Compendium of research

HyDelta

Consortium

TKI NIEUW GAS Topsector Energie

Gasunie

Netbeheer Nederland

New Energy Coalition

TNO innovation for life

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HyDelta 2.0
Compendium of research

Foreword

Dear reader,
This document proudly presents the results of the HyDelta 2.0 project, a research program on the introduction of clean hydrogen as energy carrier and feedstock in the Netherlands. The project was carried out during the period between May 2022 and July 2023 and has had a particular focus on how to stimulate, start and maintain hydrogen transport and distribution through the gas grid, with practical recommendations on how to approach technical, economic, environmental, and societal barriers and enablers. The main goal has been to answer the most urgent questions that block progress towards a wider implementation of hydrogen *right now.*

In HyDelta 2.0, 26 deliverables have been produced, all of which are publicly available on the hydelta.nl website. This compendium, consisting of the summaries of the deliverables, is meant to provide a way for readers to explore all the research findings. Readers interested in a deeper understanding of the research, methodology and detailed findings are invited to visit the website and explore more via https://reports.hydelta.nl/.

The consortium with research partners: New Energy Coalition (coordinator), DNV, TNO, Kiwa and Hanze University of Applied Sciences, and sponsoring partners: Gasunie and Netbeheer Nederland (NBNL), has carefully (selected and) answered the research questions. Further funding from the national innovation subsidy body, TKI Nieuw Gas, significantly contributed to enabling the HyDelta 2.0 project.

This is the second phase of a planned series of projects within the HyDelta programme. As the results of HyDelta 1.0 gradually became available in 2021 and 2022, and the promise of the hydrogen economy accelerated, the consortium felt there were still many remaining urgent questions that blocked further implementation steps in practice. As it stands now at the completion of HyDelta 2.0, we are well aware of what needs to be done, but the hydrogen infrastructure in the Netherlands is still in its infancy and there is only limited time left to reach our climate ambitions. When it became clear that the new national gas infrastructure research programme GroenvermogenNL would focus more on long-term and fundamental research issues than on the challenges of TSO and DSO's demanding short-term answers, further continuation of the programme towards HyDelta 3.0 is a logical next step, so look out for more!

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Another way to browse the HyDelta results is our navigation tool on reports.hydelta.nl

List of abbreviations

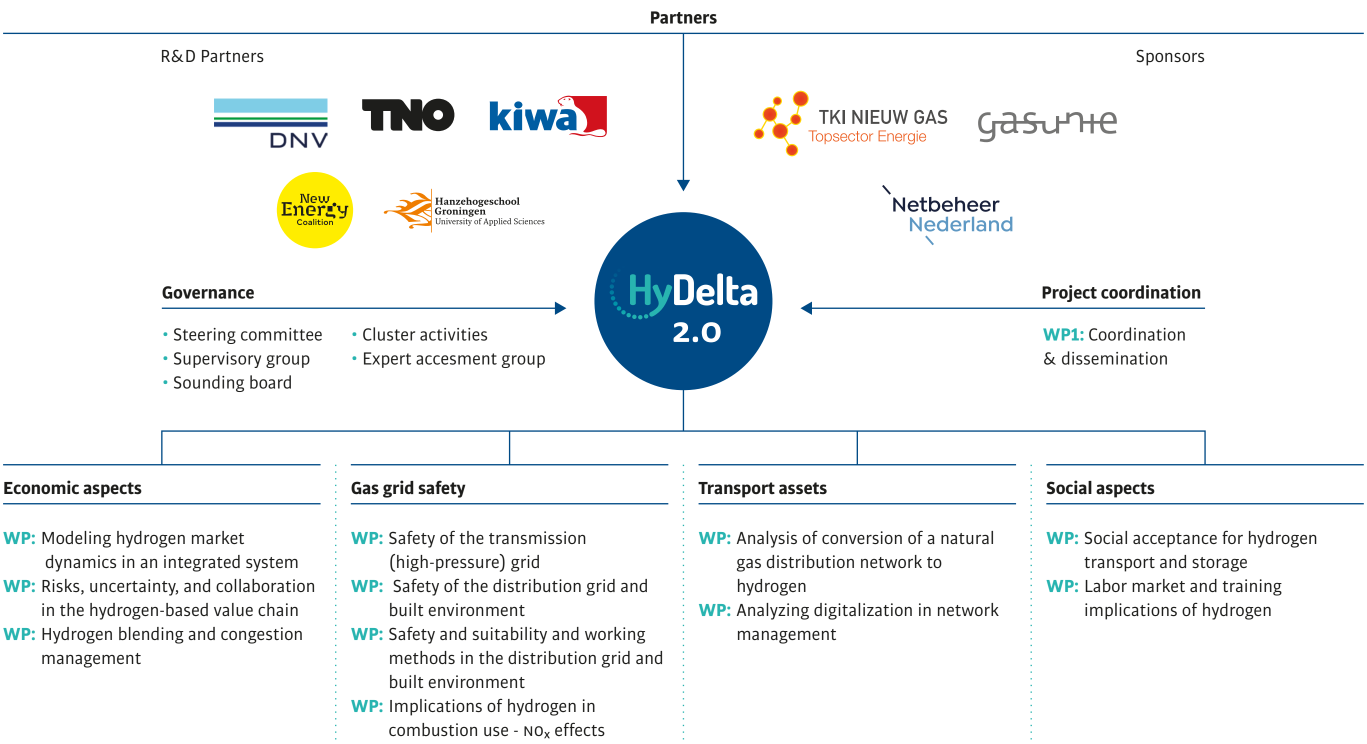
ACM	Autoriteit Consument en Markt (Dutch authority on consumers and market)
CAPEX	Capital expense
CFD	Computational Fluid Dynamics
DSO	Distribution system operator
EU	European Union
E-GRID	Electricity grid
GOS	Gas reception station
HBO	Hoger beroepsonderwijs (Higher professional education/ university of applied sciences)
HTL	High-pressure transmission line
LEL	Lower explosion limit
LFL	Lower flammability limit
NEN	Nederlandse Normalisatie-instituut (Dutch Standardization Institute)
OPEX	Operational expense
P2G	Power to Gas
PIG	Pipeline Inspection Gauge
PV	Photovoltaic
PVC	Polyvinyl chloride
QRA	Quantitative risk assessment
RES	Renewable energy source
RNB	See DSO
RTL	Regional transmission (gas) line
SEL	Societal Embeddedness Level
THT	Tetrahydrothiophene
TSO	Transmission System Operator
WGV	Working Gas Volume
WO	Wetenschappelijk Onderwijs (Scientific education)

Table of Contents

Introduction

The HyDelta 2.0 project

The HyDelta Tweede Tranche (HyDelta 2.0, TKI2022 HyDelta 1.0) project is a research project that was carried out between May 2022 and July 2023. It is a direct follow-up of the HyDelta Eerste Tranche (HyDelta 1.0, TKI2020-HyDelta) project. Like its predecessor, HyDelta 2.0 is a project focused on researching the most urgent and relevant issues related to the safety and economic aspects of retrofitting the existing transmission and distribution networks for natural gas and using them to transport (pure) hydrogen in the future.



The HyDelta Tweede Tranche project is a collaboration between the natural gas transport industry in the Netherlands, and key research institutions in the Netherlands that are specialized in different aspects of the research done.

All research done within the HyDelta program (including HyDelta 1.0 and 2.0 and future projects) can be found in the HyDelta website: https://hydelta.nl.

This project aims at contributing to strengthen the knowledge position of the Dutch gas transport industry when it comes to both safety and economic aspects of the transport of hydrogen using the existing natural gas network. The research done in the framework of this project has been so far unprecedented and has led to reinforcing the knowledge base of both Gasunie and the Dutch Distribution System Operators, who are utilizing the results from the HyDelta Tweede Tranche project for both the development of the Dutch hydrogen backbone, as well as for the successful implementation of the Hydrogen pilot projects in the built environment.

Section 1

Research themes

1 Research themes

There are four main research themes addressed in HyDelta 2.0, each subdivided in work packages that addressed a concrete set of research questions:

Table 1

Research theme	Work packages	Description
Economic aspects of the hydrogen system	Modelling hydrogen market dynamics in an integrated energy system	Techno-economic modelling to elucidate at which location(s) in the Netherlands can hydrogen production be feasible, and where can it create high market value for producers and consumers.
	Risks, uncertainty, and collaboration in the hydrogen-based value chain	Increase the understanding regarding the effects of risk, uncertainty and actor collaboration on decisions related to deployment of flexible power-to-hydrogen conversion in energy systems at different levels.
	Hydrogen blending and congestion management	Elucidate the potential for local hydrogen production and consumption in areas of the Netherlands dealing with congestion of the electricity network, and what factors play here a critical role
Hydrogen safety in the gas grid	Safe operations of the high-pressure transmission grid	Determine how operational H_2-pipelines can be operated and maintained safely e.g., can recompression be used? Is it possible to flare or blow-off? Which working procedures shall be followed? What equipment is required?
	Safety of hydrogen in the distribution grid and built environment	Carry out tests and continue developing a Quantitative Risk Assessment (QRA) to map the risks of leakages of hydrogen in the built environment and, if necessary, provide recommendations for mitigating actions.
	Safety and suitability of gas stations in the distribution grid for hydrogen	Determine what modifications to the enclosure (the housing) of gas stations are necessary for safe distribution of hydrogen through gas stations: ventilation, adjustments needed, etc.
	Safety and suitability of using inflatable gas stoppers in the distribution grid to mitigate a hydrogen leak	To gain insight into the risks associated with the use of inflatable gas stoppers for the temporarily closing of a hydrogen gas pipe, including any additional requirements
	Implications of hydrogen in combustion use – NO_x effects	Map current successfully applied NO_x-reducing strategies and elucidate the basis for design rules for hydrogen burners applied in high-temperature processes towards mitigating NO_x emissions.
Hydrogen and transport assets	Analysis of the conversion of a natural gas distribution network to hydrogen	Development of a plan for the conversion of a natural gas distribution network to a hydrogen distribution network (from gas receiving station to customers' gas installations).
	Analysing digitalization in network management	Research how digitalization (simulation and decision support tools combined with dedicated sensors) can contribute to an effective transition to hydrogen grids.
Social aspects of hydrogen	Social acceptance for hydrogen transport and storage	Study the main societal challenges for deploying hydrogen transport/ distribution, storage, and application within the built environment in the Netherlands and how could these challenges be overcome as part of the development and implementation strategy.
	Labor market and training implications of hydrogen	An inventarisation and overview of the required (future) skills and available education to match this in the upcoming hydrogen economy, to serve as a starting point to start developing attractive and comprehensive curriculums to train relevant personal in hydrogen technologies and applications.

Section 2

Economic aspects

2 Economic aspects

Sources for this section

DELIVERABLE:

D2.1 – Drivers of renewable hydrogen production in the Dutch integrated energy system

Link to deliverable

DELIVERABLE:

D2.2 – Hydrogen in the energy system: value for energy transport infrastructure and its users

Link to deliverable

Economic aspects of the hydrogen system

Modelling hydrogen market dynamics in an integrated energy system

Topics: Techno-economic modelling to elucidate at which location(s) in the Netherlands can hydrogen production be feasible, and where can it create high market value for producers and consumers.

Drivers of renewable hydrogen production in the Dutch integrated energy system

This study tries to answer two fundamental questions related to the introduction of hydrogen in the Netherlands' energy system in the period until 2030:

1. what is the likely order of magnitude of electrolyser capacity investment in the Netherlands and what are their main drivers; and
2. given such investment, and given the different sizes of electrolyser installations (varying from a scale of some MWs to GW-scale), where will those investments most likely be located and what are the most likely drivers of the choices of location?

Both questions are highly relevant for the TSO and DSOs responsible for hydrogen transport. The more hydrogen will be produced domestically as opposed to imported via the main harbours, the more transport capacity will need to be developed to service the market. The better the understanding of where hydrogen production will most likely be concentrated, the better the TSO but the DSOs in particular will be able to plan their future hydrogen related transport capacities.

Magnitude of electrolyser capacity investment

So far virtually all investment in electrolyser capacity has been characterized by a spirit of pilot and demonstration activity. The commercial exploitation of electrolysers still is something of the future given the current stage of scaling up and learning. This means that serious investment in electrolyser capacity will not come off the ground without public support, either by way of subsidies or by way of command and control via prescribing the introduction clean hydrogen to replace grey hydrogen. In assessing what the main drivers are for investment in electrolyser capacity, public support therefore clearly will be the main factor, at least in the period considered, i.e., until 2030.

In the Netherlands, support policies to stimulate hydrogen value chain development and electrolyser investment in the country have come off the ground fairly intensively during the last years: the Netherlands is the first country in Europe to invest in a national hydrogen backbone linking most of the main industrial clusters with links to Germany and Belgium; the Netherlands introduced serious subsidy volumes (several billions of Euros) to support investment in electrolyser capacity and hydrogen transport capacity and also support measures have been introduced via a certificate system for hydrogen in mobility including hydrogen refinery for that purpose; the Netherlands recently doubled its 2030 targets for both offshore wind and electrolyser capacity (to 21 GW and 6-8 GW respectively); a wave of pilots related to small scale introduction of hydrogen in industry, mobility and the built environment meanwhile has been introduced to test hydrogen applications. All such support activity has boosted hydrogen developments. The question whether or not hydrogen support initiatives in the country have been relatively substantial compared to other EU countries was outside the scope of the current study. That the support measures have been effective is, however, clear: given the current information it seems very likely that the first GW cumulative electrolyser capacity in the country will already be operational by 2026.

In the study, an extensive simulation has been carried out to assess for (the period until) 2030 how much public support/subsidy is probably needed per MWh of green hydrogen produced domestically to close the business case. Obviously, the result was sensitive to many investment-specific factors but boiled down to figures ranging from close to zero to about 100 €/MWh with most simulations ranging between some 10-35 €/MWh H_2, or some 0.5-1 €/kg H_2. Key factors reducing subsidy needs turned out to be the overall installed capacity of renewable energy in the country; national demand for hydrogen; national demand for electricity; and to a lesser extent the natural gas and CO_2 prices. The simulations assumed that the hydrogen market until 2030 will be typically national because the international shipping transport systems are expected to initially focus on demand of the hydrogen carriers (e.g., ammonia or methanol).

Another fundamental factor that, next to public support measures, will most likely have a crucial impact on domestic electrolyser capacity built up is to what extent the country will rely on the imports of hydrogen and hydrogen carriers for satisfying domestic demand. It is still an open issue to what extent nationally produced hydrogen can compete with hydrogen imported from foreign sources. The assessment of HyDelta 1.0 7A.2 suggested that for at least 2030 hydrogen production based on North Sea wind capacity could compete well with almost all other sources of green hydrogen production because differences in transport costs more than compensated those of production costs. For hydrogen carriers the assessment concluded no clear difference in competitiveness between domestic and foreign sources. This may explain why in the various simulation studies on the issue, no clear answer is provided on the issue what share of hydrogen supply will be generated nationally. A major complexity in this respect is that hydrogen and hydrogen carriers are just commodities that will be traded internationally so that a significant part of hydrogen and hydrogen carriers entering the country as imports, will be transported further to the surrounding countries. All in all, the expectation is that ‘pure hydrogen’ may well be produced domestically typically based on North Sea wind capacities, whereas hydrogen derived chemicals such as ammonia and methanol will typically be imported.

Locations of electrolyser investment

It seems likely that different scales of electrolyser capacity clusters will be introduced in the future ranging from small electrolysers (with capacities ranging from about 1 MW to several MWs), and medium sized electrolysers (with capacities between some tens to some hundreds of MWs) to large electrolysers (with capacities anywhere between 250 MW and several GWs). Obviously, the range of likely locations of such investment will differ depending on the scale of the investment clusters.

So far significant investment of electrolyser capacity of medium sized and large scale is foreseen to emerge in or near four of the five main industrial clusters (Eemshaven-Delfzijl, het Noordzeekanaalgebied (NZKG), the Rotterdam-Moerdijk area, the Schelde-Delta region in Zeeland, and Chemelot in Limburg). The locational advantages of these main industrial clusters are clear: large scale demand, the presence of major companies with considerable investment capacities, and a cluster scope supporting the economics of scale, logistics and permitting procedures. The few existing scenarios so far, for the after 2030 period, on average suggest that the major part (60-75%, depending on the scenario) of the Netherlands electrolyser capacity in the future will be located in the four coastal industrial clusters and the region of Den Helder and/or offshore. The remaining, mostly smaller electrolyser capacities will be located at the Chemelot industrial cluster and elsewhere throughout the country.

Clearly, the backbone will act as another major catalyst for electrolyser investment in its neighbourhood; all coastal main industrial clusters mentioned are positioned close to the backbone. Also, all four clusters located near the coast are already connected to energy supply networks based on power, also from offshore wind capacities, which adds to their abilities to balance and to their strong locational advantage for large scale electrolyser capacities until 2030. After 2030, the future location of offshore wind capacities may be increasingly decisive which – due to windfarms increasingly being planned in the Northern part of the Netherlands North Sea continental shelf – explains why the scenarios and investment plans suggest an increasing focus of electrolyser capacities in the North of the country.

An interesting issue, also for the DSOs in view of their network investment planning, is where electrolyser capacities can be expected to emerge inland. Where are the clusters of industrial and other economic activities that may consider installing electrolyser capacities to secure stable, green, and affordable energy by way of hydrogen as the optimal energy mode? An assessment showed that currently 27 small electrolyser projects are in operation or development, representing a total capacity of 100-150 MW. Clearly, factors determining such locational choices are: the threat of E-grid supply-side congestion becoming a problem, the presence of a serious industrial activity (usually referred to as cluster 6 locations) potentially in combination with the built environment, the availability of the production of green power in the area in combination with local demand for 'ultra-pure' hydrogen for mobility that cannot be delivered via the public grid (and purification may be considered too costly). This last category of cases could typically lead to the installation of small-scale electrolysers for mobility; similarly small-scale electrolysers may be introduced into the future to service pockets of the built environment looking for self-sufficiency, especially to be able to store and improve the use of locally produced renewable power capacities.

Given these various factors determining the locational profile of inland electrolyser capacities, the maps in the Figure below (*figure 1*) indicate where these beneficial characteristics are located in the Netherlands. Although those maps show potential within certain areas in general, already a combination of few very specific local driving forces can make or break investment in a small-scale electrolyser.

