HyDelta

WP7A – Hydrogen value chains

D7A.3 – Summary for policymakers: hydrogen value chains in the Netherlands

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Inhoudsopgave

Abbreviations

ATR	*Autothermal Reforming*
BE	*Built Environment*
BEV	*Battery Electric Vehicle*
CAPEX	*Capital Expenses*
CCS	*Carbon Capture and Storage*
CO_2	*Carbon Dioxide*
FCEV	*Fuel Cell Electric Vehicle*
FLH	*Full Load Hours*
HBE	*Hernieuwbare Branstof Eenheden ('Renewable Fuel Entities')*
HRS	*Hydrogen Refuelling Station*
HTH	*High Temperature Heat*
LCOA	*Levelized Costs of Ammonia*
LCOE	*Levelized Costs of Electricity*
LCOH	*Levelized Costs of Hydrogen*
LHV	*Lower Heating Value*
LOHC	*Liquid Organic Hydrogen Carrier*
(M)EUR	*(Million) Euros*
Mob	*Mobility*
NG	*Natural gas*
RES	*Renewable Energy Source*
WACC	*Weighted Average Costs of Capital*

1. On the relevance of the value chain approach

Decarbonization is one of the main political priorities. Both at the European and Dutch level, plans and policies have to be rolled out in the coming years to keep on track moving towards a decarbonized society by 2050. At the European level, the Fit for 55 package is now being implemented, which is the set of legislations and policies to guide the EU towards 55% emission reduction in 2030 compared to 1990 levels. In the Netherlands, while the Climate Agreement of June 2019 aimed for 49% emission reduction in 2030 compared to 1990, the current government announced in 2020 to increase this target to 55%, with ambitions to put policies in place that aim for a 60% reduction.

The considerable mitigation efforts needed to achieve those targets will clearly have to relate to both, the energy electrons and energy molecules, to be successful. Especially the timely greening of energy molecules is crucial because the uptake of energy is still dominated by molecules that still are predominantly fossil. **Green molecules will remain required to fulfil our energy and material demands in a sustainable manner, whereby a distinction can be made between greening based on biomass and other types of greening.** Because biobased molecules can be sustainably obtained only to a limited extent for reasons of risks of losing biomass and biodiversity and crowding out alternative and more valuable uses of biomass for food and feedstock, non-biological renewable and/or low-carbon hydrogen comes into the picture as probably one of the most important building blocks to fulfil the transition towards greening the molecules.

In greening the electrons, renewable electricity production capacities can be connected to the existing electricity grid without any further grid adjustment. So, green power can be transported through the existing configuration of the electricity system – that probably will have to be extended considerably though – and delivered to end users. For clean or green molecules, the picture is often different. For instance, since hydrogen physically differs from fossil gases like natural gas or synthetic methane, adjusted or sometimes even new transport and storage systems and end use equipment may need to be installed to safely introduce hydrogen in the energy mix. In other words, only deploying clean hydrogen production capacity is not enough to decarbonize the molecules; rather **all suitable value chain components must be in place and preferably be operated cost-effectively to enable an economic introduction of hydrogen for the various end uses. In the absence of just one enabling value chain element, hydrogen will most likely have problems coming off the ground.**

Since at the implementation stage every hydrogen value chain component should simultaneously be in place, in practice a major complexity of introducing hydrogen is the timing and coordination of these components, sometimes referred to as the 'chicken-and-egg problem. Moreover, in actual practice multiple sectors will probably want to make use of similar parts of the value chains, so that every sector decision on this is affecting others. Also, hydrogen can be transported via different modes and 'packaged' in different forms (e.g. in ammonia or methanol) affecting end users own required value chain components, but possibly also those of others.

Another complexity of the clean hydrogen value chain relates to its early stage of market penetration, sometimes generically referred to as the 'valley of death' stage. In such early stages investors will have to invest in assets the capital expenditures of which are still typically relatively high due to the infancy of the technology, its low scale of production, and low experience level of implementation. Market perspectives therefore are often uncertain and weak, while learning benefits may easily leak away. As long as the 'valley of death' applies, without policy intervention the early-stage commercial perspectives for clean hydrogen are often poor, while demand is still unstable. Moreover, because early supportive policies and measures or those still to be adopted, are generally complex, they can be hard to predict, which may create another challenge for potential investors in hydrogen value chain components.

To conclude, taking the full value chain into account when analysing the hydrogen market potential is necessary to generate the full picture of how to get the uptake of clean hydrogen in the energy and feedstock mix off the ground effectively. This notion equally applies for investors in value chain components and for policymakers setting up policies and measures.

In the next sections we will highlight the main insights derived from the research (reported in D7A.1 and D7A.2) under HyDelta WP 7. In that research multiple hydrogen or 'packaged' hydrogen value chains have been analysed, including: ammonia-, methanol-, distributed high temperature heat-, mobility- and built environment-applications. For each end use application, multiple value chain designs, including the expected volumes and required levelized costs per chain element, have been constructed. It is important to notify that in the analysis the levelized production costs represent the discounted production and conversion costs themselves plus the transport costs associated with bringing the energy carriers to shore. If in the analysis we refer to the levelized value chain costs, except from the levelized production costs, also the discounted costs associated with domestic transport and storage have been included and possibly those of reconversion if needed. In the following the main insights of this analysis will be discussed for each of the subsequent value chain stages.

2. Clean hydrogen production in the perspective of the value chain

Three types of clean hydrogen production modes have been distinguished in the analysis: 'domestic green', whereby dedicated windfarms are directly connected to electrolysers[1]; 'domestic blue', based on autothermal reforming (ATR) technology combined with carbon capture and storage (CCS); and 'imported green' hydrogen.

In almost all chains analysed, the production step involved the largest share of total value chain costs (see also Appendix A for detailed cost distributions). So, production costs contribute significantly to the chains' overall competitiveness. However, as mentioned before, without the right transport, storage and demand conditions being fulfilled, production of clean hydrogen is meaningless irrespective its cost levels.

For 'domestic green' hydrogen production the reference costs (i.e. the costs to generate the electricity, the costs to transport the electricity to shore and the costs of converting the electricity into green hydrogen with the help of electrolysis) projected for 2030 were found to be some €3.40/kg , while the main costs and cost uncertainties related to capital investment in wind farms and electrolyser plants. A dominant uncertainty is in fact the risk of making an unfeasible capex investment, as is reflected in the WACC of 7%. Because capex investments in windfarms and electrolysers are typically huge and returns uncertain, the major part of the overall production cost uncertainty range of €2.50/kg, namely €2.30/kg, relates to the early part of the investment process namely when the capex decision is made.

[1] It means that the electricity generated by the offshore wind farm is directly and completely channelled towards the electrolyser. The owner of the wind farm can also own the electrolyser, but not necessarily as long as an exclusive delivery contract has been secured.

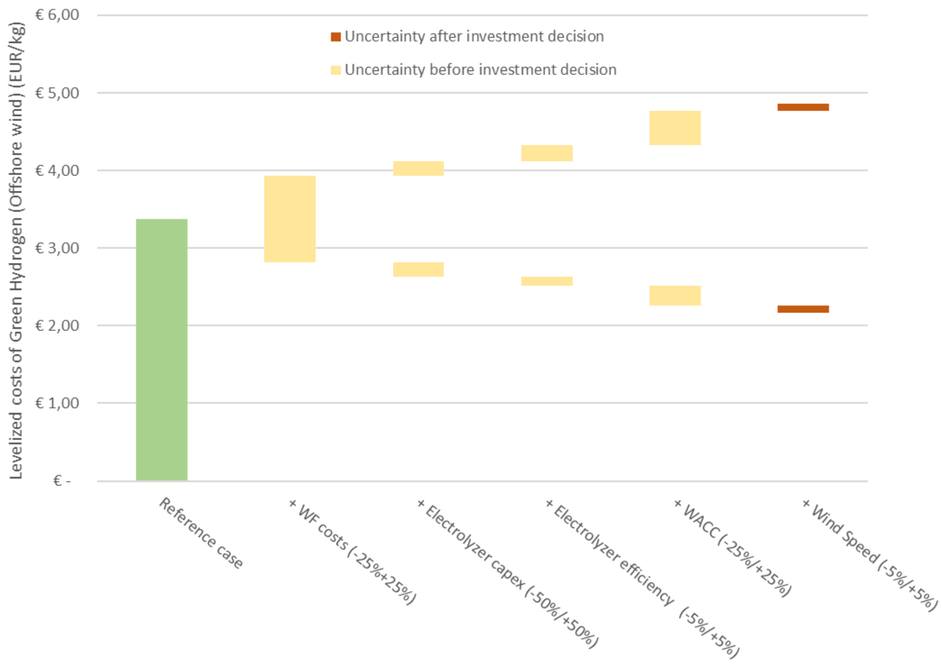

Figure 1 - Future cost of green hydrogen production via offshore wind (North Sea) in the Netherlands, 2030. Assumptions: Alkaline technology, CAPEX 450 EUR/kW, scaling factor 0.9, annual OPEX 2% of CAPEX, efficiency 47.6 kWh/kg of hydrogen, stack lifetime 60000 FLH, WACC 7%, dedicated Dutch offshore wind farm LCOE incl. 100 km cabling is 60 EUR/MWh.

This is quite different in the 'domestic blue' case (via ATR + CCS). Here our analysis indicated projected 2030 reference costs of some €1.95/kg, while production cost uncertainties typically related to opex cost components, and the uncertain future natural gas prices in particular. Investors now typically face uncertainties once the capex decision has been made and the system is up and running. This opex uncertainty covers no less than €3.30/kg of the €4.30/kg total cost uncertainty range of blue hydrogen production. It is important to point out that, while the projected 2030 blue hydrogen reference levelized production costs is considerably lower than that of green hydrogen, namely €1.95/kg versus €3.40/kg, this is not necessarily decisive for investment, because investment decisions will also depend on the horizon of feasibility. If it would turn out that after 2030 green hydrogen would relatively rapidly start to outcompete blue hydrogen, the investment horizon may be too short to generate a sound enough business case.

Another major difference between green and blue hydrogen production costs relates to the so-called levelized production costs of hydrogen. When comparing the domestic green and blue LCOHs, it turned out that capex represented 77% of the domestic green LCOH, at least for the dedicated electrolyser-wind park combinations analysed, while the corresponding figure was 27% only in case of the blue LCOH (and even lower if assuming lasting high natural gas prices).

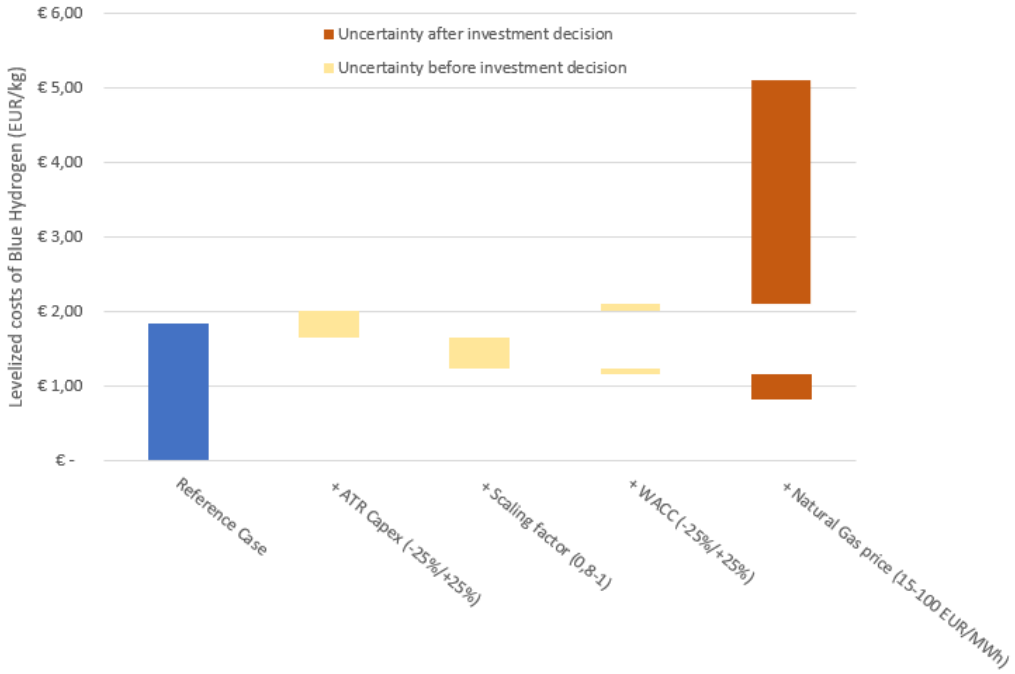

Figure 2 - Future cost of blue hydrogen production in the Netherlands, 2030. Assumptions: ATR+CCS technology, CAPEX: 1.3 MEUR/MW, annual OPEX: 4% of CAPEX, capacity factor: 92%, base scaling factor: 1, natural gas feed: 1.2 MJ NG/MJ H2 LHV, power consumption: 0.014 kWh/MJ H2 LHV, base natural gas price 25: EUR/MWh, electricity price: 60 EUR/MWh.

