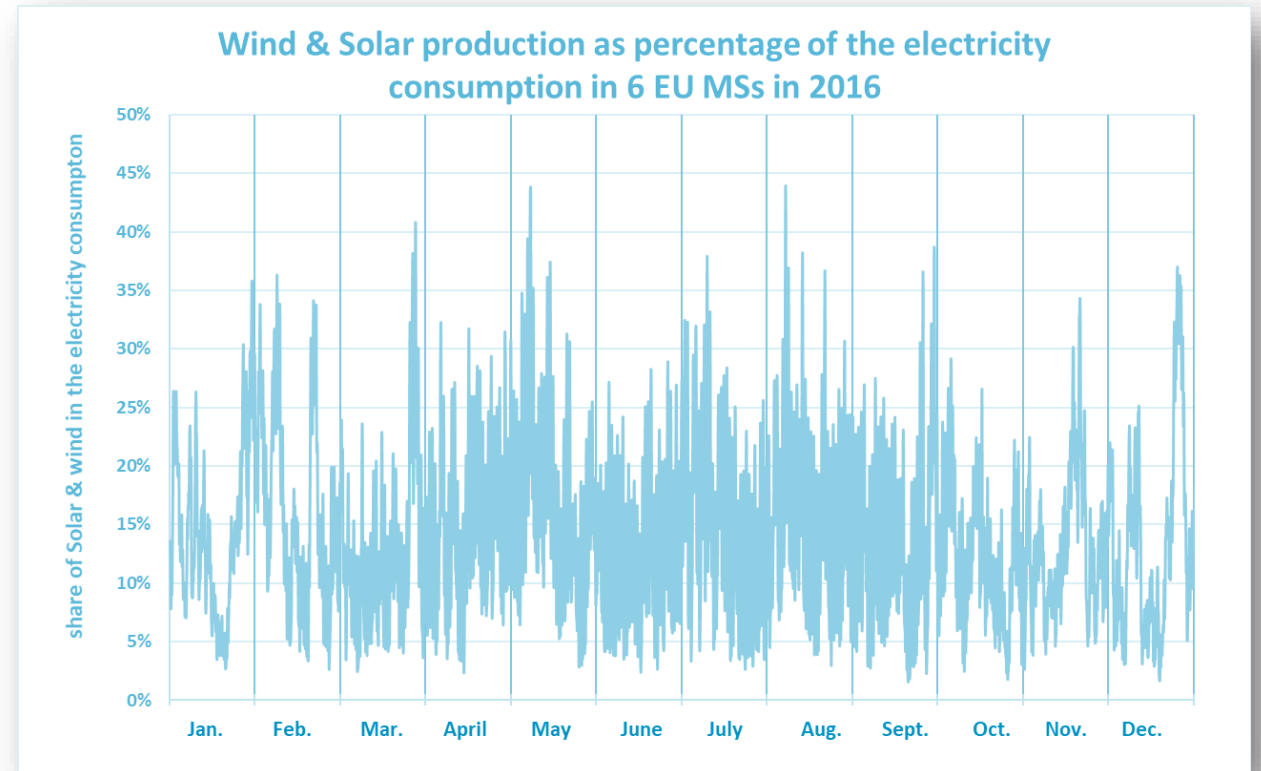
Mathilde Blanchard, Policy Advisor, Gas Infrastructure Europe

Ton Manders, Technical & Safety Director, Euro Chlor, Cefic



# Why do we need electricity storage ?

- An increasing share of wind and solar results in more imbalance
- This because wind and sun produce electricity when it is available; not necessarily when required
- Therefore, storing surplus electricity is key to ensuring it is always available when needed
- Today imbalance is compensated by Fossil/Nuclear solutions
- Current options to store electricity are:
  - Pumped hydro
  - Batteries
  - Hydrogen

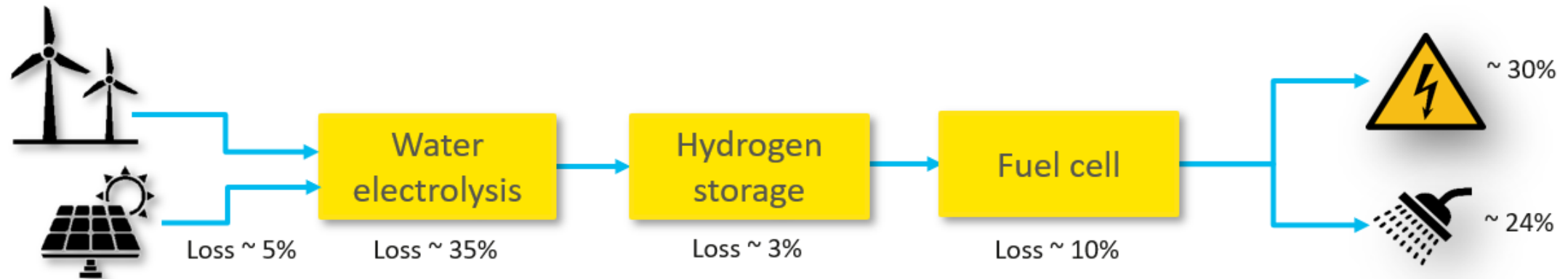




## Options to store electricity (1)

- Hydrogen

- The electricity can be used to produce hydrogen which can be stored and converted back by e.g. a fuel cell to electricity and low temperature heat



- Lower overall efficiency of approx. 54%
  - Efficiency for electricity generation ~ 30%
  - Efficiency for low temperature (50-70 °C) heat generation ~ 24%



## Options to store electricity (2)

- Hydrogen
  - For every 1 MWh (electricity) input, one gets 0.30 MWh (electricity) output
  - One day of electricity storage requires ~ 0.5 million ton hydrogen
  - Maybe not the most efficient option but possibly the best achievable option because these amounts of hydrogen can be stored



### Options to store electricity (3)

- **Pumped hydro**
  - The electricity is stored by pumping water to higher altitude and recovered by running it down again
  - High efficiency (overall approx. 80%)
  - Capacity is low (mainly due to geographic restrictions)
- **Batteries**
  - The electricity is stored by charging the battery and used by de-charging the battery
  - High efficiency (overall approx. 80%)
  - Limited capacity (amount of electricity per battery is low) and expensive
  - 1 day of today's electricity consumption would require a battery capacity of 100-200 million electrical passenger cars

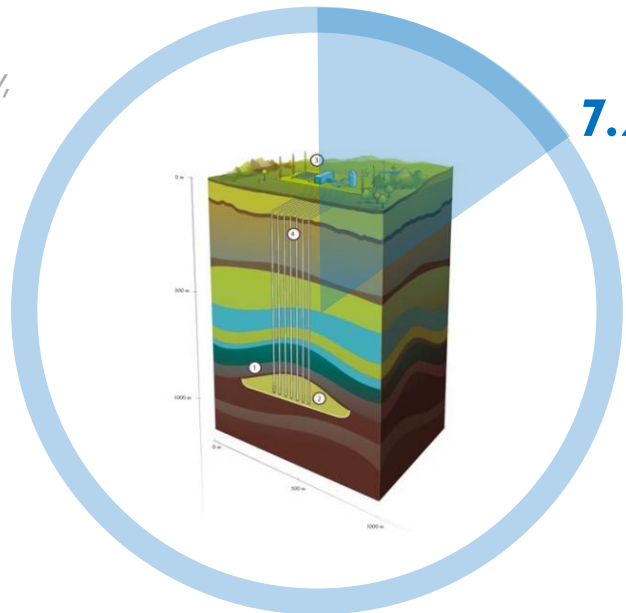


# Different types of underground gas storage

Underground natural gas storage capacity stands at 1131 TWh, which is the equivalent of the capacity of more than 5 billion Tesla PowerPack Battery units of 210 kWh (sources: GIE and Tesla websites).

## Depleted field

Deliverability,  
mcm/d



### Advantage

- Large capacity
- Relatively low cost
- Existing and understood

### Main usage

Limited multi cycle, Seasonal, Strategic

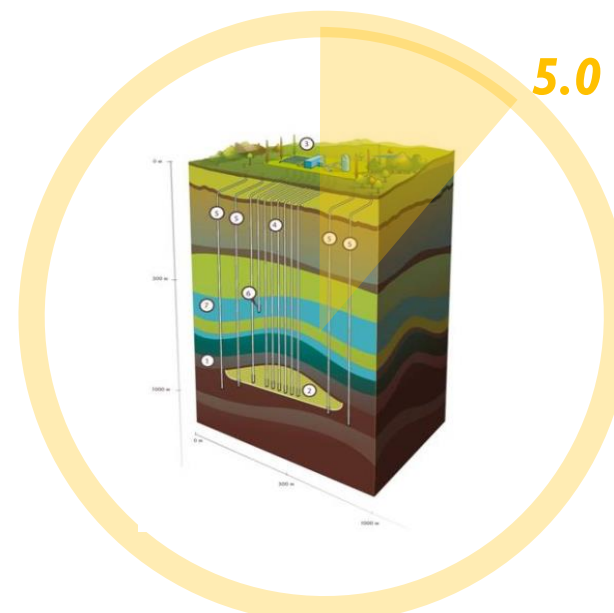
### Cushion gas requirements

45% of total capacity

### Cycle rate

2.1

## Aquifers



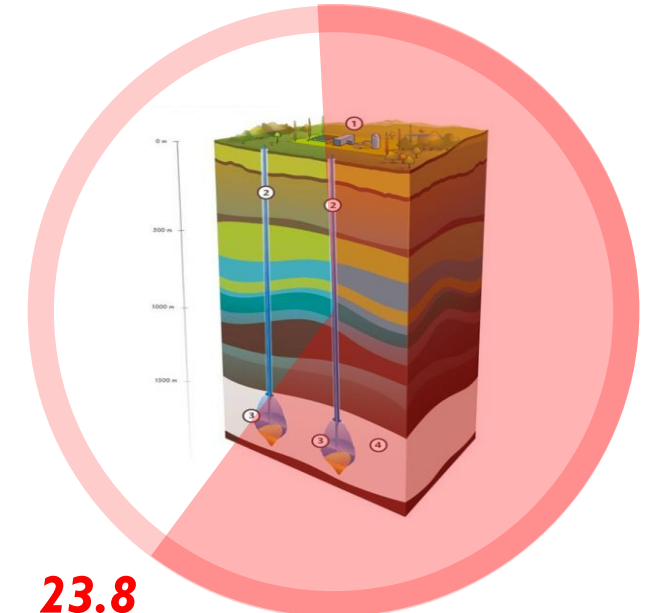
- Large capacity

Seasonal, Strategic

55% of total capacity

1.6

## Salt cavity



23.8

- High injection and withdrawal rates
- Low cushion gas
- Phased development

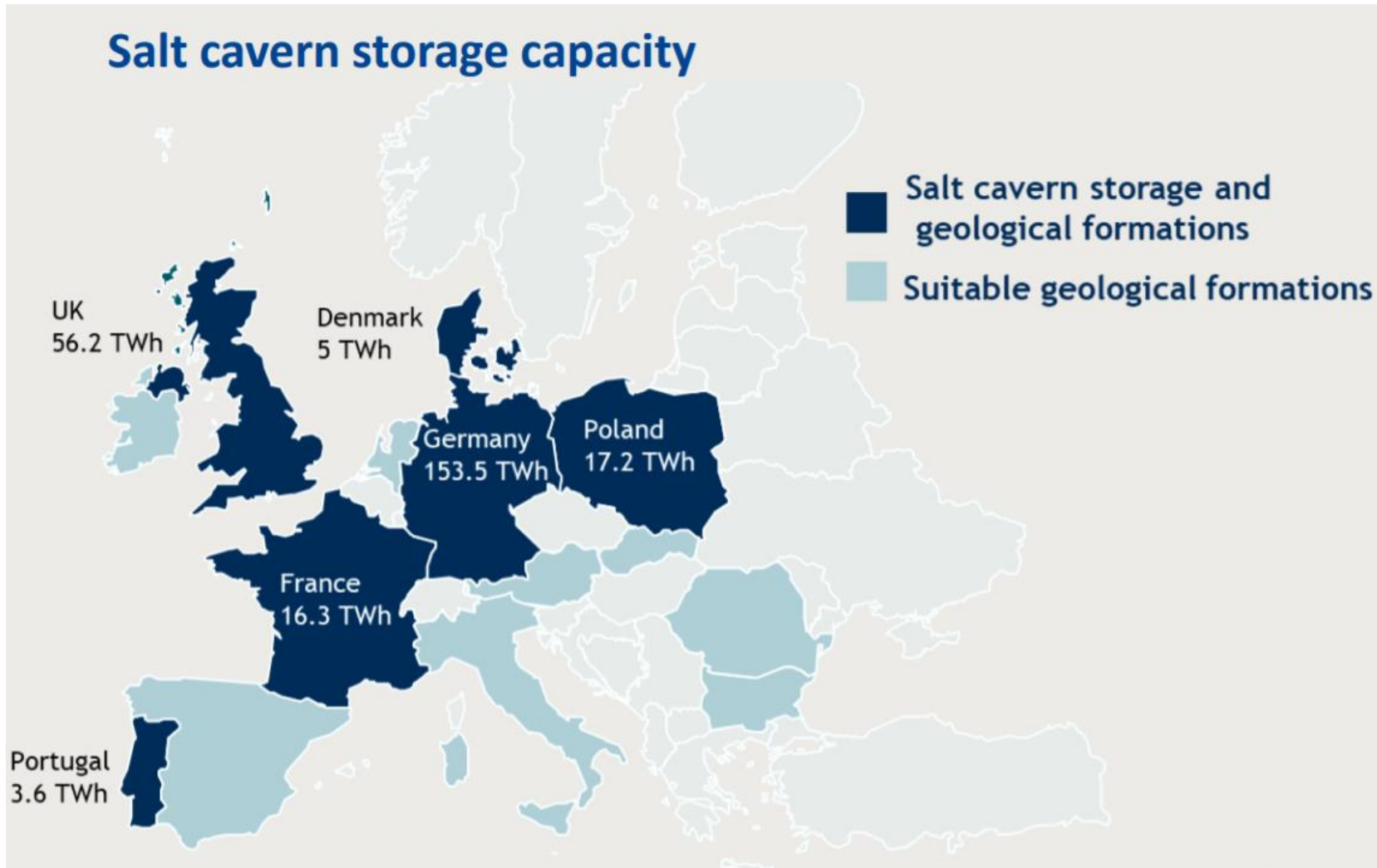
Multi-cycle

20% of total capacity

6.9



## Potential for hydrogen storage by using existing methane infrastructure

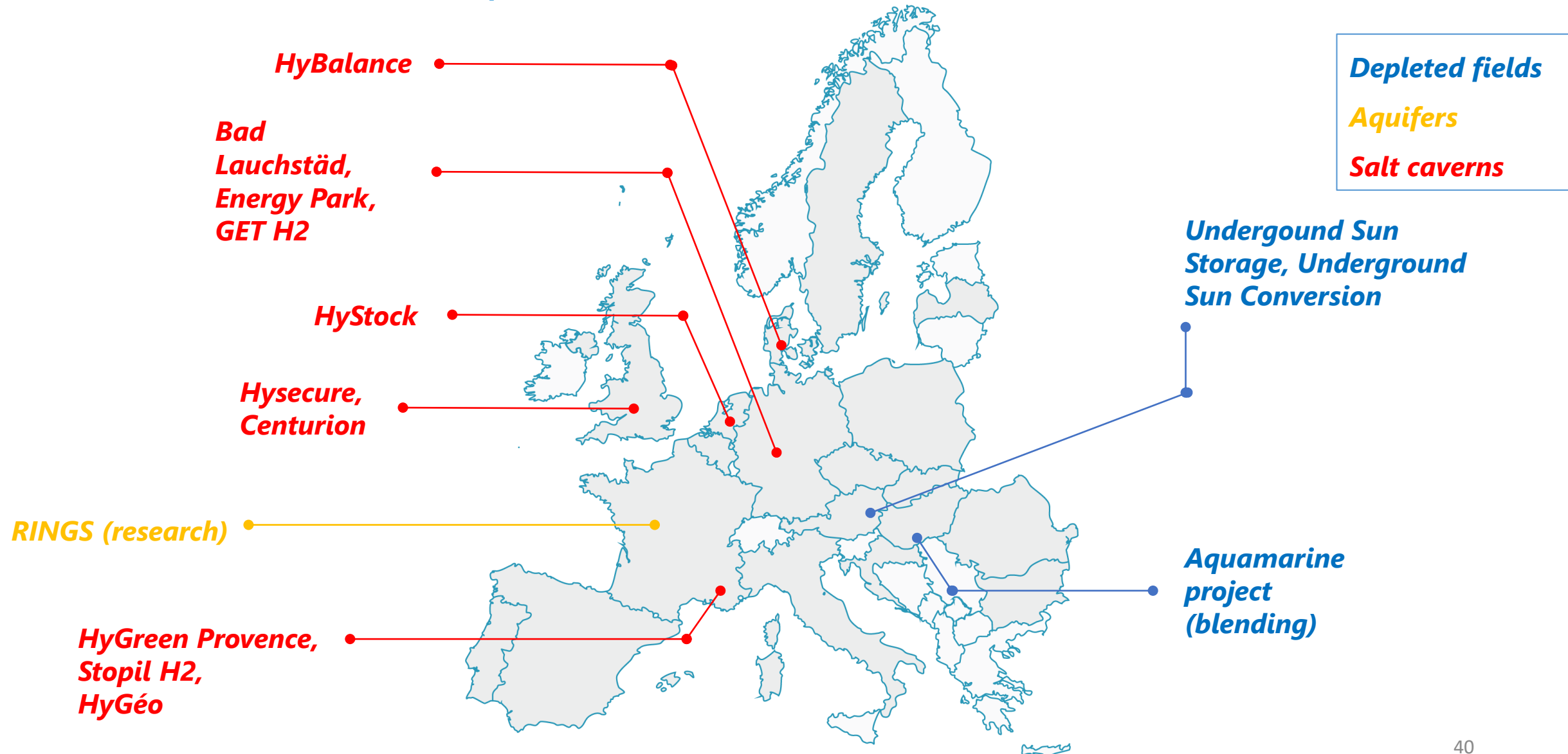


*Source: Opportunities from the inclusion of Hydrogen in NECPs (Trinomics & LBST, May 2020)*