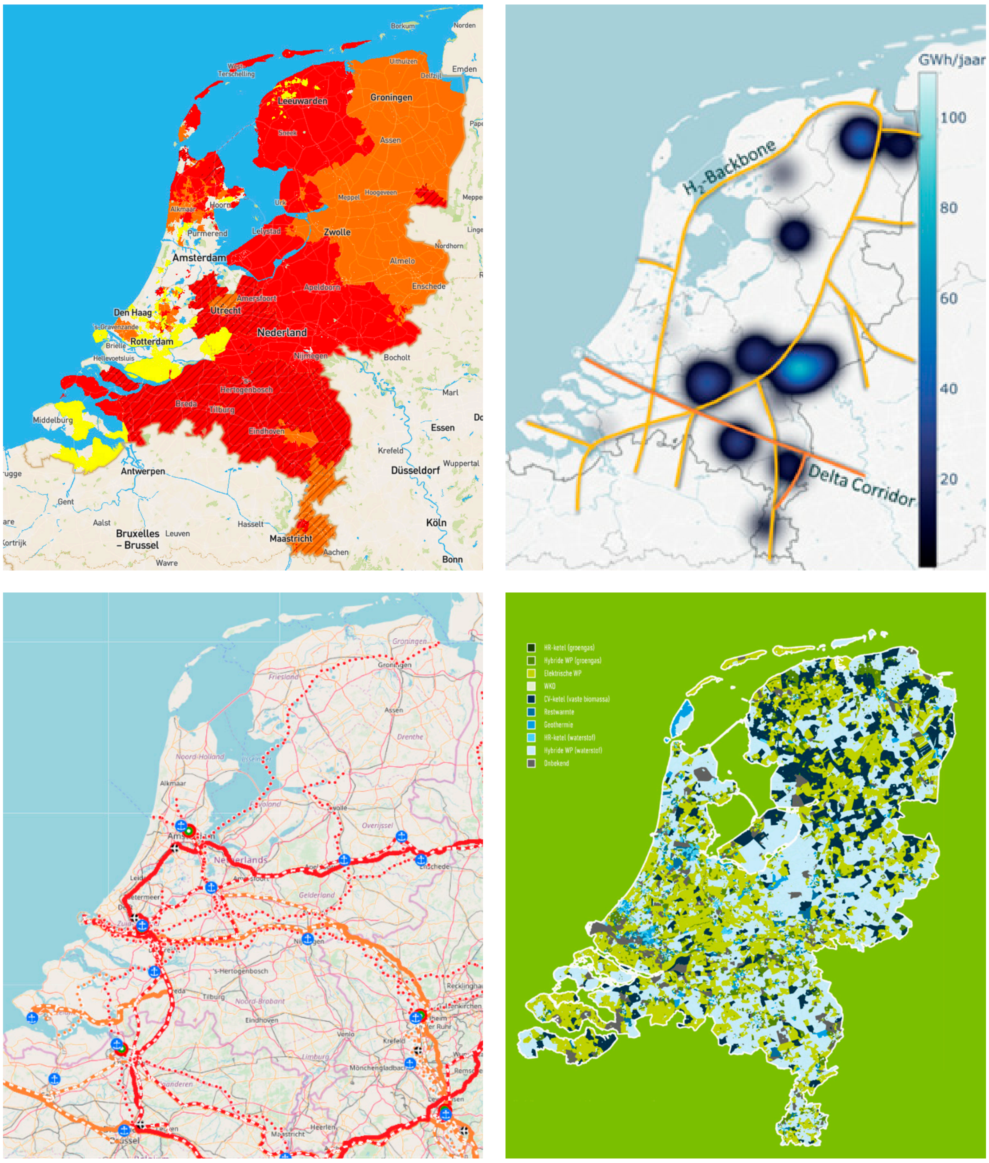


Figure 1: Four maps showing areas with relevant characteristics for decentral electrolysis. Top-left: supply-side congestion (red). Top-right: decentral industrial demand (blue) and main hydrogen infrastructures. Bottom-left: the main road (filled), water (dotted) and rail (striped) related transport & mobility corridors. Bottom-right: potential for hydrogen in the built environment (light blue).

Hydrogen in the energy system: value for energy transport infrastructure and its users

This section explores the implications of clean hydrogen developments for energy transport and storage infrastructure, focusing on maximizing the value for infrastructure users and owners. Four key research questions are addressed:

1. The value of electrolysers when electricity grid reinforcements are delayed.
2. How grid operators can influence the business case and operational strategy of decentralized hydrogen production to reduce grid congestion.
3. The impact of different customer combinations on future hydrogen distribution tariffs.
4. How different customer combinations can increase the earnings of large-scale hydrogen storage capacity.

The first two research questions mainly focussed on the value of electrolysis for dealing with electricity grid congestion.

From our analysis related to the first question, we can conclude that, if electrolysers are operated based on electricity and hydrogen market spot prices alone, they will not be able to fully replace electricity grid reinforcements. This happens because the production profile of the electrolysers driven by market prices does not correlate completely with the peak load moments of the electricity cables. Moreover, locations that are suitable for electrolysis are not necessarily the locations where congestion management has most value. This has been evaluated for two cases: landfall of offshore wind and onshore combined wind and solar generation locations. Electrolysers can and do contribute to resolving congestion, but incentives of electrolysis investors and system operators do not fully align. Hence, additional price incentives at specific moments and/or locations are needed to unlock the value of electrolysers during potential periods of delayed electricity grid reinforcements.

An additional analysis was performed to assess what financial incentives could influence the business case and operational strategy of decentral electrolysis such that electricity grid congestion can be reduced. The existing GOPACS mechanism provides intraday orders which can provide attractive additional revenues for the local electrolyser business case. However, the more effective the electrolyser is in solving the local congestion by simply being active on spot markets, the less income it receives from the GOPACS orders, because there is less residual congestion. Hence, it is not expected that this congestion management mechanism will sufficiently incentivize decentral electrolyser investments. Grid operators could take a more active role to steer the locations of electrolysers, through financial or non-financial instruments. Financial instruments could include incentives that reduce grid connection costs, allow cable pooling, or valorise by-products. Not all of these are compatible with the current regulatory frameworks in The Netherlands.

The second two research questions focus on the impact of different customer combinations on the hydrogen infrastructure earnings, and thereby also affecting the tariffs customers will have to pay.

It was seen that the number of connections is a major factor that impacts future gas distribution grid tariffs, because the fixed depreciation costs of the existing assets and potential grid removal costs have to be paid by less customers. Since small connections represent 98% of the connections and 85% of the allowed income of the regulated grid operators, the impact whether these type of connections (mainly represented by the built environment) will stay or leave the gas distribution grid is the biggest. Moreover, future gas distribution grid tariffs are impacted by three (interrelated) political issues: who will be burdened with the grid removal costs? Will future methane and potential hydrogen distribution grid tariffs be separate or combined? And how fast will the existing grid value be depreciated?

Similar to revenues of large scale underground natural gas storage facilities, revenues of hydrogen storage facilities could differ greatly over the years by external market factors and perceived uncertainty in the economy. However, the fourth research activity resulted in three effects by which also customer combinations can impact the revenues of the hydrogen storage operator as well:

1. The demand for storage (capacity and volume) in the energy system relative to the available capacity, which will increase the tariffs asked for working gas volume (WGV), injection and withdrawal capacity reservations.
2. A similar timing in fixed reservations for injection and withdrawal capacity, by which more injection and withdrawal capacity can be sold, and operational costs can be saved.
3. Complementary profiles that maximize the reserved and utilized WGV capacity during the year.

By reducing the need for storage and balancing portfolios with complementary variable profiles, storage operators will be able to increase their asset utilization and the impact of the storage tariffs can be reduced.

Section 3

Risks & uncertainty

3 Risks & uncertainty

Sources for this section

DELIVERABLE:

D3.1 – Case studies of interest regarding risks and uncertainty in the hydrogen value chain

Link to deliverable

DELIVERABLE:

D3.2 – Individual and system risks in hydrogen value chains: methodology and case studies

Link to deliverable

DELIVERABLE:

D3.3 – Individual and system uncertainties in hydrogen value chain developments

Link to deliverable

DELIVERABLE:

D3.4 – Technical analysis of hydrogen supply chains – factsheets (update 2023)

Link to deliverable

Risks, uncertainty, and collaboration in the hydrogen-based value chain

Topics: Increase the understanding regarding the effects of risk, uncertainty and actor collaboration on decisions related to deployment of flexible power-to-hydrogen conversion in energy systems at different levels.

Case studies of interest regarding risks and uncertainty in the hydrogen value chain

The scope of WP3 within the HyDelta project is to identify – together with stakeholders – risks, uncertainties, and collaboration opportunities that are crucial to understanding deployment strategies and policy in the hydrogen value chain, in particular:

1. (Quantifiable) risks and (unquantifiable) uncertainties to market participants, including OPEX risk, price risk, macro-economic systemic risks, regulatory risks, and uncertainties.
2. Uncertainty and risks to policy makers at various levels, including local and national authorities.
3. Collaboration opportunities, needs and mechanisms for the sharing of revenues between collaborating parties, as well as the sharing of risk.

The purpose of the current report is to provide a more detailed scope. An initial list of risks and uncertainties has been identified through two stakeholder workshops and is reported in this document. These risks span a wide range. Many of the key risks to individual actors are related to value chain coordination (e.g., demand, supply or storage not materializing at the same time, leading to a disconnected value chain), but there are also important risks related to the availability of key inputs (materials, but especially labor), wider economic factors, policy, and regulation. Although we were able to flag some risks as particularly important, this is based on an initial analysis only, so these assessments may change after a full quantification. For some risks, there is less consensus. The following uncertainties and risks are identified in this stage of the research (*Table 2*).

Table 2: The outlined uncertainties and risks are clearly different for different types of hydrogen value chains, e.g., combined offshore wind and hydrogen production at source, backbone-connected large-scale production and industrial use of hydrogen, and local production of hydrogen with distributed take-off. Accordingly, three different case studies have been identified to quantitatively assess the risks and uncertainties. We also outline different collaboration mechanisms which can help address these risks. These will be quantitatively analysed in the case studies, using a set of three energy system models which simulate the energy system at different geographical and timescales to capture a wide range of risks and uncertainties.

Supply chain/coordination uncertainties and risks	• Lack of electrolyser manufacturing capacity • Labor shortages • Lack of wind energy deployment • Lack of other components • Simultaneity of value chain scale-up
Demand uncertainty	• Hydrogen demand uncertainty with respect to volume, quality, timing and location
Market factors	• Energy and ETS prices • Competitive condition
Change in policy, regulation, and social acceptance	• Deprioritization from the public sector • Regulatory risks • Standardization • Environmental policy • Social acceptance • Hype bubble
Other financial and project risks	• Inflation and interest rates • Refinancing risk • Cost projections • Bankruptcy • Credit risk • Rerouting cos
Other operational risks	• Safety • Physical climate change damage • Outage of transmission and distribution infrastructure • Large-scale storage availability risks • Gas leakages

Individual and system risks in hydrogen value chains: methodology and case studies

Given the urgency of the transition, the magnitude of investment needed, and the long lead times, the timeline for hydrogen value chain development is pressing. Investment in parts of these value chains is, to a large extent, driven by the ratio of risk and return. There is a substantial amount of existing work on the system values and business cases for (parts of) the hydrogen value chain, but much less attention for risks, uncertainties, and the need for sharing of revenue and risk between collaborating stakeholders. These factors must be known and analysed to formulate effective hydrogen policy, but also to help public and private-sector investors de-risk projects and formulate investment strategies in complex supply chains. This report is a first attempt to address this gap. We focus on identifying (quantifiable) risks and (unquantifiable) uncertainties to market participants, their impact, and the needs and mechanisms for the sharing of risk and revenues between collaborating parties.

To identify key risks and uncertainties, we have conducted three workshops with experts and stakeholders in hydrogen supply chains. From these workshops, it is clear that investors in the hydrogen supply chain face a wide variety of risk and uncertainty. Moreover, to get a wide-ranging overview of these risks and uncertainties, stakeholders need to collaborate. Many risks that initially affect part of the supply chain eventually propagate up and down the supply chain. No single stakeholder that was involved in our workshops had a full overview of all the 85 risks and uncertainties that were identified during the workshops.

The 85 risks and uncertainties identified during the workshops were subsequently clustered based on common impact on the system. A selection of the resulting risk events was then modelled with a series of energy system and market models, to quantify their impact. This has yielded the following main insights:

1. Investment in commercial storage capacity is much more susceptible to certain types of risk, including the risk of lower than planned electrolysis capacity, than other parts of the supply chain. To some extent, the same is true for import facilities. Since storage is a key component of a reliable system, collaboration on storage investment could be key, e.g., through mechanisms that are currently used in natural gas systems, where system operators book storage capacity and charge the costs of this to all users of the system.
2. Infrastructure is, according to current plans, initially over dimensioned. A uniform reduction in the capacity of infrastructure is therefore not a large immediate risk for other parts of the supply chain. However, there are parts of the national infrastructure that, if they are not completed in time, would have major effects on hydrogen supply chains, both locally and nationally. These effects do not always manifest themselves in obvious locations; there are network effects.
3. Initially, electrolysis has little effect on electricity prices. Even an order-of-magnitude change in electrolysis capacity has no significant effect on (spot) electricity prices. This means that investments in large-scale electricity generation capacity are, at least before 2030, relatively immune to what happens in the hydrogen system. The opposite is not true: the amount of offshore wind present in the system has a significant impact on the hydrogen system.
4. Local markets that are not connected to national markets are very difficult to make work without coordination. Only a large amount of hydrogen storage can locally balance supply and demand, if both are responding only to price thresholds rather than local optimization. What is more, local risks are much larger in distribution networks.

These results have a number of important implications. Most importantly, they indicate the importance of explicitly considering risk and uncertainty in hydrogen value chains. They also highlight the importance of collaborative de-risking. For policy makers, they highlight the fact that policy uncertainty can be an important hurdle for the development of hydrogen systems. Moreover, they indicate that stochastic methods and other ways to include uncertainty and risk in research has important added value in understanding hydrogen investments.

Individual and system uncertainties in hydrogen value chain developments

Many uncertainties cloud the role that renewable hydrogen may fulfil in the future Dutch energy system. These uncertainties hinder decision-making by public and private stakeholders which leads to a (too) slow uptake of renewable hydrogen in the Dutch energy mix. Investment decisions of individual stakeholders stall due to uncertainties across the value chain from supply to end-use. How to effectively deploy mitigation strategies enabling investment is not self-evident in the multi-stakeholder context of a new value chain such as that of renewable hydrogen.

The main objective of this HyDelta 2.0 research activity was to enhance the understanding of the impact of risk and uncertainty on stakeholder collaboration and investment decision-making. The conclusions drawn and recommendations made in this study focus on both the uncertainty identification as well as collaborative mitigation of uncertainties.

The first key insight drawn is that the large variety (100+) of investment uncertainties can be structured in a much smaller number of groups. We have identified 11 such groups. Interdependencies between uncertainties in those groups emerge. These uncertainty groups each need to be perceived as collectively acceptable before business cases can turn positive in support of investment decisions.

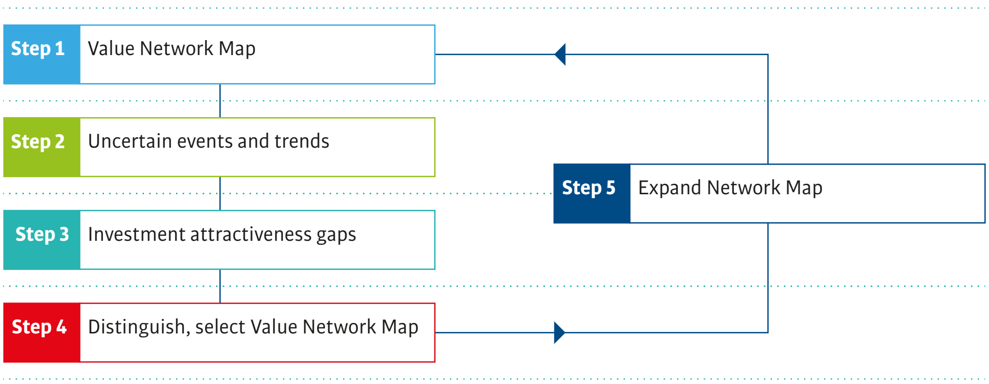
The second key insight illustrates the need to collaborate: Individual investment decision-makers rarely have a direct influence over all these groups of uncertainties. Collaboration between stakeholders along the value chain is required to reduce uncertainty to acceptable levels, enabling more synchronised decision-making.

Addressing uncertainties collectively can be done through deployment of three mitigation strategies:

1. Accept the presence of the uncertainty to prevent stalling investment decisions.
2. Transfer potential consequences of the uncertainty to stakeholder(s) able and willing to take responsibility for (e.g., governmental bodies). Partial transfer may also be a viable strategy.
3. Reduce the possibility of occurrence and/or consequence of the uncertainty by sharing the responsibility of preventive mitigation measure deployment and dealing with consequences.

Two recommendations can be considered by value chain stakeholders and Dutch government: Stakeholders in hydrogen supply chains can follow the Value Network Analysis-based process to identify, (re)distribute and mitigate investment uncertainties. An entity that has the mandate to broker agreements and distribute value, cost, uncertainties, and coordinate mitigation measures needs to lead this process to achieve acceptable residual uncertainties in investment decisions of both public and private stakeholders.

Figure 2: Five-step process for value chain stakeholder collaboration



Dutch governmental bodies should explore policy concepts that 1) triggers value chain collaboration and 2) aids in mitigating unacceptable uncertainties without an owner that hamper investments.

Technical analysis of hydrogen supply chains – factsheets (update 2023)

This document contains an update of the database with the filled-out factsheets about different components of the H_2 value chain elements modelled in the HyDelta 1.0 project.

1. The first version of these factsheets can be found here: https://doi.org/10.5281/zenodo.6469568
2. The different technologies depicted on the factsheets can be found here: https://doi.org/10.5281/zenodo.6469592
3. The original modelling done that is based on the information from these factsheets can be found here: https://doi.org/10.5281/zenodo.6514172

Note: to understand exactly what each parameter refers to (for example, some parameters presented correspond to numbers in a costing model), to find the sources used, and to better contextualize the data, the reader is referred to the accompanying Excel document, to be found in the same repository.