An important and striking conclusion (based on the combined data of WP7A and WP7B) was that **the typical 2030 levelized cost levels (LCOH, i.e. the discounted costs of production plus transport to a Netherlands harbour) of green hydrogen imported from the researched non-EU source countries[2], ranging between €4.2 - 11.7/kg, turned out to be (considerably) higher than the corresponding €2.2 - 4.8/kg cost range of domestic green hydrogen production, i.e. green hydrogen produced from North Sea wind power.** Only the import case from Morocco assuming low pipeline transport costs via a pipeline connected with the European hydrogen backbone resulted in lower 2030 reference costs, namely €2.53/kg, than the corresponding about €3.40/kg reference costs of North Sea wind-based options. **From a levelized cost perspective importing green hydrogen from non-domestic sources is therefore to be considered as a second-best option.**

If hydrogen is not imported as hydrogen itself in a gaseous or liquid way but instead by way of hydrogen carriers such as ammonia or methanol, the above conclusion changes. Then the levelized value chain costs were on the whole not too different between the import and domestic route, although costs of the domestic route were quite consistently just somewhat lower than those of the import route (for an extensive quantitative illustration, see Figure 10 and Figure 12 in Appendix A).

In determining the total value chain levelized costs of hydrogen (LCOH) rather than just its production costs only, the issue how and against what costs to deal with the seasonal pattern of power supply – and related green hydrogen production – from offshore wind generation clearly is crucial. Intermittency has its price because it may significantly increase the demand for flexibility along the value chains. From the various cost assessments of providing such flexibility it first of all turned out that local seasonal gaseous hydrogen storage in tanks is a very expensive option and therefore not

[2] Import countries analysed in WP7B are Australia, Argentina, Canada, Morocco, Iceland, Saudi Arabia, Oman and the United Kingdom.

suitable for large-scale storage. Secondly, it became clear that there are various other ways to provide the flexibility to deal with the seasonal profile mentioned, all having their own cost profiles:

1) National hydrogen transport combined with large-scale storage in salt caverns;
2) Local conversion into hydrogen carriers, and their transport and storage;
3) Combining domestically produced green hydrogen with blue hydrogen production and/or imports;
4) Matching the seasonal supply profile with demand flexibility by, for example, the seasonal off-take of hydrogen in the built environment sector or a more flexible off-take by industrial users.

Because none of these options needs to compete with the others, a mix of these 'solutions' can be feasible to get to a social cost optimum.

As was already argued, a factor having a serious impact on the overall hydrogen value chain costs is whether or not the hydrogen is used in its gaseous or liquid form, or packaged via a carrier such as ammonia or methanol. Costs assessment suggests that if hydrogen carriers are imported, it anyhow makes no sense (in terms of costs and energy efficiency) to first reconvert them to hydrogen and to later on convert them back into domestically needed ammonia or methanol. So, if domestically the carriers are needed e.g. for industry, the import route based on the same carriers is the more cost-effective than if one needs gaseous hydrogen. A second important point is that to the extent that carriers rather than gaseous hydrogen is imported, this not only affects their national transport and storage chain modalities and thus levelized value chain costs – e.g. ammonia transport by rail, barges or even dedicated ammonia pipelines –, but also affects the economies of scale, and therefore costs, of the gaseous transport and storage facilities.

To summarize, the combination of gaseous and carrier-based hydrogen sources will have direct implications for the transport and storage requirements and their costs, but also indirectly for the costs of the remaining part of the value chain.

3. Hydrogen transport and storage in the perspective of the value chain

How, when and where hydrogen is offered on the market will affect the development of their transport and storage modalities and end uses, but the reverse is equally true: once the transport and storage infrastructure has been installed this will **to a large extent determine what types of hydrogen sources and end-users will be attracted to the existing value chain ecosystem.** Two examples may serve to illustrate this:

1. Whether a specific fertilizer plant would choose to decarbonize its process with the help of green ammonia, or rather green hydrogen and nitrogen, as feedstocks, is likely to depend on the availability of a robust and cost-effective hydrogen or ammonia transport infrastructure. For example, a German fertilizer plant could either prefer to use ammonia from the Rotterdam harbour if a corresponding supply chain has already been developed, or instead use green hydrogen from the Eemshaven area if the infrastructure needed for that would be readily available.
2. For the volumes of an individual hydrogen refuelling station (HRS) supply via pipeline will not be an economically realistic option. But if the HRS is located next to a hydrogen pipeline towards an industrial plant or to a widespread local hydrogen grid, supply via a pipeline could become the most economical option dependent on the other situational characteristics.

Some major insights from the value chains modelling analysis have been summarized below, both for the case of a national and a local infrastructure.

National transport and storage

A first insight for national transport as a component of the hydrogen value chains has already been touched upon: if significant volumes of ammonia or methanol will be imported via harbours and demanded in that form domestically and/or abroad, national transport infrastructure for such carriers may be a serious option next to infrastructure for gaseous hydrogen. **Collaboration between all end users and governments involved is required to discuss the overall economics of the feasibility of such parallel transport modalities rather than just single transport modes.**

The costs of a national hydrogen pipeline infrastructure based on repurposed existing natural gas pipelines will be almost completely independent from volumes subsequently transported through it. **So, the more end-users and end-use sectors will utilize such a system once it is put in place, the greater the cost benefits for all of them (for an illustration of how transport costs depend on the volumes transported, see Figure 3).** To enable such benefits, large industrial demand clusters can act as launching customers to make the transportation system cost effective enough for being initiated, so that after that stage other (smaller) end user categories may benefit as well.

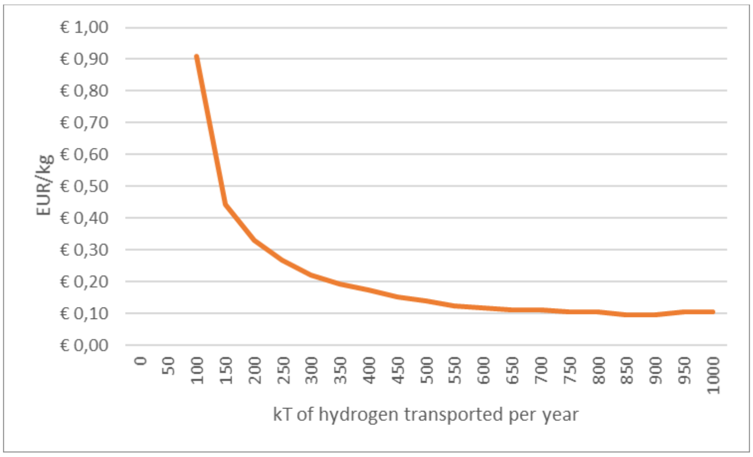

Figure 3 – Indicative impact of national volumes on national reused pipeline levelized costs of transport

Assumptions: two times 500 km. reused pipeline, 200 km. new pipeline, both diameter of 0.91 m. (see pipeline function in D7A.2 Appendix A [1] for calculation methodology)

Another important insight relates to the interrelationship between storage and transport of hydrogen. **If the desirable option to deal with the massive need for flexibility on the hydrogen market is large-scale storage in salt caverns, this will have considerable consequences for the transport infrastructure needed.** Because in the case of the Netherlands such storage is only foreseen to be available in the northern Netherlands, a national transport system will be required to channel hydrogen flows back and forth to and from these storages. This implies more hydrogen transport flows and thus also the need for more transport capacity than without such central storage. Our analysis therefore showed that also because the demand for flexibility significantly increases when domestically produced green hydrogen is used rather than alternatives, so will the need for transport infrastructure increase. **At the same time, it has to be mentioned that the costs of large-scale transport and storage only represent a relatively small fraction (less than 10%) of total levelized value chain costs (€0.20 – 0.30/kg compared to the €3.38/kg reference 2030 levelized hydrogen production costs).**

Regional transport and storage

Three types of potential hydrogen distributed end-users have been distinguished in analysing how demand patterns may affect transport and storage costs, namely: industries requiring high temperature heat (HTH); hydrogen refuelling stations (HRSs) for mobility; and units of the built environment demanding hydrogen for heating. The spatial profile of demand of all types will obviously differ, but the challenge is to try to develop smart transport (and storage) combinations of different units of hydrogen end-users. **Our analysis has shown that via such smart combinations, the transport cost savings over the 'last-mile' to collectively connect these end-users can have significant impact on total value chain costs.**

Fundamentally two hydrogen transport modes for national hydrogen transport can be distinguished: transport by trucks and by pipeline. Both modes have their pros and cons.

Trucks have the advantage that relatively small hydrogen volumes can flexibly and easily be transported against acceptable costs. Moreover, transport unit investment costs are relatively modest (compared to pipeline systems) and can be introduced quickly and for a relatively short timeframe (e.g. some 10 years only), if needed. The main disadvantages are: that a relatively significant amount of energy and fuel (see also Figure 4) is required to move the trucks (causing CO_2-emissions or hydrogen losses); that absolute truck transport costs of gaseous and liquid hydrogen are relatively high; that large volumes of hydrogen transported by trucks will require significant truck fleets which may cause local traffic, safety and acceptance concerns; that LOHC transport may require heat at the demand location to separate the hydrogen from its carrier; and that hydrogen delivery with trucks to the built environment may have a strong seasonal profile so that the fleet may stand idle part of the year (see Figure 18 in Appendix A).

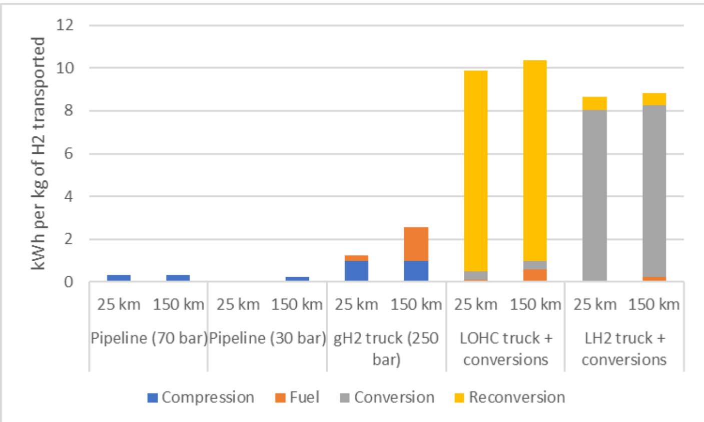

Figure 4 – Energy consumption required for the transportation of one kg of hydrogen (equals 33,3 kWh of energy content) Note: during conversion of hydrogen to LOHC 8 kWh of heat is released.