# Hydrogen storage solutions in the European Union – concrete examples

(non-exhaustive map)

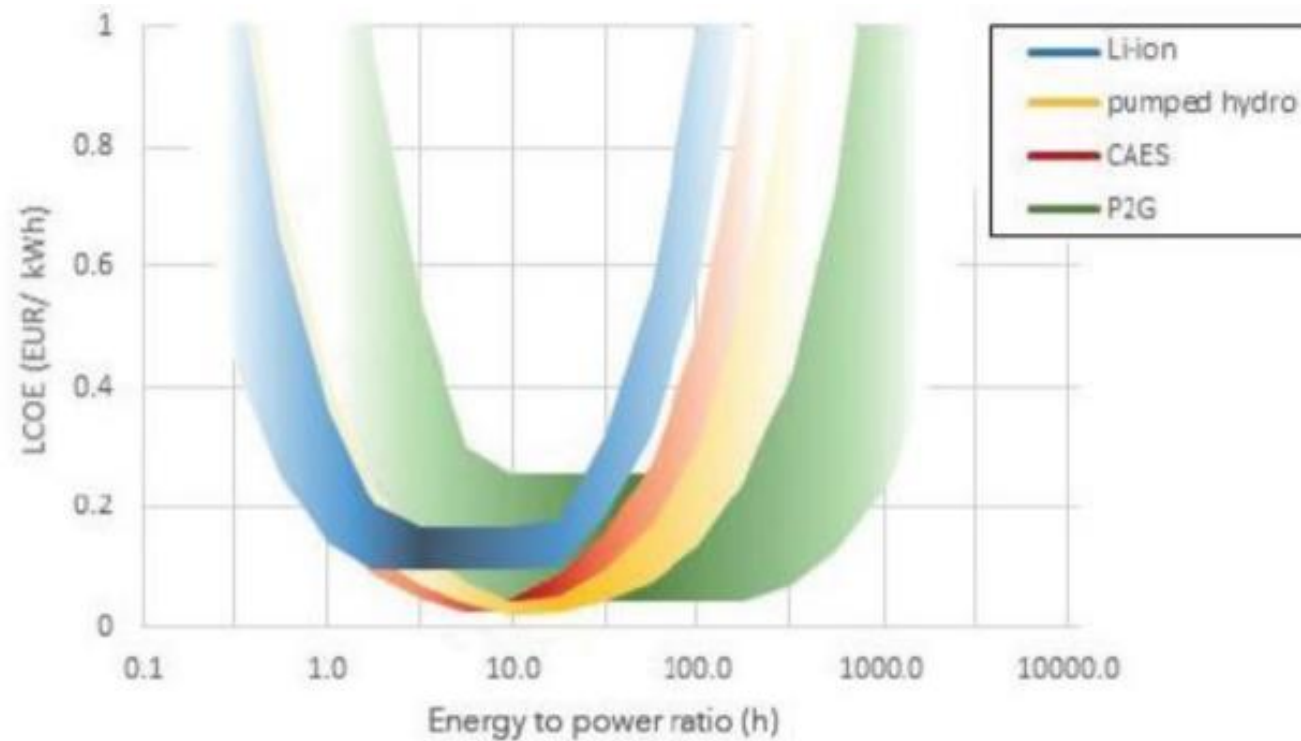






## Hydrogen storage costs

P2G\* with hydrogen storage in a salt cavern provides the lowest cost for medium-term, long-term and seasonal storage.



\* Power-to-Gas

Source: Oxford Institute for Energy Studies (October 2018)



# Hydrogen Transport

*Presented by*

**Roxana Caliminte**, Deputy Secretary General, **Gas Infrastructure Europe**

**Dina Lanzi**, Head of Technical Hydrogen, Snam Hydrogen Business Unit, **Snam**



## Current state of play

### Worldwide

- In 2016, more than 4,500 km of hydrogen pipelines in total, the vast majority of which operated by hydrogen producers (HyARC 2017).
- The longest pipelines are operated in the USA, in the states of Louisiana and Texas, followed by Belgium and Germany.\*

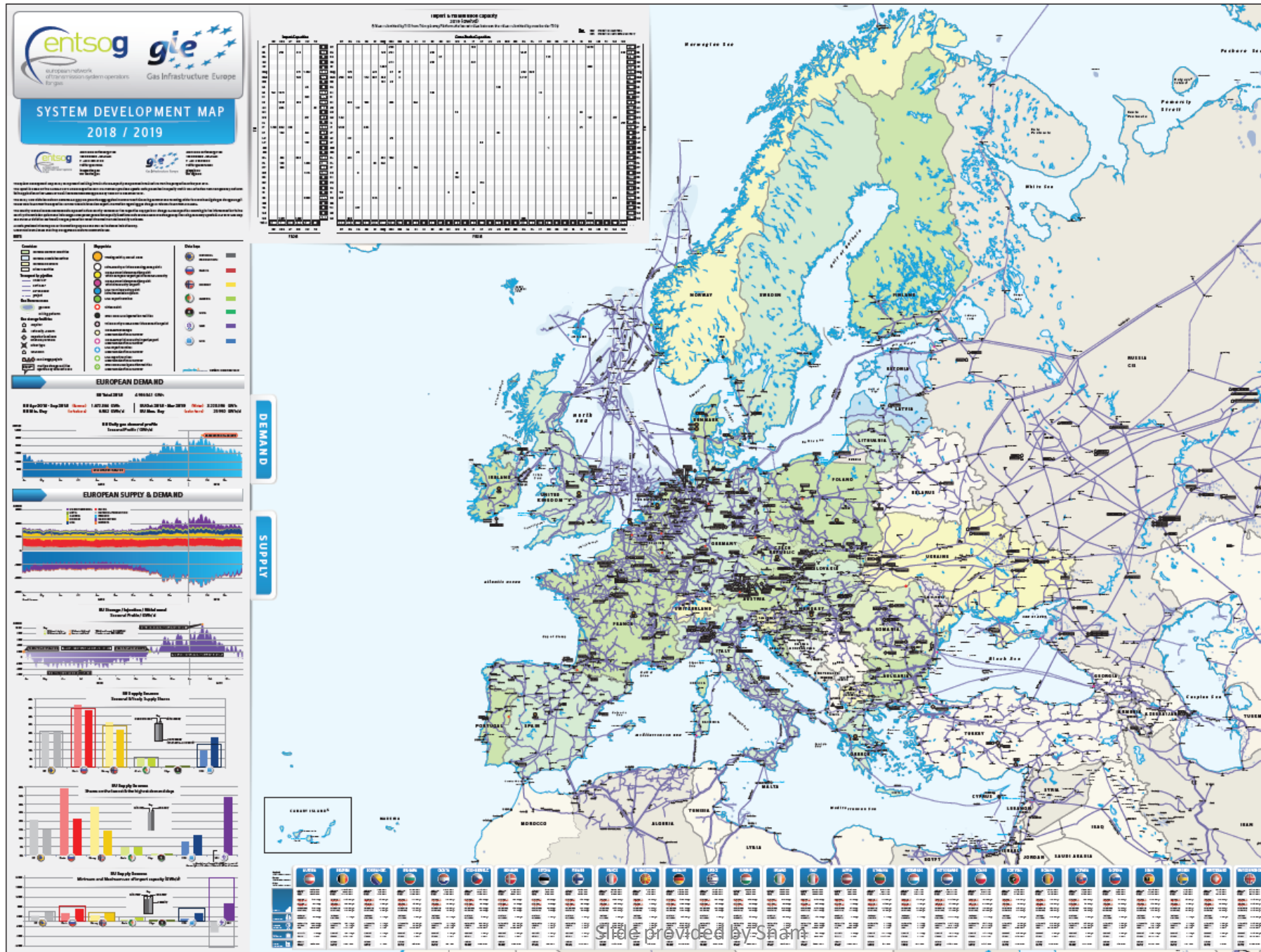
### Europe

- The existing EU transmission natural gas network: 250 000 km of transmission\*\*
- Total gas pipeline length (including distribution): over 2 million km\*\*\*
- Pipelines size ranges from 20 inch in diameter to 48 inch and above.
- Converted 36- and 48-inch pipelines can transport around 7 resp. 13 GW of hydrogen per pipeline across Europe

\*“For a European Green Deal A 2x40 GW Initiative” by Hydrogen Europe

\*\*Survey methane emissions for gas transmission in Europe by MARCOGAZ

\*\*\*[Report of MARCOGAZ & GIE](#)



Source: [Map from 2019 by GIE & ENTSG on system development](#)

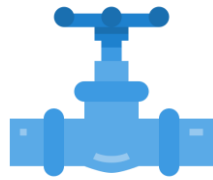


## Transport of hydrogen

Hydrogen can be transported over long-distance **under different formats**.

Today, the transport of compressed gaseous or liquid hydrogen by lorry and of compressed gaseous hydrogen by pipeline to selected locations are the main transport options used.

**The most common hydrogen transportation methods are:**



Pure H<sub>2</sub>  
Pipelines vs  
Blending  
with natural gas



Liquefied form  
via LNG Terminals



Lorry or Trucks

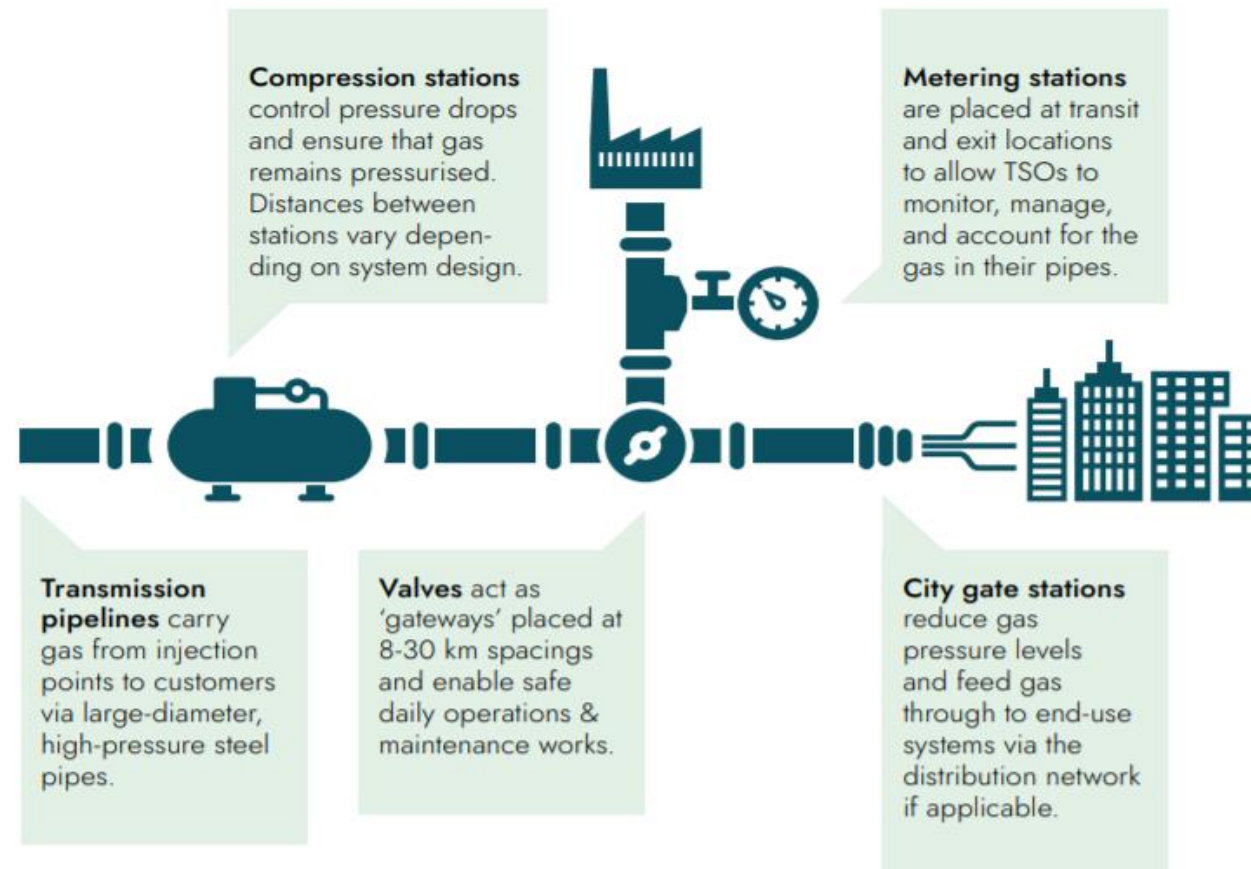
Source: [www.hydrogeneurope.eu](http://www.hydrogeneurope.eu)



## Pathways to transport hydrogen (1)

### Transport by pipelines

Hydrogen can be transported through pipelines that were built for natural gas.  
The key components of the gas transmission networks are:



Source: [European hydrogen backbone report](#)  
by Gas for Climate



## Transport via pipelines: adaptations required (1)

### Pipelines

- Dedicated hydrogen pipelines do not differ significantly from natural gas ones
- Existing natural gas pipelines need little modification to be fit for 100% hydrogen transport
- Main elements of the conversion process include:
  - ⇒ Nitrogen purging
  - ⇒ Pipeline crack monitoring
  - ⇒ Valve replacements (where needed)
  - ⇒ Operation at a slightly lower pressure (this may be avoided by adding a layer of internal coating)

### Valves

- Valves separate sections of pipe and minimise gas loss in case of pipe failure
- Partial replacement of valves and seals will be enough in some regions, other regions will need full equipment replacement to prevent leakages.

### Structural integrity

- Hydrogen can accelerate pipe degradation through a process known as hydrogen embrittlement
- The optimal solution to this problem varies per pipeline and depends on:
  - ⇒ transport capacity requirements
  - ⇒ status of existing pipelines
  - ⇒ trade-offs between capital and operating expenditure

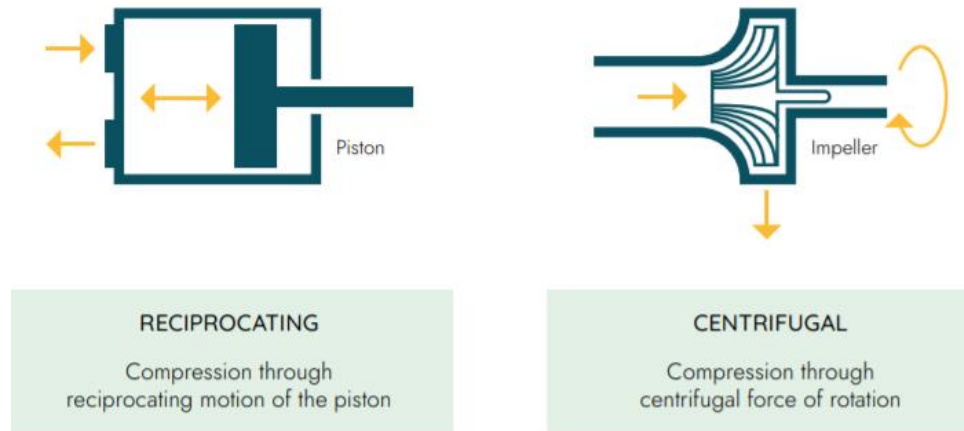
Source: [European hydrogen back bone report by Gas for Climate](#)





## Transport via pipelines: adaptations required (2)

The current gas network utilises 2 types of compressors:



### Compressors

- The energy density of hydrogen is a factor of **3 times lower** than that of natural gas.
- To provide the same energetic content, the volume of hydrogen transported must be **3 times greater** than of natural gas
- Views on how these greater compression efforts impact the suitability of existing compressor types vary

### Metering & city gate stations

- Given the different chemical composition of hydrogen compared to methane gas, metering equipment will likely need to be adapted.
- City gate stations hydrogen-specific conversion requirements are minimal and require coordination with distribution system operators (DSOs).