Section 4

Blending & congestion

4 Blending & congestion

Sources for this section

DELIVERABLE:

D4.1 – Introducing hydrogen in decentral end-user areas to deal with E-grid congestion in the Netherlands

Link to deliverable

DELIVERABLE:

D4.2 – Cost-benefit analysis of various short-term supply-side E-grid flexibility options in local areas in comparison to conventional grid-expansion techniques

Link to deliverable

DELIVERABLE:

D4.3 – Report on the main policy implications of the potential of hydrogen for regional electricity grid congestion mitigation

Link to deliverable

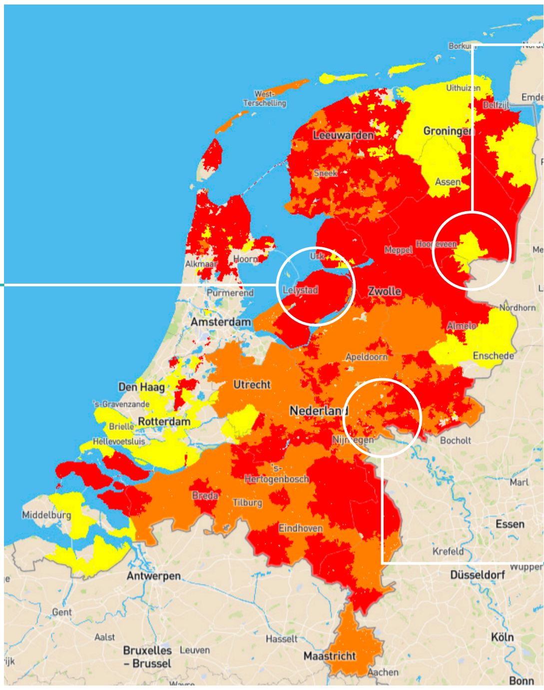
Hydrogen blending and congestion management

Topics: Elucidate the potential for local hydrogen production and consumption in areas of the Netherlands dealing with congestion of the electricity network, and what factors play here a critical role.

Introducing hydrogen in decentral end-user areas to deal with E-grid congestion in the Netherlands

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid (E-grid). Reinforcement of this grid costs time also because of the immanent electrotechnical workforce scarcity in the country. Therefore, Dutch electricity DSOs already face and foresee rapidly growing (localised) challenges in providing grid connections (in time) for connecting local renewable energy capacities. In this study, it was investigated whether and to what extent local or regional P2G systems may alleviate congestion in the E-grid in some critical areas by introducing green hydrogen produced via P2G – blended or otherwise – in decentral industrial clusters and/or the mobility sector in particular areas.

The focus in the study on decentralized (so-called cluster 6) industry and local mobility as potential green hydrogen consumers (rather than the five main industrial clusters in the country) was chosen because, unlike the main industrial clusters, the more local industry and mobility hydrogen uptake is typically not easily connected to the foreseen national hydrogen backbone. Therefore, the regional transmission gas line (RTL) will have to act as the main potential hydrogen grid connection for these industries. To identify the country's most suited areas for establishing such potential local hydrogen connections (and hydrogen blending), four location criteria have been combined: the severity of supply side driven E-grid congestion; the presence of local industry with a grid connection decoupled from the built environment/public distribution system (because such a connection would complicate blending); the proximity to (future) renewable energy production sites; and the assumed little industries' decarbonization alternatives. Based on these criteria, some dozen potential 'hydrogen blending regions' were identified throughout the Netherlands, each with multiple possible local blending sites (*see figure* 3).



Area: Lelystad / Swifterband

Name	Capacity (MW)	Type
Noordermeerdijk	195.0	Wind
Westermeerwind	195.0	Wind
Zuidwester	195.0	Wind
Princess Alexia	195.0	Wind

Area: Emmen / Coevorden

Name	Capacity (MW)	Type
Klazienaveen	1.3	Solar

Area: Doetinchem / Lochem / Hengelo

Name	Capacity (MW)	Type
Solarpark Azewijn	1.8	Solar

Figure 3: Potential blending sites

Modelling[1] of the supply side economics of P2G congestion solutions for these regions revealed that, although the P2G option may be promising on the longer term, currently its business case is difficult from the perspective of energy suppliers given the combination of current assumed market prices of green hydrogen and local industry demand levels. Under the present conditions for energy suppliers in the selected regions trying to deal with E-grid congestion, utility-scale batteries turned out to offer a higher utilization rate and to be more cost-effective to deal with the issue. The latter is due to batteries' scalability and currently lower CAPEX-levels (than electrolysers) and to handsome electricity trading margins given current high electricity prices. Obviously, the most economic congestion combatting option for the suppliers of energy will not always coincide with what is most economic from the perspective of the demand side, i.e., industries or mobility sector units in the area of-taking energy. The same may apply if cost conditions alter e.g., as P2G technology matures.

1) The modelling activities that took place in this study were based on the 2022 state of the art with respect to the cost of batteries and electrolyzers and with respect to the availability of SDE++ subsidies and conditions.

Another key finding from modelling the optimal options for energy suppliers to deal with congestion via hydrogen blending in the given regions under current conditions was that deliveries to the mobility sector dominated. This was because hydrogen prices in mobility are assumed to be higher than those for industry. A backdrop of delivery to mobility, however, is that both prices and demand volumes are more uncertain than deliveries to industry.

Interviews with various stakeholders revealed the following main perceived opportunities and barriers of implementing P2G investment and local blending in decentral industries.

The main barriers:

1. As long as it is uncertain if local E-grid congestion is a lasting and growing or instead a temporary problem in a particular region (e.g., because operators may or may not extend grid-capacities), the profitability of an electrolyser investment by a local energy provider to deal with congestion will be uncertain as well. Given that electrolyser and related equipment CAPEX levels are quite high, such uncertainty can pose a serious barrier.
2. If congestion is mitigated via P2G involving a relatively small hydrogen blend of, say, 10% hydrogen admixed to natural gas (corresponding with ≈3% emission reduction), the decarbonisation impact remains quite small. At the same time the energy content of the blend gets smaller than that of natural gas alone (when compared at constant volumetric flowrate). Introducing hydrogen blends therefore is only considered to be worthwhile by decentral industries if it offers a serious and ultimately complete step forward towards decarbonising the use of gas.
3. P2G investment to deal with congestion remains tricky as long as uncertainty remains about the degree to which energy system operators are legally allowed to facilitate 'pure' hydrogen connections to the gas grid to serve specific local demand and to apply blends of hydrogen in their local grid.

The main opportunities:

1. Local P2G investment and subsequent hydrogen blending can be a first step towards local integration of the electricity and gas systems. This way it can help offering a solution for local E-grid congestion problems; enhance the profitability of RES investment; and improve local security of supply conditions.
2. Local P2G investment designed to deal with E-grid congestion can also: act as a steppingstone to synergistically serve an increasing number of end users besides local industry (e.g., mobility and the built environment); and may act as a dominant enabler of a decisive decarbonisation trend in the entire relevant area.

Market conditions for P2G are generally expected to improve as the technologies are scaling up such that ultimately hydrogen may develop into a dominant energy carrier. Given this perspective, first-mover issues may have to be taken for granted for the technology to ultimately pay off. Not following this path carries the risk of missing out in the future.

Cost-benefit analysis of various short-term supply-side E-grid flexibility options in local areas in comparison to conventional grid-expansion techniques

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid. This causes very serious E-grid congestion issues. Reinforcement of the E-grid can be very expensive if technologically and/or legally feasible at all, costs considerable time for various reasons and requires an electrotechnical workforce that often is not or scarcely available. So, Dutch electricity DSOs are facing growing congestion problems in providing grid connections in time for new renewable energy capacities. It is in fact likely that in the Netherlands E-grid congestion will be a reality and growing concern for at least the coming decade. This results in sometimes long connection waiting times for solar and wind farms (i.e., supply-side congestion) and similar adverse access conditions for the energy end-users (demand-side congestion), and also means that in the near future new solar and wind farms will not be able to deliver electricity to the grid at all times.

To determine the most cost-effective solutions for this issue from an energy system perspective covering different energy carriers and stakeholders involved, this study looked into alternative supply-side grid flexibility solutions provided by electrolyzers, batteries and their combinations alongside curtailment methods. The net costs of these options have then been compared with those of traditional grid expansion techniques. Such comparative economic analysis has been carried out via a case study in the context of a quasi-realistic setting in which a 38MWp solar park is introduced in Friesland, a Netherlands' region facing serious supply-side E-grid congestion.

The striking overall result of the case analysis of such newly added solar capacity in a rural E-grid-supply-congestion region, i.e., where electricity supply already exceeds demand during peak moments, is that under the current (2023) cost and energy price conditions considerable societal net benefits can be achieved by connecting the solar park to the market via the multiple flexibility options mentioned, rather than by just reinforcing the local electricity grid.

Various sensitivities were explored to analyse the impact of parameter changes on the various flexibility components. For this purpose, an impact assessment was made of changing: the distances between the solar park and a hydrogen refuelling station; the capacity of the solar park and electricity demand; hydrogen and electricity prices; the mode of transport of hydrogen via the RTL and tube trailers; the level of mobility demand, the CAPEX of electrolysers; and the way of sourcing the electricity from the grid. Of all sensitivities, changes in hydrogen and electricity prices turned out to have a large impact especially via their impact on returns on selling hydrogen to mobility. The impact of the option to sell hydrogen to mobility was anyhow important because its prices received per kg green hydrogen were assumed to be higher than those offered by industrial uptake.

Simulation results also showed that in the economic optimum, large-scale batteries played a significant role in providing flexibility for dealing with supply-side congestion. Especially combinations of batteries and PtG proved effective in raising electrolyser use. Electrolysers and electrolyser/battery combinations were the optimal flexibility solution at the lower solar PV capacities, whereas battery solutions were considered at the higher end of the PV capacities.

All in all, our results suggest that from the overall energy system cost perspective it can be very promising to systematically assess costs and benefits of alternative ways to integrate new local renewable energy capacities into the energy system, especially in rural E-grid congestion regions. It should, however, be mentioned that the lowest cost energy system option can only be realised if somehow the stakeholders losing are at least compensated for their losses by the stakeholders gaining: one therefore somehow needs legislative framework that supports such compensation. This underlines the role that governmental policies and incentives on such planning issues will have to play apart from their role, e.g., with respect to the development and implementation of new technologies for greening energy production, etc. (see also HyDelta 2.0 D4.3 on this).

Some assumptions and caveats about the research have been included below:

1. Annualized costs and benefits methods was used for assessing the various scenarios in comparison to a Net Present Value (NPV) method this was done in order to fairly compare assets with different lifetimes with each other.
2. This study considers the mutual costs and benefits of multiple stakeholders: renewable electricity producer, battery and/or electrolyser operator and the distribution grid operator. We acknowledge that under current market circumstances these actors will not operate their assets in a mutually optimal way. However, this methodology has been chosen to show what the societal optimum is when financial incentives of these actors would be aligned.
3. Costs and benefits show the results for a pre-investment decision phase, considering both investment and planned operational considerations of a one year timeframe. Hence, the results are not yielded by the actual performance and differences over the years.
4. Re-use of the RNB pipeline is considered for the transportation of hydrogen in most of the scenarios (RTL is not utilized). RNB gas pipeline of 8 bars is suitable for the level of output that is derived from the electrolyzer and serves the regional aspect of our study.
5. Mobility demand of hydrogen – with a relatively high willingness-to-pay – is limited by regional demand constraints considered in our scenarios, the sensitivity of the results based on this demand has been evaluated. The industrial demand was not limited as it was perceived that any industrial off taker would need to be connected to national hydrogen transport infrastructure in order to receive enough volume and security of supply.

Report on the main policy implications of the potential of hydrogen for regional electricity grid congestion mitigation

As a short supplement, this deliverable serves as a policy recommendation document in regard to the results derived from deliverable D4.1 and D4.2. Both deliverables investigated solutions for mitigating the prevalent and ongoing electricity grid congestion in the Netherlands from a regional perspective via the implementation of PtG systems (e.g., via electrolyzers) and other flexibility providing options such as utility scale batteries and curtailment techniques. It was shown that local PtG investments and subsequent hydrogen blending can be a first step towards local integration of electricity and gas systems. These investments can help by offering a solution for local E-grid congestion problems; enhancing the profitability of RES investments; and improving local security of supply conditions. They can also act as a steppingstone to synergistically serve an increasing number of end users besides local industry (e.g., mobility and the built environment); and may act as a dominant enabler of a decisive decarbonisation trend in the entire relevant area.

This can be done by:

1. Authorities providing as clear information as possible on local supply-side congestion perspectives.
2. That reliable information is provided if local investment in a hydrogen blend really involves a step towards full decarbonisation of natural gas use in decentral industries: one has to be sure that ultimately one will be able to implement pure green hydrogen via increasing blending percentages.
3. Reducing the regulatory uncertainty of, if, and when the gas transmission service operator (TSO) and/or distribution service operators (DSOs) are legally allowed and/or capable to facilitate a 'pure' hydrogen transport connection to the gas grid, or, in the preceding stages, to apply blends of hydrogen in the grid.

Results also clearly indicated that a mix of flexibility solutions can cost-effectively reduce electricity grid reinforcement needs and therefore societal costs, but only if cost-benefit analyses are systematically implemented and new legislation and regulatory measures are introduced, supporting that the incentives to get to the optimal solution are implemented. These alternative options require alignment of stakeholders' interests and a supportive legislative and regulatory framework. Hence, some main recommendations can be given to policy makers:

1. Identification of which specific legislations and regulatory measures would be required to provide right incentives for solar park and wind farm operators, regional grid operators, and electrolyser and battery operators such that maximum green energy benefits are delivered against lowest overall costs.
2. Based on systematic regional prognoses for new decentral renewable capacities and electricity demand, regions should be identified where electricity supply will exceed demand regularly. This information can be used to identify the regions in which decentral hydrogen production is the most promising. This information should be made public so that new investors in solar (and wind) capacity and the distribution grid operator can together investigate several options to integrate the additional renewable energy in the system.
3. Given the seriousness of the domestic E-grid congestion issues, such developments are urgently needed (both for the distribution and transmission E-grid); in fact, not having them in place can be seen as a serious obstacle for green hydrogen and battery investment, and a stimulus for growing undue E-grid congestion.

Section 5

Gas grid safety

5 Gas grid safety

Sources for this section

DELIVERABLE:

D5.1 – Venting and flaring of hydrogen in a high-pressure transmission network

Link to deliverable

DELIVERABLE:

D5.2 – Report on safe isolation, de-pressuring, and evacuating of high-pressure hydrogen pipelines and installations for maintenance purposes

Link to deliverable

Hydrogen safety in the gas grid

Safe operations of the high-pressure transmission grid

Topics: Determine how operational H_2-pipelines can be operated and maintained safely e.g., can recompression be used? Is it possible to flare or blow-off? Which working procedures shall be followed? What equipment is required?

Venting and flaring of hydrogen in a high-pressure transmission network

As part of the national research programme HyDelta, a study was carried out into the possibilities of depressurising high-pressure hydrogen transport pipelines by venting and flaring. The research as described in this section is part of work package 5 "Working safely on the high-pressure transport network".

Gasunie was commissioned by the Dutch government to create a national hydrogen transport system. During the operation of this network, sometimes modifications have to be made to this transport system. In some cases, hydrogen needs to be extracted from the network in a controlled manner to be able to work safely. To decrease the amount of hydrogen that has to be extracted, this will be done by pressure equalisation and followed by recompression. The residual hydrogen in the transport network has to be removed via venting or flaring.

To determine whether high-pressure hydrogen pipelines can be depressurised using venting and flaring, 13 more specific research questions were formulated. These were answered by conducting theoretical and practical research.

The theoretical study considered the differences between venting and flaring in general and made a comparison between flaring of natural gas and hydrogen. In addition, market information was gathered by interviewing two large industrial users familiar with hydrogen flaring and two flare installation suppliers.

In the practical investigation, a flare was assessed for:

1. Direct ignition behaviour
2. The behaviour in delayed ignition
3. The risk of flame impact

Various measurements were performed: flow rate, heat radiation, flame appearance, noise levels, wind speed and NO_x emissions.

The findings of the experiments were compared with theory and various mathematical models. In particular, the flow profile through the flame arrestor, flame height, heat radiation and noise production were compared.

The overall conclusion is that flaring is preferable instead of venting. This is after pressure equalisation and recompression has taken place. With the utilized flare installation, flaring of flow rates of 500, 2500, 4000 and 6000 Nm^3/h were possible. During the experiments, no excessive noise production or excesses in pressure waves were observed. It is recommended to validate to what extent the results can be extrapolated for the application of flaring of larger flow rates and at larger diameters.

In any hydrogen combustion process, forming NO_x can be an issue. It is recommended to carry out further research on NO_x measurements and reducing measures. For the design of hydrogen flare plants, existing theoretical models can be used. The results obtained from the experiments appear to be in reasonable agreement with the theoretical findings.

Report on safe isolation, de-pressuring, and evacuating of high-pressure hydrogen pipelines and installations for maintenance purposes

Maintenance on high-pressure hydrogen pipelines, such as the Hydrogen Network Netherlands, needs strategic consideration and planning. In this section, we provide an overview of the guidelines and methodology for isolating and evacuating a high-pressure pipeline or installation for a maintenance operation. The dialogues with various experts from the hydrogen gas industry provided a diverse range of perspectives and knowledge, helping to validate the nuances of different methodologies better. The general methodology of the maintenance procedure consists out of a few steps:

1. Identify the sections that need maintenance.
2. Isolate the section that needs maintenance, utilizing valve schemes or stopples.
3. Depressurize the system.
4. Evacuate hydrogen with nitrogen, utilizing pigging, purging, or dilution techniques.
5. Ensure secondary isolation and a bleed mechanism is in place.
6. Execute maintenance operations.
7. Flush the maintenance area with nitrogen before reintroducing hydrogen.

The different evacuation and isolation methods impose slightly different methodologies, which will be explored in this section.

When isolating between valve schemes, evacuation with a separation pig minimizes the mixing of hydrogen and nitrogen. The report discusses leakage rates along the pig for different types of pigs. These rates will be approximately 20-30% higher for hydrogen operations compared to using natural gas. Although the leakage is higher, the amount of back mixing is still very limited compared to the other techniques described in this report. Separation pigs will have an increased stick-slip behaviour since the reduction of the acoustic impedance increases 3 to 4 times. However, valve schemes with pigging facilities can be typically distanced 50 km to 100 km apart, this method requires closing down a large section of the pipeline. The process of pigging becomes less feasible for very long pipelines due to the large loss of gas volume and possible disruption of flow from suppliers and to industrial consumers.

If it is not feasible to start a pigging operation over a large section of pipeline due to loss of large volumes of hydrogen, a smaller section, between two valve schemes without the necessary facilities to perform a pigging operation, can be isolated and evacuated by performing a purge or dilution-based purge with nitrogen gas. The section cannot always be evacuated by purging due to physical constraints, such as stratification or the presence of dead volumes, dilution can be used to lower the concentration of hydrogen gas till acceptable levels. Evacuation by displacement or purging has its challenges, especially for long pipeline sections where stratification can occur. The minimum velocity requirements to prevent stratification for hydrogen and natural gas are computed and show that the velocity requirements are higher for hydrogen. The diffusion fronts of hydrogen and natural gas are computed in this report, demonstrating that the diffusion front length is velocity-independent and results in approximately equal volumes of remaining gas-air mixtures at different velocities. The distance of these valve schemes varies within the network but can be up to 50 km apart. When the distance between valve schemes is high, the amount of hydrogen volume lost can still be quite large.