The alternative transport mode, regional and local hydrogen transport by pipelines, typically has much larger capex levels and will therefore only be an economic option if transported volumes are large enough. So, the denser hydrogen demand is in a specific region, the more cost-effective hydrogen pipeline transport becomes. The generally relatively large regional demand volumes of distributed plants requiring HTH can sometimes – by opening attractive pipeline transport options – be used as accelerator of other hydrogen demand in the same region. Our empirical results illustrating this finding for the situation in the Netherlands have been summarized in Figure 5 (see 'shared' costs compared to 'individual' costs) and clearly show **that levelized value chain costs of hydrogen for the built environment and mobility will come down some 40% if one can join an existing pipeline for transport**.

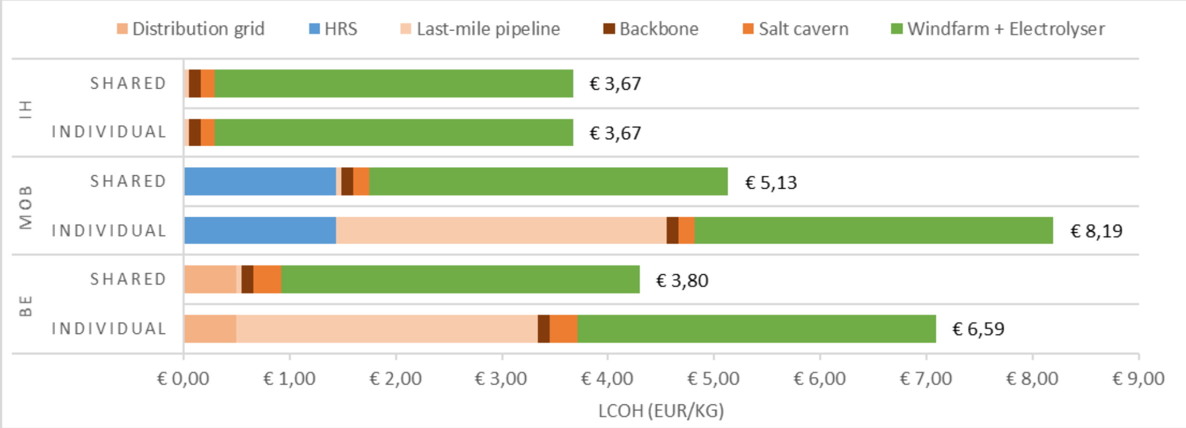

Figure 5 – Cost reduction of sharing last mile (regional) pipelines compared to using individual pipeline infrastructure per end use. Assumptions: in the individual chains a single end user (industrial plant (IH), HRS (Mob) or neighbourhood (BE)) is connected to the last-mile pipeline of 25 km. connecting the end user with the backbone. If that pipeline can be shared among the one of each three types of end users, the pipeline costs are based on the consumption volumes of those three end users together.

It is altogether clear that local and regional delivery costs of hydrogen strongly depend on regional characteristics such as: options to create end-user smart combinations for transport and the overall regional demand volume of hydrogen, the distance of potential end-users in the region from a potential hydrogen backbone, the availability of waste heat for cases in which LOHC reconversion is needed, or the potential for local hydrogen production. That is why in assessing local transport (and storage) costs of introducing hydrogen a regional approach is imperative. For instance, without such a regional approach the benefits of joint, multi-sector use of (repurposed) pipeline transport or storage options would be unduly disregarded, etc. **Therefore, for a proper analysis of the development of value chains one should not take the perspective of sectors only, but also and in particular of geographical clusters as well: it may in itself be too costly to connect a particular industrial area with the backbone, but if combined with other end users it may perfectly make sense to do so from a cost perspective.**

4. Final uptake of hydrogen by end users

Any hydrogen value chain can only develop if there is sufficient demand against prices that can compete with the alternative, initially fossil and eventually carbon neutral, options. In the modelling work of our analysis five types of end-users have been distinguished each with its own most logical carrier: ammonia as resource for the fertilizer industry; methanol as resource for fuel production; high temperature heat with the help of hydrogen for decentral industries; and gaseous hydrogen for refuelling stations for mobility and for the built environment. For all applications the simulations suggested that **the value chain costs with clean hydrogen are higher than the fossil alternative society has been used to during the last decades.** In several cases, such as greening the production of ammonia or methanol or heating houses that are very hard to insulate, except from using carbon neutral hydrogen virtually no alternatives have sufficiently high technological readiness levels to be implemented at short notice on a considerable scale. So, higher energy/feedstock cost levels than in the fossil past will need to be accepted as fact of life if the accepted mitigation targets are to be achieved.

It is extremely important both for investment and policymaking to get more understanding of when and under what conditions green and blue hydrogen or hydrogen carriers for industrial use can compete with grey hydrogen (carriers). Our analyses concluded that of all factors the prices of natural gas and CO_2 allowances had by far the most impact on the production costs of the various varieties of hydrogen. **Figure 6 shows in this respect that if offshore wind and electrolyser capex costs come down towards 2030 as generally is expected based on the learning curves, and if the 2021 natural gas and CO_2 prices (of respectively €75/MWh and €60/ton) will remain at that level towards the end of the decade, then the green ammonia routes will be competitive against the grey ones by about 2030. For green methanol a similar finding of the impact of the mentioned set of assumptions is seen** (even if CO_2 prices have less impact on costs of fossil alternatives because part of the CO_2 emitted is used as feedstock to produce the methanol; see Figure 13 in Appendix A).

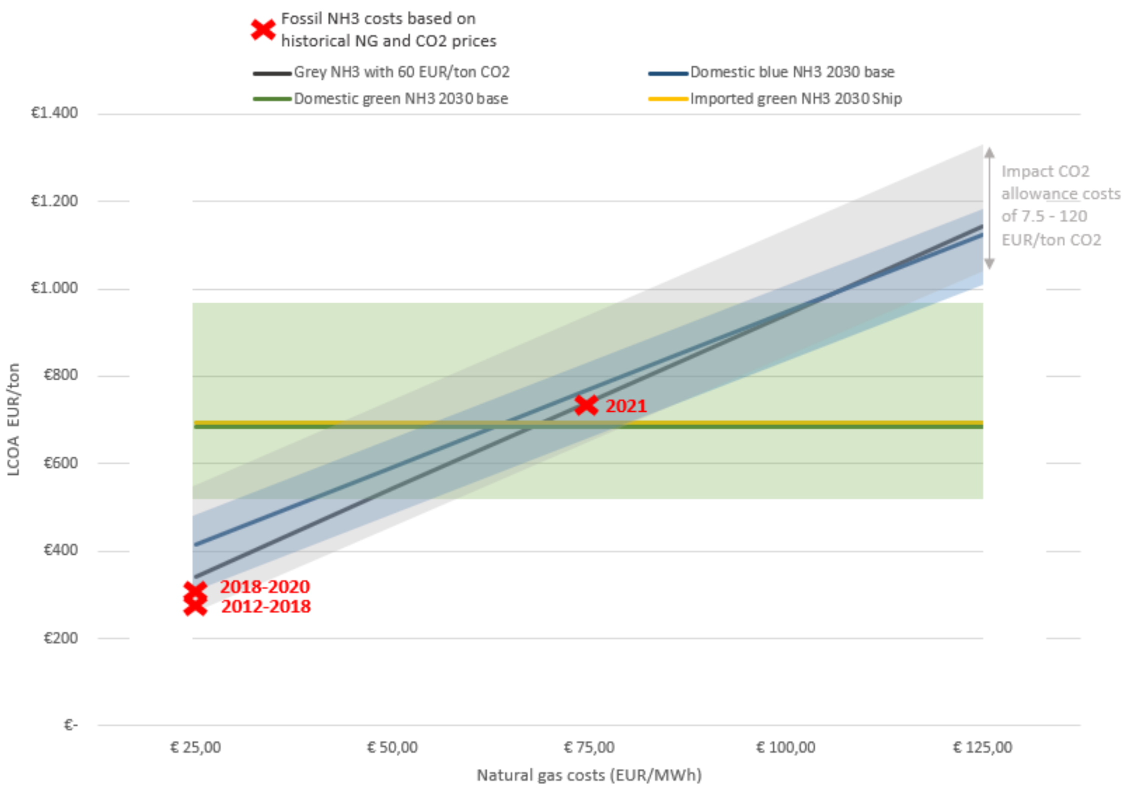

Figure 6 - Visualization of the impact of the natural gas and CO_2 price on the reference price of NH_3 and on carbon-neutral NH_3 produced from blue hydrogen. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty in fossil NH3 costs based on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport to end-use site. The reference costs of NH3 are calculated using 1.75-ton CO_2/ton NH_3 [2]; the natural gas price and the CO_2 costs of the past decade have been, respectively, +/- 25 EU/MWh and 5-15 EU/ton CO_2 [3] [4] [5]. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to over 60 EUR/ton CO_2).

In the comparable case of distributed industries that need HTH the gap between grey and green hydrogen instead is larger, since natural gas is burned directly to produce the heat. If one assumes that by 2030 the natural gas price is €75/MWh and CO_2 allowance costs are €60/ton CO_2, then the break-even levelized price of green (versus grey) hydrogen used for high-temperature-heat purposes will be €2.90/kg (for more information, see Figure 14 in Appendix A). Because our 2030 projection of the reference levelized green hydrogen value chain costs boils down to some €3.75/kg, green hydrogen costs are getting much closer to those of grey hydrogen, but cannot yet compete for heat purposes by 2030. This conclusion obviously may change to the extent that the gas and CO_2 prices will be higher by 2030. **It is important to note in this respect that already in the beginning of 2022 the natural gas and CO_2 prices are at such levels that green hydrogen would slightly outcompete grey hydrogen in 2030. It is still to be seen if and to what extent the early 2022 conditions on the energy markets are an exception or rather the beginning of a trend.**

The competitiveness of the blue pathways also typically depends on the carbon and natural gas costs. **If one makes the 'conservative' assumption of natural gas costs of €50/MWh, then carbon costs of €91/ton CO_2, €274/ton CO_2, €124/ton CO_2 are needed to make the blue pathway competitive against resp. the grey ammonia, grey methanol and natural gas for HTH pathways.**

From a perspective of levelized total value chain costs, mobility and the built environment often have serious potentials as end users of green hydrogen. Whether there is actually a solid business case for such hydrogen uptake, however, almost always strongly depends on location-specific conditions. To illustrate, FCEVs can often be fuelled relatively cheaply at home, but **if driving ranges are >400km and external electric fuelling can only be done at a relatively high fast-charging rate of some €0.55/kWh, then fuelling FCEVs instead with green hydrogen becomes the more cost-effective alternative if that hydrogen can be supplied at <€6.20/kg (taking the assumed purchasing and use costs differentials of vehicles into account). For trucks the corresponding break-even figure is <€6.40/kg**. In fact, multiple value chain options of direct use of green hydrogen for mobility have economic potential if hydrogen can be supplied against the green hydrogen prices just mentioned. Typical conditions under which direct use of green hydrogen in mobility may provide a sound business case are: chains with the availability of locally produced hydrogen; chains with LOHC transport and heat surpluses for reconversion; or chains where transport can benefit from cheap regional hydrogen pipeline infrastructure (for a detailed survey of the levelized value chain costs of various mobility options, see Figure 16). On the whole local green hydrogen mobility options become attractive to the extent that the following assets are available: local RES, local waste heat for LOHC reconversion, and local regional pipeline infrastructure.

In the built environment using clean hydrogen for heating and cooking is a way to decarbonize without on the whole large technical implications and adjustment costs for the end-users. Just as in mobility, also in the built environment there is a range of decarbonization options, such as electrification, introducing heat grids, or switching to clean gases. The latter is typically a promising decarbonisation option for older, hard-to-insulate buildings, or buildings in rural areas where extending the electricity and heating grids is problematic. Introducing biomethane is typically cheaper and easier-to-implement than renewable hydrogen, but often its available amount is limited. Then clean hydrogen comes into the picture. In our analysis it was consistently found that for the introduction of clean hydrogen in the built environment in a particular area to be cost-effective, for transport cost reasons it needs to be used in other sectors in that area as well.

