Roundtable discussion with Commissioner Kadri Simson

Snam contribution

1. How do you see the transport of hydrogen developing in the future?

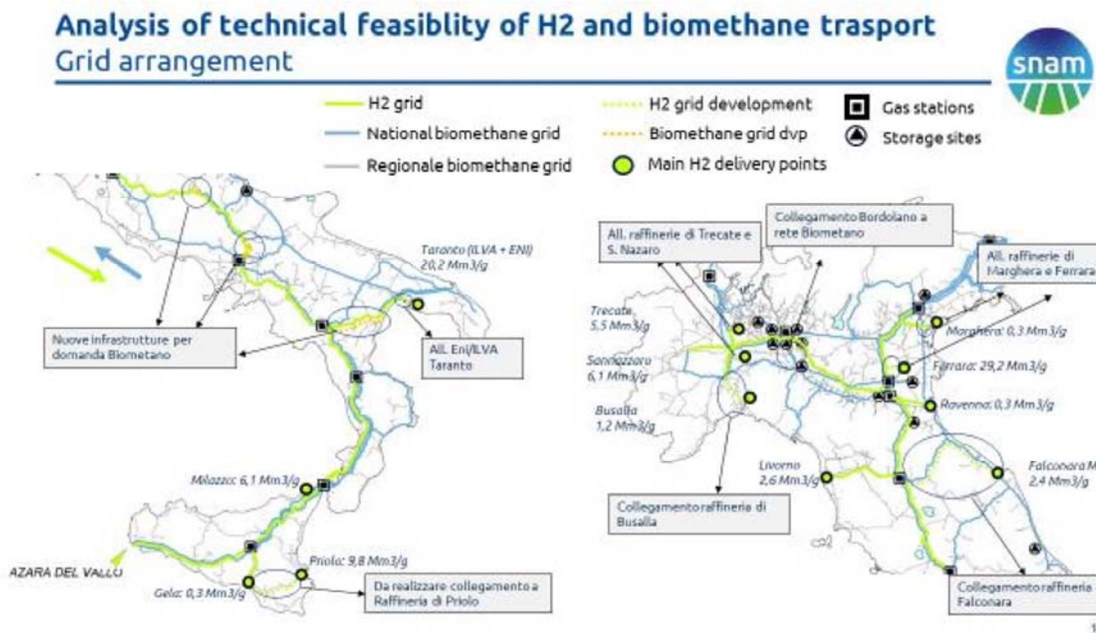
- **Endgame (2050 +)**
    - H2 share in EU final consumption ca. 25%[1] (mainly industrial, heavy transport + feedstock for ammonia & synthetic kerosene for ships and planes, also some residential heating and flexible power generation).
    - H2 mainly produced at scale in areas favourable for renewable power (ie Southern Europe for solar power, North Sea for wind power, potential for green H2 imports from North Africa), with some distributed electrolysis from over-generation/grid.
    - Availability also of biomethane (ca. 100bcm[2]) leveraging agricultural and forestry residues, low ILUC risk cover crops and urban organic waste
    - Predominantly segmented transport network, with one part dedicated to 100% hydrogen and another to 100% biomethane/low carbon gas. Should membranes prove to be effective, there may be some residual blending.
    - European hydrogen backbone and interconnections for cross-border trade, to increase supply security and efficiency (together with a Guarantee of Origin mechanism in place). Networks to be interconnected with liquid hubs to provide competitive and transparent pricing.
    - Integrated transport, terminals and storage for gaseous and liquid forms of hydrogen.

As part of the effort to identify optimal endgame solutions, we are working on an internal project "Future of the Italian grid", where we have localised hydrogen and biomethane production and consumption centres in the long term, and looked at how the network could be segmented with minimal additional requirements. This exercise is giving us some key take aways:

- Biomethane production would be fragmented and distributed small-scale plants, mainly in the North of the country, collected by the gas network.
- Subsea gas connections from North Africa could offer a route for H2 import, with a more regular supply over the year
- National and local grid required to collected H2 generation from overgeneration from renewable electricity

[1] EU Hydrogen Roadmap, FCHJU
[2] Gas for Climate study, 2019

- Segmentation required to bring H2 from South to North, and biomethane from North to South. Italian gas transmission grid structure well suited to be segregated into parallel grids, thanks to its multi-pipe backbone