When it is more feasible to isolate and evacuate a smaller section, stopples can be installed to provide temporary isolation. Sections isolated with stopples can be sufficiently small to allow for the installation of a bypass, thus ensuring the continuity of gas flow to preserve gas supply within the hydrogen network. The current procedures used for the natural gas network will not suffice for the hydrogen network, since they do not provide a double block and bleed. Alternative techniques, such as hydraulic stopples or a stopple train, do provide a double block and bleed and are discussed. These alternative techniques will need different equipment than the equipment currently in use and will need further research before applied in the field.

In complex systems or installations, such as the hydrogen storage facility HyStock, it is impossible to avoid dead volumes or spaces where the hydrogen flow is limited in the installation. Here, a dilution-based purge should be used. Alternating the pressure in the spaces with restricted gas exchange can also contribute to achieving a suitable dilution-based purge. Although this method will use an increased amount of nitrogen since it requires multiple purge-cycles for a successful purge, theoretical analyses and experimental data indicated that pockets of hydrogen would mix more efficiently with nitrogen compared to natural gas pockets, approximately 3.8 times faster.

Isolated section	Preferred evacuation technique	Advantages	Disadvantages
Between valve schemes with pigging facilities (50-100 km distance)	Purging with a separation pig	• Minimizes the mixing of hydrogen and nitrogen • No stratification problems and smaller diffusion front • Evacuation method is similar to natural gas	• Large loss of gas volume • possible disruption of suppliers and industrial consumers • Higher flowrates along the PIG with respect to natural gas pigging
Between valve schemes without pigging facilities (10-50 km distance)	Purging	• No disruption of suppliers and industrial consumers • Evacuation method is similar to natural gas	• Possible large loss of gas volume • Stratification issues will arise more often with respect to natural gas
Installing temporary seal with stopple	Purging	• Limited loss of gas volume • Possibility to install temporary bypass	• Current evacuation methods used for natural gas will not suffice • More research needed on stopple trains and hydraulic stopples
Valve schemes (installation, complex piping systems)	Dilution-based purge	• Can be applied in many cases • More effective hydrogen dilution with respect to natural gas dilution.	• Multiple cycles of nitrogen purging needed before successful purge.

Table 3: Summary of advantages and disadvantages of different isolation and preferred evacuation techniques

The isolation methods and their preferred evacuation methods are described in the Deliverable 5. The table above (*table 3*) shows an overview of the different techniques used.

Section 6

Distribution & built safety

6 Distribution & built safety

Sources for this section

DELIVERABLE:

D6A.1 – Outflow experiment results: concentration build-up at leakages between 50 – 1000 dm³/h

Link to deliverable

DELIVERABLE:

D6A.2 & D6A.3 – Quantitative Risk Assessment of the distribution grid and built environment in the Netherlands: application and case studies

Link to deliverable

DELIVERABLE:

D6A.4 – General recommendations: applicability of QRA tools, detection of hydrogen fires, effectiveness of odorisation, and effect of hydrogen permeation

Link to deliverable

Safety of hydrogen in the distribution grid and built environment

Topics: Carry out tests and continue developing a Quantitative Risk Assessment (QRA) to map the risks of leakages of hydrogen in the built environment and, if necessary, provide recommendations for mitigating actions.

Hydrogen has different properties from natural gas. Its physical and chemical characteristics are known in detail, but there is still insufficient knowledge about the safety risk when applied in gas pipelines in the built environment. However, this knowledge is needed to know whether different safety measures need to be taken than for natural gas. This required knowledge mainly relates to probabilities and consequences of the unwanted release of hydrogen. Mitigating measures are then aimed at reducing the probability of a hazardous situation arising and/or reducing its consequences.

In HyDelta 1.0 (the predecessor of this project), concentration measurements were therefore made to gain insight on the diffusion of hydrogen versus methane at small leak sizes of hydrogen and methane in the gas meter cabinet (up to 20 and up to 15 dm³/h, respectively). In the present study, which falls under HyDelta 2.0, the measurements were scaled up to higher gas outflows, namely 50, 100, 300 and 1000 dm³/h. The measurements were carried out in a container composed of a room (26 m³) and a hall (10 m³) containing a gas meter cabinet (*figure* 4).

The distribution of gases was measured with gas sensors attached according to a matrix with three height positions, three width positions and six length positions (*figure* 5).

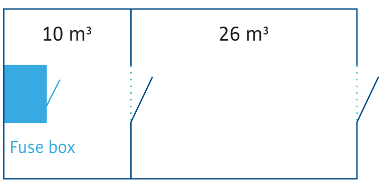


Figure 4: Top view of container with division into hall (10 m³) and room (26 m³)

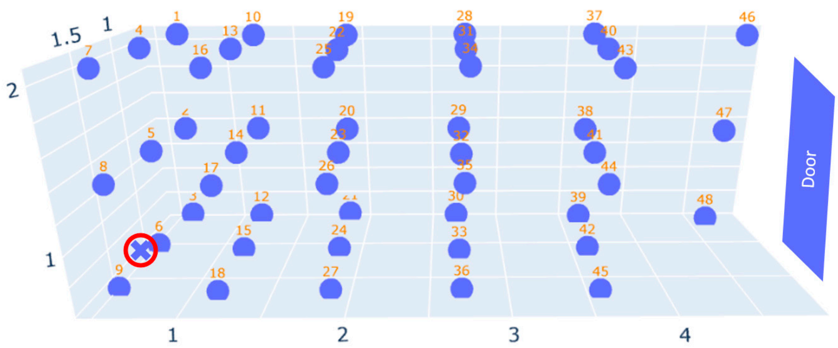


Figure 5: Side view of container showing positions of gas sensors. Red circled the gas discharge point. Gas sensor 50 is used as additional protection (with limit value of 60% of LEL).

Table 4

Experiments were conducted with the following variables:

Gas outflow:	50, 100, 300 and 1000 dm^3/h
Gas types:	hydrogen/natural gas
Ventilation grilles from gas meter cabinet (ventilation to hall):	open/closed (sealed)
Ventilation grille from the hall to the outside (left, top):	open/closed
Door between hall and room:	open/closed
Air intake over floor:	18 and 36 dm^3/h
Air extraction via external air grille:	18 and 36 dm^3/h

The gas outlet was stopped as soon as one of the sensors registered more than 50% LEL. This safety measure was taken to prevent unwanted ignition of the gas. Extrapolation was used to estimate whether 100% would also be achieved if the gas outflow had not been stopped.

On this basis, the results of the experiments were classified according to final concentration into one of three categories: less than 50% LEL; between 50% and 100% LEL and greater than 100% LEL. As long as the concentration throughout the container is below 100% LEL, the situation is safe in any case because the gas-air mixture cannot ignite.

The measurement results for both hydrogen and natural gas lead to the following findings A and B:

A Inside the gas meter cabinet
At a gas outlet in the gas meter cabinet of:
- 50 dm^3/h or more, the concentration rises to more than 100% LEL if no ventilation grilles are fitted, but to less than 100% LEL if grilles are fitted in accordance with the standard.
- 100 dm^3/h or more, the final concentration does exceed 100% LEL.

B Outside the gas meter cabinet
At a gas outlet in the gas meter cabinet of:
- 50 or 100 dm^3/h, the concentration outside the gas meter cabinet remains below 100% LEL.
- 300 dm^3/h, the concentration rises above 100% LEL in part of the experiments (hydrogen: 3 out of 8; natural gas in 1 out of 8); and
- 1000 dm^3/h, the final concentration exceeds 100% LEL in all cases.

The results lead to the following conclusions:

1. The build-up of concentrations (hydrogen and natural gas) remains below 100% LEL in the gas meter cabinet and other rooms when the gas meter cabinet is fitted with the vents prescribed for natural gas, at a gas outlet of up to 50 dm³/h.
   This means that a leak size in the meter cabinet of up to 50 dm³/h can be technically accepted. The ventilation grilles prescribed for natural gas are therefore more than sufficient for hydrogen. It is recommended to install ventilation grilles in meter cabinets for hydrogen gas meter installations in accordance with the current standard NEN 2768 + A1 for natural gas meter cabinets.

2. Hydrogen has stronger stratification than natural gas.
   Especially with low ventilation, this can lead to areas of high gas concentration ("dead spots") under the ceiling. Mechanical ventilation can reduce the likelihood of this. Both extraction and air supply can reduce the likelihood of such zones:
   - With extraction high in the room, the highest concentration is discharged.
   - When air is blown in, the gas is more mixed with air so dead ends are avoided.

3. The usefulness of a gas stopper cannot be demonstrated with this study
   Based on this study, no recommendation can be made on whether or not to apply a gas stopper, as the gas stopper only intervenes well above the gas outflow used in the project.

4. Mechanical ventilation is highly effective
   The ventilation flow rates determined afterwards, calculated on the basis of a change in concentration, are often higher than the set ventilation flow rates. This means that mechanical ventilation often appears to be even more effective than expected on the basis of the set air supply or air exhaust.

   Some possible causes were found for this; however, an unambiguous explanation cannot be given based on the results.
   - The results lead to the following possibilities for follow-up research:
   - Experiments with different set-up locations for gas meters than examined here
   - Experiments with small spaces other than a gas meter cabinet (e.g., a crawl space, kitchen sink or riser cupboard).
   - Experiments or CFD calculations to understand the causes of higher-than-expected ventilation (see above under 4).

Quantitative Risk Assessment of the distribution grid and built environment in the Netherlands: application and case studies

To make an initial assessment of the risks of hydrogen in the Dutch distribution network, a quantitative risk assessment (QRA) has been conducted. It compares the risk between the current natural gas distribution system and the future hydrogen distribution system. The total risk in the analysis consists of the risk arising from leaks in the distribution network and the risk arising from leaks in the house itself.

The model simplifies the built environment in the Netherlands in order to control the number of variables and associated calculations. For this initial version, detached houses were chosen for validating the model. In addition, semi-detached houses were also used in the case study of a representative sample neighborhood. The distribution network is simplified by using a limited number of materials, pressures, and diameters. An important input parameter of the model is the failure frequency of the different components. The failure frequencies for the distribution network were determined based on historical failure reports. However, no reliable dataset for the components behind the meter (meter assembly, internal piping, and end-use appliance) could be found for the Netherlands, so values from the UK were used instead. Given the aforementioned assumptions, the model provides an approximation of the location-specific risk resulting from fires or explosions. All calculated location-specific risks in this study for both natural gas and hydrogen remain well below 1×10^{-6} per year, indicating a very limited risk.

Based on the aforementioned failure frequencies in the dwelling, it is found that the location-specific risk for natural gas due to leaks behind the meter aligns well with the (limited) historical data. The probability of a fatal accident in the Netherlands resulting from an explosion or fire per dwelling, based on historical data, is 0.06×10^{-6}, excluding cases involving intentional gas releases. Additionally, the probability of injuries is 1.1×10^{-6}. The model yields respective values of 0.02×10^{-6} for fatal accidents and 0.4×10^{-6} for injuries, indicating a similar order of magnitude to the historical data. The risk scales linearly with the failure frequency.

With the same set of parameters and without additional mitigating measures, it is found that the effect of explosions with hydrogen is more severe than with natural gas. The location-specific risk for hydrogen is 3.8 times greater, i.e., 0.18×10^{-6}, when the risk of carbon monoxide poisoning is not considered. When comparing the risk between hydrogen and natural gas in the house, the risk due to carbon monoxide poisoning should also be considered. The mortality risk due to carbon monoxide poisoning is 0.37×10^{-6} per natural gas connection. When this risk is included in the comparison, it is found that there is a shift from reduced risk due to carbon monoxide poisoning to increased risk from explosions. The total location-specific risk with the chosen set of assumptions and without additional mitigating measures is lower for hydrogen than for natural gas.

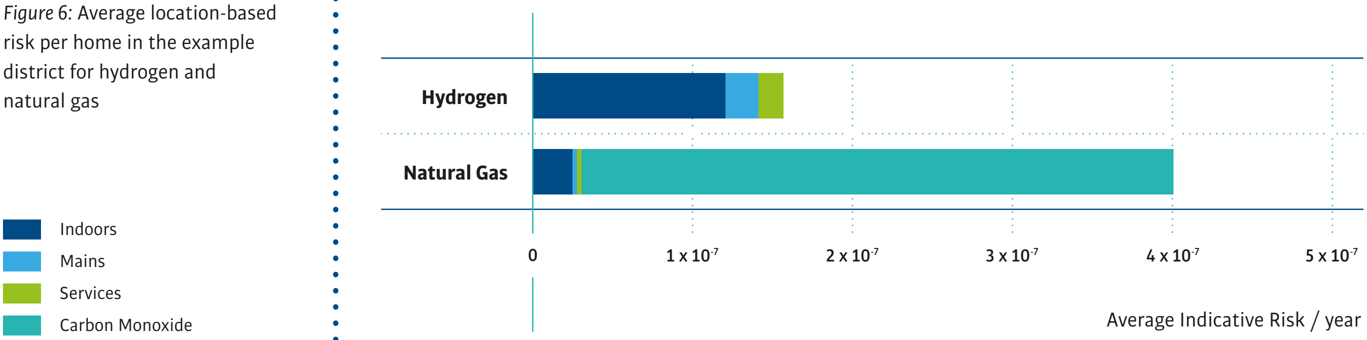
The effect of ventilation on the accumulation of (dangerous) concentrations in the house was determined by analysing ten identical houses with different ventilation rates. For hydrogen, halving the ventilation rate increases the risk by a factor of 1.8, while doubling the ventilation rate reduces the risk by a factor of 2.2. Ventilation has a stronger effect on the risk in the dwelling for hydrogen compared to natural gas.

The factor between the total risk from the distribution network without additional measures for hydrogen and natural gas is nearly 2.5 times. Based on the assumptions made in the model and averaged per connection (7.2 million), the risk from the distribution network in the dwelling is approximately 0.2×10^{-6} for hydrogen, assuming no additional mitigating measures are taken.

To gain a better understanding of the relative effects of leaks behind the meter and from the distribution network, a case study of a representative neighborhood was analyzed. This neighborhood consists of 57 homes connected to a 100-mbar main pipe through service lines. The 100-mbar network is fed by an 8-bar steel pipe running through the neighborhood. The 100-mbar network is modeled in several segments with different materials and diameters. The homes are modeled based on their surface area and include both detached and semi-detached houses. Additionally, the risk posed by leaks behind the meter has been determined for each of the homes.

The likelihood of leaks leading to the accumulation of gas inside a home is higher for leaks behind the meter. For hydrogen, it appears that the majority of the location specific risk is caused by leaks behind the meter (approximately 73%). The remaining portion is caused by the main pipe and service line connected to the home, as well as nearby sections of the mains. Generally, the contribution of the 100-mbar pipe is greater than that of the 8-bar pipe, depending on the distance between the homes and these pipes. The risks are highest for semi-detached houses compared to detached houses. Similar to the aforementioned risks, the impact of explosions is greater for hydrogen than for natural gas. However, the overall risk per dwelling in the neighborhood is lower for hydrogen compared to the risk posed by natural gas when considering the contribution of carbon monoxide poisoning, as indicated in the summary below. It is important to note that even without additional measures, the total risk remains well below 1×10^{-6} in both cases, indicating a relatively small risk.

Figure 6: Average location-based risk per home in the example district for hydrogen and natural gas



In summary, it is concluded that the risks calculated in the model are relatively small. In perspective, the total number of fatal accidents in the Netherlands in 2021 was approximately 6,500. The majority of these accidents were caused by accidental falls (5,430, corresponding to a risk per resident of approximately 3×10^{-4}/year). The total number of fatal accidents caused by smoke, fire, and flames in 2017 was 43, corresponding to a risk of 2×10^{-6}. The share caused by natural gas in the built environment is a fraction of this.

The risk associated with hydrogen can be reduced by achieving lower failure frequencies. It is found that spontaneous leaks in frequently occurring parts of the network (100-mbar) contribute most to the total risk. Damage from interference is detected earlier, resulting in less frequent accumulation of gas to dangerous concentrations in enclosed spaces. The greatest effect can be achieved through mitigating measures that reduce the frequency of spontaneous failures in pipelines or components, such as periodic leak detection or the replacement of couplings that often lead to leaks. An initial assessment has been made of the impact of excess flow valves and gas sensors with acoustic signals applied to the risk of hydrogen in the case study of a typical neighborhood. This is based on (yet) unpublished initial calculations applicable to the UK situation. The approximation shows that excess flow valves, depending on the assumptions in the model, can achieve a potential risk reduction for hydrogen of approximately 20%. For gas sensors, the estimated reduction is about 27%.

The results described in this section were obtained considering the set of assumptions as described. In this simplified model of the distribution network and built environment, several refinements of the model are possible. It is recommended to further improve the model by incorporating a greater variety of housing types. The model mainly used detached houses. The effect of explosions is calculated for nearby homes in the model, resulting in a higher risk for semi-detached houses. In a refined version of the model, a distribution of housing types (detached/semi-detached/row houses/small apartments, etc.) should be applied. One of the assumptions used, considered currently as a limitation of the model, is that PVC pipes have the same leak size distribution as PE pipes. In practice, this may be different. Hard PVC has a more brittle character and may potentially lead to more brittle fractures. This results in a different leak size distribution, which consequently affects the calculated risk. Further research on the leak size distribution is recommended. Lastly, it is recommended to model the effect of the excess flow valve and gas sensors. Based on initial outcomes from the UK, an initial estimation has been made. It is advisable to expand the model for the Netherlands by simulating the implementation of these measures.

Additional recommendations

Applicability of QRA tools, detection of hydrogen fires, effectiveness of odorisation, and effect of hydrogen permeation

In HyDelta 2.0's work package "Safety of hydrogen in the distribution network and the built environment", research has been conducted on the risks of hydrogen through a quantitative risk model and additional experiments around the effect of ventilation on the accumulation of gas in a home. In addition to these two main tasks, a number of smaller topics related to the same main objective were conducted. These knowledge gaps were identified during HyDelta's scoping phase and may lead to additional measures in the pilot projects. They are:

1. Are existing QRA tools applicable for hydrogen gas pressure regulating stations?
2. Is flame detection necessary for hydrogen fires?
3. To what extent is the effectiveness of barrier odorization affected by, for example, adsorption and/or absorption of the odorant?
4. What is the effect on safety and gas quality of the permeation of nitrogen, oxygen and water from outside the pipeline to the inside?