Source: [European hydrogen backbone report by Gas for Climate](#)





## Dedicated infrastructure: some examples

### Gasunie, the Netherlands

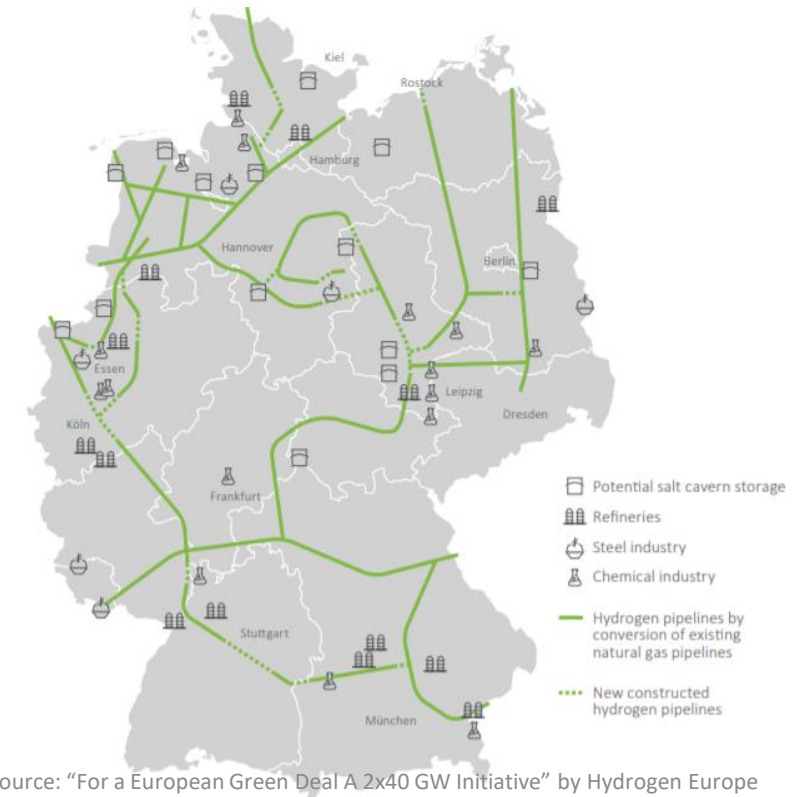
- **12 km** natural gas pipeline converted into a **hydrogen pipeline**.
- **Operational** since November 2018.
- Connects hydrogen production sites, among others from **offshore wind** at the North Sea, to hydrogen storage in salt caverns and to the demand in **industrial clusters**.



Source: [Gasunie](#) & “For a European Green Deal A 2x40 GW Initiative” by Hydrogen Europe

### FNB Gas, Germany

- A plan for a **5.900 km** hydrogen transmission grid, partly by **converting existing natural gas pipelines**.
- **Aim:** connect future hydrogen **production centres** in northern Germany with **large scale hydrogen storage in salt caverns** and multiple customers in the west and south.



Source: “For a European Green Deal A 2x40 GW Initiative” by Hydrogen Europe



## Pathways to transport hydrogen (2)

### Blending

- Gas at concentrations of **up to 10 vol%** hydrogen can be transported in the existing natural gas network **without the risk of damages**
- Separation and purification technologies downstream allows to extract hydrogen from the natural gas blend close to the point of end use
- A main concern is the potential for increased probability of ignition and resulting damage
- The durability of some metal pipes can degrade when they are exposed to hydrogen over long periods.

### Other pathways

- Put a small hydrogen pipe in a natural gas pipeline
- Build green Ammonia ( $\text{NH}_3$ ) plants in harbour areas and export the hydrogen by shipping the ammonia.
- Build hydrogen liquefaction plants in harbour areas and export liquid hydrogen in special cryogenic vessels similar to LNG.



## Costs

### Difference between electricity transport by cables & hydrogen transport by pipelines

	Cable (BritNed)	Pipeline (BBL)
Capacity	1 GW	15 GW
Cost of construction	€ 500 mln	€ 500 mln
Volume (year)	8 TWh	120 TWh

- **Costs:** Hydrogen transport cost by pipeline are about 10-20 times cheaper than electricity transport cost by a cable.
- **Capacity:** an electricity transport cable has a capacity between 1-2 GW, while a hydrogen pipeline can have a capacity between 15 & 30 GW.
- **Efficiency:** transporting electricity via cables incurs losses, while hydrogen transport by pipelines does not have losses.



Transport by hydrogen pipeline is up to 20 times cheaper than electricity

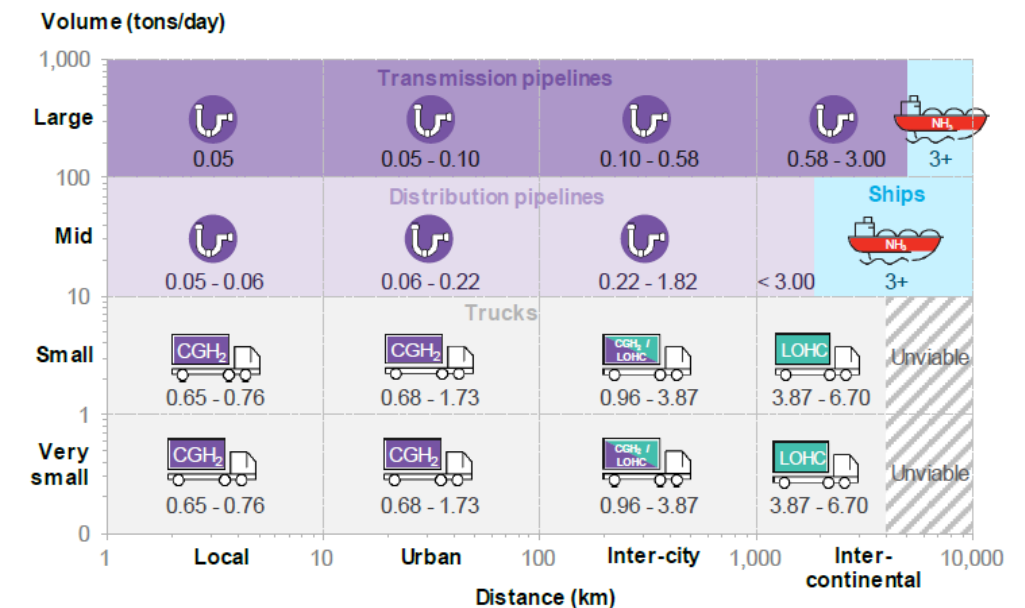


1 hydrogen line can carry as much energy as 3 high-voltage lines (1 gas pipeline = 9 lines)

Source: "For a European Green Deal A 2x40 GW Initiative" by Hydrogen Europe  
[Report from Gasunie](#)

Hydrogen flows nearly **3 times faster** than methane through pipes, making this a cost-effective option for **large-scale transport**

Figure 4: H<sub>2</sub> transport costs based on distance and volume, \$/kg, 2019



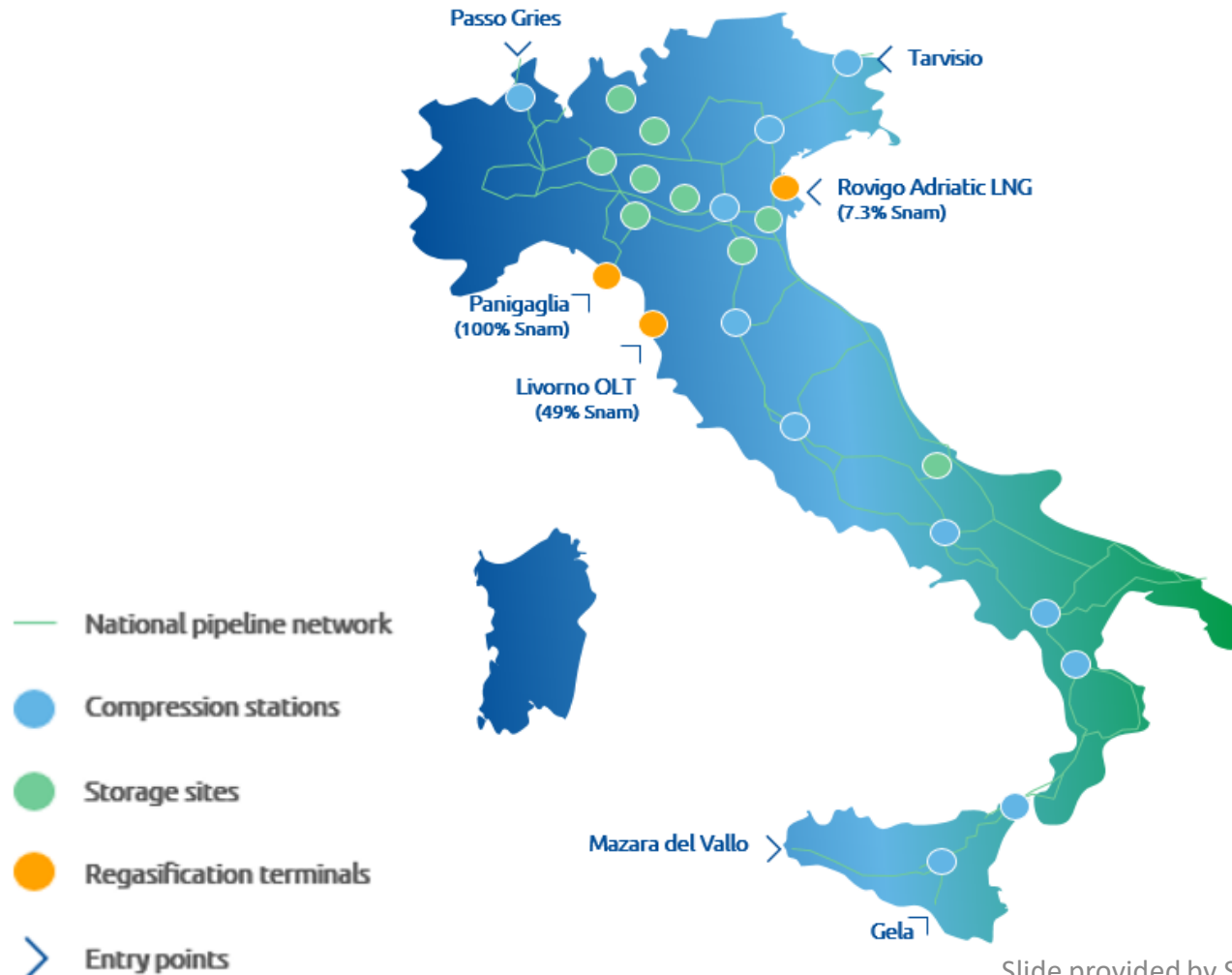
Source: BloombergNEF. Note: figures include the cost of movement, compression and associated storage (20% assumed for pipelines in a salt cavern). Ammonia assumed unsuitable at small scale due to its toxicity. While LOHC is cheaper than LH<sub>2</sub> for long distance trucking, it is less likely to be used than the more commercially developed LH<sub>2</sub>.

Source: Scheme from "Hydrogen Economy Outlook" by Bloomberg



## A case of Blending in the EU: Snam case and main results

### Snam transmission facilities in Italy



#### Main figures

- Over 32,625 km of pipelines
- 11 compressor stations
- 3 LNG plants
- ✓ ~ 70 BCM of gas demand per year
- ✓ ~170 clients
- ✓ ~7000 redelivery points

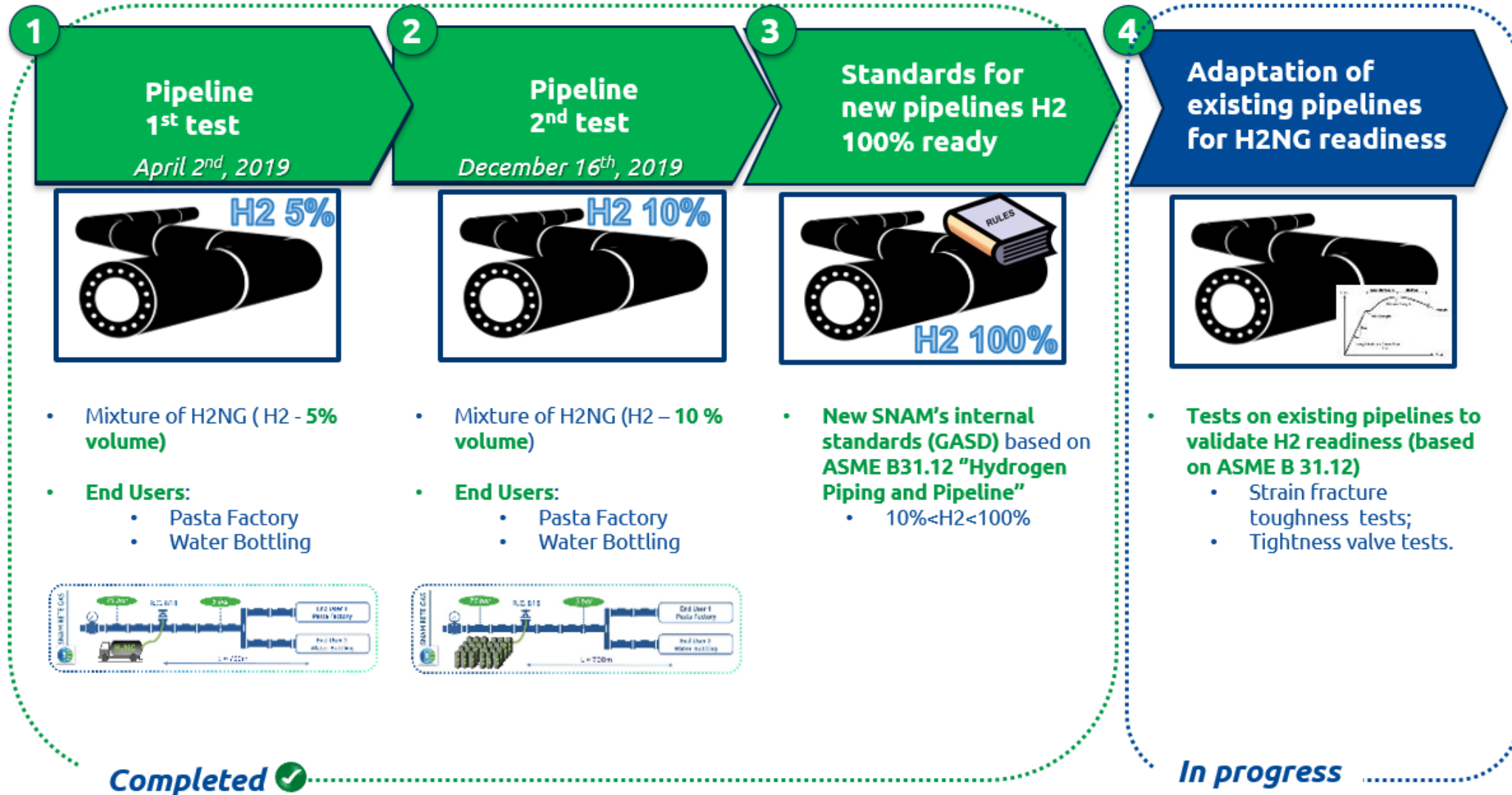


#### Market Shares

- 94% in gas transportation
- 96% in gas storage
- 3 out of 3 regasification terminals in Italy



# Asset readiness





## Test 2019: features and constraints



### Goal

Injection into a **portion of the network** of a **mixture of H2NG up to 10 % of volume** to check compatibility of current infrastructure to transport **H2NG mixtures**.

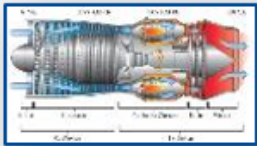
### CONSTRAINTS:



**CNG distributors**



**Underground storage in porous rocks**



**Gas turbines of compressor stations**



**End Users with production processes sensitive to gas quality**

### ***Mixture features (Natural gas up to 10% H2)***

- ✓ **Quality characteristics** set by the Ministerial Decree 18 May 2018 for the natural gas transport: **respected**;
- ✓ **Materials HE (Hydrogen Embrittlement): checked**;
- ✓ **ATmosphères ed Explosives zones identification: checked**.

### ***Public bodies Involved***

- ✓ **National and Local Fire Departments**



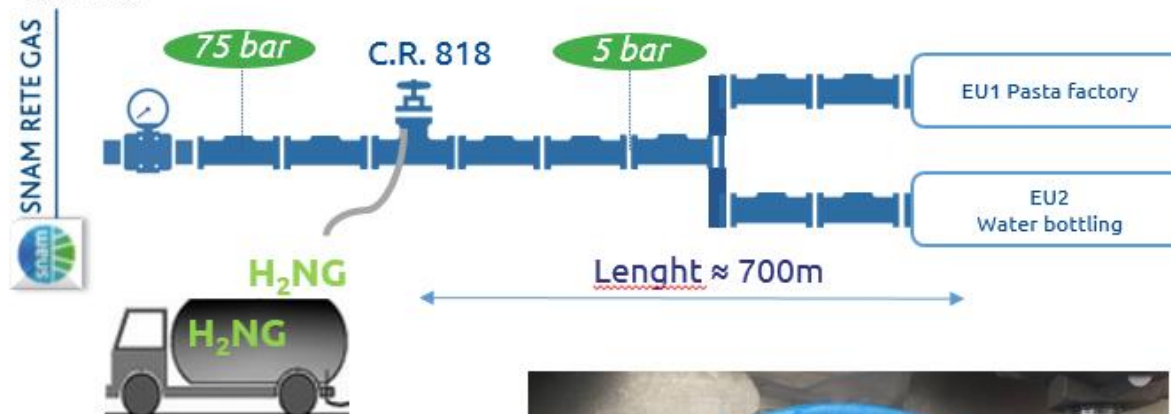


## Test 2019

### 1st Injection campaign of a hydrogen-natural gas blend (H2NG) in a portion of the Snam grid

#### Key features

Injection campaign of a H2NG blend with H2 at 5% and 10% in volume in a portion of the Snam gas transport grid, in order to verify the readiness of the existing asset with respect to the transport of the considered blends.