- **During the period 2030-2050:**
  - Transport network initially operates **in blending mode**, until tipping point is reached for full segmentation to create dedicated (bio) methane and hydrogen networks.
  - Throughout the period **some dedicated H2 infrastructure** will be converted to serve and connect regional clusters, and also internationally to form a European hydrogen backbone.
    - Conceptually, the blending ceiling is the maximum achievable without the need for significant investments. The blending level will depend on season/location, can be adjusted (also through methanation) where needed.
    - Blending level will also depend on deployment of H2 boilers, which are currently being developed.
    - Snam's Contursi experiment shows that a 10% H2NG blend is already possible on most parts of the network today. Snam is running a "hydrogen-readiness" audit of existing pipelines, which shows 70% are could accept blends up to 100%. New procurement standard for 100% hydrogen acceptability.
  - Increasing development of **regional hydrogen clusters** (100%), thanks also to growing specific sector penetration targets on industry, heavy transport and specific use cases.

    - Hydrogen clusters grow outwards, extending to commercial and residential consumers around first hydrogen projects

- **During the decade 2020-2030**:
    - Requirement of at least 25GW of electrolyser capacity to be constructed globally a significant portion of which in Europe, which is leading in this area and also has the potential to develop a strong industrial footprint. The 25GW is the installed capacity required to reach €2/kg H2 costs within the decade, the price at which hydrogen be competitive with fossil fuels and grey hydrogen in a number of applications, particularly in heavy transport and in industrial uses in the chemicals and refining sectors.
    - Very few natural gas pipelines available to switch to hydrogen, therefore blending in the natural gas grid is the only way to allow efficient long distance hydrogen transport.
    - Compulsory blending (in a limited percentage) in the natural gas grid would provide initial boost to green hydrogen consumption.
    - The blending level/ceiling could be harmonised among European countries to increase interoperability
    - Limited number of initial clusters with 100% H2 consumption to serve some early adoption "anchor" customers in sectors where green H2 would carry limited additional cost (eg. Grey hydrogen uses such as ammonia production, refineries, where green hydrogen quotas could be set) or to serve industrial clients which would switch to hydrogen as part of their natural reinvestment cycles. Cluster areas could also serve additional demand like trucking fleets.
    - Clusters may also have high H2NG blends to start decarbonisation of specific areas
    - Potential to use of membranes to "shield" areas/final uses that cannot accept hydrogen blend above ca. 5% raises overall blending "ceiling". Also provides for flexible delivery of pure hydrogen through the grid. Snam is working on a field test of membrane technology.

2. Do you see the need to transport significant amounts of hydrogen in gaseous form over transmission pipelines or rather just local use?

We see hydrogen in transmission pipelines as essential because it has clear advantages over alternative scenarios, either because they are much more expensive, or technically very challenging.
To simplify, there are three alternative scenarios to supply H2 to consumers:

- *"H2 backbone scenario"* - A world where H2 can be produced centrally and transported from supply best location to demand centers
- *"Full decentralized scenario"* - Where hydrogen is produced near the consumption centre through dedicated renewables

- *"Full power grid scenario"*- In which electricity is transported through the grid to electrolysers near the point of consumption

Comparison of alternative hydrogen infrastructure scenarios

	Generation	Transport	Storage	Security of supply	Market empowerment
H2 backbone scenario	• Use of best natural resources, lower renewable cost • Economy of scale for large electrolyzer installation	• Lower cost for transporting molecules compared to electrons • Leveraging existing gas infrastructure where possible	• Unlock the use of geological sites (large in size and lowering costs)	• Multiple sources of supply connected: large centrally in/ outside EU and small decentralized • Higher flexibility and easiness of dispatching	• Enable EU and national hydrogen markets, cross border/ import exchanges and support hub liquidity
Full decentralized scenario	• Electricity cost highly dependent on local natural resource conditions • Economy of scale for large electrolyzer installation	• No need for transport infrastructure	• Requires local storage like above ground tanks, to match daily shift and seasonal mismatch of supply and demand	• To be ensured by local resources and backup alternatives • Could lead to excess of small storage solutions	• No market can develop, only small local monopolies and point to point solutions
Full power grid scenario	• Use of best natural resources, lower renewable cost • Small scale electrolyzer, higher capex	• Higher cost per energy transported • Constraints on development of new power lines	• Electricity storage cannot cope with seasonal shifts • Requires anyway local storage solutions	• Security to rely only on electricity infrastructure	• Electricity to be left as the sole EU energy market, most likely to remain regional