If the (without energy tax) natural gas price remains at levels above €70/MWh, renewable hydrogen can compete with natural gas as a fuel for the built environment by 2030, at least if the current energy tax on natural gas remains and renewable hydrogen would benefit from an energy tax exemption. If moreover the energy tax on natural gas would rise towards 2030 by 75% from its current level, as projected in the Netherlands' Climate Agreement [6], only a natural gas price >€50/MWh is needed to make clean hydrogen competitive against natural gas.

For each value chain different support intensities of the monetary value of financial support are needed to make clean hydrogen competitive against fossil alternatives (see The generic table below shows this for different types of end-uses and hydrogen sources while assuming: a natural gas price of €50/MWh, a CO_2 allowance price of €60/ton, and the levelized value chain costs of the base scenarios of our study. **It shows first that in all generic cases the imported hydrogen will need more support to compete with fossil alternatives than all the corresponding domestically produced hydrogen (carrier); in other words, except from some country specific exceptions, imports of green hydrogen and hydrogen carriers is only economically attractive to the extent that domestic production is insufficient to meet the demand.** The table also illustrates that **clean hydrogen for ammonia**

production requires the lowest financial support intensity of the four options considered. For instance, per ton of CO_2 reduced an overall support level of €60 plus €81, or some €140, is needed to make domestically produced green ammonia competitive against fossil ammonia This result is especially so, because the natural gas and CO_2 allowance price impact on the fossil ammonia costs are largest compared to the other hydrogen applications. This explains why the impact of CO_2 allowance prices is less for the grey methanol value chain, as part of the carbons are used to produce the methanol. Finally, if **clean hydrogen is used for heating (both industrial and in the built environment) rather than as a feedstock, it will require higher support per kg of hydrogen produced to get the full chain competitive**.

Table 1; for an extended version, see Appendix B). The generic table below shows this for different types of end-uses and hydrogen sources while assuming: a natural gas price of €50/MWh, a CO_2 allowance price of €60/ton, and the levelized value chain costs of the base scenarios of our study. **It shows first that in all generic cases the imported hydrogen will need more support to compete with fossil alternatives than all the corresponding domestically produced hydrogen (carrier); in other words, except from some country specific exceptions, imports of green hydrogen and hydrogen carriers is only economically attractive to the extent that domestic production is insufficient to meet the demand.** The table also illustrates that **clean hydrogen for ammonia production requires the lowest financial support intensity of the four options considered.** For instance, per ton of CO_2 reduced an overall support level of €60 plus €81, or some €140, is needed to make domestically produced green ammonia competitive against fossil ammonia This result is especially so, because the natural gas and CO_2 allowance price impact on the fossil ammonia costs are largest compared to the other hydrogen applications. This explains why the impact of CO_2 allowance prices is less for the grey methanol value chain, as part of the carbons are used to produce the methanol. Finally, if **clean hydrogen is used for heating (both industrial and in the built environment) rather than as a feedstock, it will require higher support per kg of hydrogen produced to get the full chain competitive**.

Table 1 – Overview of support intensities required to make hydrogen value chains competitive against the fossil alternative (see Appendix B for more details and the main assumptions)

	Ammonia				**Methanol**		
Support intensity	Blue	Green	Import green		Blue	Green	Import green
€/ton of product	52	142	153		94	207	250
€/kg H2	0.29	0.80	0.86		0.47	1.04	1.25
€/ton CO2 reduced	31	81	87		49	106	128

	Industrial heating				**Built environment**	
Support intensity	Blue	Green	Import green		Green (without tax differentiation)	Green (with tax differentiation)
€/MWh	42	64	83		70	23
€/kg H2	1.25	1.90	2.49		2.11	0.69
€/ton CO2 reduced	64	96	126		107	35

5. Policy aspects related to the hydrogen value chain

For the development of a hydrogen system, also policymakers will have to think in terms of the hydrogen value chain rather than just its components. So far in the Netherlands in policy making much attention has been given to supporting the production of clean hydrogen (e.g. Porthos, PosHydon, National Growth Fund, NorthH2) with a large focus on electrolyser capacity, and on preparing a national transport system e.g. HyWay27. Much less attention so far has been devoted to the other value chain components such as storage modalities and market uptake perspectives. As **a broad picture of what seems advisable for policymaking it is important that the balance of political attention would focus more strongly on measures covering the entire value chain, and that more attention will be given to dealing with the issues of final uptake of hydrogen and of flexibility in terms of conversions and storage that are required in a future Dutch energy system.**

The relevant insights of the study for policy development are categorized per component of the value chain:

Hydrogen production and sources

- **The existing policies cannot take away the fact that there still are large uncertainties as to what degree specific sources of hydrogen will be demanded or not**, e.g. with respect to: the future role of blue hydrogen, the future role of hydrogen imports versus domestic production, the choice of energy carriers (pure hydrogen versus ammonia or methanol), and also the future choice on rules with respect to additionality. A role policy could play is to provide more clarity on such perspectives, as most of these uncertainties have underlying fundamental political choices about self-sufficiency, the perception of sustainability, and the role the nation should play in the global industrial ecosystem.
- Scenarios with a focus on: green hydrogen production e.g. via dedicated wind parks; blue hydrogen production with ATR+CCS; or imported hydrogen, significantly differ in their capex versus opex cost distributions and the dependency of their costs on market developments, such as natural gas and CO_2 allowance prices.
- Each hydrogen production source has its own requirements and consequences:
    - For green hydrogen large amounts of power is required if large industries will (partially) depend on this source, which can be an issue when green power is still scarce. **An important political point of attention is how, and based on what criteria, it is determined for what purposes the scarce green power is used**, e.g. industrial or small-scale electricity users, new data centres, mobility, or green hydrogen production.
    - How to provide flexibility is already a point of growing political attention with respect to electricity markets getting increasingly dominated by intermittent supply. The same amount of attention will have to be applied to the **flexibility needed on the hydrogen market**. The intermittent character of green hydrogen production will demand for flexibility elsewhere in the hydrogen value chain. **To develop such flexibility new policies and measures may be required.**
    - **Blue hydrogen requires a robust, acceptably priced and reliable natural gas market, which is not a certain precondition anymore since the autumn of 2021**. That is why the recent natural gas price surge may affect the competitive edge and long-term market potential of blue and grey hydrogen compared to green hydrogen. An advantage of blue hydrogen is, however, remains that production is predictable and therefore does not require the flexibility in the value chains that green hydrogen

demands. Moreover, blue production can probably be utilized to (partially) stabilize the green hydrogen production pattern.
  - If the Netherlands want to keep its position as an European energy hub, energy imports is expected to remain of strategic importance, because it is unlikely that NW Europe will be able to produce sufficient volumes of clean hydrogen itself, at least not on the short and medium term. This means that policy makers will have to prepare for a serious import flow of hydrogen, e.g. in terms of setting the stage for contracts with foreign suppliers and for logistics, licencing conditions etc. especially in suitable harbour areas. **Import of hydrogen by ships can enter harbours in all sorts of hydrogen carriers. This does not imply that it always needs to be reconverted to gaseous hydrogen and put into a gas pipeline system**. Throughput of hydrogen (carrier) flows to other locations in the Netherlands or neighbouring countries may ask for specific Dutch infrastructure requirements, not only for hydrogen, but also for its carriers such as ammonia and methanol. Certain choices can have large demands and costs impacts on the Dutch railways, highways and waterways or even newly constructed pipelines, and therefore oversight and coordination is required. This deserves significant attention of the government.

Transport and storage

- **Especially if the hydrogen market is still under development, new infrastructure can be an enabler or inhibitor of specific hydrogen activity**. The government therefore can steer regional hydrogen developments through their decisions together with the TSO and DSOs on hydrogen infrastructure, which makes hydrogen infrastructure development also a special governmental responsibility for regional economic development.
- **The government should carefully consider if and to what extent it will enable conditions for hydrogen transport and storage by way of pure hydrogen or as a hydrogen carrier**. There is a distinction between hydrogen carriers that are demanded as feedstock to make specific products (like ammonia and methanol), and hydrogen carriers that are used for transport and storage purposes only. For ammonia and methanol applications the discussion is where conversion should take place: at the location of production or consumption, or anywhere else? For liquid hydrogen and LOHC the modelling suggests that those carriers can play a role in the initial stages of development and in specific value chains related to mobility, but that in the long run gaseous hydrogen transport and distribution with pipelines will in most cases be the preferred option for economic reasons.
- **The main recommendation for the deployment of a pipeline transport system for hydrogen is to focus on geographical clusters with different categories of end-users that collectively can benefit from economies of scale of infrastructure use**. Areas connected with hydrogen supply chains for industrial application can easily also develop hydrogen mobility clusters or more intensive hydrogen in the built environment, simply because the hydrogen infrastructure in the area is readily available and relatively cost-effective.
- Any future hydrogen mandatory blending regime – especially physical blending – will have a strong impact on the hydrogen transport and storage demand[3]. Blending policies and policies towards introducing new infrastructure for hydrogen therefore will have to be well coordinated in order not to risk economic losses. The same applies with respect to policies

[3] For an extensive overview of the various blending issues and how blending could be introduced in the gas system, the reader is referred to HyDelta D8.1-D8.5 [20] [19] [18] [17] [21].

supporting the position of the Netherlands as a future hydrogen transit hub of North-Western Europe.

- Assuming that carbon neutral hydrogen eventually will also dominate the gases in the distribution grid, the government will have to carefully communicate with the grid operators and their end-users how and when it wants to achieve this. If blending is introduced, a right balance has to be found between a virtual blending scheme e.g. based on 100% and 0% blending rates per part of the grid on the one hand, and a pro-rata physical blending throughout the distribution grid on the other hand.
- A storage strategy is likely to be needed on the long term when the role of hydrogen is much more dominant than nowadays. Just as the need to balance the electricity market, so will the future hydrogen market need to be balanced to correct the mismatch between the time profiles of supply and demand. Essentially large-scale storage can be done by storing hydrogen in salt caverns, or by storing hydrogen carriers in large tanks. Next to that various storage options for smaller volumes are currently under development. Economic conditions will clearly determine how storage modalities will develop, but the government will probably have to play an active role to get to a smooth and economical storage capacity development. It is important that any future decisions on storage options are incorporated in the overall design of the hydrogen transport system, because centralized large-scale storage will clearly have strong repercussions on transport needs of hydrogen.

End-users

- The development of value chains for different categories of end-users should not be assessed independent from each other. **Launching customers are required to develop the value chains and open infrastructure for other types of end-users**. A logical sequence based on the volumes and locations of end-users is to start with the large, centralized industries to enable the introduction of a national infrastructure. Thereafter, investments to supply distributed industries can be made, which can be followed by even more local users, such as the built environment. This supplements the recommendation made in previous section to deploy hydrogen infrastructure based on geographical clusters. For such clusters to be successful, it often is important to organise the full-scale support of the relevant stakeholders to join well in advance, to prevent that costly dual transport systems need to be maintained just to serve a small minority of end-users that have not been included in the hydrogen concept in time.
- **Multiple mobility value chains were seen to be relatively cost-effective without the requirements of large economies of scale** using local hydrogen chains or LOHC. The main issue here is the coordination of a simultaneous development of both refuelling infrastructure and vehicles. Unlike in the built environment, mobility off-take with its typically relatively small uptake volumes can already be initiated without the help of strong launching customers.
- The seasonal time profile of demand of the built environment (higher in winter) matches well with the supply profile of (offshore-)wind-based hydrogen production (also higher in winter). So, combining such demand with such supply overall reduces seasonal storage requirements.
- In order to stimulate clean hydrogen use by different types of end-users, some generic issues should be taken into account:
    - Clean hydrogen competes better with fossil hydrogen than with natural gas.
    - Tax differentiation, such as a tax holiday for green hydrogen, will have a significant impact on stimulating renewable hydrogen for the built environment.
    - Given the prices of €13-16 paid for HBE's (=1 GJ of fuel supplied) in 2020-2021, and the acceptance of hydrogen in this scheme from 2022, hydrogen supplied to vehicles

could already receive an amount of €1.50-€1.90/kg of support, and even when including the multiplier of 2.5, €3.90-4.80/kg of support.