Based on literature review, these 4 questions were answered.

Applicability of existing QRA tools for hydrogen gas pressure regulating stations

The most common and available tools for performing a so-called Quantitative Risk Assessment (QRA) were assessed and compared. For the comparison, it was specifically examined which tools would be suitable for determining the risk contours around a so-called gas pressure regulating stations operating on hydrogen.

The application area and scope of each tool were analysed. From the analysis it was concluded that the software tools Safeti-NL and Conifer are suitable for determining the risk contours around a gas pressure regulating station, with the former being accepted by the Dutch competent authorities as an unequivocal calculation method for facilities for performing a QRA. Conifer is less well-known in the Netherlands and at this point in time does not have the option of being licensable but has been specifically developed for that part of the gas network from the gas pressure regulating station (< 8 barg) to the gas meter (20 – 25 mbar). Considering the validation programs of both tools, it is expected that the risk contours of both tools around a gas pressure regulating station will largely overlap. Both tools have been validated for use with natural gas and the validation with hydrogen is steadily being expanded. Based on the current validation datasets, the risk contours for the same situation for hydrogen are greater than those for natural gas. It should be noted that for both software tools – in case of hydrogen – worst case scenarios are used with the calculations. For example, the ignition probability of hydrogen is set to 100% by default. Such parameters have a clear influence on the risk contours. Knowing that the validation process is still in full swing, it is therefore not appropriate to make a statement about how the risk contours of hydrogen and natural gas relate to each other in terms of size. Comparing the first results, it is expected that after full validation the difference will be limited.

Detection of hydrogen fires

A hydrogen flame may be less visible depending on the circumstances. Reduced visibility may result in injury to persons when they get too close to the flame. Currently, there is a lack of experience with hydrogen flame visibility under various conditions. Because the experience is lacking, it is recommended that tools be made available for service technicians in pilot projects to detect a hydrogen flame and make them aware of the possible presence of a hydrogen flame. With the experience gained during the pilot projects and additional research, it can be determined whether future flame detection tools should be available for work on hydrogen grids. Gathering of information on the visibility of burning odorized hydrogen and the visibility of flames during incidents is recommended.

Determining the effectiveness of THT odorant

Based on the literature review, it was determined that, in specific situations, the effectiveness of odorization by THT can be negatively affected. Despite this influence, the effectiveness of odorization of hydrogen by THT is comparable to that of natural gas. With this, there is no reason to take additional control measures when distributing hydrogen odorized with THT.

Determining the effect on safety and gas quality due to permeation of nitrogen, water, and oxygen

Permeation is a natural phenomenon that occurs in both natural gas and hydrogen distribution. As long as there is gas flow through the pipelines, the effect with respect to safety and quality is negligible. In situations where there is an isolated pipeline section, based on a theoretical consideration, there will be an effect with respect to safety and quality over time. This considered the permeation of individual components, oxygen, nitrogen, and water, from outside the pipeline to inside the pipeline. In order to understand the total process of permeation and its effect on safety and gas quality, it is recommended that pilot projects monitor the gas composition especially in situations where there is long-term shutdown of hydrogen in pipelines.

Table 5

	Knowledge gap	**Recommendation**
Detection of hydrogen flame	Experience with the visibility of a hydrogen flame	Availability of tools for detection of hydrogen flames to service technicians. Gather information on visibility of odorized hydrogen and flame visibility during incidents.
Effectiveness of THT odorant	None	None
Effect of permeation	Understanding the overall process of permeation of multiple components	Monitor gas composition when there is prolonged stoppage of hydrogen in pipelines.

Section 7

Gas station safety

7 Gas station safety

Sources for this section

DELIVERABLE:

D6B.1A & D6B.1B – Inventory, modelling, and experiments related to ventilation in different types of pressure reducing stations in the distribution (low pressure) grid in the Netherlands, in natural gas and hydrogen atmospheres

Link to deliverable

Safety and suitability of gas stations in the distribution grid for hydrogen

Topics: Determine what modifications to the enclosure (the housing) of gas stations are necessary for safe distribution of hydrogen through gas stations: ventilation, adjustments needed, etc.

Ventilation in different types of pressure reducing stations

Inventory, modelling, and experiments related to ventilation in different types of pressure reducing stations in the distribution (low pressure) grid in the Netherlands, in natural gas and hydrogen atmospheres.

This section is a follow-up to the gas stations work package from HyDelta 1.0. That study showed that for various types of gas cabinets, hydrogen more often leads to a combustible mixture at the ventilation openings than natural gas, assuming the leakage flow rates chosen in that study. This led to the recommendation to carry out additional research to identify the effects of smaller, more common leakage flow rates. It was also recommended to investigate which types of different gas cabinets are frequently used in the Netherlands. This report further develops these recommendations.

This follow-up research is important because ventilation is an important measure in the event of an unintentional gas leak. Ventilation dilutes the gas and minimizes the risk of ignition or explosion. For the transition to hydrogen, it is important to know whether these gas pressure regulating stations with the same types of gas cabinets carry the same risk with the hydrogen of application.

The aim of this study is to gain further insight into how hydrogen behaves in existing gas cabinets compared to natural gas. That insight was obtained by looking at the issue from different angles: experiments as well as simulations using finite element method (CFD). This provided interesting insights that will help policymakers determine whether, and if so what, further measures can be taken.

1st step: Inventory common types of gas cabinets

Some 55,000 gas stations are operated by district system operators (DSOs) in the Netherlands. An inventory of gas cabinets used in the Netherlands was carried out. It focused on cabinets installed by DSOs in the last 10 years, because conversion of installations to hydrogen will initially take place with relatively new cabinets and these installations are designed in accordance with NEN 1059. This does not mean they are exactly the same, but they are designed with the same minimum functional requirements. Three types of gas cabinets comprise a substantial part of the total population. These are mini-gas cabinets with a volume < 0.5 m³ (these are mostly used for a high-pressure delivery station), ½ m³ gas cabinets and 4 m³ gas cabinet stations.

What is a realistic leakage size?

There has been a lot of focus in this study on which leakage is representative in (normal) operation and for which leakage rate ventilation should be effective. Different sources use different assumptions to determine the expected leakage rate. This is not surprising, as leakage rates can differ due to operational pressures, maintenance, or environmental factors.

This study tested both with the highest leakage rate from a recent field study (40 l/h) of more than 700 gas stations. Also, leakage flow rates were based on leakage openings in other standards (0.025 mm^2 and 0.25 mm^2). This is still a wide range of leakages where, especially for the larger leaks, it is expected to be noticed by the public coincidently in close proximity of the gas cabinet with a leak. The leaks measured in the field study of more than 700 stations are considered realistic, with the largest measured leak being 40 liters per hour.

2nd step: Measurements

An extensive test program was carried out with a ½ m^3 cabinet and a 4 m^3 cabinet station. With a mini cabinet, some indicative measurements were performed to get a first impression. This was done by positioning a reference leak in the center of the cabinet during the experiments. From this, gas (hydrogen or natural gas) flows at a known flow rate controlled by a Mass Flow Controller. The gas concentration was then measured at various points in the gas cabinet, directly at the vent openings outside the gas cabinet and at a distance of about 0.5 meter away from the gas cabinet. The smallest leak selected has a flow rate of 40 l/h of natural gas (125 l/h for hydrogen). The largest leak is based on a leak opening of 0.25 mm^2 at a pressure of 8 bar (that is: 1.8 m^3n /h natural gas or 5.6 m^3n /h hydrogen). Between these extremes, several other leakage flow rates were chosen.

Key data from the experiments are shown in the three graphs on the next page for the ½ m^3 cabinet, the 4 m^3 cabinet station and the mini cabinet where the leakage rate on the x-axis decreases in size. The first dataset on the x-axis represents both 1.8 m^3n /h natural gas and 5.6 m^3n /h hydrogen. This reasoning also applies to the other, smaller leakage flow rates.

In the case of the mini cabinet, some indicative measurements were done to check for leakages at a leakage opening of 0.025 mm^2 at 8 bar pressure (i.e., 0.18 m^3n /h natural gas or 0.56 m^3n /h hydrogen) and 1 bar pressure (i.e., 40 l/h natural gas or 125 l/h hydrogen).

Figure 7: Gas concentration (vol%) at different leakage rates natural gas and hydrogen in a ½ m³ cabinet

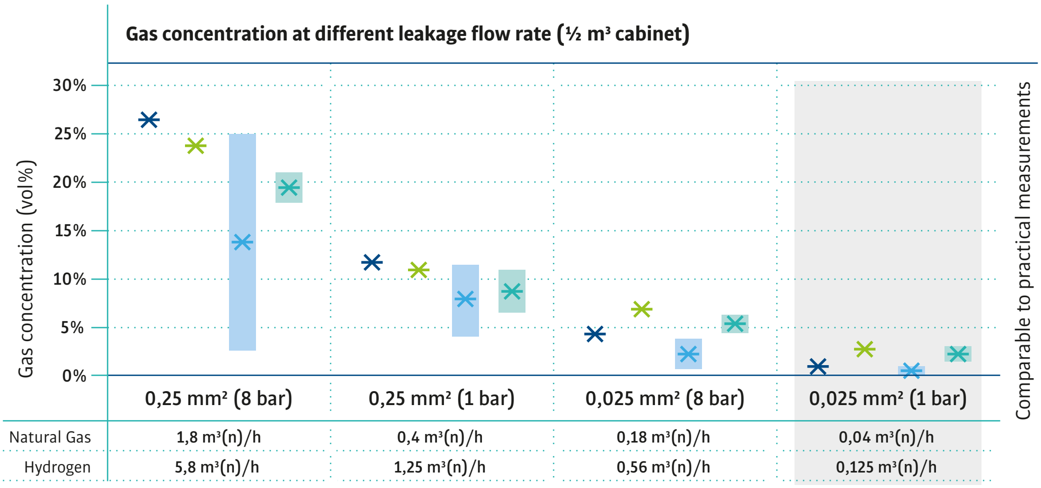


Figure 8: Gas concentration (vol%) at different leakage rates of natural gas and hydrogen at the 4 m³ cabinet station

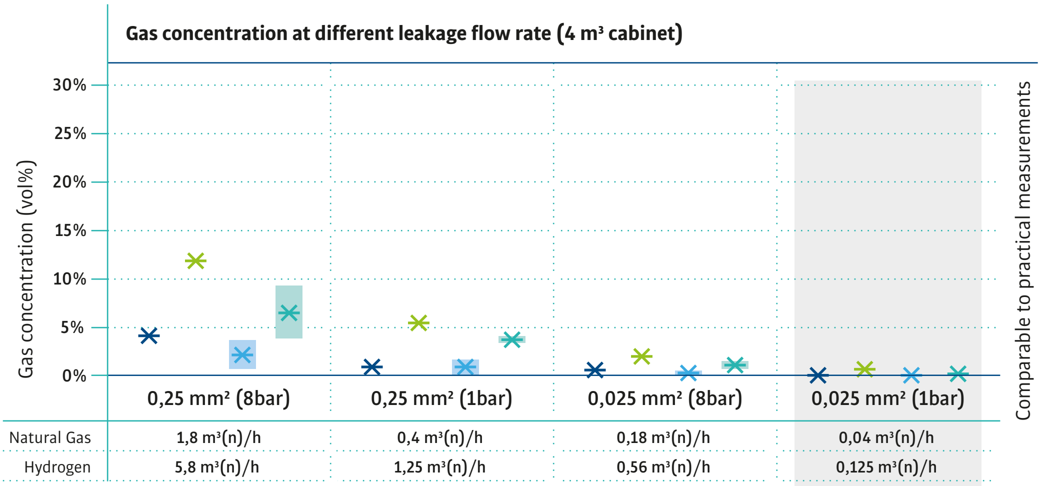
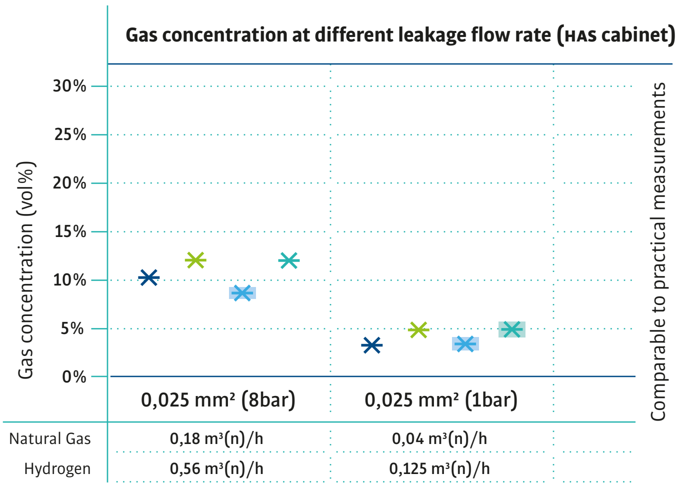


Figure 9: Gas concentration (vol%) at different leakage rates natural gas and hydrogen in a mini cabinet



Section 8

Inflatable gas stoppers safety

8 Inflatable gas stoppers safety

Sources for this section

DELIVERABLE:

D6B.2A & D6B.2B – Report on ignition scenarios and experiments during the use of inflatable gas stoppers to mitigate natural gas and hydrogen leaks in the low-pressure gas distribution grid

Link to deliverable

Safety and suitability of using inflatable gas stoppers in the distribution grid to mitigate a hydrogen leak

Topics: To gain insight into the risks associated with the use of inflatable gas stoppers for the temporarily closing of a hydrogen gas pipe, including any additional requirements.

Report on ignition scenarios and experiments during the use of inflatable gas stoppers to mitigate natural gas and hydrogen leaks in the low-pressure gas distribution grid

As part of the national research programme, HyDelta, a study was conducted on the suitability of inflatable gas stoppers as a fast temporary seal in a hydrogen distribution network (of the RNBS: regional network operators).

The study as described in this section is part of work package D6-B2 "Safe use of hydrogen in the low-pressure distribution network and urban areas; suitability of assets and working methods". Inflatable gas stoppers are also used in the transport network (from Gas Transport Services, GTS), but the application is different from in a distribution network. The results in this report do not relate to the application of inflatable stoppers in the gas transport network.

The research question addressed in the report is as follows:
Are inflatable gas stoppers, as they are currently applied in natural gas distribution networks, suitable for application in a hydrogen distribution network?

To answer this question, eight sub-questions were formulated. These were answered by conducting theoretical research and by carrying out practical experiments. The theoretical research was focused on ignition scenarios when using inflatable gas stoppers and the experiences of grid operators with malfunctioning inflatable gas stoppers.

The practical research consisted of:

1. Performing leak-tightness measurements on two types of stoppers in two types of pipe materials (PVC and PE), and four different diameters.
2. Determining the maximum leakage rate at which the concentration in a working pit remains below 10% LEL.[2]
3. Determining how a gas stopper behaves in case of direct ignition of leakage gas near the pipe end.
4. Determining how a gas stopper behaves when a combustible mixture in the working pit is ignited due to an increased leakage rate from the pipe end.
5. Determining how a gas stopper behaves when extinguishing a gas fire.

The aforementioned experiments were conducted with both hydrogen and natural gas.

2) 100% LEL = 5.9% Groningen natural gas.

100% LEL = 4.0% hydrogen.

LEL refers to the lower flammability limit. Below the lower flammability limit, there is insufficient fuel present to sustain a combustion reaction. LEL and LFL refer to the same lower flammability limit. For hydrogen, the LEL/LFL is 4 vol% hydrogen in air.

UEL refers to the upper flammability limit. Above the upper flammability limit, there is insufficient oxygen present to maintain a combustion reaction. UEL and UFL refer to the same upper flammability limit. For hydrogen, the UEL/UFL is 75 vol% hydrogen in air.

Kiwa uses the abbreviations LEL and UEL for the lower and upper flammability limits of a gas, respectively. Kiwa uses these abbreviations in order to stay in line with Dutch and European standards as well as to avoid any confusion of the concepts.

The main conclusions from this study are as follows:
Inflatable gas stoppers, as they are currently applied in natural gas distribution networks, can also be applied in a hydrogen distribution network if additional measures are considered.

In normal operations, when placing inflatable gas stoppers at a distance of 1 metre from an outlet, there is no difference between a natural gas and hydrogen distribution network. A small natural gas leak (< 0.2 m^3/h) and a small hydrogen leak (< 0.6 m^3/h) near the stopper were found to be ignitable. This could cause the stopper to break, which is also the case with a natural gas leak. So far, this kind of failure has only occurred to a limited extent in practice. However, preventing the presence of ignition sources in working pits is and remains a key issue in preventing this kind of failure with natural gas as well as hydrogen. Taking a few additional measures could further reduce the risks.

During an incident response, inflatable gas stoppers were placed at a safe distance from an outlet (depending on the wind direction and the related LEL limit, among other factors). In this practical test, a distance of 20 metres was chosen. The current stoppers are not suitable for application in hydrogen networks without the incorporation of additional measures. In fact, it appears that if even a limited leakage rate of hydrogen is ignited, a stopper can be ejected due to the intense ignition.

Measures to reduce the risks include applying two stoppers (block & bleed), applying forced ventilation in the working pit, and measuring the gas concentration near the pipe end. The effectiveness and feasibility of these measures will need to be further investigated. This report includes recommendations for gas stopper manufacturers, the Gastec QA Board of Experts, and regional grid operators.

Section 9

NO_X effects

9 NO_x effects

Sources for this section

DELIVERABLE:

D9.1 & D9.2 – literature research on low NO_x hydrogen burners and developing design rules for low NO_x burners

Link to deliverable

Implications of hydrogen in combustion use – NO_x effects

Topics: Map current successfully applied NO_x-reducing strategies and elucidate the basis for design rules for hydrogen burners applied in high-temperature processes towards mitigating NO_x emissions.