- The gas blend has been supplied with a trailer tank, with a capacity of 5.000Nm<sup>3</sup>, filled with the H2NG blend at a pressure of 200 bar.
- The injection campaign lasted two months.
- **No adaptation needed both on pressure reduction plant and on end users appliances.**



#### Bloomberg



#snam4hydrogen  
#idrogenoinrete



#### The New York Times



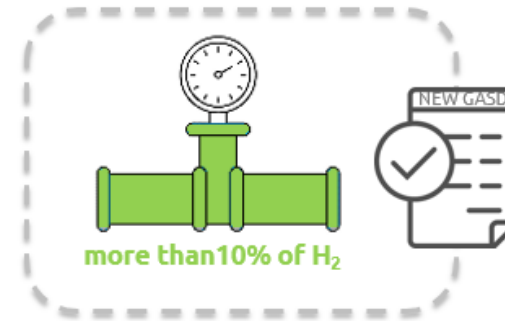
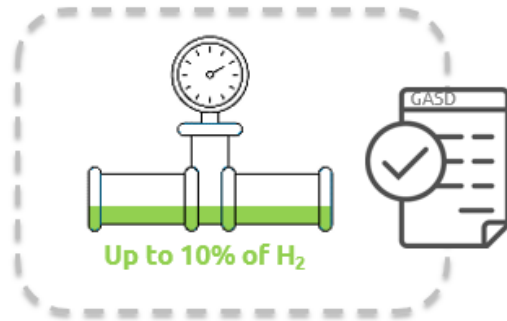
## Standards (1)

SNAM internal standards ("**GASD**") come from the implementation of the **ISO, EN, UNI \***.

Design and construction of all SNAM pipelines and plants are based on these standards including company's know-how.

**Pipelines internal standards** "hydrogen ready" are based on the ASME B31.12' "Hydrogen Piping and Pipeline" standard.

GASD remain unchanged for H<sub>2</sub>NG mixtures up to H<sub>2</sub> 10% in volume. Once this limit has been exceeded, new GASD must be followed. The standards regulate design and construction phases of new gas pipelines \*\*.



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\*SNAM regularly participates in the UNI, EN and ISO working groups by actively participating in the drafting and definition of industry standards.

\*\*The legislation relating to the compressor stations construction is being developed.





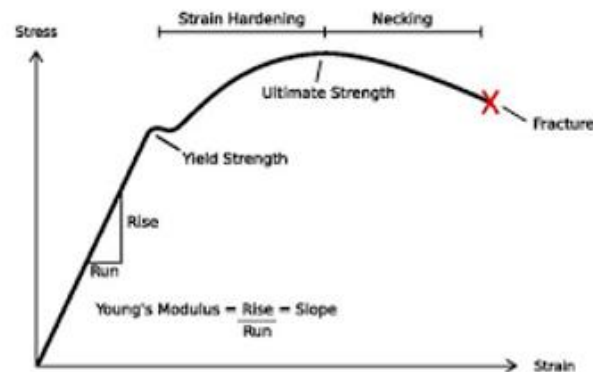
## Standards (2)

### GASD highlights

H2NG mixtures, H2 up to 10% in volume - No specific/additive prescription

H2NG mixtures, H2 over 10% in volume – piping **specific requirements size** (thickness) and carbon steel **characteristics**]

**New leak testing requirements for valves**



**TRASPORTO DI MISCELE DI GAS NATURALE E IDROGENO  
FINO A RAGGIUNGERE IL 100% DI IDROGENO  
CRITERI GENERALI PER NUOVI PIPELINE**

**GASD  
H.01.01.01  
foglio 2 di 7**

## **1 PREMESSA**

La presente norma fornisce le indicazioni necessarie a stabilire i criteri da applicare per il trasporto in condotta di miscele di gas naturale e idrogeno a percentuali crescenti in volume fino a raggiungere il 100% di idrogeno.

Collegati al presente documento, sono sviluppati i singoli documenti normativi che, prendendo a riferimento le tabelle della normativa per il trasporto di gas naturale, ne indicano il possibile utilizzo, con eventuali limitazioni o integrazioni, per il trasporto di miscele di gas naturale e idrogeno a percentuali crescenti in volume fino a raggiungere il 100% di idrogeno.

Al momento della stesura della presente normativa, non risultano standard EN o ISO che forniscono le indicazioni tecniche per la realizzazione di tubazioni per il trasporto di idrogeno e quindi la realizzazione di gasdotti hydrogen ready al momento incontra gravi difficoltà di ordine tecnico e normativo.

Il riferimento disponibile al momento per la realizzazione di un idrogenodotto o di una condotta che trasporti comunque percentuali significative di idrogeno è la ASME B31.12-2014 "Hydrogen Piping and Pipelines", pertanto, la normativa del capitolo H1 viene redatta facendo riferimento ai requisiti tecnici previsti nel suddetto documento.

L'attività di ricerca e di definizione delle normative per il trasporto e l'utilizzo di idrogeno nell'ambito del Comitato Europeo di Normalizzazione porterà probabilmente entro qualche anno alla pubblicazione di normative che potrebbero differire da quanto disponibile attualmente.

## **2 NUOVI PIPELINE**

### **2.1 NORMA ASME B31.12-2014 "HYDROGEN PIPING AND PIPELINES"**


#### **2.1.1 QUANDO SI APPLICA**

La norma si applica alle condotte e ai relativi impianti che trasportano miscele di gas con almeno il 10% di idrogeno in volume.

La rete realizzata in conformità ai capitoli di normativa gasdotti relativi al trasporto di gas naturale è idonea anche al trasporto di miscele di gas con percentuale di idrogeno inferiore al 10% in volume.

#### **2.1.2 QUALITÀ DELL'IDROGENO**

La norma pone una limitazione sul contenuto di acqua nel gas trasportato, che non deve superare 20 ppm, corrispondenti ad un dew point di -28°C a 70 bar.



normativa interna

COMPIUTO

VERIFICATO

APPROVATO

REV.

0

DATA



## Backup slide

### SNAM Turbocompressors

- Factory test - TC BHGE , model NOVA LT12 (New Supply) for Istrana Compressor Station** BHGE

factory test in Florence to verify gas turbine operation fueled with H2NG mixture (H2 up to 10% in volume and variable over time)



Factory Test Procedure

ID	Phase	FUEL
1	Start	Natural Gas (NG)
2	Warm up	NG
3	Operation	NG
4	Full load	NG
5	Full load	NG + 3% H2
6	Full load	NG + 10% H2
7	Partial load (75%)	NG
8	Partial load (75%)	NG + 3% H2
9	Partial load (75%)	NG + 4% H2
10	Partial load (50%)	NG
11	Partial load (50%)	NG+ 3% H2
12	Partial load (50%)	NG + 4% H2
13	Partial load (50%)	NG
14	Stop	NG



- Factory test - TC BHGE, model PGT 25 (most used in existing plants) for Sergnano Compressor Station (Storage plant)**

Feasibility study to develop a test procedure to verify gas turbine operation fueled with H2NG mixture (H2 up to 10% in volume and variable over time)



# Hydrogen Distribution

*Presented by*

Carmen Gimeno, Secretary General, GEODE

Julie Pinel, Head Smart Gas Grid, GRDF

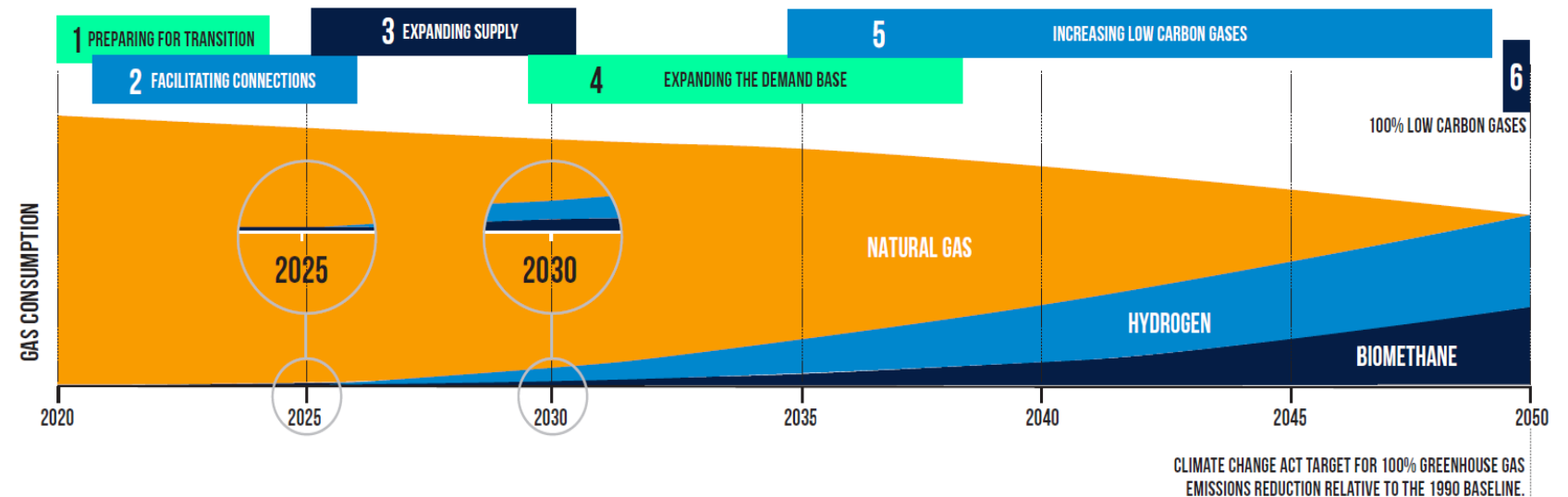


## Facts on the distribution network in Europe

- **Gas distribution network operators** are between the transmission and the consumer.
- **The gas distribution network** is estimated to represent around **2.2 million km of pipes in Europe**, operated by **1500 gas DSOs**

**Gas Goes Green – the UK example** will deliver zero carbon gas grid by 2050.

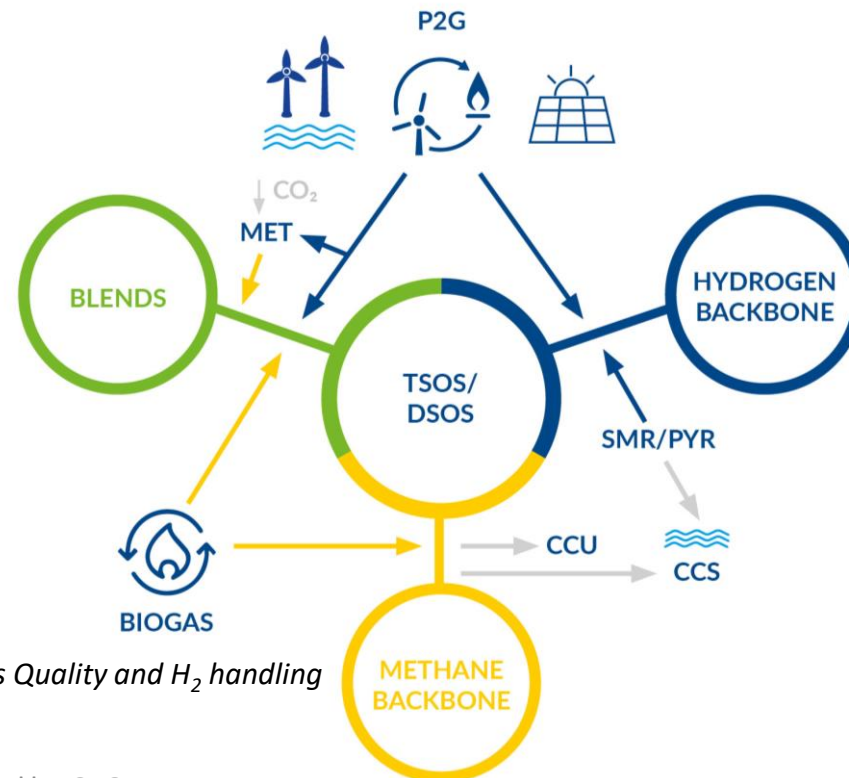
It will make the changes needed to move Britain's gas network infrastructure from delivering methane-based natural gas to zero carbon hydrogen and biomethane.





## Grid configuration for new gases

- Hydrogen being key part of the solution to achieve the climate target, distribution operators have to transform the existing gas network
- Pathways materialise differently and co-exist depending on local/regional framework:
  - Blending
  - H<sub>2</sub> backbone creation via retrofitting or H<sub>2</sub> grid
  - Mathanation



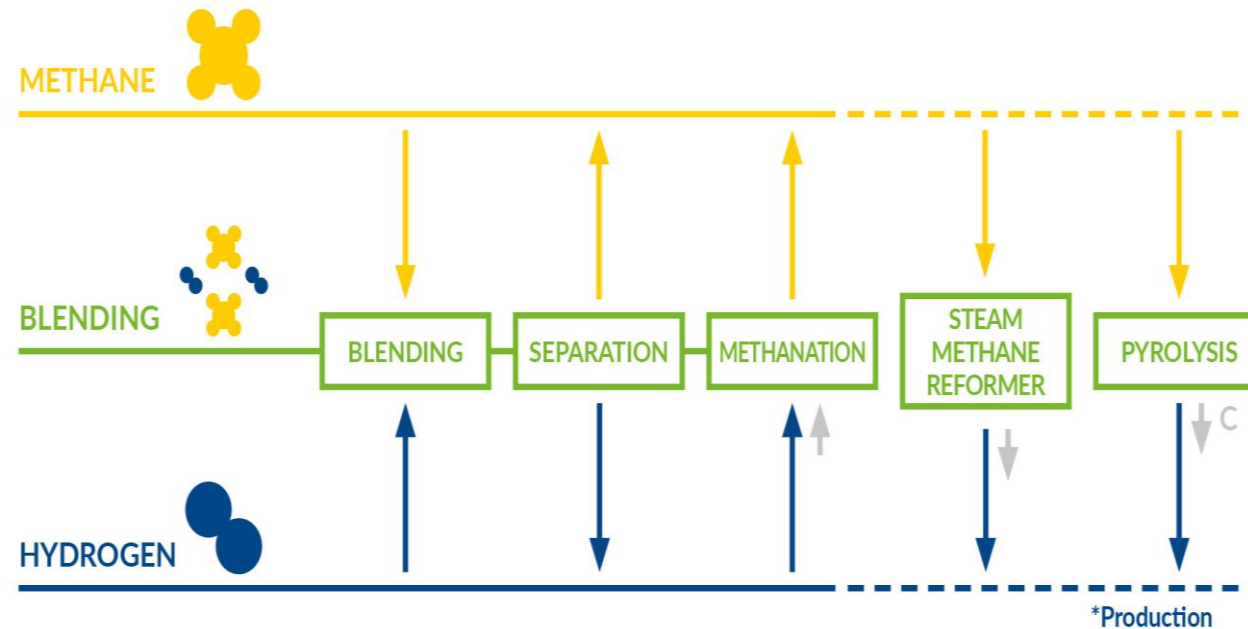
Source : Prime movers' group on Gas Quality and H<sub>2</sub> handling



## Gas Quality & Hydrogen Handling

With an increasing number of connections at a local level, it will be crucial to ensure :

- The **physical flow of gas**
- The set of **technical rules for DSO/TSO connection, interaction, gas quality managing principles and information flow in either ways**
- Increased **coordination and planning** of TSO/DSO grids



Source: Prime movers' group on Gas Quality and H<sub>2</sub> handling



## Hydrogen Distribution infrastructure : blending and retrofitting

Hydrogen can be delivered (initially and in the medium-term) **making use of existing gas distribution grids** for managing H<sub>2</sub> trough:

- **Blending:** injecting H<sub>2</sub> into existing gas grids
- **Retrofitting:** converting existing gas grids for dedicated H<sub>2</sub> transport

Advantages of making use of existing gas distribution grids:

- It will **optimise the use of existing gas infrastructure**
- It is the **most cost-effective solution** – allowing savings in new infrastructure – to deliver decarbonized energy to customers, particularly for the building sector where distribution grids play a major role
- It would cause **limited changes in consumers habits and end-user appliances**
- Blending methane **with up to 10-20% of hydrogen** does not require major changes in infrastructure and end use applications

Unblended pure hydrogen networks will develop in **specific demand sectors** (e.g. manufacturing)