Overview of deliverables

D7A.1 'Hydrogen value chains literature review' [7]

This deliverable provides an overview of the existing literature and knowledge about hydrogen value chains, including the separate stages (production, transport, storage and end-users) along the value chain and different approaches to model them.

D7A.2 'Techno-economic analysis of hydrogen value chains in the Netherlands: value chain design and results' [1]

This deliverable describes the chain designs and detail results of the HyDelta Value Chain model for five types of applications: ammonia for fertilizer production, methanol for E-fuel production, high temperature heat in distributed industries, mobility and the built environment. The deliverable describes the levelized cost distributions for each element to make the chains economically viable and the main sensitivity impacts. Thereby, other important considerations to establish the chains, including the interdependencies between different sectors.

D7A.2 Appendix E 'Untangling the dynamics of a future hydrogen market' [1]

The Appendix E of D7A.2 is an independent readable paper that explores the factors that determine future hydrogen carrier market dynamics. Three main issues and directions for solutions are presented. The appendix gives background to the market environment in which hydrogen value chains will develop, including its interdependencies.

Related deliverables in HyDelta 7B

D7B.1 'Datasheets' [8]

The datasheets provide techno-economic information about hydrogen carrier supply chains, including production, transportation, storage and conversion. The techno-economic data is used as input for the Supply Chain Model (HyDelta 7B) and the HyDelta Value Chain model (HyDelta 7A).

D7B.3 'Comparison of different carrier import chains'

This deliverable presents the hydrogen (carrier) import costs to the Netherlands from different destinations and transported via different types of carriers for 2030 and 2040. The import costs of 2030 are used as input for the HyDelta Value Chain model to calculate the import hydrogen value chains and compare them to the domestic ones.

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Appendix A: summary of results Techno-economic value chain analysis

Based on the results and analysis performed in HyDelta D7A.2, we conclude the following key insights related to different parts of the value chain:

1. **Hydrogen production. There is a high uncertainty range in the dominant cost factors that will determine what source of hydrogen will become most competitive in 2030.**

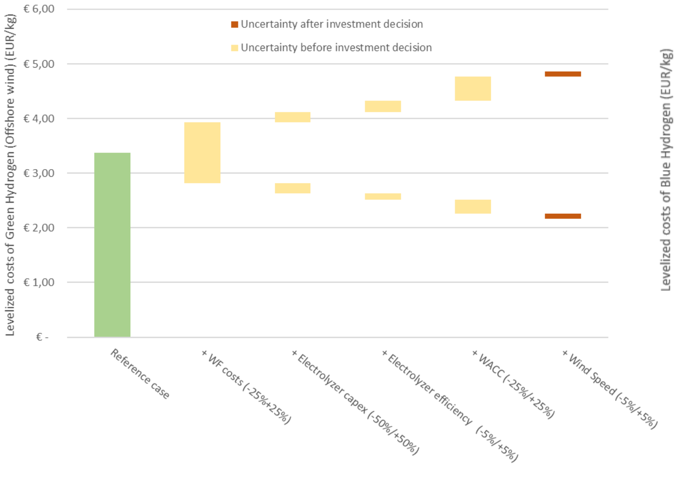

Figure 8 - Future cost of green hydrogen production via offshore wind (North Sea) in the Netherlands, 2030. Assumptions: Alkaline technology, CAPEX 450: EUR/kW, scaling factor: 0.9, annual OPEX: 2% of CAPEX, efficiency: 47.6 kWh/kg of hydrogen, stack lifetime: 60000 FLH, WACC: 7%, Dedicated Dutch offshore wind farm LCOE incl. 100km cabling: 60 EUR/MWh.

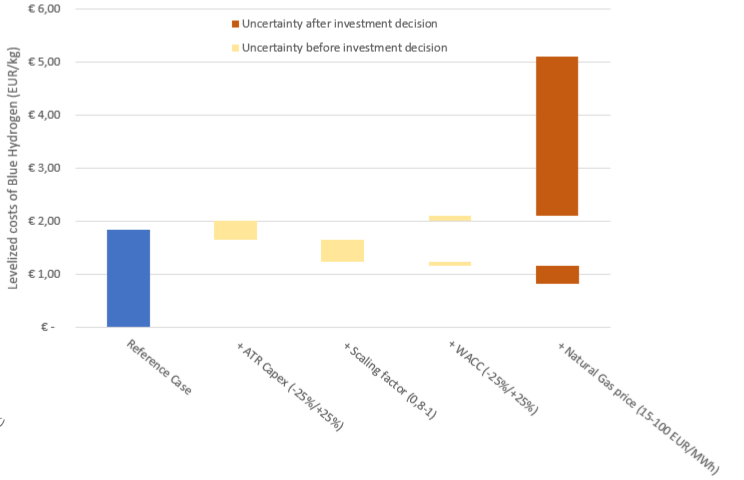

Figure 7 - Future cost of blue hydrogen production in the Netherlands, 2030. Assumptions: ATR+CCS technology, CAPEX 1.3 MEUR/MW, annual OPEX: 4% of CAPEX, capacity factor: 92%, base scaling factor: 1, Natural gas feed 1.2 MJ NG/MJ H2 LHV, Power consumption: 0.014 kWh/MJ H2 LHV, base natural gas price: 25 EUR/MWh, electricity price: 60 EUR/MWh.

A significant difference between green hydrogen production plants with dedicated offshore windfarms and newly constructed blue hydrogen production plants using ATR+CCS, is that the main cost uncertainty of green is in the capex, before the investment decision, while for blue these are in the opex (i.e. natural gas price), which remain uncertain at the moment when the investment decision is made.

2. **Transport. Launching customers can act as steppingstones towards a cost-effective transport system for hydrogen on a national, regional and local level.**

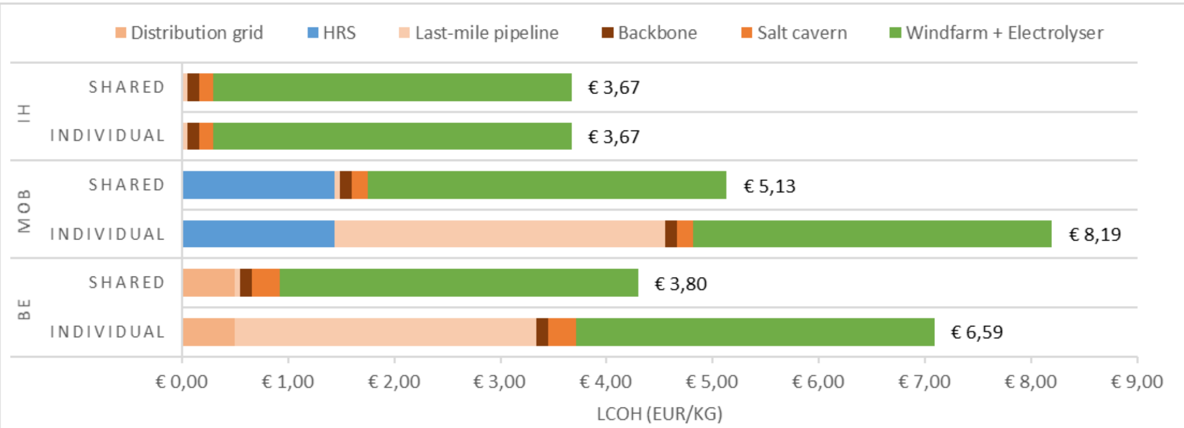

Figure 9 – Overall value chain costs and cost reduction of end user sharing last mile (regional) pipelines compared to using pipelines per individual end user. Assumptions: in case of transport use by a single end user (industrial plant (IH), HRS (MOB), or neighbourhood (BE)), 25 km of the last-mile pipeline is connected to the backbone. If that pipeline can be shared by the 3 end user categories, the pipeline use costs are based on joint consumption volumes.

Figure 9 shows an example how a cross-sectorial approach could benefit the transport costs of regional pipelines for different types of end users. In this example, the relatively large volumes of decentral industrial high temperature heat plants could help to achieve the volumes to make hydrogen locally available for other types of end users.

3. **End-users. In all types of hydrogen end uses, production costs represent the largest share in the total value chain costs. Note in this regard, however, that in the end no single value chain step can be missed to make hydrogen available at the right place, form and time. Situational aspects, technological details and/or mutual benefits of combinations between end-users strongly determine what options are available and cost effective, and where and when.**

We will give a brief overview of the main findings per type of end user.

Industrial feedstock: ammonia for the fertilizer industry

- Providing the required flexibility - assuming a variable production profile of green hydrogen produced with national offshore wind versus a stable demand for ammonia - is critical in the development and value chain costs of carbon neutral ammonia. Because seasonal gaseous hydrogen storage in tanks is very expensive and can only be implemented in very specific small-scale cases, one will typically have to resort to: 1) national hydrogen transport systems combined with large-scale hydrogen storage in salt caverns; 2) trying to increase the flexibility of the ammonia synthesis process; and/or 3) increasing hydrogen production flexibility (e.g. by combining domestically produced green hydrogen with blue hydrogen production and/or import of carbon neutral hydrogen; or by using other carbon neutral sources of electricity in the production process of hydrogen).

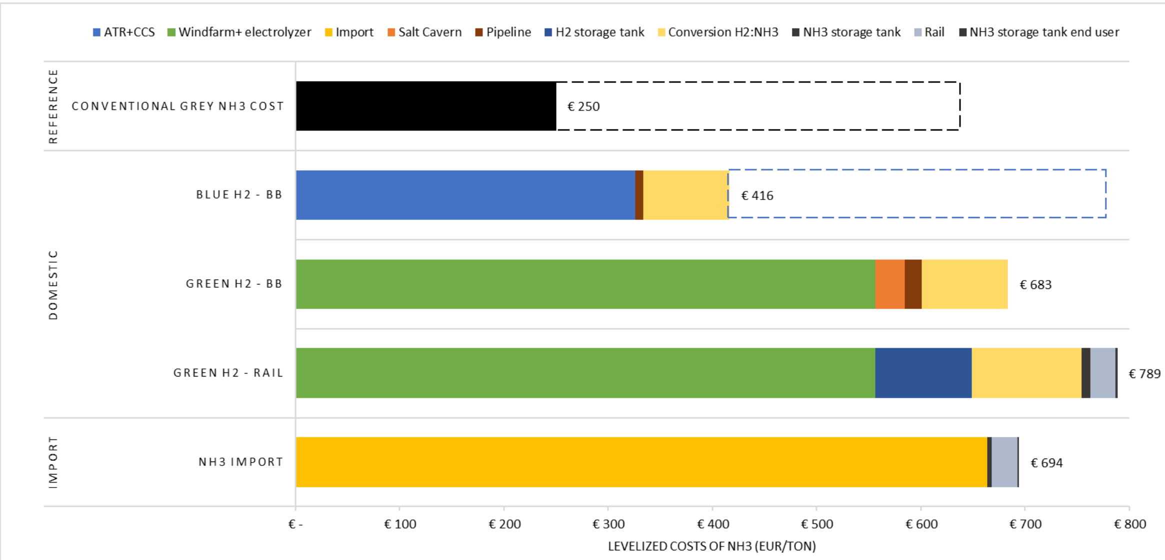

Figure 10 - Results of 2030 cost decompositions for ammonia value chains.

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show the impact of a natural gas price of 75 EUR/MWh: grey reference LCOA increases to 650 EUR/ton and blue H2 BB to 770 EUR/ton), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser: 60 EUR/MWh, green NH3 import costs include the average import costs by ship from Canada, Australia and Morocco, for the Green H2 Rail chain results of flexible conversion operation mode are presented, which partially follows the offshore wind pattern.