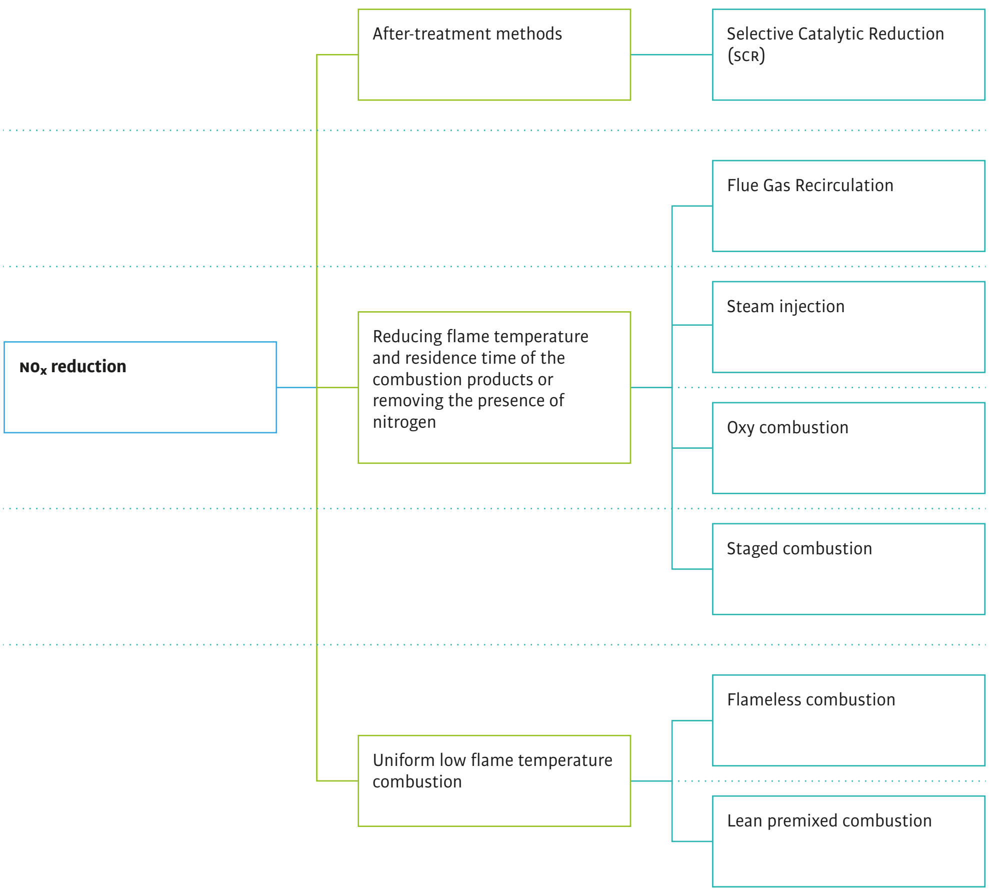
Literature research on low NO_x hydrogen burners and developing design rules for low NO_x burners

The energy-intensive industry is investigating the option to use hydrogen as a fuel to drastically reduce the carbon intensity of their manufacturing processes to meet the climate agreements. One of the challenges is to gain highly efficient combustion while keeping the NO_x emissions low. Towards this end, this research is aimed to accelerate the development of LowNO_x hydrogen burners needed for the large-scale introduction of hydrogen in the high-temperature industry. The project is divided into two phases. In phase 1 a literature inventory was performed on the different burner types used in the industry and on the NO_x mitigating strategies that can be applied for these burner types. Furthermore, the differences between the NO_x emissions from natural gas and hydrogen combustion for various industrial high temperature burners were investigated. This information obtained in phase 1 was used for the development of new design rules for low NO_x hydrogen burners which was developed in phase 2 of the project.

The inventory on the different burner technologies reveal that many different burner types are used in industrial processes, each designed for a specific process. For example, several burners are designed with the aim of generating mainly radiative heat transfer while other are designed to generate mainly convective heat transfer. Generally, the burners can be divided into premixed and non-premixed burners. In processes where the air and fuel are premixed prior to entering the burner, switching to hydrogen can result in flashback and burner tip overheating. However, by increasing the combustion excess air, these issues can be overcome with the additional advantage that the NO_x emission will be reduced. Most burners used in the high temperature industry rely on the non-premixing concept referred to as diffusion or nozzle mix burners. The literature inventory shows that the diversity of different designs of nozzle mix burners is large. Examples of nozzle mix concepts identified in the literature are swirl burners, pipe-in-pipe burners, FLOX burners, regenerative burners, recuperative burners, and radiant heaters.

The literature inventory reveals that the major challenges with blending hydrogen to natural gas (up to 100%) are higher flame temperature, wider flammability limits, faster diffusion, and higher burning velocity. Altogether, upon hydrogen addition the flame moves closer to the burner tip causing lower internal flue gas recirculation and higher flame temperatures. As a result, it was found that for most of the burners tested, hydrogen addition to natural gas increases the NO_x emission. NO_x mitigating measures identified in the literature show that reducing the residence time, hot zones with high (local) temperature and oxygen concentration are effective measures to reduce the NO_x emission. For example, experiments performed on a forced draught burner present in an industrial boiler system show that switching from natural gas to hydrogen results in a three times higher NO_x emission than the legal NO_x limit allows. By applying external flue gas recirculation, the NO_x emission, when using pure hydrogen, was successfully reduced below the Dutch legal NO_x limits (70 mg/m³, 3% O_2). However, for burners present in high temperature processes reducing the NO_x emissions is still a challenge to be solved, since the flue gas temperatures are often too high for external flue gas recirculation. Prototype hydrogen burner designs found in the literature aim to lower the NO_x emission by creating more internal flue gas recirculation by, for example, increasing the distance between the fuel and air nozzles, changing the number of fuel and air nozzles, and changing the diameter of the fuel and air nozzles. Furthermore, several dedicated burner designs are making use of, for example, the Coanda effect with the aim of creating an under-pressure to create more flue gas entrainment. Other techniques identified in the literature used are mild combustion (FLOX), staged fuel combustion, water injection and micro combustion. The Figure below (*figure 10*) gives an overview of the NO_x mitigating measures identified in the literature.

Figure 10



The literature inventory reveals that the degree of mixing between hydrogen, air and flue gases is essential to reduce the NO_x emission. To find some general design rules for burners, it is important to have a better understanding of the mixing between hydrogen, air, and flue gases. Towards this end a jet model was developed in this study to calculate the mixing of hydrogen, air and flue gases using different burner design parameters. The jet calculations are supplemented with numerical flame calculations. The simulation results reveal that due to the wider flammability range of hydrogen and faster burning velocity, combustion takes place much closer to the burner head in comparison to methane and creates higher temperatures near the burner head. Consequently, the NO_x formation rate increases when switching from methane to hydrogen. Based on numerical flame simulations internal flue gas recirculation and staged combustion were found to be effective strategies in reducing NO_x. Both strategies are based on decreasing the burning velocity and flame temperatures. Comparison between the calculated amount of flue gas recirculation and measured values needed to reduce the NO_x emission back to that of methane combustion show excellent agreement. Simulations show that about 16% flue gas need to be present in the H_2/air mixture to get the same NO_x levels as that for methane for a furnace temperature of 1000 °C. Furthermore, simulations show that combustion under fuel rich conditions results in low NO_x formations, when the equivalence ratio is higher than j=1.2 the NO_x formation is in the same range as for methane combustion.

Based on the knowledge gained in the study three different conceptual burner designs are proposed; 1) a pipe-in-pipe burner, 2) a swirl burner and 3) a staged combustion design. All three burner designs are equipped with a venturi to create internal flue gas recirculation. The burner design parameters, such as the fuel- and air nozzle diameter, diameter of the venturi and air pressure needed to create sufficient flue gas recirculation and/or staged combustion to supress the NO_x formation were calculated using the jet model.

It is recommended to construct the burner in such a way that the burner heads can be flexibly exchanged and test the burner in a (semi)-industrial furnace. During these tests, the effect of different burner heads and burner configurations on the NO_x emission will be studied. The information acquired during these tests will be used to create the optimum configuration for the three proposed low NO_x industrial high-temperature hydrogen burner designs. Together with industry partner(s) and burner manufacture(s), one burner design will be selected for a field test. The test will also give valuable insights for the design of hydrogen burners for various industrial applications.

Section 10

Transport assets

10 Transport assets

Sources for this section

DELIVERABLE:

D7.1 – Inventory of relevant aspects for conversion of gas distribution networks to hydrogen

Link to deliverable

DELIVERABLE:

D7.2 – Concept of a natural conversion plan of a natural gas distribution network to hydrogen

Link to deliverable

Hydrogen and transport assets

Analysis of the conversion of a natural gas distribution network to hydrogen

Topics: Development of a plan for the conversion of a natural gas distribution network to a hydrogen distribution network (from gas receiving station to customers' gas installations).

Inventory of relevant aspects for conversion of gas distribution networks to hydrogen

A model conversion plan is being developed in work package 7 of HyDelta 2.0 "Conversion of a natural gas distribution network to hydrogen" for large-scale conversion of gas distribution networks to hydrogen. This is done considering distribution networks from practice as case studies. The conversion plans for these practical case studies will be drafted based on the existing knowledge in and experience with converting distribution networks to hydrogen. This section is an inventory of the knowledge and experience that will be used when drafting the plans for the case studies. This section also provides an overview of the relevant aspects to be considered when drawing up a model conversion plan.

Projects and studies

Based on literature, an overview of hydrogen projects and conversion studies has been made. The overview includes 11 projects (mainly field tests and pilots) and 8 studies. Out of these 19 projects and studies, 14 are from the Netherlands, 3 from Germany and 2 from the United Kingdom.

Regulation

Similar to the natural gas market, regulation will apply to the hydrogen market. This regulation is still under development. The European Commission intends to amend the Gas Regulation and the Gas Directive for this purpose. In the proposed new regulation, among other things, a hydrogen distribution network will require a separate network operator, separate from the network management of the natural gas distribution network. If the natural gas distribution network is to be used for hydrogen, those assets must be transferred to the operator of the hydrogen distribution network.

In the absence of a specific legal framework (the current framework prohibits network operators from playing a role in hydrogen pilots), ACM has drawn up a Temporary Framework for Hydrogen Pilots for the next 5 years. A pilot must relate to the built environment and have a specific learning objective. Grid operators are allowed to distribute hydrogen through the grid, but have no role in the production, trade, and supply of hydrogen.

Materials, components and technical knowledge and skills

Based on the available literature, an overview of components and materials present in the current gas distribution network and end-use installations, indicating whether they are suitable for hydrogen, or whether they need to be replaced or require adjustments has been made. In this overview for some components, it is indicated that the suitability for hydrogen is not yet sufficiently known, and that further research is required. An inventory was also made of the required technical skills and knowledge for the conversion.

Supply areas for hydrogen

Before plans can be made for the actual conversion of gas distribution networks to hydrogen, municipalities will draw up plans in consultation with property owners, residents, and network operators (DSO and TSO) to determine which customers will continue to be supplied with gas or which will switch to another form of heat supply. In the areas where the gas supply is maintained, a choice is made for the type of sustainable gas: green gas or hydrogen.

For the built environment, the most cost-effective sustainable heat supply can be determined per neighbourhood, such as green gas or hydrogen supply. A similar consideration can be made for business customers (business parks, horticulture greenhouses). In the case of hydrogen, the basic principle is that the existing gas network of DSOs and TSO is used, because this is cost-effective and accelerates implementation. A distribution network of a DSO consisting of a medium and low-pressure network behind a city gate station (GOS) comprises several tens of thousands of customers. A low-pressure system just behind a district station provides about 250 to 500 home connections. There are major differences between distribution networks of a DSO in urban areas, rural areas, and business parks. If the hydrogen supply is provided from the regional transport pipeline network of a TSO (RTL), other distribution networks and industry connected to this RTL network must be considered.

Hydrogen supply

Five situations can be distinguished for hydrogen supply, of which 4 relate to the supply of (almost) pure hydrogen. Delivery from a GOS that is connected to the high-pressure transmission line (HTL) hydrogen backbone via a regional transmission line (RTL) seems to be the most attractive in the long term, considering cost effectiveness and security of supply. Hydrogen supply areas behind a GOS can have a size of several tens of thousands of customers. Smaller hydrogen projects with several tens to hundreds of customers, which will probably be the first to be developed, can be supplied with hydrogen via tube trailers and/or hydrogen produced locally with electrolysers. These projects can be scaled up at a later stage and connected to a GOS that supplies hydrogen from the RTL network connected to the hydrogen backbone. This will improve security of supply and reduce the need to store hydrogen locally. Hydrogen distribution networks that are fed from the hydrogen backbone will be the first to arise in the vicinity of this backbone and where RTL pipelines are converted to hydrogen transport, for example for supplying hydrogen to industrial customers.

Step-by-step plans

In some of the conversion projects and studies that were analysed, a step-by-step plan has been developed for the conversion of natural gas distribution networks to hydrogen. These step-by-step plans relate to the preparation and the actual implementation. Although the step-by-step plans are quite different and therefore difficult to compare with each other, they offer different starting points for developing a model conversion plan in the remainder of the study.

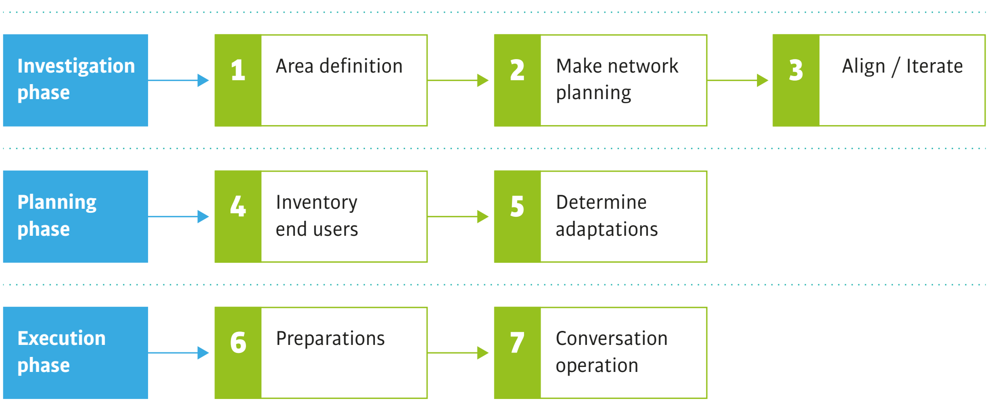
Concept of a conversion plan of a natural gas distribution network to hydrogen

In work package 7 of HyDelta 2.0 "Conversion of natural gas distribution networks to hydrogen", a model conversion plan has been developed for the large-scale conversion of existing gas distribution networks to almost pure hydrogen. This model conversion plan is based on experiences and insights gained in hydrogen projects and conversion studies in the Netherlands and abroad. In order to understand in more detail what a conversion plan entails, two case studies have been developed for this project. The generic conversion plan offers regional network operators a basis for a specific conversion plan. Because each region and the gas distribution network located therein is unique, the generic conversion plan will have to be adapted to the specific characteristics of the gas distribution network.

Structure of the conversion plan

The model conversion plan contains a description of more than 50 activities to be carried out, divided into 3 phases and a total of 7 steps (*figure* 11):

Figure 11



Alternatives are possible for some activities. The choice between alternatives depends, among other things, on the availability of devices/components and availability of suitably qualified personnel, or on the preference of the grid operator. Sometimes there are alternatives that require further research.

Time planning

Part of the conversion plan is a time schedule. Assumptions and preconditions apply to the time planning, such as the number of personnel to be deployed or the maximum duration of the gas interruption during the conversion. The lead time of the various steps and phases depends on the size of the distribution network and the number and types of end users. The lead time of steps and phases can be influenced by changes in assumptions and preconditions. During the execution phase of the conversion plan, the time schedule may have to be adjusted on the basis of the information obtained in the planning phase.

Tasks and responsibilities

A large number of parties will be involved in the implementation of the conversion plan: municipality/municipalities, distribution system operator, operators of the natural gas and hydrogen transport network, hydrogen suppliers, installers, and end users. The model conversion plan indicates for each activity how the tasks and responsibilities can be divided. Because the conversion is a complex and time-consuming process, good coordination is essential. The municipality is the appropriate party to coordinate the conversion of the distribution network to hydrogen because municipalities are designated to decide on and implement the energy transition at a local level. It has the necessary powers to do so, can make a broad assessment of interests and is supervised by a democratically elected council. The execution of work can be outsourced by the parties involved to contractors and consultants.

The parties involved will have to inform each other and good coordination is necessary for certain activities. The municipality is responsible for communication with the end users and will draw up a communication plan for this. Multiple communication forms and channels can be used. In addition, the municipality can set up an information point where end users can go to with their questions during the entire conversion process.

Conclusions

This research has yielded the following insights:

1. Coordination, responsibilities, and communication:
   - A large number of parties are involved in the implementation of the conversion plan. It is essential to make good agreements about the responsibilities of the tasks to be executed.
   - Because the conversion is a complex and time-consuming process, good coordination is essential. The municipality is the appropriate party to coordinate and communicate about the conversion of the distribution network to hydrogen.

- Parties involved will have to inform each other optimally and good coordination is required for certain activities.
- Support by the end-user is an essential precondition. This concerns the public acceptance that the energy supply with natural gas can no longer continue to exist, that hydrogen is a good replacement for natural gas, i.e., safe, affordable (compared to alternatives such as all-electric) and security of supply is guaranteed.
- The municipality is responsible for communication with the end users and will have to draw up a communication plan for this.

2 Duration of the conversion plan:

- The conversion of a part of the gas distribution grid (from planning phase to execution phase) can take several years. In the two cases studied, this varies from about 3 years (3,700 connections) to more than 6 years (30,000 connections).
- If a different choice is made for replacing natural gas, such as for a heat network (construction of a new network) or for all-electric (grid reinforcement), a plan will also have to be drawn up and implemented. The activities are partly comparable to those of the conversion plan to hydrogen and will also entail a considerable lead time. However, no comparison has been made in this study.
- The duration of the conversion plan is determined by the size of the distribution network (i.e., the number of connections) and the required number of qualified personnel or by new Hydrogen Distribution Station(s) (HDS) to be realised and expansion/upgrading of the distribution network, including the lead time of permit granting. The latter requires a joint planning by the national and regional gas network operator.
- The execution phase (preparatory work and conversion operation) takes up more than 70-80% of the total time.
- The duration of the conversion operation, during which the gas supply to end users is interrupted, can be limited by carrying out as much work as possible during the preparatory work (such as replacing the existing central heating boiler with an H_2-ready boiler). Even if this saves little time in total, this shift does provide more flexibility in the implementation.
- The physical conversion (last step of the conversion plan) can be shortened considerably if a dual-fuel boiler and dual-fuel gas meter can be used and flushing the gas pipes with nitrogen can be omitted. This makes the conversion process less complex, shortens the total lead time of the conversion plan and can lead to cost savings.
- Most technically trained personnel are required for inspection of the installations at the end users (planning phase) and replacing the gas installations (execution phase). By deploying more personnel, the lead time can be reduced.