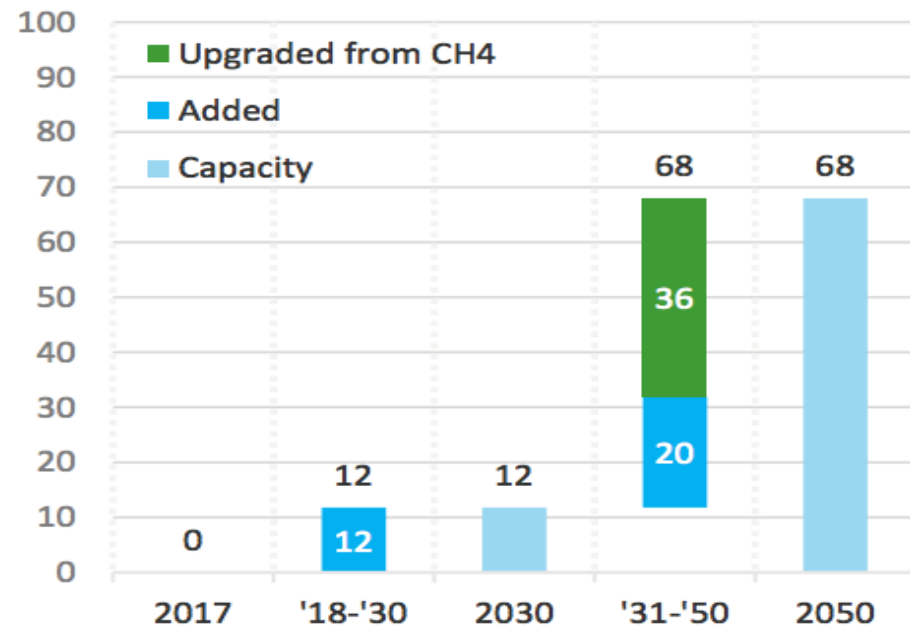




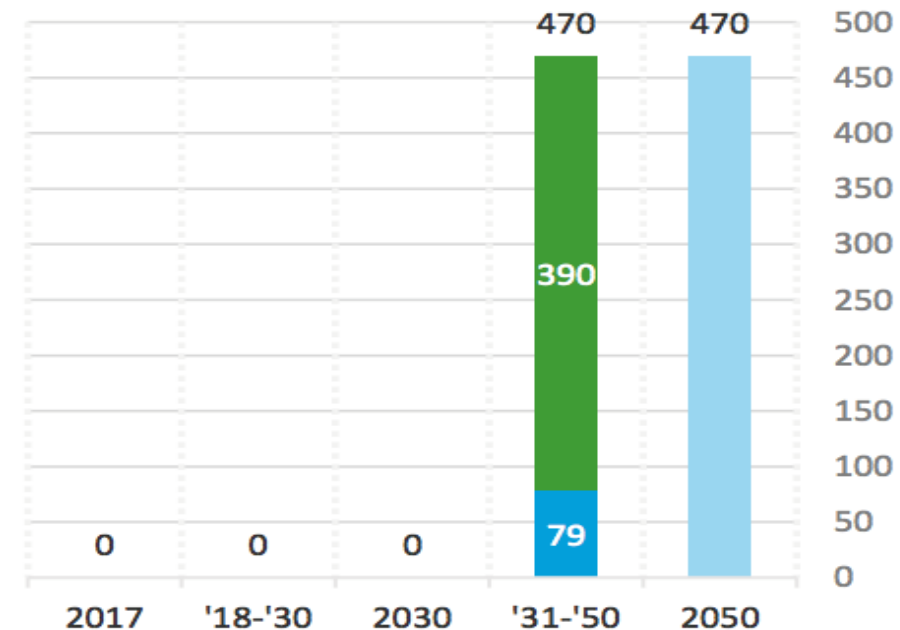
## Hydrogen Distribution Infrastructure: a look to the future (1)

*“In the medium term there is very limited need for dedicated distribution grids as most of the hydrogen is blended in existing methane supply. Although some dedicated hydrogen distribution systems are constructed post-2030, the majority is converted from methane (i.e. biomethane and natural gas) to hydrogen.”*

**Hydrogen transmission grid capacity**  
Units: TW-km



**Hydrogen distribution grid capacity**



Source: [DNV GL Eurogas Report – Reaching European Carbon Neutrality Full Report](#)





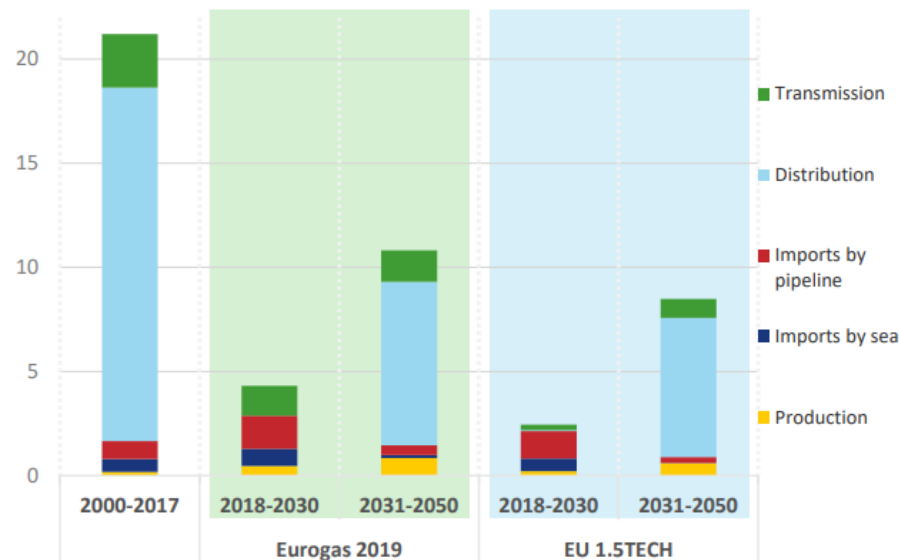
## Hydrogen Distribution Infrastructure: a look at the future (2)

**thus most of the network capex is dedicated for hydrogen accommodation.**

- In the Eurogas scenario, gas infrastructure CAPEX is primarily (>80%) to accommodate decarbonized hydrogen supply, focused on distribution grids post 2030

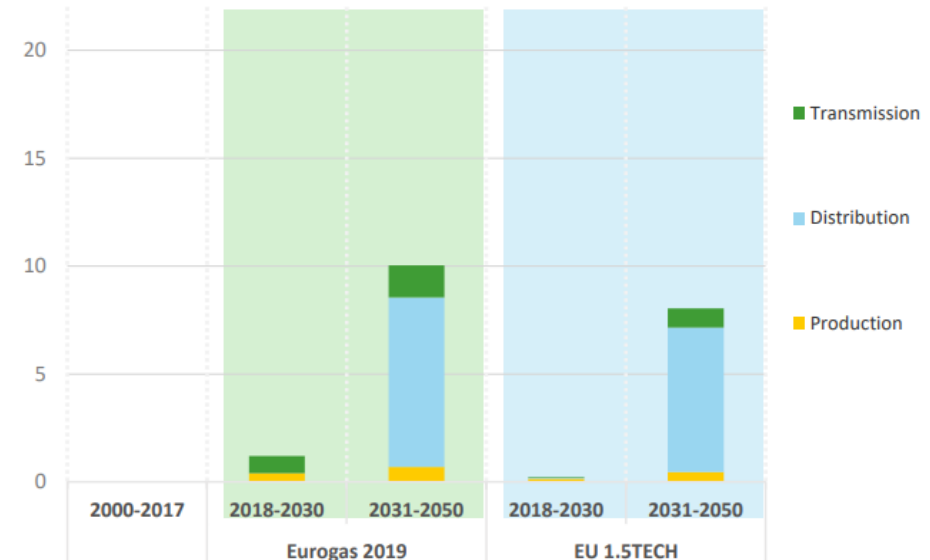
Gas infrastructure CAPEX (methane + hydrogen), average over the period

Units: Bn€/yr



Hydrogen infrastructure investments, average over the period

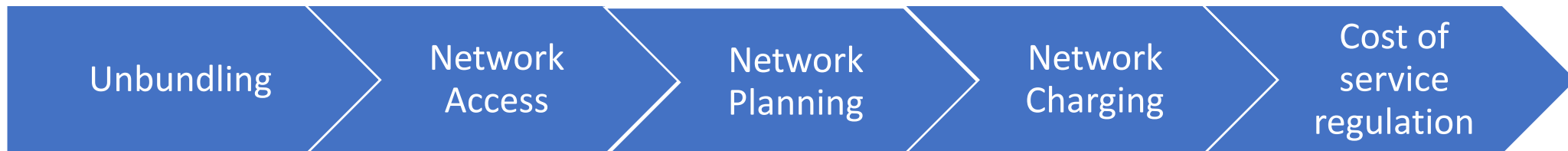
Units: Bn€/yr





## A look at regulation: regulatory barriers

- The current regulatory framework prevents the integration of hydrogen
- Changes are needed for a uniform framework of multiple gases that :
  - enables different technological developments
  - is open for applications and **networks with different mixture ratios of hydrogen, biogas and in the medium-term natural gas**
  - while respecting subsidiarity of national energy systems
- Regulatory elements :





## A look at regulation: necessary adjustments in EU law

The current Gas Directive 2009/73/EC is restricted to natural gas

- Other gases like hydrogen are only co-regulated when injected into the natural gas system
- This creates problems for operating pure H2 networks or „mixed“ networks

It is advisable that a new regulation should consider the following:

- Open regulation for all gases, integrate the term „hydrogen“ as a base gas alongside natural gas
- Natural gas distribution operators allowed to be regulated combined network operators
  - To prevent a special write-offs on the current natural gas grids at the end of their life cycle
  - To provide investments by the cash-flow of natural gas network

### Article 1 Gas Directive

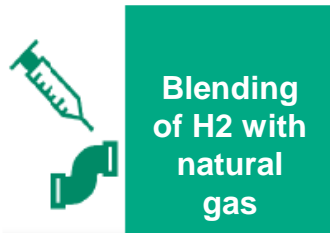
(1) *This Directive establishes common rules for the transmission, distribution, supply and storage of **natural gas**.*

(2) *... shall also apply in a non-discriminatory way to **biogas and gas from biomass or other types of gas** in so far as such gases can technically and safely be injected into, and transported through, the **natural gas system**.*



## As we have seen, there are 3 technical options for gas infrastructures to support development of low carbon H<sub>2</sub>

### Most likely to be implemented



Blending  
of H<sub>2</sub> with  
natural  
gas

*Dilute H<sub>2</sub> into natural gas up to a certain % (20% in volume considered as a max.)*



Methanation

*Combine decarbonized H<sub>2</sub> with CO<sub>2</sub> (captured on industrial or AD facilities) to produce synthetic methane*

Dedicated  
H<sub>2</sub> networks  
(conversion  
or newly  
built)

*Distribute H<sub>2</sub> with dedicated pipes to decentralized customers (e.g. industrials, mobility stations)*

### MAIN CHALLENGES · KEY DRIVERS

- Offer a complementary value to direct H<sub>2</sub> end-use applications
- Offer a solution for energy system flexibility (gas-elec. Coupling)
- **Certify admissible % along the whole gas chain**
- Identify adaptation needs (network and sensitive consumers) / compatible network design and operations

- **Offer a solution to locally recycle CO<sub>2</sub>**
- No or limited impacts on gas quality (residual H<sub>2</sub>)
- **Identify the most valuable models** (coupling with AD, optimized power-to-methane chain)
- **Prove ability to be deployed at industrial scale with contained costs**

- **Decrease logistic costs of hydrogen in case of large demand**
- Achieve scale effects to support conversion or greenfield development costs (foreseeable in industrial areas)
- Assess security impacts and adapt O&M tools and procedures



# GRHYD project: testing blending up to 20% (in volume) at distribution level



- Key objectives: assess technical feasibility and social acceptability of H<sub>2</sub> blended with natural gas up to 20% in vol. and injected into the grid
- Based near Dunkirk (Cappelle-la-Grande)
- Total budget: EUR 16m
- Full power-to-gas chain; limited perimeter for injection
- Laboratory tests and security studies (2017-2018)
- Field test (June 2018 – March 2020) : injection from 6% to 20% in vol.
- Legal derogatory framework on gas quality (calorific value)



LE GRAND PLAN  
D'INVESTISSEMENT

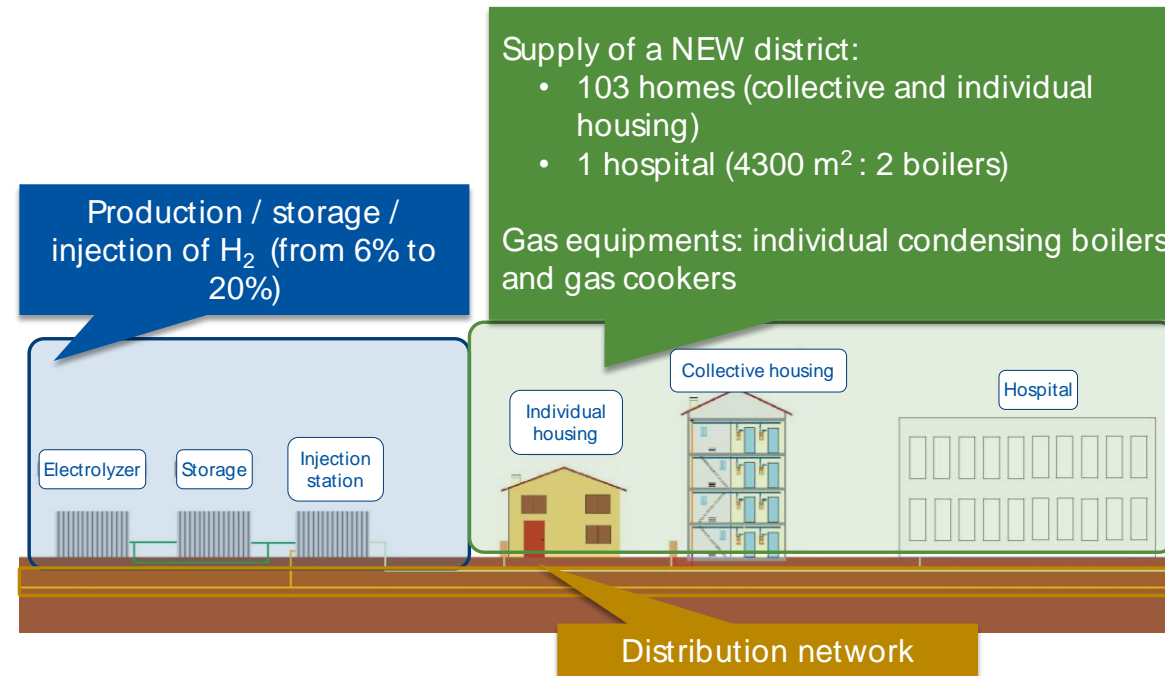


AREVA H<sub>2</sub>Gen



INERIS

McPhy energy





# GRHYD project has successfully tested injection of H<sub>2</sub> into a new gas distribution network up to 20% in volume

## Key findings / Main results

- **Injection station** designed for GRHYD well adapted to a power-to-gas chain (monitoring of H<sub>2</sub> rate and overall gas quality)...  
... but blending injection scheme not adapted to low and seasonal transit (dilution constrained by volatility of gas consumption, especially low volumes in summer)
- **Blending technically feasible up to 20% in vol. in a new distribution network.** Have been successfully tested:
  - Embrittlement of components
  - Leakage
- **New residential and tertiary end-use equipment suitable for blending** (performance, security) as well as some old equipment tested in laboratory
- **O&M equipment and procedures** implemented satisfying industrial security requirements
- Good level of **acceptability** thanks to information deployed on security aspects. Main concern relates to the impact on billing



GRHYD © GRDF

## Next steps

- Identify injection scheme more adapted to local projects
- R&D work to be pursued on existing distribution network and downstream installations
- Certify equipment



Methanation is the conversion of carbon monoxide and carbon dioxide (CO<sub>2</sub>) to methane (CH<sub>4</sub>) through hydrogenation

### Catalytic methanation

(reaction at elevated temperature in the presence of a nickel catalyst)



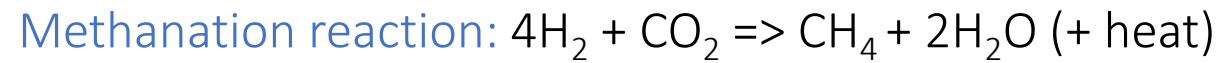
HZI (ex Etogas)

### Biological methanation

(conversion process by means of highly specialized microorganisms (e.g. Archaea) )



Electrochaea



### Synthetic Methane

(renewable if H<sub>2</sub> renewable + GHG emissions below threshold for end-use)