- The "*H2 backbone scenario"* enables the centralised **H2 production**, which supports the localisation of production where:
    - Conditions are favourable for renewable electricity (e.g., solar production in central Europe 1000 hours, Southern Italy 1500, North Africa 2000+, meaning that all other things being equal the LCOE in North Africa would be half that of central Europe) which ensure an efficient land use
    - Electrolysis can be carried out at scale (Capex benefit of scaling up electrolysers in the market today: -25% to increase scale from 0.5 MW to few MW, saving increased to -55% for 1GW scale, with greater efficiencies for even larger scales)

- **Transporting** energy in the form of molecules has some clear advantages compared to electrons:
    - For the same amount of energy transported, onshore power lines can easily have a cost of 5-10 times higher compared to transporting gas
    - Large amount of energy would require new power lines, not often easy to be build (NIMBY), compared to the option of converting existing gas infrastructure
    - Gas infrastructure can also enable the use of geological storage sites, provide higher flexibility (i.e., line pack) and hence easiness of dispatching

- An integrated national (and cross border) hydrogen transport system also lowers the cost of **storage** because:
    - It smooths out consumption and supply peaks, lowering overall storage need
    - It also enables imports from the best renewable resource regions, eg. North Africa, which have lower seasonal variation. Transport cost from N. Africa calculated at 0.15€/kg (3.5€/MWh) using existing infrastructure
    - It allows for centralised storage. We are studying the feasibility of using existing geological storage for H2, technical tests are ongoing. These solutions are the cheapest option: they depend on local conditions, but there are several studies that see it around or below 1€/kg (25€/MWh) for bi-annual cycles[3]
    - The other scenarios would require some kind of above-ground tank storage locally installed. These types of storage solutions (like electrochemical storage) are typically intended for daily cycles, but to cope with H2 supply and demand seasonal pattern, they will be also asked to provide seasonal /monthly storage; this would imply a prohibitive cost, today 100x more expensive than centralised ones (e.g., pressurized tanks).

- An integrated national hydrogen transport system with cross border and import exchanges also **supports supply security** as H2 can be transported from more than one area if anything fails, **promoting collaboration among EU member states,** and is the only one that creates the conditions to **empower a national and European H2 market** and support hub liquidity

3. **What do you think about refurbishing existing gas pipelines for the transport of hydrogen or the construction of dedicated hydrogen infrastructure?**

- Refurbishment will be the predominant option. 70% of our 33.000km of pipelines are already fully hydrogen compatible. The main investments would require compressors and minor equipment such as valves, measuring instruments etc. These normally account for up to 5% of the capex for a newbuild pipeline. We are testing the H2 level which would work with our storage sites.

[3] BNEF – Hydrogen: The economics of storage – July 2019

4. What is your view on blending hydrogen with natural gas?

- Blending does not provide the lowest cost initial demand (as H2 initially substitutes natural gas rather than higher value pure H2 uses) but this is more than offset by the **speed and size of implementation** to:
  - quickly reduce H2 costs. We calculate a 15% learning rate, which would require 25GW of H2 capacity to reach 2€/kg, and this could be reached by blending 2.5% hydrogen (by volume) in the European grid
  - Ensure sufficient capacity is available to reach net zero by 2050. If we relied on ETS to stimulate hydrogen, we would start to see it develop in the late 2030s – too late to reach the scale required in 2050.
  - Leverage the natural reinvestment cycles of industrial users in the 2020s and 2030s.
  - If one agrees with an endgame which sees renewable electricity being turned into hydrogen in the most favourable areas, centrally stored where necessary, and then used throughout the country, it makes sense to start with blending to avoid incentivising sub-optimal de-localised H2 production.

- The reduction in gas consumption due to energy efficiency gains and conversion to electrical power will progressively make available part of the existing gas infrastructure: blending is seen an intermediate step to ensure ramp up of hydrogen transport before being able to fully retrofit a large part of the infrastructure. And once the H2 backbone will be in place, the H2 will be delivered as pure H2 to end-users