3 Dividing the distribution network into sections:
- For the conversion, the gas distribution network will be divided into sections. The number and size of these sections depends on two preconditions: the duration of the gas interruption and the number of installers to be deployed to convert the gas equipment at the end users.
- If dual-fuel devices/components can be used (such as gas meter, central heating boiler), the sections can be larger, or no sectioning is required at all.
- The order in which the sections are converted from natural gas to hydrogen depends on the position of the hydrogen and natural gas feed-in points in the grid. It may be necessary to use a temporary feed-in point (for example a tube trailer with hydrogen or natural gas or via an additional pipeline to be installed).

4 Security of supply:
- Because existing gas infrastructure is used and adjacent areas have to be supplied with natural gas in addition to the area being supplied with hydrogen, it is often impossible to maintain the security of supply of the hydrogen distribution network at the same level as in the situation when natural gas was still being distributed. The risk of an interruption of the hydrogen supply to end users will then have to be dealt with in a different way.

5 Alternatives:
- Replacing the central heating boiler with an H_2-ready boiler or with a dual-fuel boiler (if available) during the preparatory work: A dual-fuel boiler saves time during the conversion operation. The lead time for the preparatory work remains the same as for replacement by an H_2-ready boiler.
- Whether or not to flush the distribution pipe, connection pipe and/or indoor pipe with nitrogen: If flushing with nitrogen can be skipped, this simplifies the work during the conversion operation.
- Whether or not to use gas stoppers at every customer: These are now being used for new connections, but they are not present for existing connections.
- Temporary gas supply from the existing gas network or with tube trailers: During the conversion, end users who have not yet been supplied with hydrogen will still have to be supplied with natural gas. This is possible if the distribution network that is being converted still has a city gate station that is connected to an RTL on natural gas or is connected to a gas distribution network that remains on natural gas. Alternatively, a tube trailer can be used for the temporary supply of natural gas or hydrogen.

Recommendations

This research leads to the following recommendations:

- Lessons learned from current pilots: Various pilot projects will be carried out in the coming years. The experiences and insights gained (also with regard to coordination, responsibilities, and communication) can form an important input for the further development of the model conversion plan.
- Acceleration of permit procedures: the lead time of permit procedures can have a major impact on the lead time of the whole conversion plan (e.g., the permit procedure for the HDS). It is recommended to investigate how the lead time of permit procedures can be shortened.
- Remediation: For gas distribution networks that are being converted to hydrogen, it is recommended to replace old pipe sections, including cast iron, in the coming years.
- Suitability of valves: Insufficient research has been carried out into the leak-tightness (both internal and external leakage) of valves running on hydrogen. Further research into this is recommended.
- Inerting indoor pipelines: The extent to which the indoor pipeline should be inertised with nitrogen is still under discussion. It is therefore recommended to conduct additional research into this.
- Filling the gas network with hydrogen: Research must show how a meshed network can be safely filled with hydrogen.
- H_2-ready boiler: The use of an H_2-ready boiler is decisive for the implementation of the conversion. However, a good definition or standardization of an H_2-ready boiler is still lacking. It is recommended to set this up.
- Dual-fuel components: Availability of dual-fuel boiler and gas meters greatly simplifies and accelerates the physical conversion. It is recommended to have a dual-fuel boiler developed or to encourage market parties to do so. More clarity is also needed about the suitability of gas meters for both natural gas and hydrogen.
- Security of supply: Compared to natural gas distribution, the security of supply of hydrogen distribution cannot always be maintained at the same level due to a smaller number of feed-in points and/or less meshing of the grid. It is recommended that research be carried out into the risk of interruption of the hydrogen supply and how this can be mitigated.
- Increasing conversion efficiency: The costs of the conversion have not been mapped out in this study. A better insight into the conversion costs can be helpful in improving the cost efficiency of the conversion process. In addition, the conversion to hydrogen may be simplified, for example by performing activities more efficiently or limiting the number of actions. Research could be carried out into this.

Availability of affordable hydrogen: Whether it is attractive for end users to switch to a hydrogen-based gas supply depends on the future availability and affordability of hydrogen. This is an important precondition for converting the gas distribution network. It is recommended that developments with regard to the hydrogen supply be followed closely.

Section 11

Digitalization analysis

11 Digitalization analysis

Sources for this section

DELIVERABLE:

D8.1 & D8.2 – State of the art technologies in the current gas grid and gap definition with the future hydrogen grid

Link to deliverable

DELIVERABLE:

D8.3 & D8.4 – Simulation of selected cases for digitalisation in a Dutch hydrogen distribution network

Link to deliverable

Analysing digitalization in network management

Topics: Research how digitalization (simulation and decision support tools combined with dedicated sensors) can contribute to an effective transition to hydrogen grids.

State of the art technologies in the current gas grid and gap definition with the future hydrogen grid

The Dutch government's central goal with the National Climate Agreement is to reduce net greenhouse gas emissions in the Netherlands by 55% by 2030 compared to 1990 levels and 100% by 2050. Hydrogen will carry out a number of critical functions within energy and raw material systems.

The Distribution System Operators (DSOs) in the Netherlands may play an important role delivering (green) hydrogen to the built environment via their existing gas transport network for sustainable heating of homes and business.

Replacing natural gas by hydrogen in the existing DSO infrastructure will give several challenges (next to safety aspects, social acceptance, etc.) on the security of supply of energy to the end-users, related to the physical aspects of the assets in the hydrogen network. We would like to analyse where digital technology can contribute to accelerating the natural gas grid transformation. The scope of the research is limited to 100% hydrogen grids.

As a research methodology to execute work we chose for the following approach:

1. Get insight in the state of the art of digitalization of the current DSO gas grids, by sending a questionnaire and interviewing DSO representatives. The same questionnaire has been sent to TSO Gasunie to get a benchmark.
2. Get insight in the needed digitalization of the future hydrogen grid. This was done by:
   - Literature study, mainly regarding foreign DSOs.
   - A workshop with Dutch DSO representatives.
3. Both the literature study and the outcome of the workshop with the DSOs give an indication of the desired situation of digitalization of the (future) hydrogen grid. The concrete topics can be compared with the current situation regarding Modelling, Monitoring and Control. Within in the scope of this research, we will give a qualitatively description on the technology gap, and a (preliminary) prioritization of the gaps.

Main results from the state-of-the-art investigation for three systems are given below.

Modelling

All DSOs use commercial tools for capacity calculation, designing the gas grid and determining risk levels regarding delivery. All capacity simulations are based on worst case scenarios, like maximum demand at -12 or -13 ºC. No dynamic hourly demand profiles are used. For risk analysis the N-1 approach (omitting one asset) is used, in most cases for design reasons. The tools are able to work with different gas compositions but are only used for natural gas at this moment.

For most DSOs the capacity calculation tool is validated based on pressure measurement data at district stations and total flowrates at GOS. The data from measurements in the grid is not yet directly integrated to the capacity simulation tool. Currently the data is used as a manual input of the tool or by manually comparing the value in Excel table.

Monitoring

Pressure is the most common parameter being measured in the network. Mostly, there is no sensor placed in the pipeline, only a limited number of stations are being measured. Need for flow data has been observed and most DSOs are working on that topic. Data from GOS and green gas suppliers is available.

Most of the data is manually accessed by the DSO by sending people to an onsite location or a manual download from the website. Some station data of some DSO can be retrieved automatically via Remote Terminal Unit (RTU).
The use of smart meter data at small consumers is limited. Individual demand of small consumers is predicted by 'Standaard JaarVerbruik' (SJV) or by contract values for large consumers.

Control

The grid control at DSOs is autonomous on pressure. The pressure setting is changed manually. The grid is robust with respect to capacity. DSOs recognize no huge need for advanced control of the grid capacity in normal operation. More advanced control might be needed in some cases of green gas supply in the grid, e.g., boosters and dynamic pressure management.

Most activities regarding Control are on green gas feed-in. Control is done by closing the valve in case of deviating gas quality. Manual control of the GOS pressure is done by request, to allow green gas feed-in in low demand periods.

From the workshop with the DSOs, we found the main challenge of operating a hydrogen grid is about balancing the hydrogen grid. There are several factors that contribute to this challenge:

1. Increasing dynamics in supply and demand, like changing user profiles, increasing local supply and local storage and line-pack.
2. From a stand-alone gas grid to a multi-connection grid. Observed trends are connection to other DSOs, connection to Gasunie backbone and connection to E-grid (bi-directional).
3. Get access to real time data, on both Demand and Supply.

The workshop delivered many ideas on how to address the main challenges:

1. Monitoring. Real-time data on Supply, Demand and Storage. Measurements in the grid (stations, pipes): Flow, Pressure, Quality and Temperature.
2. Modelling. Real-time capacity models with coupling to externals: E-grid, Gasunie, other DSOs. And tooling for short term transition planning from natural gas to hydrogen.
3. Control. Controlling the priority of suppliers which can feed into the network.

The main results of literature study on mainly foreign DSOs are globally in line with the results from the Dutch state of the art investigation and the main outcomes of the workshop.

Both the literature study and the outcome of the workshop with the DSOs gives an indication of the desired situation of digitalization of the (future) hydrogen grid. Especially, the 'HOW' topics can be compared with the current situation to come to a qualitatively description on the technology gaps.

From technology point of view, we come to the following summary of the technology gap in digitalization of the hydrogen grid.

Table 6

Tech	Topic	Gap
Monitoring	Realtime supply data	Available, but should be extended
	Realtime consumer data	Rarely available
	Realtime storage data	Not available
	Flow measurements in assets	Not available
	Pressure measurements in assets	Available, but should be extended
	Quality measurements in assets	Not available
Modelling	Tool for modelling a large complex network	Available, but should be extended
	Tool for modelling multi-commodity interaction	Not available
	Tool for modelling transient effect in the network for high pressure	Rarely available
	Tool for modelling storage	Not available
	Direct integration with real-time sensor data	Not available
	Modeling tool for transition from natural gas to hydrogen	Rarely available
	Tool to enable simulation of dynamic profiles	Rarely available
Control	Optimization algorithm for producer priority allocation or network operational strategy	Not available
	Actuators that can be controlled remotely	Rarely available

- Not available (red)
- Rarely available (orange)
- Available, but should be extended (blue)

Figure 12: Prioritization of technology gaps with respect to monitoring and control hydrogen infrastructure

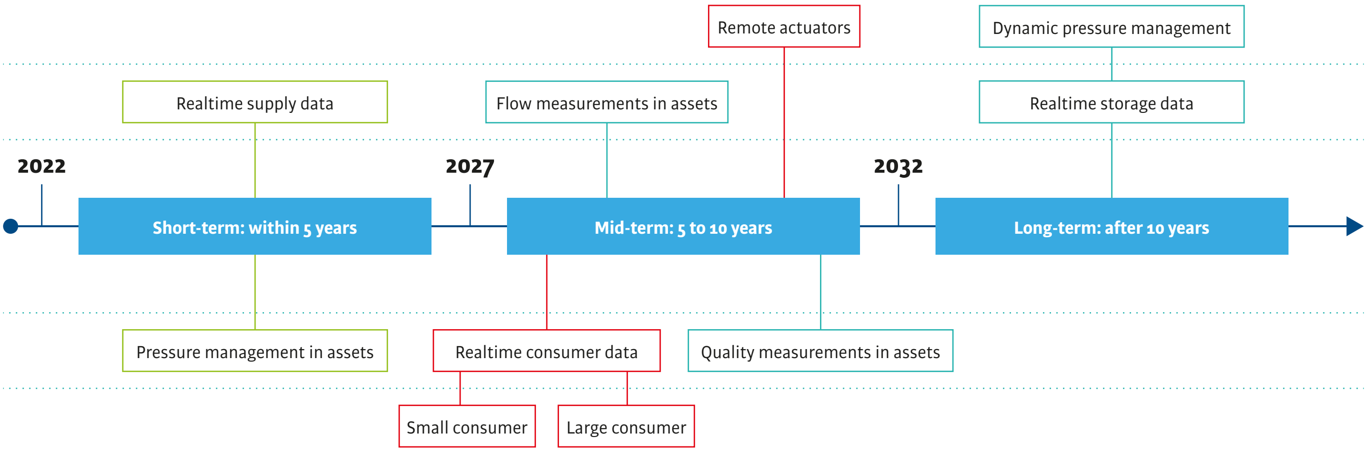
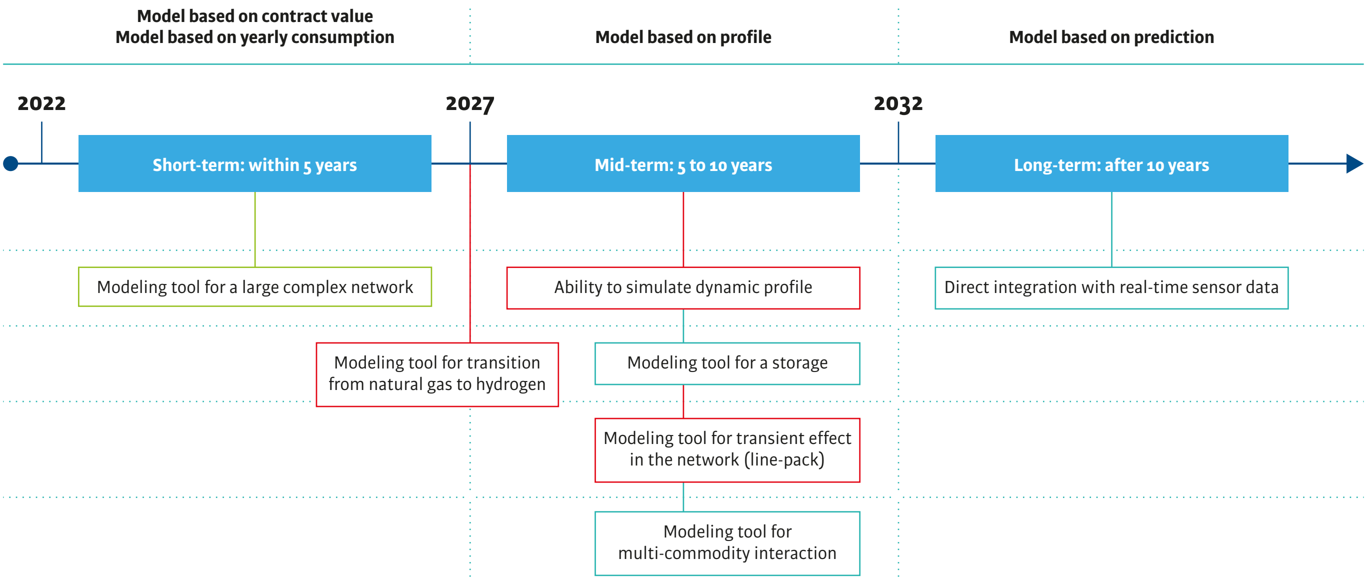


Figure 13: Prioritization of technology gaps with respect to modelling hydrogen infrastructure



Combining the technology readiness and timing, results in a preliminary prioritization of the technology gaps for modelling, monitoring and control.

To provide more quantitively information regarding the development of the main technologies for digitalization of the hydrogen grid, in the second part of the current HyDelta 2.0 project we will investigate a selection of the gaps in use cases:

1. Investigation on the number of flow sensors and pressure sensors needed in the grid. Investigate the added value of flow sensors?
2. Investigation on the added value of using demand profiles and intermittent supply profiles for balancing the hydrogen grid using storage by utilizing producer priority and grid pressure regulation.

Simulation of selected cases for digitalisation in a Dutch hydrogen distribution network

Replacing natural gas by hydrogen in the existing DSOs infrastructure will give several challenges to the security of supply of energy to the end-users, related to the physical aspects of the assets in the hydrogen network. Within the HyDelta 2.0 program, WP8 Digitalization, the need and benefit of digitalization of the gas grid has been investigated.

In the current gas grid, digitalization is limited in all aspects: monitoring, modelling, and control. This means that a lot of digitalization aspects could be developed to handle the needs of a future hydrogen grid, which have to deal with the following trends: increasing dynamics in supply and demand, from a stand-alone grid to a multi-connected grid and a need for real-time data on supply and demand. A roadmap has been developed on how to deal with the main challenges in balancing the future hydrogen grid, for all aspects of digitalization.

In the frame of the HyDelta 2.0 program we have chosen for the use case 'Smart sensor placement' for pressure and flow sensors in the Kapelle area, which covers the main digitalization aspects, with a focus on the short- and mid-term.

On this grid several scenarios have been applied, using TNO's dynamic gas grid simulation tool Aurora. Starting with a base case where natural gas is replaced by hydrogen. Subsequently scenarios have been simulated on adding new supply locations for electrolyzers with a dynamic profile, adding large consumers and a scenario with one 'broken gas pipe'.

The flow and pressure in the whole grid have been simulated for all scenarios, with realistic supply and demand data. The gas grid simulator has been validated in the current (natural gas) situation by available pressure and flow data. By replacing natural gas with hydrogen and maintaining the delivery of the same amount of energy to all users, the flows in the grid are about three times higher and the pressures will remain about the same. However, the flows stay below the allowable limits. In the case of adding two realistic electrolyzers with a total capacity of 3 MW, the maximum pressures stay below the allowable limits. An N-1 situation has been simulated by a pipe break in the 4-bar grid, showing the critical pipe segments where the pressure becomes too low. In the next scenario three additional large consumers are added, resulting in a pressure drop which is on some locations just below the allowable limit. Finally, the effect of replacing the two current supplies with one supply with another location on the grid has been investigated. The simulation tool has been used to find the optimal locations in terms of pressures and flows within the acceptable limits.

In all scenarios an uncertainty in the domestic demand has been introduced and the number of (flow and pressure) sensors and their location have been determined, to minimize the uncertainty in flow and pressure in the whole grid. The overall picture for the scenario is that adding two sensors will give the main gain in reducing the uncertainty. Adding two pressure sensors reduces the uncertainty in pressure by about 60% to 70%. Adding flow sensors has a much smaller effect on the reduction due to restriction on placing the sensor. The location for placing the sensor is globally the same for all scenarios.

The different scenarios show the need for a dynamic modelling tool that is able to calculate flows and pressures in the grid in case of a dynamic supply and demand situation. Only a tool will not be sufficient to get full insight, because of uncertainties in the input data for the grid. Besides uncertainty in the demand profile, there can be incompleteness of the geometrical information (pipe diameters, pipe roughness, etc.) and pressure settings which deviate from the numbers that are used in the model. So, to get a full insight into the grid, measurement data will always be needed. The benefit of a simulation tool to investigate the number and location of sensors has been demonstrated, showing that the number of pressure sensors in the grid should be increased.

Furthermore, the insight in the physical behavior of the grid is essential in the foreseen increase of the number of local decentralized hydrogen suppliers (both from solar/wind and surplus of the electricity grid) and the ability of DSOs to control and manage the pressure in the distribution network.