- The results of the value chain levelized cost assessments of green ammonia did not show significant cost differences between those of domestic versus imported green ammonia. A precondition for ammonia imports, however, is the availability of domestic transport modalities for ammonia[4]. In our study only the rail option has been assessed and may provide acceptable transport costs. However, this transport mode is known for its practical hick-ups due to rail availability, and safety and public acceptance issues. The practicality and costs of alternative inland ammonia transport options via trucks, inland barges or dedicated ammonia pipelines will therefore require further research.

The levelized value chain costs of green ammonia computed in this study (683 €/ton domestic; 694 €/ton import) are significantly higher than the traditional costs of fossil ammonia of the past decade (250 €/ton). Note, however, that natural gas prices showed a remarkable surge by the end of 2021, just as allowance prices did. These prices strongly affect the competitiveness of green vs grey and blue hydrogen so that whether or not the surge mentioned is part of a long-term trend is rather crucial for short-term chances of green ammonia becoming commercially feasible. For renewable ammonia, only biomethane (production costs of 50-100 €/MWh [9]) and some specific technologies in R&D readiness level are available.

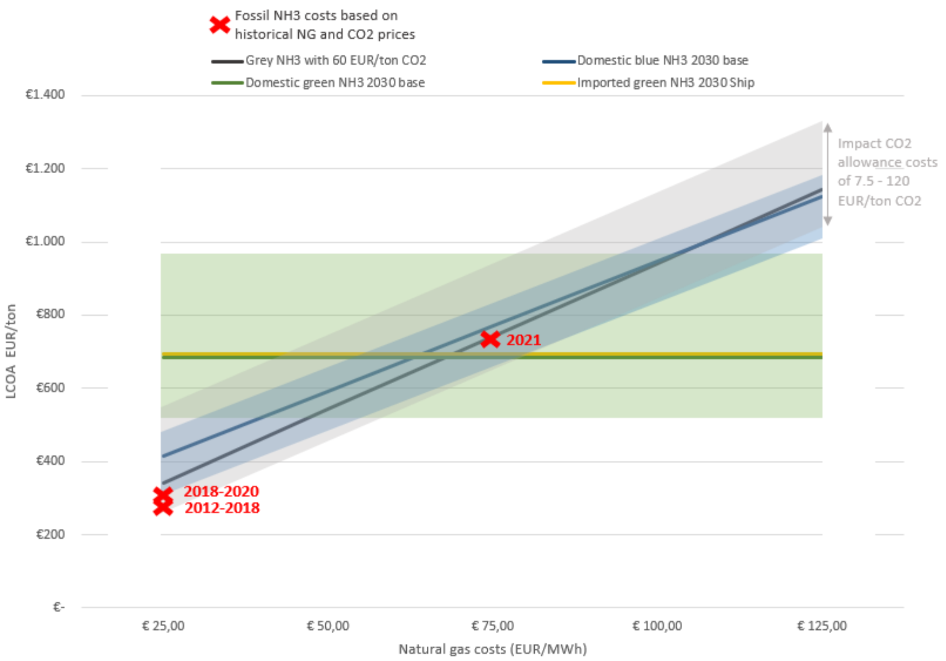

Figure 11 - Visualization of the impact of the natural gas and CO2 prices on the reference price of NH_3 and on carbon-neutral NH_3 produced from blue hydrogen. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty in fossil NH3 costs based on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized value chain costs presented include transport to end-use site. The reference costs of NH3 are calculated using 1.75-ton CO_2/ton NH_3 [2], the natural gas and CO_2 prices of the past decade have been, resp. some 25 EU/MWh and 5-15 EU/ton CO_2 [3] [4] [5]. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021 the natural gas price rose to 80-180 EUR/MWh and the allowance price to 60-90 EUR/ton CO_2).

Industrial feedstock: methanol for E-fuels

Just like ammonia, so does the fluctuating production profile of intermittent RES/green hydrogen-based methanol require some type of flexibility (by production, storage, conversion and/or end use) in order to match with the time profile of demand. That is why blue methanol is also considered to be a serious option, because securing a stable supply flow of it throughout the value chain is more easily possible than supply of green methanol, although the significant impact of the natural gas price can act as a backdrop.

[4] Theoretically reconversion of imported ammonia to hydrogen, followed by transport of hydrogen and conversion of hydrogen to ammonia at the end use location is possible, but this is a rather expensive option including significant energy losses.

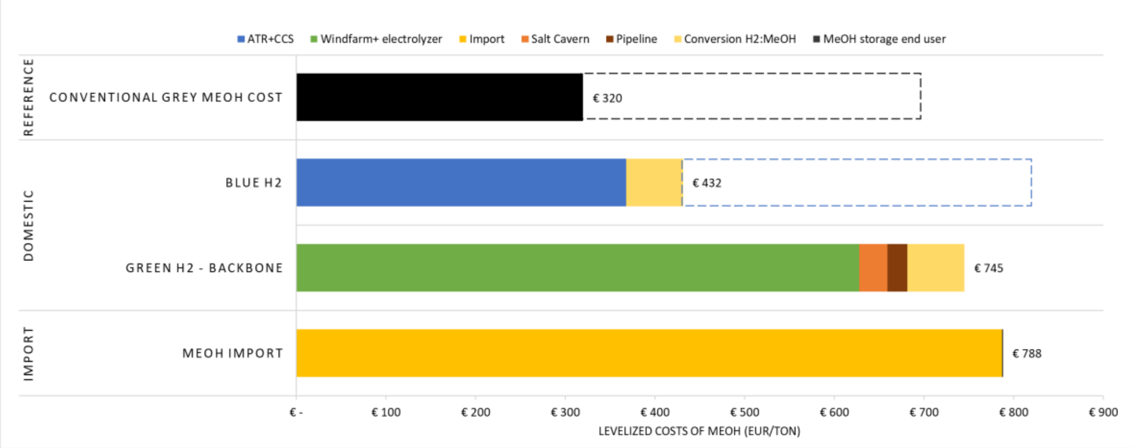

Figure 12 - Results of 2030 cost decompositions for methanol value chains.

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show impact of a natural gas price of 75 EUR/MWh: grey reference LCOM increases to 704 EUR/ton and blue H2 to 832 EUR/ton), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green MeOH import costs include the average import costs by ship from Canada, Australia and Morocco.

Since the impact of the hydrogen production costs on the total methanol chain costs is larger than in the ammonia case, the uncertainty ranges (based on the uncertainty of hydrogen production costs) presented for blue and green are larger as well. Moreover, for fossil methanol CO_2 allowance costs have less impact on overall methanol production costs, so that for methanol a higher CO_2 allowance price is required to make the blue and green supply chains competitive to the grey alternative, than for ammonia.

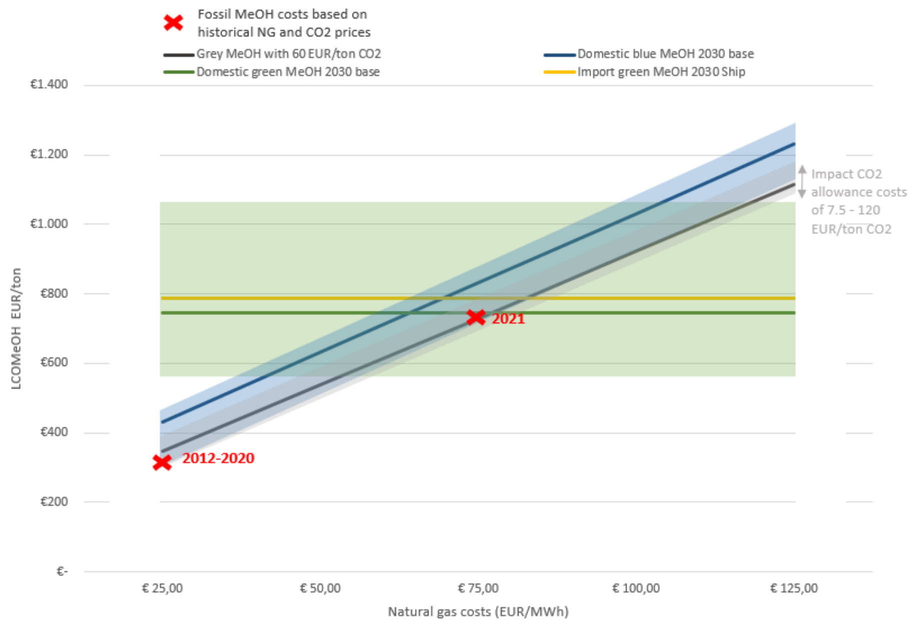

Figure 13 – Visualization of the impact of the natural gas and CO2 price on the reference price of MeOH and on carbon-neutral MeOH produced from blue hydrogen and sustainable CO2 extracted from the air. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty range of fossil MeOH costs depending on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized value chain costs presented include transport to end-use site. The reference costs of MeOH are calculated using 0.5-ton CO_2/ton MeOH [10], the natural gas price and the CO_2 price of the past decade have been used, respectively, +- 25 EU/MWh and 5-15 EU/ton CO_2 [3] [4] [5]. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to more than 60 EUR/ton CO2).

Decentralised industries using high temperature heat

- Since for generating heat gaseous hydrogen can be burned directly, import of hydrogen via a carrier for the purpose of generating heat is generally less attractive due to the additional conversion steps needed.
- Clearly for determining industrial heating value chain costs, the location and hydrogen demand volumes of decentral plant(s) matter a lot. Generally, it holds that the closer a plant is located to a backbone and the larger its demand volume is, the more suitable pipelines are; and the smaller the demand volumes are and the more remote the plant is from other users and a backbone, the more suitable trucks are. As far as the applicability of transport with LOHC trucks is concerned, this depends significantly on the availability and costs of local heat.

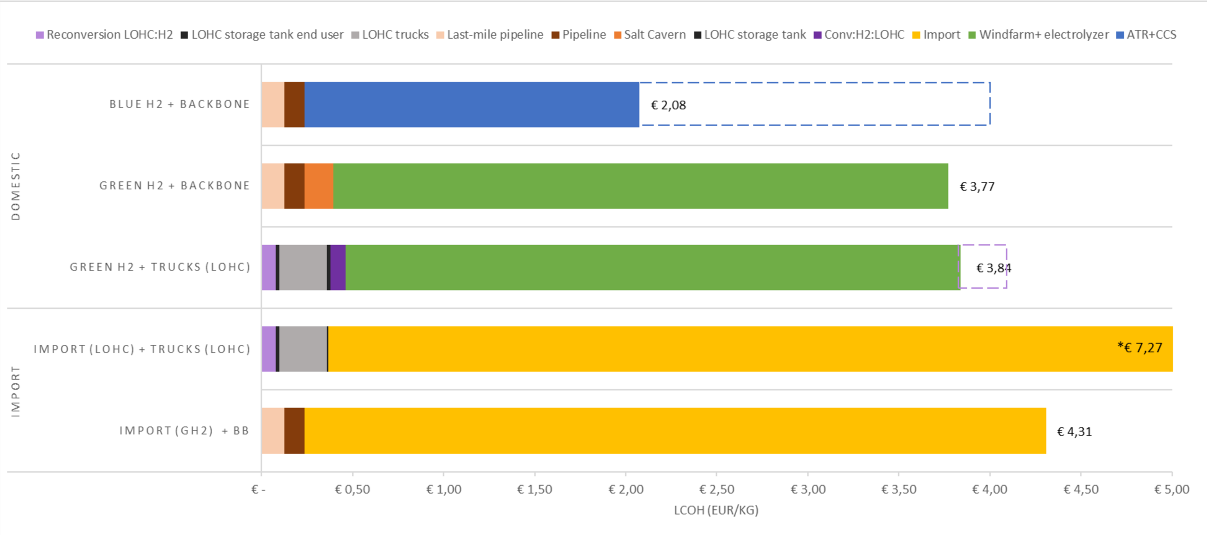

Figure 14 - Results of 2030 cost decompositions for industrial heating value chains.