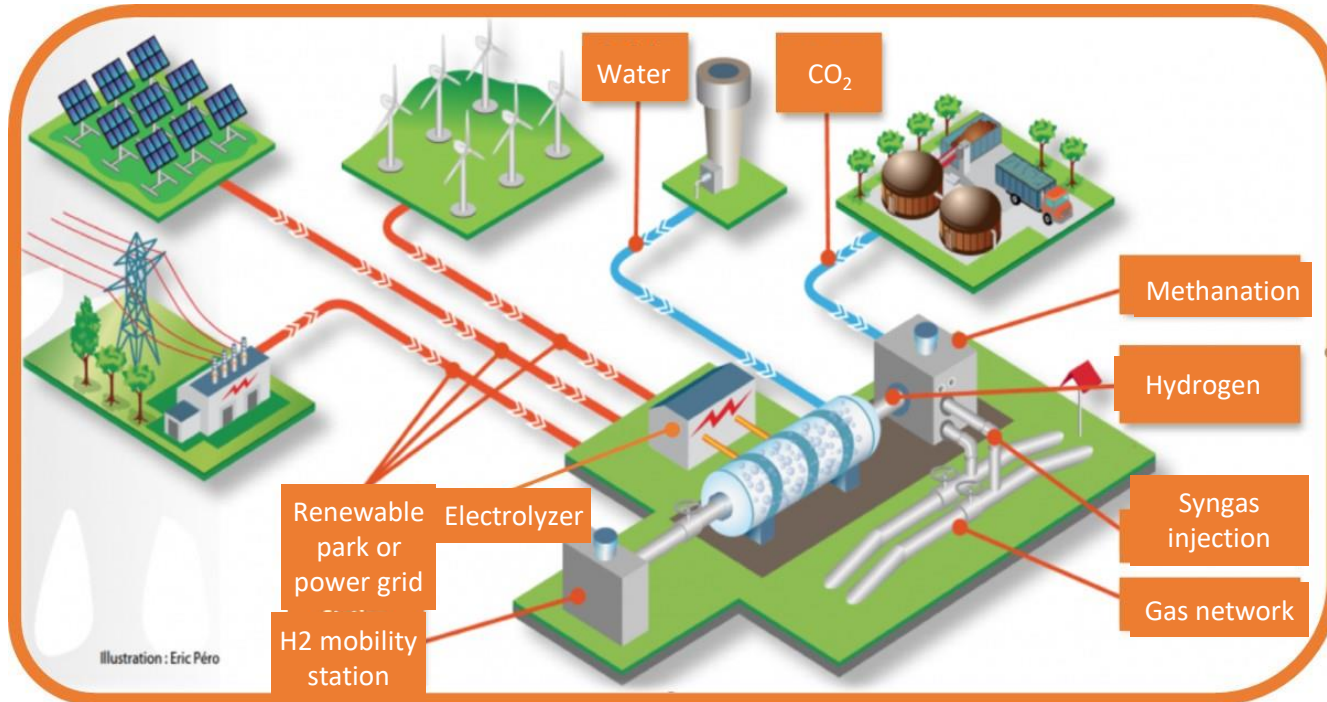
*Electrolysis*  
(power-to-gas)

*Carbon capture*  
Anaerobic Digestion plant,  
combustion, industrial process, air





# Methanation: a promising pathway for hydrogen especially in synergy with biomethane production



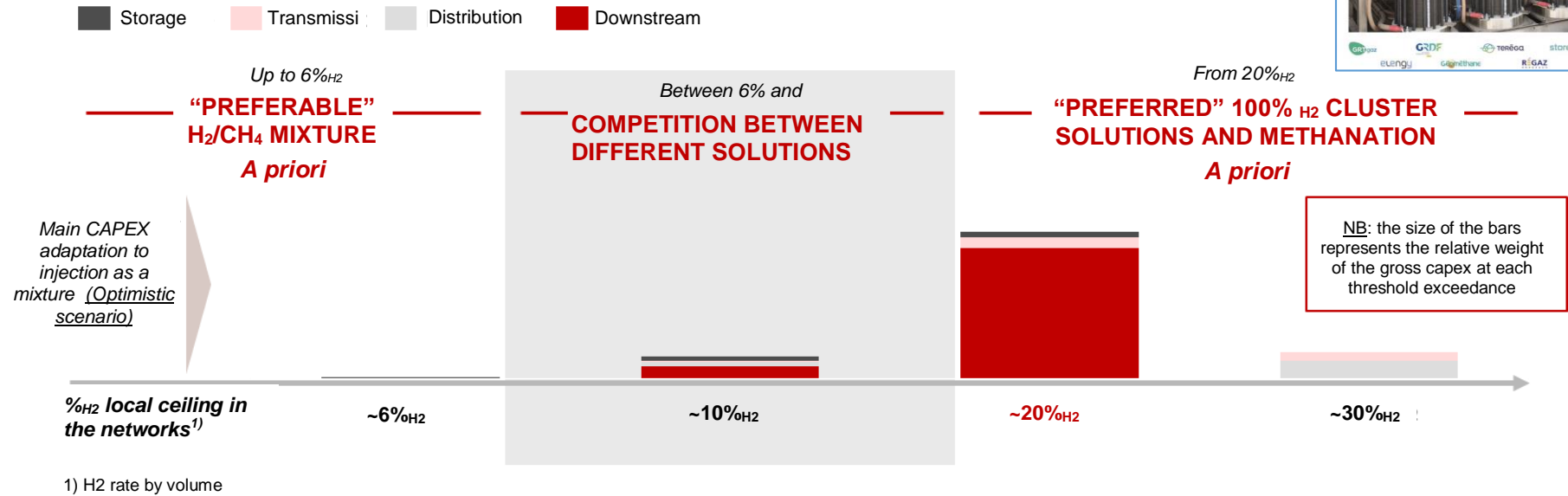
- Synthetic methane = CH<sub>4</sub> (sometimes with limited % of residual H<sub>2</sub>) easy to integrate into gas network and the whole gas chain
- Adapted to coupling with local P2G projects / decarbonized H<sub>2</sub> projects
- Offer a local CCU option (interesting in a context of limited CCS solutions)
- Really optimized when coupled with wastewater AD installations (re-use of co-products: O<sub>2</sub> and heat)





# According to the level of H<sub>2</sub> to be incorporated, each solution has its own competitive area

## COMPARED COMPETITIVENESS OF H<sub>2</sub> INCORPORATION OPTIONS



Results of modelling: **possible to integrate hydrogen for infrastructure adaptation costs from € 1 / MWh to € 8 / MWh by 2050<sup>1</sup>**

Source: E-CUBE Strategy Consultants analysis, Technical and economic conditions for injecting H<sub>2</sub> into natural gas networks, 2019, <http://www.grtgaz.com/fileadmin/plaquettes/en/2019/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf>

<sup>1</sup> Gas demand scenarios in 2050 (195 and 295 TWh, H<sub>2</sub> injection scenarios in 2050 (10 TWh, 40 TWh) with different injection schemes (centralized, decentralized)



# Results of different studies on the future of hydrogen in Europe

*Presented by*

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## European Hydrogen Backbone: How a dedicated hydrogen infrastructure can be created (July 2020)

### The Gas for Climate consortium

Gas for Climate was initiated in 2017 to analyse and create awareness about the role of renewable and low carbon gas in the future energy system, aiming to full compliance with the Paris Agreement target to limit global temperature increase to well below 2°C.

To this end, the entire economy has to become (net) zero carbon by mid-century.

The Gas for Climate group consists of ten leading European gas transport companies and two biogas consortia.



### Aim of the study

- Describe how a dedicated hydrogen infrastructure can be created in a significant part of the EU between 2030 and 2040, requiring work to start during the 2020s.

### The preparatory steps: definition of potential and pathway

- How gas can help to achieve the Paris Agreement target in an affordable way (march 2019)
- Gas Decarbonisation Pathways 2020-2050 (April, 2020)

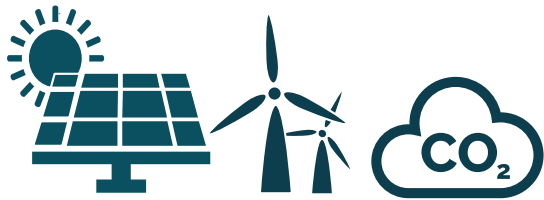


## Backup slide

### Background and scope of the study

- Hydrogen supply, demand, and policy trends are leading to rapidly improving prospects for affordable low-carbon hydrogen

#### Hydrogen production capacity is ramping up rapidly



- Rapidly declining costs for renewable electricity
- Planned global investments in electrolyzers increased from 3.2 to 8.2 GW between Nov 2019 and Mar 2020<sup>1</sup>
- Various industry initiatives: Hydrogen Europe, Hydrogen Council, Clean Hydrogen Alliance

#### Rising demand as sectors look to fully decarbonise



- Decarbonisation of heavy industrial processes (steel, cement, chemical)
- Complement electrification in hard-to-abate parts of the transport system (aviation, shipping, heavy duty trucking)
- Long-duration storage to support an electricity system with a large share of wind and solar.

#### Supported by a clear policy direction at EU-level



- Renewable fuels are one of three central pillars of the EU's Energy System Integration Strategy<sup>2</sup>
- EU's Hydrogen Strategy launched in July 2020 targets 1 Mt green hydrogen by 2024 and 10 Mt by 2030<sup>3</sup>
- Various financing mechanisms and funds have been announced.

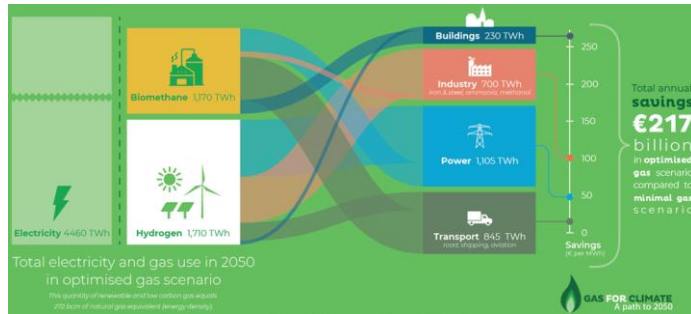
1. Source: Wood Mackenzie; 2. Source: European Commission, COM(2020)299; 3. Source: European Commission, COM(2020)301



## Backup slide

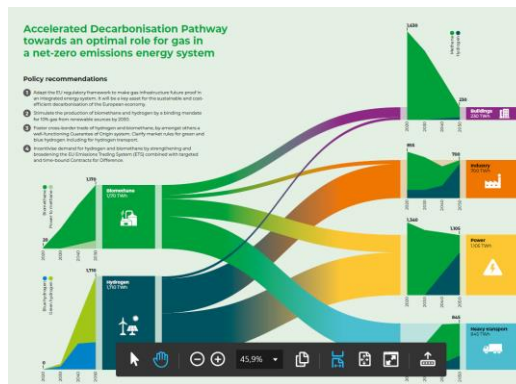
### The preparatory steps: definition of potential and pathway

- ***“How gas can help to achieve the Paris Agreement target in an affordable way” (march 2019)***



- Best choice to decarbonise the energy system by a smart combination of hydrogen and biomethane (up to 270 NG bcm equivalent by 2050) with electricity
- EU saves society €217 billion annually by 2050
- Cost reductions for hydrogen, biomethane and P2G is possible

- ***“Gas Decarbonisation Pathways 2020-2050” (April, 2020)***



- Descriptions of gas decarbonisation pathways from 2020 to 2050
- Identification of the required investments to scale-up hydrogen and biomethane
- Additional EU climate and energy policies to achieve net zero by 2050



## Backup slide

# The role of infrastructure

The availability of infrastructure connecting supply and demand is a key condition for widespread use of hydrogen as an energy carrier



Driving hydrogen development past the **tipping point** requires a large-scale infrastructure network that only the EU and the single market can offer



An EU-wide infrastructure will enable transport of hydrogen over **long distances** from areas with large renewable potential to demand centres located in other Member States, as well as **international trade** with EU's neighbouring countries in Eastern Europe, and Southern and Eastern Mediterranean countries



Infrastructure plays a facilitating role within a **full value chain approach**, whereby scale-up of production, infrastructure, and market demand go in parallel to activate a **virtuous circle** of increased supply and demand for hydrogen with reduced supply costs



With increasing demand, an **efficient and interoperable** transport network is needed to create an **open and competitive EU market** that provides clean and safe hydrogen at the lowest cost to end users who value it most



The existing gas grid can be partially repurposed, providing an opportunity for a **cost-effective transition** in combination with limited newly built dedicated hydrogen infrastructure





# The European Hydrogen Backbone (1)

A dedicated infrastructure can pave the way to large-scale competitive hydrogen for the European market

A hydrogen network can emerge from the mid-2020s onwards to an initial **6,800 km** pipeline network by 2030.

By 2040, a hydrogen network of **23,000 km** is foreseen, 75% of which will consist of converted natural gas pipelines, connected by 25% of new pipeline stretches.

**A pan-EU hydrogen backbone**

The backbone has an estimated cost of **€27 to €64 billion**, which is relatively limited in the overall context of the European energy transition.

The levelised cost is estimated to be between **€0.09-0.17 per kg per 1000 km**, allowing hydrogen to be transported cost-efficiently over long distances across Europe.

**At affordable cost**

The group of gas infrastructure companies is convinced that the hydrogen backbone will eventually cover **the entire EU**.

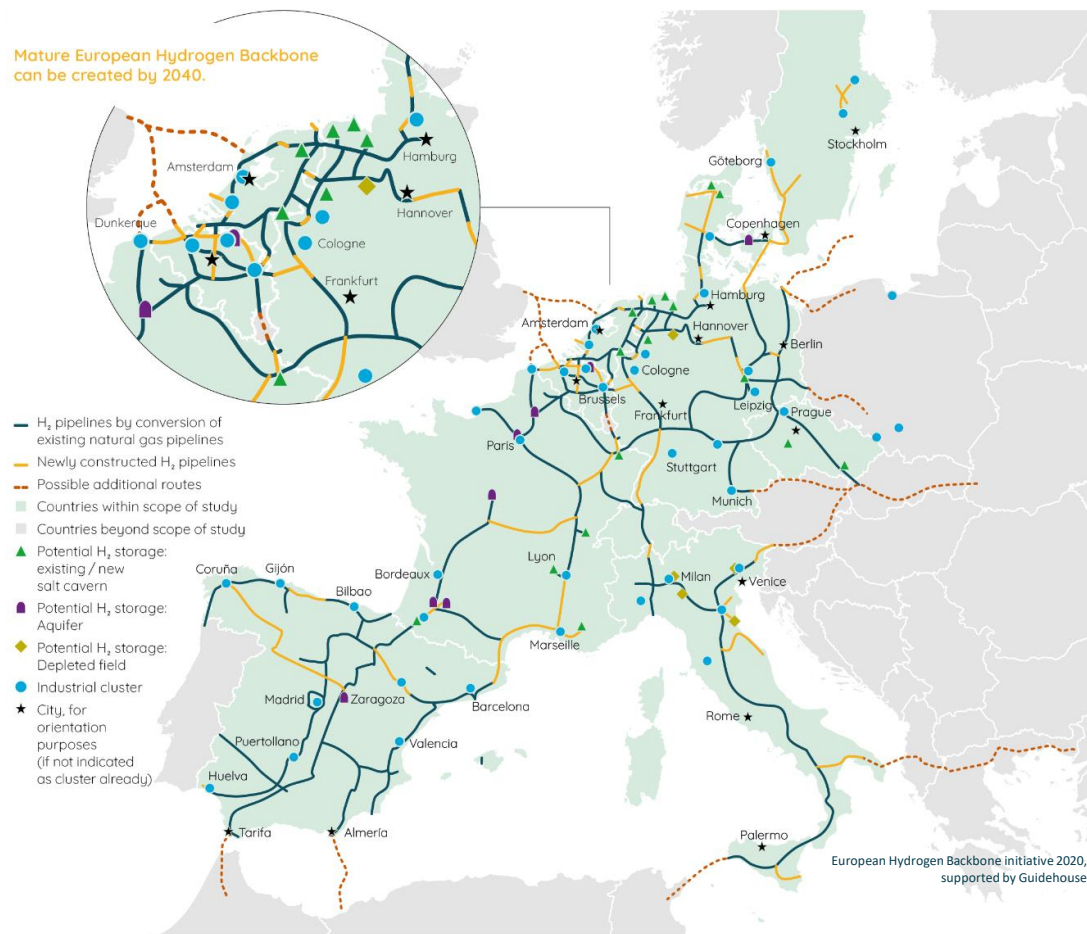
The group **invites** other European gas infrastructure companies to join in the thinking to further develop the backbone plan.