Overall, we can draw a conclusion on the added value of digitalization of the gas grid. The gas grid is currently facing several broad challenges which can be aided by digital technologies: different heating technologies, declining number of customers and gas demand, converting of the grid to hydrogen (and biomethane) and decentralized production. Current standard operations such as maintenance planning and security of supply can benefit from digitalization, by allowing the DSOs to make better decisions and proper investments. Digitalisation will create more accurate and real-time insight and a combination of a robust calculation model and online data from a limited number of sensors will generate sufficient insight. Moreover, digitalisation will facilitate scenario analysis and creates more opportunities for renewable gasses in the gas network.

Section 12

Social aspects

12 Social aspects

Sources for this section

DELIVERABLE:

D10.1 – Overview from the literature / studies on societal support for new energy technologies and hydrogen in particular

Link to deliverable

DELIVERABLE:

D10.2 – Stakeholder perspectives on the societal embeddedness of the development and deployment of hydrogen technologies in the Netherlands

Link to deliverable

DELIVERABLE:

D10.3 – Case study report with best practices regarding risk governance and societal embeddedness of innovative energy technologies

Link to deliverable

DELIVERABLE:

D10.4 – Synthesis: Towards societal risk governance strategies

Link to deliverable

Social aspects of hydrogen

Social acceptance for hydrogen transport and storage

Topics: Study the main societal challenges for deploying hydrogen transport/distribution, storage, and application within the built environment in the Netherlands and how could these challenges be overcome as part of the development and implementation strategy.

Overview from the literature / studies on societal support for new energy technologies and hydrogen in particular

Social acceptance is an important aspect in the realization and implementation of various renewable energy technologies. Our main objective with this literature review is to provide insight into public support, social acceptance, and societal readiness for new energy technologies in general, and hydrogen, both as an energy carrier and as an application in the built environment, in particular. 110 relevant articles were identified, of which 28 have been included in this literature review, based on relevance and year of publication (2012-2022). Generally, the findings show there is low awareness concerning hydrogen, as well as limited knowledge and familiarity with this new energy technology, especially concerning hydrogen storage. Despite this, there is overall moderate to high willingness to accept hydrogen, which decreases when it comes to the local implementation of hydrogen projects. Safety and affordability were two important characteristics of a hydrogen industry that would motivate people to support this industry, together with climate change mitigation. Safety concerns over the flammability of hydrogen are mostly expressed when used for household activities and storage, and less so when it concerns the use of hydrogen for transportation. Communication about safety and risks, transparent interaction between all parties and the community, as well as giving the community a voice in the decision-making process, will be essential for hydrogen acceptance. Together with the results from five case studies (deliverable 10.3 of the HyDelta 2.0 project), recommendations regarding the elements that should and should not be included in a development and implementation strategy will be given.

Stakeholder perspectives on the societal embeddedness of the development and deployment of hydrogen technologies in the Netherlands

Hydrogen has the potential to play an important role in the future (sustainable) energy system of the Netherlands and reducing greenhouse gas emissions. For the development and application of energy technologies, it is important to consider social aspects in addition to technical aspects.

Based on 14 semi-structured interviews, hydrogen developments in the Netherlands were mapped according to the four Societal Embeddedness Level (SEL) dimensions (impact on the environment, stakeholders and public, policy, laws & regulations and market & (financial) resources). Because environmental and market impacts are also highlighted in other work packages of HyDelta 2.0, these interviews focused on stakeholder and public involvement and policy laws and regulations.

The research question for this task is:
"What are the stakeholder perspectives on the societal embeddedness of the development and deployment of hydrogen technologies in the Netherlands and associated societal risks?"

First, the impact of hydrogen as an energy carrier in the Netherlands on the environment was examined. This shows that the greatest potential impact is experienced when it comes to (the feeling of) safety, use of space for energy transition and living environment and nuisance from light, noise, and use of space during the (re)construction of projects.

Second, we looked at stakeholder and public involvement. Here it emerges that hydrogen seems to have a positive image among the public, although the level of knowledge is still low. There is a need for communication from either the government or knowledge institutions to the public, but also to organizations that (want to) get involved with hydrogen. Public information needs are in the areas of practical issues, safety, and finance. Organizations (wanting to) get involved with hydrogen need more communication about the vision and goals regarding hydrogen in the Netherlands. In obtaining and maintaining public support, information and communication play an important role, but trust and a sense of justice are also important.

Third, policy, laws and regulations were examined. This shows that the policy framework regarding hydrogen is still evolving. New standards need to be set and the roles of established and new parties are changing. Licensing procedures still have a long lead time, which is perceived as a challenge by the parties involved. There is much development in this area, for example in the form of the Temporary Guidelines for Safety.

Finally, we looked at market and financial resources. Here it emerges that the market for hydrogen has yet to be established or brought into being. There is still uncertainty in the development of supply and demand. The uncertainty of supply and demand combined with uncertainty in the policy framework and long-term vision from the government means that investing in hydrogen is often still seen as risky.

The analysis of the perspectives of hydrogen in the four SEL dimensions shows that social support for hydrogen in the Netherlands is currently good. A number of (societal) challenges also emerge:

1. There is no consensus yet on how hydrogen should be applied in the Netherlands.
2. Public support may diminish when project developments start. This can be influenced by:
   - Lack of trust in activities or parties involved.
   - Lack of sense of fairness.
3. Lack of policies and standards can delay project development and deter companies from investment decisions.
4. The long lead time of permitting procedures can delay the progress of project development.
5. The energy system is changing, and so are roles, for example those of government, grid operators, regulators, and energy providers.
6. The energy transition is a major task but available space in the Netherlands is limited. A risk is that insufficient space is available.
7. There is scarcity of knowledge and labor. The tightness in the labor market can cause project development and permitting to have a longer lead time.

The results from this report indirectly contribute to the results of HyDelta work package 3 (risks and collaboration in H_2) and HyDelta work package 6 (safe operations LP grid).

Following this task, the results of the literature review, local case studies and stakeholder interviews will be brought together in a synthesis. Through co-creation workshops with HyDelta research partners and (local) stakeholders the results will be compared, validated, and worked towards what ‘risk governance strategies’ for societal risks and uncertainties can look like.

Case study report with best practices regarding risk governance and societal embeddedness of innovative energy technologies

Societal aspects play an important role in successful implementation of renewable energy technologies such as hydrogen. In Work package 10 (WP10) within the HyDelta 2.0 research program, we investigated the societal challenges and lessons learned for deploying hydrogen transport/distribution and application within the built environment in the Netherlands. Furthermore, we studied how these societal challenges can be successfully embedded within an implementation strategy. In this deliverable (D10.3), the conducted field research of four cases, each in a different phase of implementation (Rozenburg, Lochem, Wagenborgen, Stad aan 't Haringvliet), is described. The central themes that we covered in this research are public support, (risk) communication, safety and the experience of safety, and perceived success of the project. For each case, we interviewed local stakeholders (24 interviews in total) and residents, including people living nearby the hydrogen pilot (17 interviews, 68 questionnaires and approximately 90 conversations). The results show mostly positive indications for public support (although this is not yet known for Stad aan 't Haringvliet). In all cases, the importance of communication between stakeholders and between stakeholders and potentially participating residents is acknowledged, even though there seems to be a lack of communication with residents living in the vicinity of hydrogen pilots. This is a missed opportunity and a potential risk, as these residents may have questions and doubts, for instance about the progress and decisions that have been made in the project. Positive attitudes concerning the safety are partly attributed to the trust people have in the involved stakeholders. It also seems important that there is a contact person whom people can reach in case of questions or concerns. Additionally, in some of the cases a demonstration house, where people can experience what it means when a house is heated with hydrogen, seems successful. Thus, the findings emphasize the importance of broad and frequent communication, not only with the directly involved residents, but also with people who live in the vicinity of a hydrogen pilot. Communication is not only important in the planning and implementation phase of the project, but also at the end of the implementation phase. Finally, shared ownership of the project and inclusion of all stakeholders in all phases of the project seems important to prevent delays in the project.

Synthesis: Towards societal risk governance strategies

In HyDelta 2.0 WP10 we found through literature research, four local case studies and stakeholder interviews that the public perception of hydrogen developments in the Netherlands is now generally positive, nevertheless fragile. The knowledge level of the general public is not high: both concerning the technologies, vision, and goals regarding hydrogen applications in the Netherlands. This lack of knowledge increases the risk of misinterpretation of information or change of perception with false information. The knowledge level can be increased with central communication about hydrogen developments, the vision and goals around hydrogen and policies. Improving central communication to the public raises the knowledge level and helps local implementation by unburdening local participation processes, which are currently extensive with first hydrogen developments and pilots. However, the fact that the entire energy system and policy framework concerning this is in transition, makes communication about hydrogen developments to the public challenging. Roles and responsibilities in the sector are subject to change and there is uncertainty about what the energy system will look like in the future. This makes it challenging to provide unified information about the position of hydrogen in the future energy system. The current uncertain position of hydrogen applications in the future energy system, in combination with unclear roles and responsibilities and long lead times of permit procedures, contributes to a challenging climate for market parties to make investment decisions.

In task 10.1 we did a literature review about social acceptance of hydrogen. In task 10.2 we did interviews with stakeholders along the hydrogen value chain about the societal embeddedness of hydrogen in the Netherlands and in task 10.3 we did four (local) case studies, studying public support, communication and risk and safety perception. In task 10.4 we used the results of tasks 10.1, 10.2 and 10.3 to work towards three risk governance strategies for nine societal risks occurring in four main subjects: 1) participation, 2) communication, 3) policies and regulations and 4) decision making. These strategies focus on what participation processes could look like in the coming years, how communication to the public can be optimized and what role the government could take to accelerate the development of the hydrogen value chain in The Netherlands by enabling stakeholders. The risk governance strategies have been developed in a co-creation setting. The strategies can be enhanced and improved by working out a stepwise approach and testing them in use case scenarios.

Section 13

Labor & training

13 Labor & training

Sources for this section

DELIVERABLE:

D11.1 – The future requirements for HBO, WO, and postgraduate personnel in the hydrogen industry

Link to deliverable

Topics: An inventarisation and overview of the required (future) skills and available education to match this in the upcoming hydrogen economy, to serve as a starting point to start developing attractive and comprehensive curriculums to train relevant personal in hydrogen technologies and applications.

The future requirements for HBO, WO, and postgraduate personnel in the hydrogen industry

As the Dutch government and organisations continue to implement plans for the production and use of hydrogen in the ongoing energy transition, there is an expected surge in demand for human capital with hydrogen-related skills at applied universities (HBO), universities (WO), and postgraduate levels. While it's true that some of these skills can be transferred from existing sectors such as natural gas network operators and renewable energy developers, the scale of the government's plans to rollout hydrogen at large scale means that a mismatch between the supply and demand of specialized personnel across various disciplines is likely to arise.

The goal of this study was to qualitatively examine the skills and competences needed for trained personnel in the HBO (applied sciences education), WO (scientific education), and postgraduate education (retraining of professionals) levels in the Netherlands, in order to work in the hydrogen transport sector; this was done with a focus on the skills and training needed for the gas network operation sector.

In this work, we present an estimation of the number of trained personnel that will be needed in the hydrogen transport industry in the Netherlands, where we found that between 1,800 and 4,700 full time jobs could be required in 2030 for the construction of hydrogen distribution systems or work in commissioning hydrogen transport to the built environment, and between 4,200 and 12,500 full time jobs could be made available to work in the operation and maintenance of such networks. These values are heavily dependent on the degree of uptake of hydrogen in the built environment.

Moreover, we carried out a series of interviews with stakeholders in the hydrogen industry in the Netherlands, and we identified the most important hard skills that are needed by trained personnel in the hydrogen industry. The interviews and analysis revealed that engineering skills, across various disciplines, were the most frequently mentioned.

Next to the stakeholder interviews, we analysed the current job postings on a popular job posting website, where we identified 40 job postings that are specifically recruiting hydrogen professionals. We proceeded to carry out an analysis regarding the most common hard and soft skills requested by the job postings, as well as the levels of education needed to fulfil those vacancies. We found that most of the vacancies are looking for engineers with either a Bachelor's degree (that can also be understood as HBO training) or a Master's degree (WO training) in engineering disciplines, with Chemical engineering being the most frequently asked (followed by mechanical and electrical engineering).

We finalise the Deliverable by adding a series of recommendations for different stakeholders (educators, industry and government) on how to enhance hydrogen in the existing curricula and what practices could ensue that sufficient trained personnel in the area of hydrogen are made available in the following years to fulfil the expected rise in job openings in the energy transition and hydrogen in particular, thereby preventing potential gridlocks caused by a lack of specialized personnel.

Annex I

List of publications

Annex I

List of publications of the HyDelta 2.0 project

The HyDelta 2.0 project led to a total of 31 publications, divided as follows:

1. 26 reports, where all the research results have been published.
2. 4 plenary presentations, where the researchers involved in the HyDelta 2 project discussed the progress of the different work packages.
3. 1 summary report, prepared as per the request of the subsidy giver TKI Nieuw Gas

All publications from the HyDelta 2.0 (and the HyDelta 1.0) project are publicly available and can be found in the hydelta.nl/research-programme website. To increase the traceability and findability of all publications, e.g., to be cited or included in further research down within and without the HyDelta programme of projects, each publication was given a Digital Object Identifier (DOI), i.e., a persistent identifier that uniquely points at each publication. On the next pages is a list of all publications and their respective DOIs, whence the insights that were included in this summary report were taken.

DOI	Publication
https://doi.org/10.5281/zenodo.7997216	D2.1 Drivers of renewable hydrogen production in the Dutch integrated energy system – 2023-06-02
https://doi.org/10.5281/zenodo.8153970	D2.2 Hydrogen in the energy system: value for energy transport infrastructure and its users – 2023-07-17
https://doi.org/10.5281/zenodo.7516478	D3.1 Case studies of interest regarding risks and uncertainty in the hydrogen value chain – 2023-01-09
https://doi.org/10.5281/zenodo.7907222	D3.2 Individual and system risks in hydrogen value chains: methodology and case studies – 2023-05-08
https://doi.org/10.5281/zenodo.8134658	D3.3 Individual and system uncertainties in hydrogen value chain developments – 2023-07-11
https://doi.org/10.5281/zenodo.8123743	D3.4 Technical analysis of hydrogen supply chains – factsheets (update 2023) – 2023-07-07
https://doi.org/10.5281/zenodo.7405420	D4.1 Introducing hydrogen in decentral end-user areas to deal with E-grid congestion in the Netherlands – 2022-12-06
https://doi.org/10.5281/zenodo.8123334	D4.2 Cost-benefit analysis of various short-term supply-side E-grid flexibility options in local areas in comparison to conventional grid-expansion techniques – 2023-07-07
https://doi.org/10.5281/zenodo.8123378	D4.3 Report on the main policy implications of the potential of hydrogen for regional electricity grid congestion mitigation – 2023-07-07
https://doi.org/10.5281/zenodo.8153986	D5.1 Venting and flaring of hydrogen in a high-pressure transmission network – 2023-07-17
https://doi.org/10.5281/zenodo.8154119	D5.2 Report on safe isolation, de-pressuring, and evacuating of high-pressure hydrogen pipelines and installations for maintenance purposes – 2023-07-17
https://doi.org/10.5281/zenodo.8154317	D6A.1 Outflow experiment results: concentration build-up at leakages between 50 - 1000 dm^3/h – 2023-07-17
https://doi.org/10.5281/zenodo.8069169	D6A.2 & D6A.3 Quantitative Risk Assessment of the distribution grid and built environment in the Netherlands: application and case studies – 2023-06-22
https://doi.org/10.5281/zenodo.8189651	D6A.4 General recommendations: applicability of QRA tools, detection of hydrogen fires, effectiveness of odorisation, and effect of hydrogen permeation – 2023-08-09
https://doi.org/10.5281/zenodo.8164498	D6B.1A & D6B.1B Inventory, modelling and experiments related to ventilation in different types of pressure reducing stations in the distribution (low pressure) grid in the Netherlands, in natural gas and hydrogen atmospheres – 2023-07-19
https://doi.org/10.5281/zenodo.7889396	D6B.2A & D6B.2B Report on ignition scenarios and experiments during the use of inflatable gas stoppers to mitigate natural gas and hydrogen leaks in the low-pressure gas distribution grid – 2023-05-03
https://doi.org/10.5281/zenodo.8171441	D7.1 Inventory of relevant aspects for conversion of gas distribution networks to hydrogen – 2023-07-21
https://doi.org/10.5281/zenodo.8171514	D7.2 Concept of a conversion plan of a natural gas distribution network to hydrogen – 2023-07-21

https://doi.org/10.5281/zenodo.7501854	D8.1 & D8.2 State of the art technologies in the current gas grid and gap definition with the future hydrogen grid – 2023-01-03
https://doi.org/10.5281/zenodo.8016454	D8.3 & D8.4 Simulation of selected cases for digitalisation in a Dutch hydrogen distribution network – 2023-06-08
https://doi.org/10.5281/zenodo.7956518	D9.1 & D9.2 Literature research on low NO_x hydrogen burners and developing design rules for low NO_x burners – 2023-05-22
https://doi.org/10.5281/zenodo.7494526	D10.1 Overview from the literature / studies on societal support for new energy technologies and hydrogen in particular – 2022-12-30
https://doi.org/10.5281/zenodo.7795566	D10.2 Stakeholder perspectives on the societal embeddedness of the development and deployment of hydrogen technologies in the Netherlands – 2023-04-03
https://doi.org/10.5281/zenodo.7828082	D10.3 Case study report with best practices regarding risk governance and societal embeddedness of innovative energy technologies – 2023-04-14
https://doi.org/10.5281/zenodo.8068926	D10.4 Synthesis: Towards societal risk governance strategies – 2023-06-22
https://doi.org/10.5281/zenodo.8191790	D11.1 The future requirements for HBO, WO, and postgraduate personnel in the hydrogen industry – 2023-08-09
https://doi.org/10.5281/zenodo.7304548	HyDelta 2.0 Webinar Economic aspects of the hydrogen system – 2022-11-08
https://doi.org/10.5281/zenodo.7428739	HyDelta 2.0 Webinar Hydrogen and transport assets – 2022-12-12
https://doi.org/10.5281/zenodo.7317935	HyDelta 2.0 Webinar Hydrogen safety in the gas grid – 2022-11-15
https://doi.org/10.5281/zenodo.7428773	HyDelta 2.0 Webinar social aspects of hydrogen – 2022-12-12
https://doi.org/10.5281/zenodo.8189705	Openbaar Eindrapport HyDelta 2 – 2023-09-22