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show the impact of a natural gas price of 75 EUR/MWh: Blue H2 value chain costs increase to 4.08 EUR/kg), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green hydrogen import costs via LOHC include the average import costs by ship from Canada, Australia and Morocco, the green gaseous hydrogen import costs assumes the import costs from Morocco by pipeline, if an European Hydrogen Backbone would be available. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh. If these costs for heat would be 25 EUR/MWh, additional 0.24 EUR/kg costs are added in those chains. However, released heat during conversion to LOHC can potentially be sold as well. For national pipeline costs, 0.11 €/kg of hydrogen has been used, which is based on a general analysis (see section 5.3 in D7A.2 [1]).

Figure 15 shows that for both natural gas and CO_2 allowances fairly high prices are required for making green hydrogen for distributed heating plants to become a cheaper option than natural gas. Compared to biomethane (50-100 €/MWh production costs [9]), the production costs of hydrogen range higher (94 €/MWh, low and 63-141 €/MWh high) while transport to the distributed plants has more challenges. Note, however, that biomethane is generally less available and thus only provides a solution for some locations.

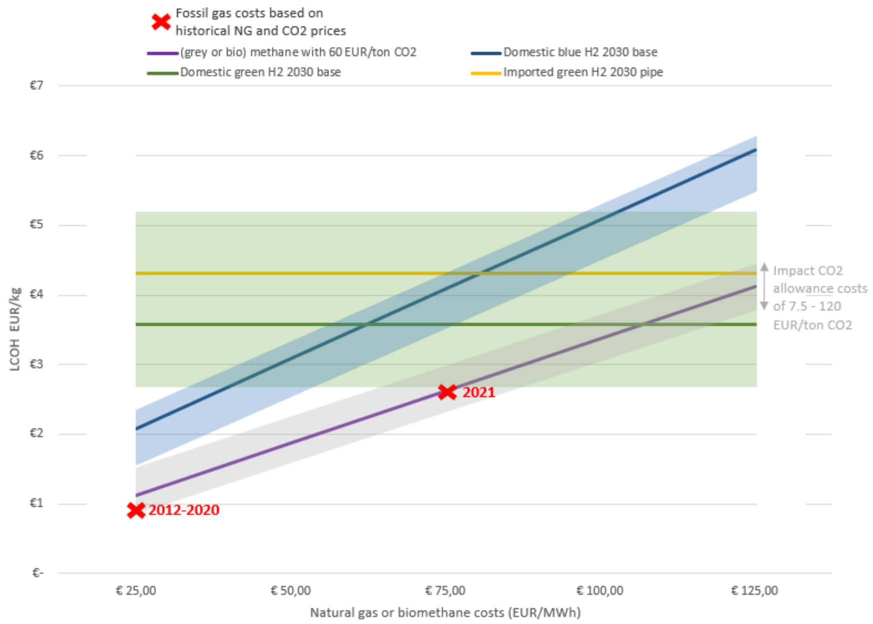

Figure 15 - Hydrogen supply costs (import, green and blue H_2) compared to the reference costs of natural gas. In comparing natural gas with hydrogen, an equivalent amount of energy has been used. This is presented via a hydrogen price equivalent (i.e. the required price for hydrogen to be competitive with natural gas given its price and allowances for polluting CO_2). The respective green and blue areas mark the uncertainty ranges of the green and blue hydrogen production costs until 2030; the grey area represents the cost range of burning methane depending on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized value chain costs presented include transport costs to the end-use site. The carbon costs of using natural gas are calculated using 0.203 ton CO_2/MWh of natural gas; the natural gas and CO_2 prices of the past decade have been used: respectively, +- 25 EU/MWh and 5-15 EU/ton CO_2 [3] [4] [5]. However, in 2021 a sharp increase of both European natural gas and carbon prices took place (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to over 60 EUR/ton CO2).

Mobility

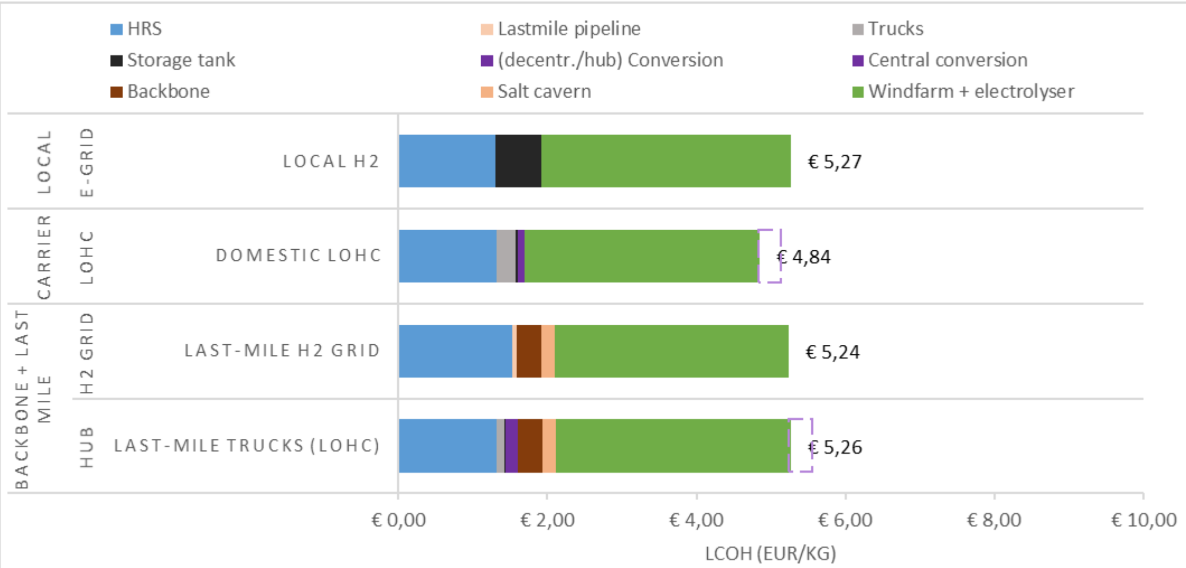

Figure 16 – Overview of cost-distributions of the lowest-cost value chain options for mobility.

**Chain steps have been presented in the opposite direction as in the other cases in order to better show the impact of the different transport options on value chain costs*

Main assumptions: 1000 HRS delivering 400 kg/day, the assumed demand pattern results in a 50% HRS utilization rate, national demand: 141 kT/y. LCOE of domestic offshore windfarm connected to electrolyser: 60 EUR/MWh, LCOE of local onshore windfarm: 53 EUR/MWh, but having a lower utilization (0.35 compared to 0.55) than offshore generation. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh. If costs for heat would be 25 EUR/MWh, 0.24 EUR/kg costs has to be added (see purple dotted boxes). However, heat released during conversion to LOHC can potentially be sold as well. National pipeline costs of 0.11 €/kg of hydrogen are taken into account based on a general analysis (see section 5.3 in D7A.2 [1]). For the last-mile H2 grid, costs of 0.05 €/kg are taken into account considering a shared regional pipeline with other end-users.

Different mobility chains result in comparable cost projections. However, for each chain situational local conditions must be fulfilled to be able to develop them cost effectively if at all:

- Local chains have only economic potential if part of the electricity is produced locally at suitable locations where (enough) demand from hydrogen vehicles can be expected;
- Domestic LOHC truck chains require central conversion to LOHC for more than 20 tank stations to reach economies of scale. Local heat should be available at the HRS to reconvert LOHC to gaseous hydrogen;
- To economically connect HRSs to a regional hydrogen grid, one has to be able to make regional combinations of end users that are all connected to the same hydrogen grid;
- In order to economically use LOHC trucks for last-mile transport only, also similar economies of scale for conversion and locally available heat for reconversion are required.

So, there is potential for hydrogen to be used for long-range (>400km) or heavy-duty vehicles. The costs of fuels have less impact on the TCO of long-range vehicles than of heavy-duty vehicles. In the end, it is the price formation at the HRS or electricity charging station that will determine which prices consumers actually will have to pay.

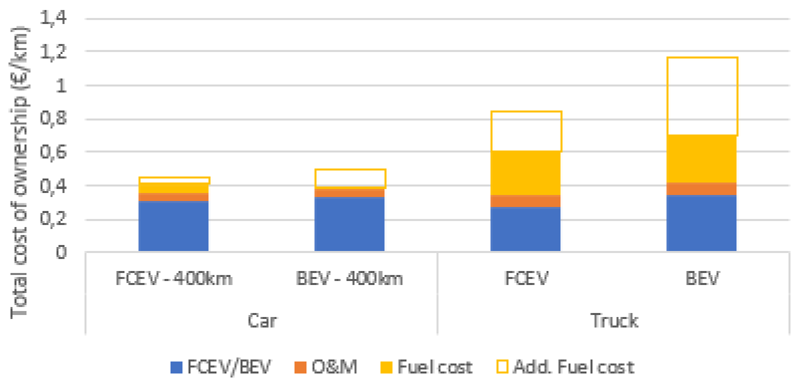

Figure 17 – Future Total cost of ownership comparison of BEV & FCEV based on [11].

Assumptions: cars with range >400km, charging costs FCEV car low: 0.04 EUR/kWh (self-generated electricity at home) high: 0.55 EUR/kWh fast charging costs excl. taxes. FCEV truck 0.2-0.55 EUR/kWh fast charging costs excl. taxes. Hydrogen fuelling costs 4.8-9.07 EUR/kg. For remaining assumptions see [11].

Built environment

- The seasonal demand profile has a strong impact on the built environment chain. Since the offshore wind production and demand both peak during winter, the required storage capacity can be reduced if both seasonal patterns can be combined;
- Pipeline (grid) transport turned out to be very suitable and cost-effective for this end user category, if enough volume is demanded either because a significant number of buildings is connected, and/or because the regional pipeline can be shared with other types of end users with sufficient volumes;
- More research on repurposing the distribution grid for hydrogen and its costs and benefits is required to assess the impact of increasing insulation of buildings and to analyse what transport system adjustment may be needed in dealing with hydrogen flows.

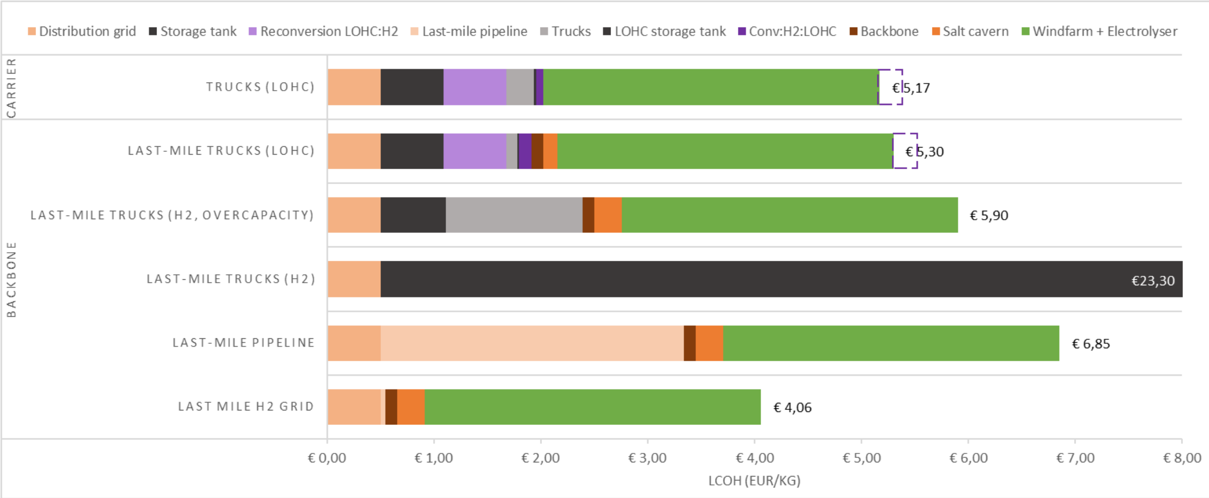

Figure 18 – Overview of the 2030 cost-distributions of built environment value chains

**Chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: national hydrogen demand: 359 kT/y (43 PJ). LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh, if these costs would be 25 EUR/MWh, 0.24 EUR/kg costs are added in those chains (see purple dotted boxes). However, heat released during conversion to LOHC may be sold as well. National pipeline costs of 0.11 €/kg of hydrogen are taken into account, based on a general analysis (see section 5.3 in D7A.2 [1]). For the distribution grid costs 200 EUR/house CAPEX and 150 EUR/house annual OPEX is assumed [12] [13]. For the last-mile H2 grid, costs of 0.05 €/kg are taken into account considering a shared regional pipeline with other end-users.