**An open initiative**



## The European Hydrogen Backbone (2)

The EHB is a shared vision from eleven TSOs<sup>1</sup> to engage in a truly European undertaking



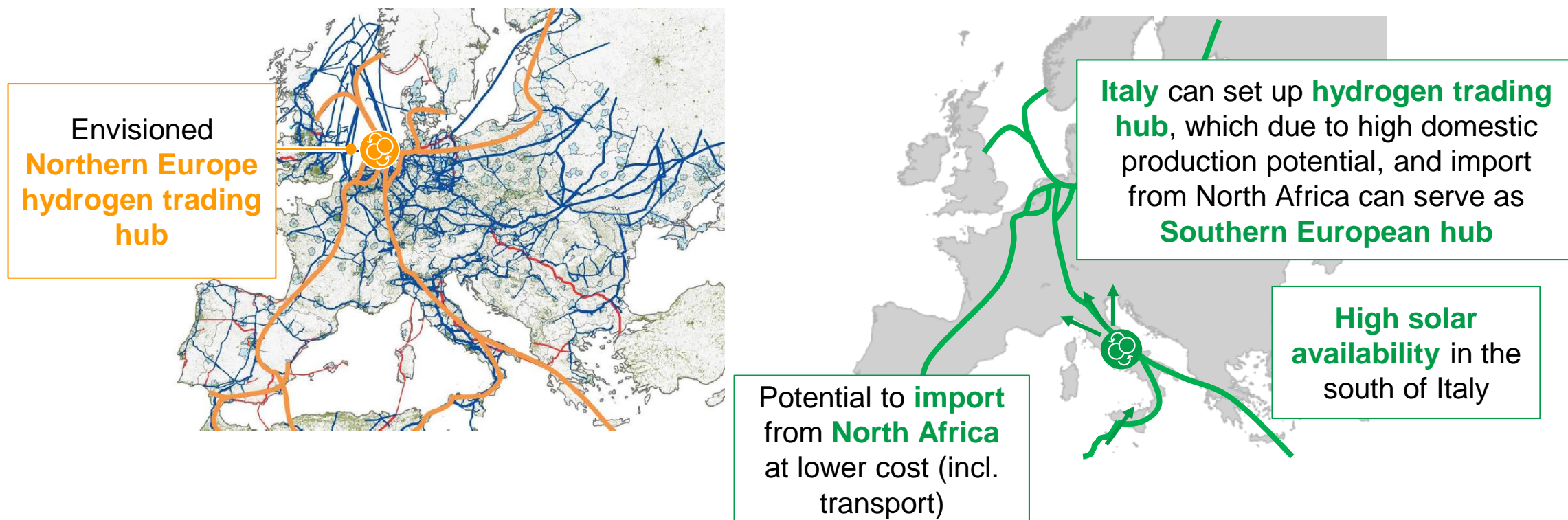
- A proposal for a **dedicated hydrogen transport infrastructure**, connecting supply and demand from north to south and west to east.
- Starting with an emerging 6,000 km pipeline network connecting hydrogen valleys by 2030; then stretching into all directions with a length of about **23,000 km by 2040**, with expected further expansion up to 2050.
- Converted 36- and 48-inch hydrogen pipelines, commonly used for long-distance gas transport in the EU, can provide **7 and 13 GW** (at LHV<sup>2</sup>) of hydrogen capacity per pipeline, respectively.
- The proposed backbone requires an estimated total investment cost of **€27-64 billion by 2040**, based on using 75% repurposed natural gas pipelines connected to 25% newly built dedicated hydrogen pipelines.
- Levelised transport costs amount to 0.09-0.17 €/kg per 1000 km, enabling **cost-effective long-distance transport** across Europe.
- The EHB is an **open initiative** – gas TSOs from adjacent geographies, associations GIE and ENTSG, gas storage operators, DSOs, and other market players are encouraged to join in the thinking, to further develop this pan-European undertaking.

1. Includes Enagas, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Teréga, Snam, Swedegas; covering Germany, France, Italy, Spain, the Netherlands, Belgium, Czech Republic, Denmark, Sweden, and Switzerland (indirectly through Fluxys Belgium); 2. LHV: Lower heating value, the energetic value of a gas, after subtracting the heat of vaporisation from the higher heating value.





## Italy is optimally positioned to become a leading hub for green hydrogen from North Africa to Europe



SOURCE: Snam analysis



# Cost of the European Hydrogen Backbone

Total investment and operating costs are lower than previously estimated

Total investment, operating, and levelised costs of the EHB

			Low	Medium	High
Investment cost	Pipeline	€ billion	17	23	28
	Compression	€ billion	10	17	36
	<b>Sub-total</b>	<b>€ billion</b>	<b>27</b>	<b>40</b>	<b>64</b>
Operating cost	O&M (excluding electricity)	€ billion	0.7	0.9	1.1
	Electricity	€ billion	0.9	1.2	2.4
	<b>Sub-total</b>	<b>€ billion</b>	<b>1.6</b>	<b>2.1</b>	<b>3.5</b>
Levelised cost	100% new	€/kg/1000km	0.16	0.20	0.23
	100% retrofitted	€/kg/1000km	0.07	0.11	0.15
	<b>EHB: 25% new, 75% retrofitted</b>	<b>€/kg/1000km</b>	<b>0.09</b>	<b>0.13</b>	<b>0.17</b>

Key messages

- Total investment cost of the envisaged 2040 EHB is expected to be between **€27 to €64 billion**. This translates to a levelized cost of **0.09-0.17 €/kg/1000km<sup>1</sup>**; compared to a previous estimate of **0.23 €/kg/1000km<sup>2</sup>**.
- In the medium case, 60% of total investment cost will be dedicated to pipeline works and the remaining 40% will be spent on compression equipment.
- At 13 GW<sub>LHV</sub>, initial analysis suggests that compression needs are 190-330 MW<sub>e</sub> per 1000 km; which translates to 1.5-2.3% of the transported hydrogen's energy content consumed for compression purposes per 1000 km transported.
- There is more scope for cost optimisation<sup>3</sup>, yet reducing pipeline capacity as described previously already shows the importance of optimisation to provide long-distance hydrogen transport at modest cost.

1. Conversion factors for hydrogen: 1 kg = 0.033 MWh (at lower heating value); 1 kg = 0.039 MWh (at higher heating value); 2. Source: Gas for Climate: *The optimal role for gas in a net zero emissions energy system (2019)*; 3. For example by optimising compression ratio.



## Pathways to a Carbon Neutral 2050: The role of hydrogen (June 2020)

What we have set  
out to achieve

To assess a pathway to a carbon neutral future

Comparing it to the European Commission's 1.5TECH

Commissioned DNV GL to carry out the study

To outline at what point, and under which conditions, renewable and decarbonised gases will be available in Europe



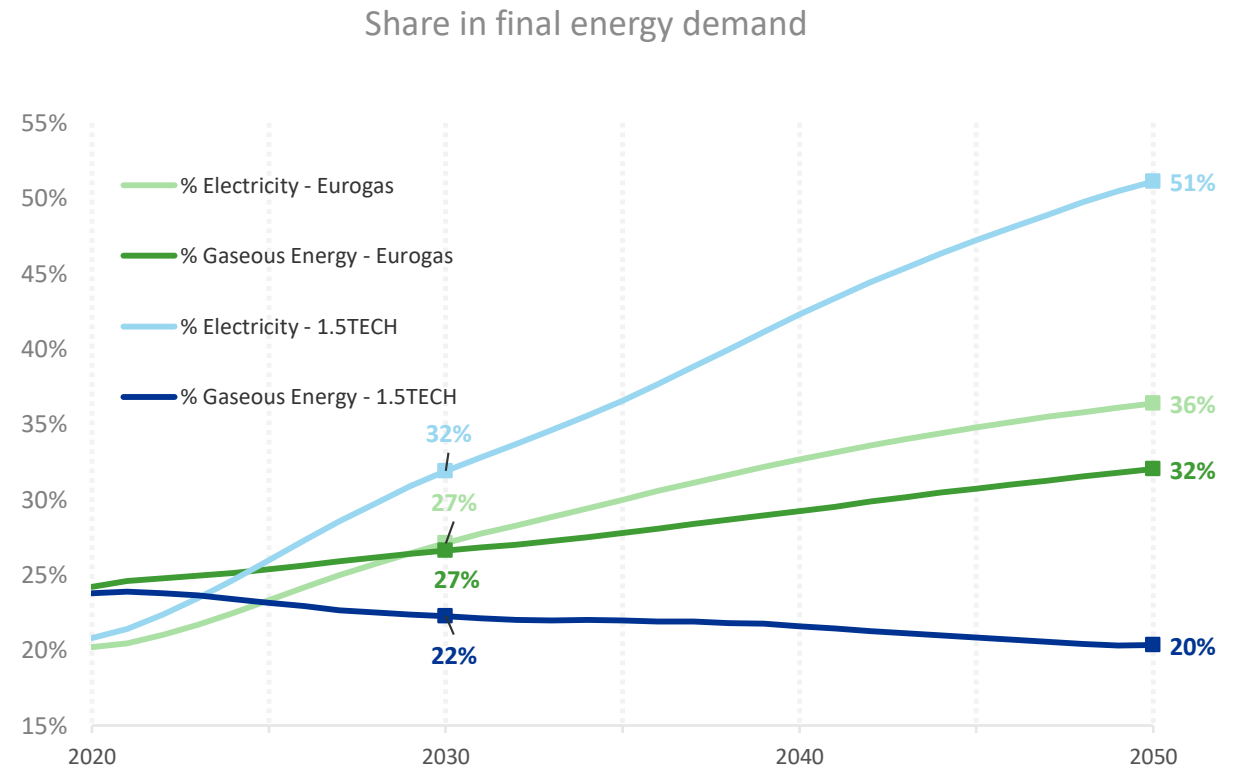
## A multi-vector transition is more realistic and more cost-effective

Primary energy use declines in both scenarios, 29% under Eurogas, 34% under 1.5TECH

Electrification makes sense, but only up to a point – and provided the power sector decarbonises

Economy wide savings under the more balanced Eurogas scenario reach €4.1 trillion until 2050 compared to 1.5TECH

Gas enables cost-efficient decarbonisation of the building sector



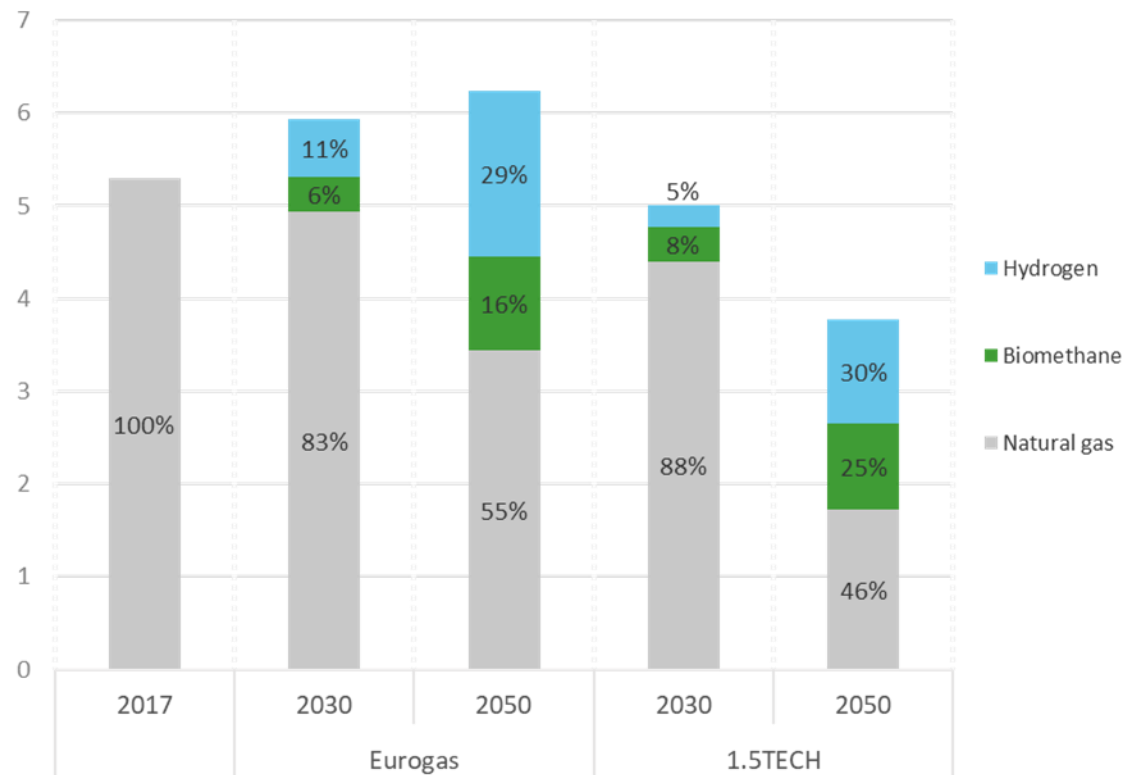


## The gaseous energy supply chain can decarbonize...

Gaseous energy supply in the Eurogas scenario increases by 18% over 2017 levels (natural gas supply reduces by 35%) and is 89% decarbonized in 2050

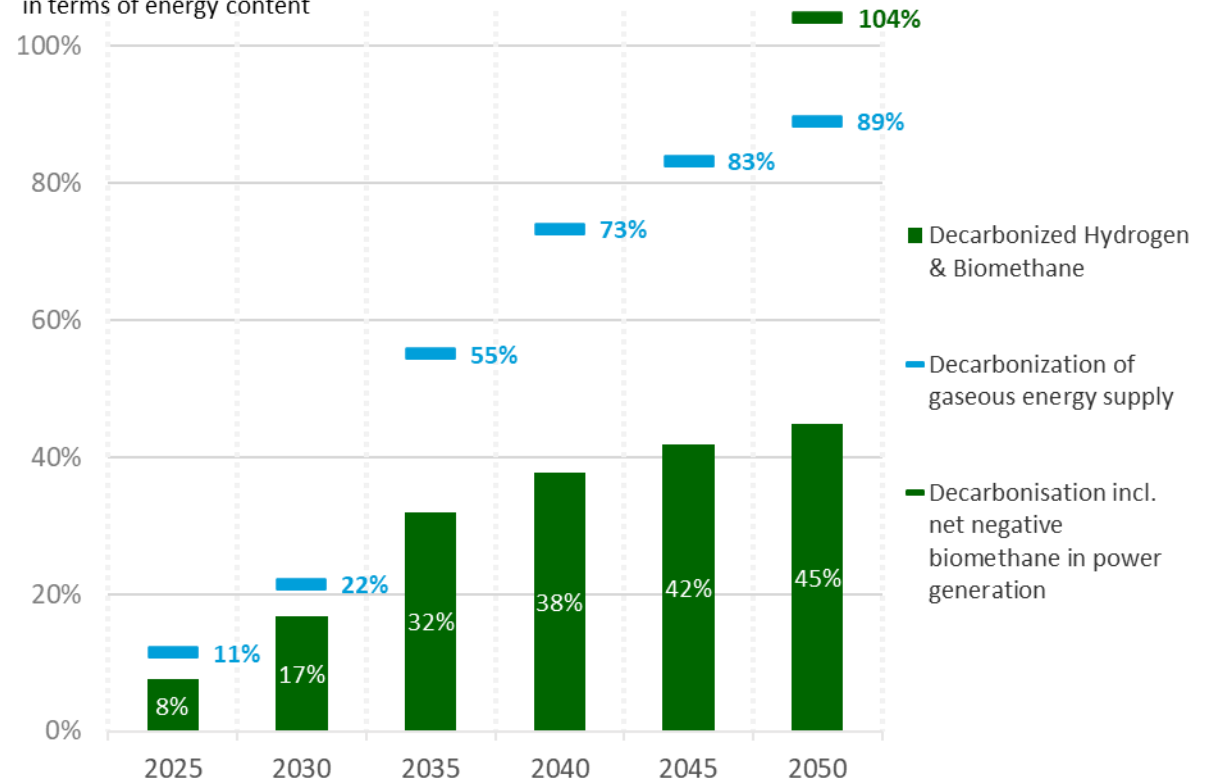
Gaseous energy supply

Units: PWh/yr



Decarbonized Gaseous Energy Supply - Eurogas scenario

in terms of energy content





## Demand for hydrogen as an energy carrier increases in both scenarios

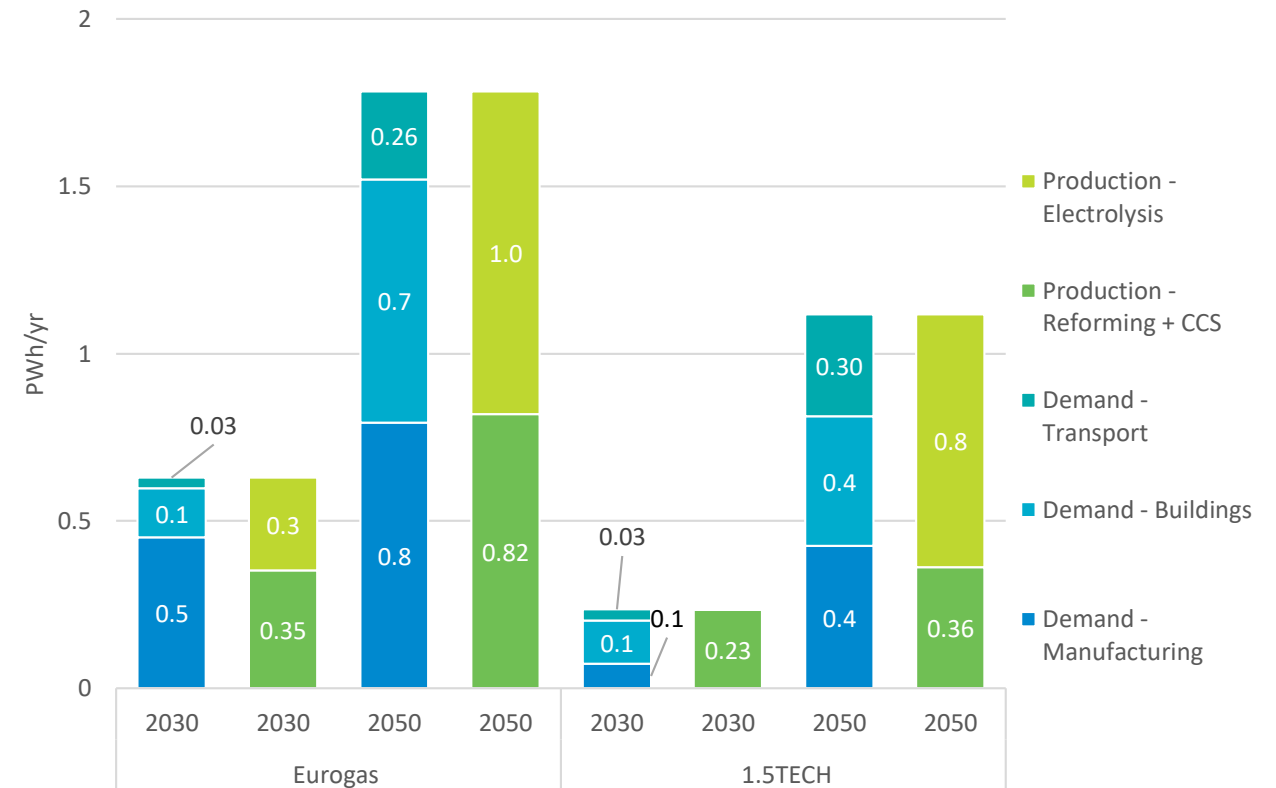
Eurogas scenario sees manufacturing lead hydrogen uptake until 2030