The cost range of green hydrogen applied in the built environment is typically large because its costs strongly are affected by the scale of application especially of the transport system and whether combinations with other hydrogen up-takers can be made (see also Figure 18). Clearly, as Figure 19 shows, hydrogen tax conditions will have a major potential impact on its future economic potential as an energy carrier for the built environment as well.

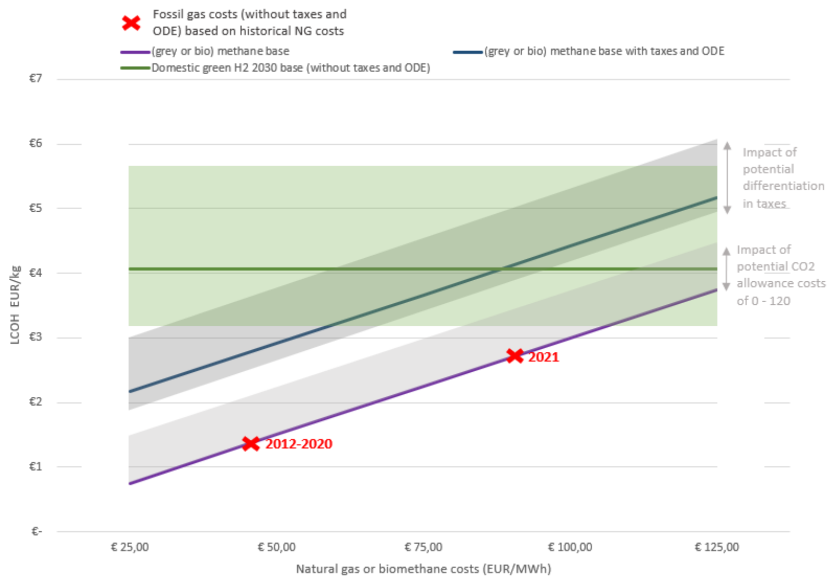

Figure 19 – Cost competitiveness of renewable hydrogen in the built environment. Assumptions: In comparing natural gas with hydrogen, an equivalent amount of energy has been used. This is presented via a hydrogen price equivalent (i.e. the required price for hydrogen to be competitive with natural gas given its price). Both natural gas costs have been shown, i.e. those excluding (purple line) and including taxes and ODE based on 2021 tax values [14] (grey line). The purple area addresses the impact of a potential CO2 price in the built environment for burning methane (0-120 EUR/ton CO_2) and the grey area the impact of tax differentiation (low: only differentiation in normal taxes without ODE, high: increased taxes of 75% in 2030, according to plans described in the Climate Agreement [15]). The levelized value chain costs presented include transport costs to the households. The green areas mark the uncertainty cost ranges of the green hydrogen production cost developments until 2030. The carbon costs of using natural gas are calculated based on the assumption of an emission of 0.203 tCO_2/MWh. The natural gas price of the past decade was some 30 EUR/MWh and transport costs for households some 15 EUR/MWh. Currently, the built environment is not part of the EU Emission Trading Scheme (ETS). However, in the recent RED II amendment a similar emission trading scheme is proposed for this sector.

Appendix B: Policy intensities required to make chains competitive

The tables below provide insights in: the impact of natural gas and carbon allowance prices on the levelized value chain costs of hydrogen (carriers); the policy measures required to make the hydrogen value chain competitive against the traditional alternatives; and the cost-effectiveness of carbon emission reductions.

Table 2 shows the LCOA values related to grey, blue and green ammonia used for fertilizer production. Both the natural gas and carbon allowance prices have a significant impact on grey ammonia costs. If the natural gas costs increase with 1 €/MWh, the levelized value chain costs of grey ammonia increase by 8 €/ton. If the CO_2 allowance price increases with 1 €/tCO2, the levelized value chain costs of grey ammonia increase with 1.75 €/ton. Under the probably conservative assumptions of 60 €/tCO_2 and 50 €/MWh natural gas price, a support of 142 €/ton NH_3, or €0.80 per produced kg of hydrogen, is required to make the domestic green ammonia value chain competitive against the grey one. Such support would imply that 81 euro is spent per reduced ton of CO_2 emitted.

*Table 2 – Impact of market developments and policy measures to make green and blue ammonia cost competitive. Assumptions: NG price: €50/MWh and CO_2 allowance price: €60/ton. LCOA is based on the value chain analysis of HyDelta D7A.2 [1]. **The emissions cover the value chain ranging from the natural gas (input) to the ammonia (output). Emission costs associated with natural gas production have been included in the NG price.*

	Insights				Policy measures for competitiveness				Effect
Chain	Base LCOA	CO2 emission	Impact NG price	Impact CO2 allowance	NG tax	CO2 price	Support scheme		
	€/ton	tonCO2/tonNH3**	€/ton LCOA per €/MWh	€/ton LCOA per €/ton CO2	€/MWh NG	€/ton CO2	€/ton NH3	€/kg H2	€/ton CO2 reduced
Grey NH3	541	1.75	8	1.75	N/A	N/A	N/A	N/A	N/A
Blue NH3	593	0.06	7.08	0.06	60	91	52	0.29	31
Green NH3	683	0	0	0	21	141	142	0.80	81
Green import NH3	694	0	0	0	23	147	153	0.86	87

Table 3 shows the levelized value chain costs of grey, blue and green methanol if used for E-fuel production. The CO_2 allowance prices have less impact on the grey methanol costs than on the grey ammonia costs. This is because part of the CO_2 derived from the natural gas can be used to produce the methanol and will be emitted when the E-fuels are burned, even if it remains outside the scope of the ETS. All this means that per ton of CO_2 emitted less, 106 euro is spent by introducing the domestic green methanol route replacing grey methanol.

Table 3 – Impact of the market developments and policy measures to make green and blue methanol cost competitive. Assumptions: NG price: €50/MWh and CO_2 allowance price: €60/ton. Levelized value chain costs of methanol are based on the value chain analysis in HyDelta D7A.2 [1].

	Insights				Policy measures for competitiveness				Effect
Chain	Base LCO-MeOH	CO2 emission	Impact NG price	Impact CO2 allowance	NG tax	CO2 price	Support scheme		
	€/ton	tonCO2/ton MeOH	€/ton LCO-MeOH per €/MWh	€/ton LCO-MeOH per €/ton CO2	€/MWh NG	€/ton CO2	€/ton MeOH	€/kg H2	€/ton CO2 reduced
Grey MeOH	538	0.5	7.68	0.5	N/A	N/A	N/A	N/A	N/A
Blue MeOH	632	0.06	8	0.06	N/A	274	94	0.47	49
Green MeOH	745	0	0	0	31	474	207	1.04	106
Green import MeOH	788	0	0	0	36	560	250	1.25	128

Table 4 shows the values related to green and blue hydrogen used for high temperature heat in distributed industries compared to natural gas. The two types of molecules are compared for the same energy content delivered. Support of 57 €/MWh, or €1.71 per produced kg of hydrogen, is required to make the domestic green hydrogen value chain competitive to natural gas, under the assumptions of 60 €/ton CO_2 costs and 50 €/MWh natural gas costs. This means that per reduced emitted ton of CO2, 87 euro is spent. The difference in required support costs between blue and green is less significant in this case compared to the ammonia and methanol case. Import is significantly more expensive than domestic routes in this case compared to the two previous type of end users.

Table 4 – Impact of market developments and policy measures to make green and blue hydrogen for high temperature heat in distributed industries cost competitive. Assumptions: NG price: €50/MWh and CO_2 allowance price: €60/ton. €/kg H2eq means the costs of an energy content delivered similar to 1 kg of hydrogen (=33.33 kWh). Levelized value chain costs of hydrogen are based on the value chain analysis in D7A.2 [1].

	Insights					Policy measures for competitiveness			Effect
Chain	Base Levelized costs		CO2 emission	Impact NG price	Impact CO2 allowance	CO2 price	Support scheme		
	€/kg H2eq	€/MWh	tonCO2/kg H2eq	€/MWh NG per €/MWh H2eq	€/MWh per €/ton CO2	€/ton CO2	€/MWh	€/kg H2	€/ton CO2 reduced
NG H2eq	1.87	62	0.66	1	0.66	N/A	N/A	N/A	N/A
Blue H2	3.12	104	0.01	1.2	0.01	124	42	1.25	64
Green H2	3.77	126	0	0	0	156	64	1.90	96
Green import H2	4.36	145	0	0	0	186	83	2.49	126

Table 5 shows the levelized value chain costs of green hydrogen used in the built environment and their comparison to the use of natural gas. The table shows that, since the natural gas costs for consumers consist for a large part of taxes, a tax differentiation will have a strong cost impact. If no tax differentiation is applied, a support of 70 €/MWh, or €2.11 per produced kg of hydrogen, is required to make the domestic green hydrogen value chain competitive against the natural gas value chain, at least assuming 50 €/MWh without tax natural gas costs and 15 €/MWh transport costs. Then 107 euros are spent per reduced emitted ton of CO_2.

*Table 5 – Impact of market developments and policy measures on making green hydrogen for the built environment to become cost competitive. Assumptions: NG price: €50/MWh, NG transport costs: €15/MWh, taxes including general tax and ODE at 2021 levels [14] and a CO_2 allowance price of €0/ton. *The built environment does not fall under ETS. However a similar emission trading scheme is proposed to be introduced according to the amended RED II [16]. **tax differentiation applied means that no additional tax is charged for hydrogen and existing additional tax and ODE levels are charged for NG. €/kg H2eq means the costs of an energy content delivered similar to 1 kg of hydrogen (=33.33 kWh). Levelized value chain costs of hydrogen are based on the value chain analysis in D7A.2 [1].*

<table>
<tr><td></td><td colspan="5">Insights</td><td colspan="4">Policy measures for competitiveness</td><td>Effect</td></tr>
<tr><td rowspan="2">Chain</td><td colspan="2">Base Levelized costs</td><td>CO2 emission</td><td>Impact NG price</td><td>Impact CO2 allowance</td><td rowspan="2">Tax diff. applied? **</td><td>CO2 price*</td><td colspan="3">Support scheme</td></tr>
<tr><td>€/kg H2eq</td><td>€/MWh</td><td>tonCO2/kg H2eq</td><td>€/MWh NG per €/MWh H2eq</td><td>€/MWh per €/ton CO2</td><td>€/ton CO2</td><td>€/MWh</td><td>€/kg H2</td><td>€/ton CO2 reduced</td></tr>
<tr><td>NG H2eq (excl. tax)</td><td>1.95</td><td>65</td><td rowspan="2">0.66</td><td rowspan="2">1</td><td rowspan="2">0.66</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td></tr>
<tr><td>NG H2eq (incl. tax)</td><td>3.37</td><td>112</td></tr>
<tr><td rowspan="2">Green H2</td><td rowspan="2">4.06</td><td rowspan="2">135</td><td rowspan="2">0</td><td rowspan="2">0</td><td rowspan="2">0</td><td>No</td><td>107</td><td>70</td><td>2.11</td><td>107</td></tr>
<tr><td>Yes</td><td>35</td><td>23</td><td>0.69</td><td>35</td></tr>
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