Hydrogen (*and biomethane*) displace natural gas in heating after 2030 towards 2050

Both scenarios show an important role for hydrogen from reformed natural gas as an early driver to provide scale by 2030

The share of hydrogen from electrolysis overtakes hydrogen from reformed natural gas by 2050

Hydrogen demand by sector and production by source





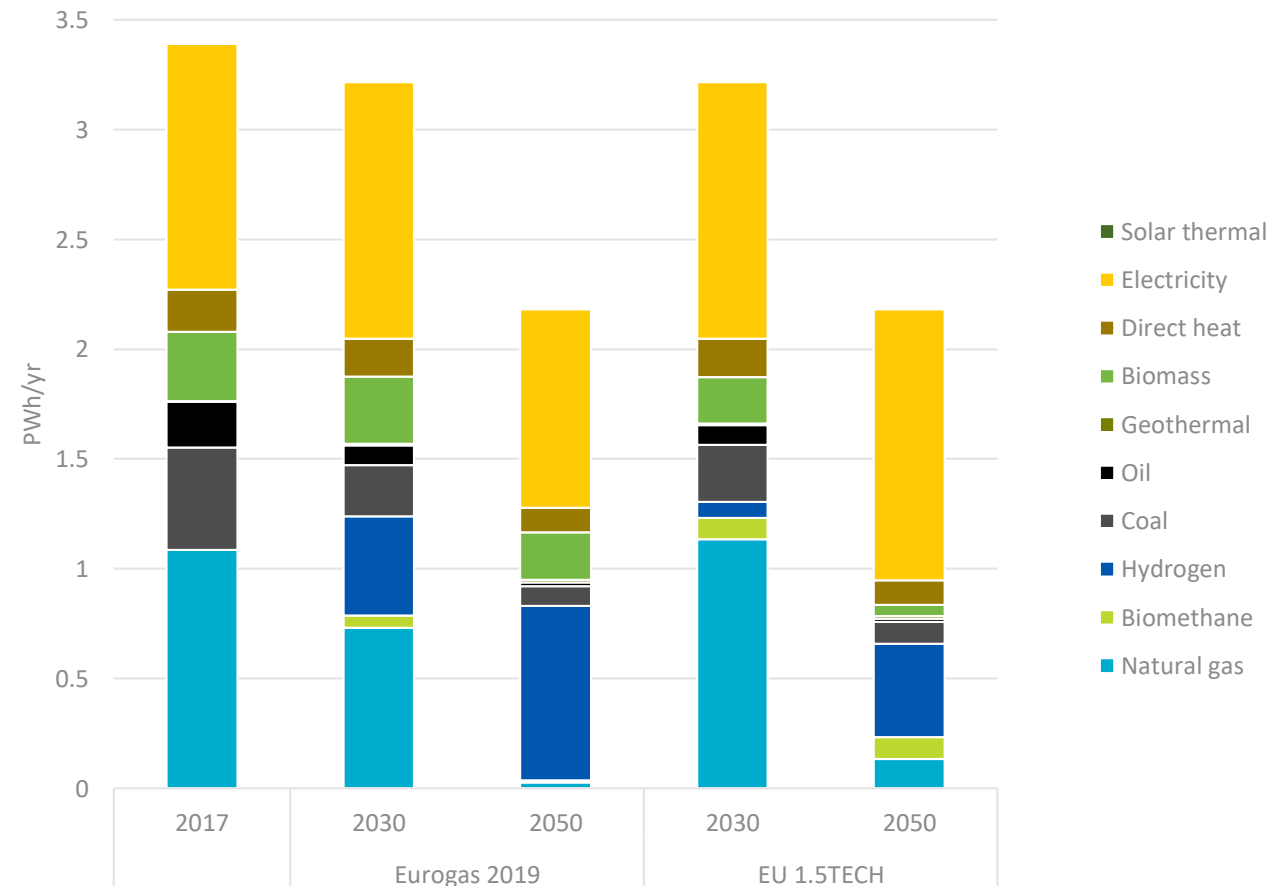
## Manufacturing leads the uptake of hydrogen until 2030

Manufacturing sector is the main driver for initial large-scale hydrogen demand

These volumes lead manufacturing to trigger the necessary infrastructure investments

Using hydrogen in manufacturing requires less subsidies and has lower energy costs than the strong electrification seen in 1.5TECH

Manufacturing energy demand by energy carrier

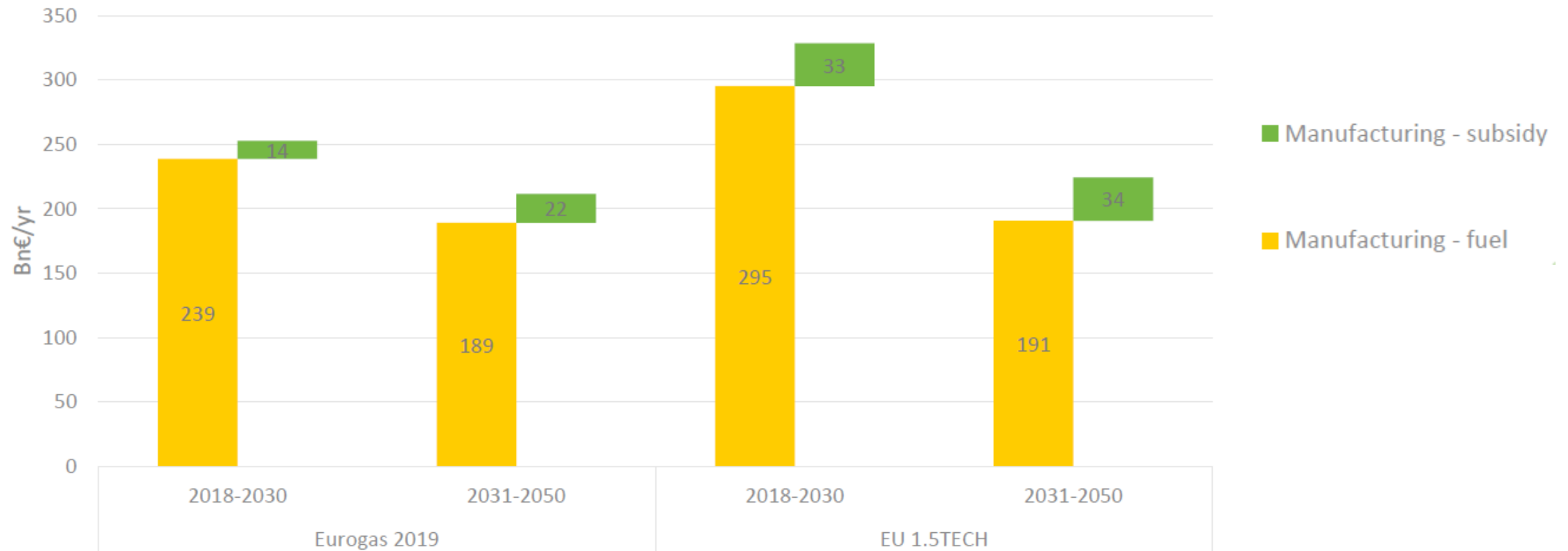




# More affordable to decarbonise manufacturing sector with hydrogen than electricity – save EU competitiveness

## Total costs - manufacturing

The cost advantage is particularly apparent in the period to 2030







# Technology cost development for Biomethane and Hydrogen

OPEX and CAPEX benefit from regional and global cost learning

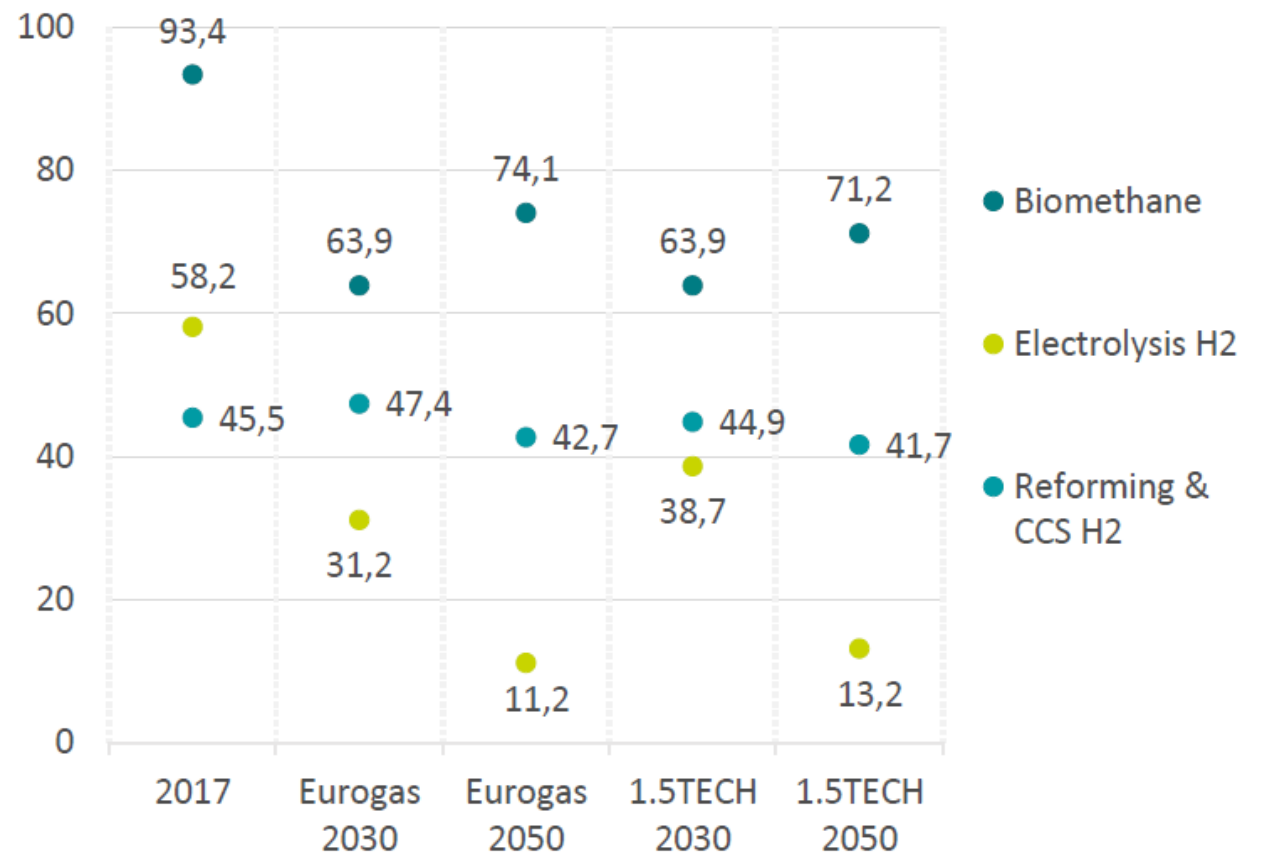
Carbon price causes natural gas to become less competitive, but also pushes cost escalation in feedstock

Cost of electrolysis for hydrogen decreases faster in Eurogas scenario than in 1.5 TECH more cost learning due to higher installed capacity

Costs of reforming with CSS are relatively stable, as CCS is a minor part of total cost, while reforming is a mature technology with limited cost learning

Cost of decarbonised gas

Units: €/MWh



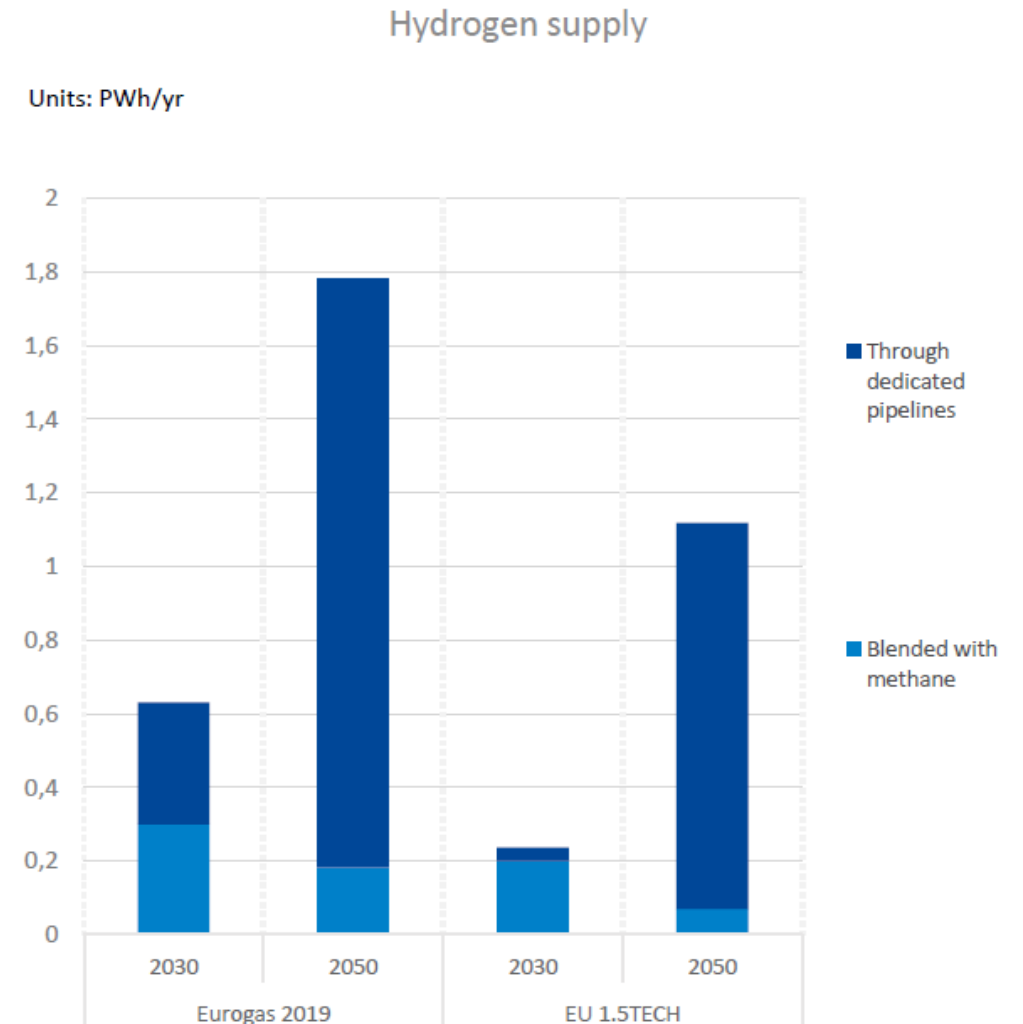


## Hydrogen will be supplied blended and unblended

Pure hydrogen networks develop in specific demand sectors (e.g. manufacturing) already in the 2020s and become the norm by 2050

Initially blending will play an important role to start scaling the hydrogen market without delay and optimise the use of existing infrastructure

As there are technical limits that making continuously increased blending levels uneconomical, the share of dedicated infrastructure jumps to 90% by 2050





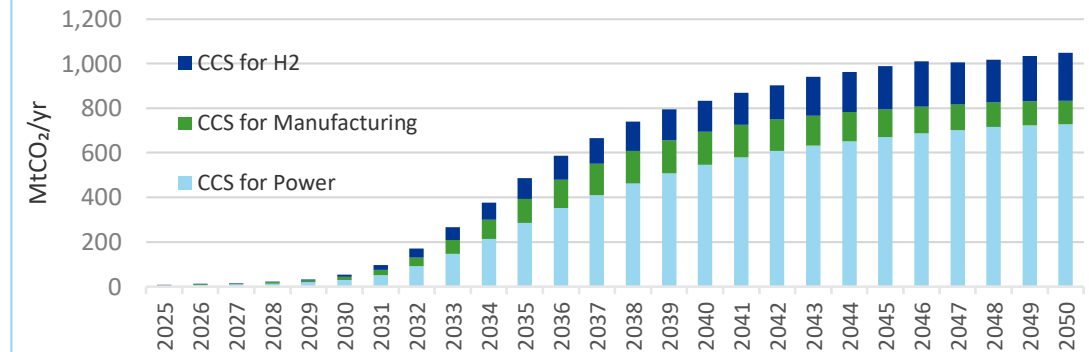
## Whatever scenario we choose. CCS is not an option. It is a necessity.

Both scenarios rely on CCS, especially to decarbonize the power and manufacturing sector

Although the Eurogas scenario has a higher share of natural gas, it decarbonizes the energy system with 15% lower cumulative CCS deployment towards 2050 than 1.5TECH

Under conservative assumptions and restrictive policies, both scenarios use 11-13% of available storage capacity, and have between 114-130 years of storage left in 2050

CCS uptake Eurogas scenario



CCS uptake 1.5TECH scenario

