HyDelta 2

WP3 – Risks, uncertainty and collaboration in the hydrogen-based value chain

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

Status: final

Dit project is medegefinancierd door TKI Nieuw Gas | Topsector Energie uit de PPS-toeslag onder referentienummer TKI2022-HyDelta.

Document summary

Corresponding author

Corresponding author	Michele Tedesco
Affiliation	TNO
Email address	michele.tedesco@tno.nl

Document history

Version	Date	Author	Affiliation	Summary of main changes
1	27-1-2023	Harry van der Weijde, Thomas Hajonides, Pieter Verstraten, Lauren Clisby	TNO	First version
2	10-3-2023	Harry van der Weijde	TNO	Incorporating EAG and partner comments

Dissemination level

PU	Public	X
RE	Restricted to • Project partners including Expert Assessment Group • External entity with whom a Non-Disclosure Agreement exists	

Document review

Partner	Name
TNO	Sebastiaan Hers
NEC	Rob van Zoelen, Julio Garcia
DNV	Jan-Willem Turkstra
Stedin	Tjebbe Vroon
Gasunie	Udo Huisman
NBNL, Gasunie, Kiwa, DNV, TNO, NEC, Hanze	HyDelta Supervisory Group

Samenvatting

Gezien de urgentie van de energietransitie, de omvang van de benodigde investeringen en de lange doorlooptijden, is de een versnelling van de ontwikkeling van waardeketens voor groene waterstof relatief urgent. Investeringen in deze waardeketens worden voor een groot deel gedreven door de verhouding tussen risico en verwachte rendementen. Er is veel bestaand onderzoek naar de systeemwaarden en businesscases voor (delen van) de waterstofwaardeketen, maar veel minder aandacht voor risico's, onzekerheden en de noodzaak om opbrengsten en risico's op de juiste manier te verdelen tussen samenwerkende stakeholders. Meer kennis over deze factoren is voor beleidsmakers nodig om een effectief waterstofbeleid te formuleren, maar ook nodig om investeerders uit de publieke en private sector te helpen bij het de-risken van projecten en het formuleren van investeringsstrategieën in complexe toeleveringsketens. Dit rapport is een eerste poging om deze lacune aan te pakken. We richten ons op het identificeren van (kwantificeerbare) risico's en (niet-kwantificeerbare) onzekerheden voor marktpartijen, hun impact, en de noodzaak en mechanismen voor het delen van risico's en opbrengsten tussen stakeholders.

Om de belangrijkste risico's en onzekerheden te identificeren, hebben we drie workshops gehouden met experts en stakeholders uit de waardeketens van waterstof. Uit deze workshops blijkt duidelijk dat investeerders in de waardeketens van waterstof te maken hebben met een groot aantal en een grote verscheidenheid aan risico's en onzekerheden. Bovendien moeten stakeholders samenwerken om een breed overzicht van deze risico's en onzekerheden te krijgen. Veel risico's die in eerste instantie een deel van de waardeketen treffen, verspreiden zich uiteindelijk verder in de waardeketen. Geen enkele stakeholder die betrokken was bij onze workshops had een volledig overzicht van alle 85 risico's en onzekerheden die tijdens de workshops werden geïdentificeerd.

De 85 risico's en onzekerheden die tijdens de workshops zijn geïdentificeerd, zijn vervolgens geclusterd op basis van de vergelijkbare impact op het systeem. Een selectie van de resulterende 'risk events' is vervolgens gemodelleerd met een reeks energiesysteem- en marktmodellen om hun impact te kwantificeren. Dit heeft de volgende hoofdinzichten opgeleverd:

1) Investeringen in commerciële opslagcapaciteit zijn veel gevoeliger voor bepaalde soorten risico's, waaronder het risico van lager dan geplande elektrolysecapaciteit, dan andere delen van de waardeketen. Hetzelfde geldt tot op zekere hoogte voor importfaciliteiten. Aangezien opslag een belangrijke bijdrage levert aan de betrouwbaarheid en leveringszekerheid van het systeem, kan samenwerking op het gebied van opslaginvesteringen van cruciaal belang zijn; bijvoorbeeld via mechanismen die nu in aardgassystemen worden gebruikt, waarbij netbeheerders opslagcapaciteit boeken en de kosten hiervan doorberekenen aan alle gebruikers.
2) Infrastructuur is volgens de huidige plannen in eerste instantie overgedimensioneerd. Een uniforme vermindering van de capaciteit van de infrastructuur is daarom geen groot direct risico voor andere delen van de waardeketen. Er zijn echter delen van de landelijke infrastructuur die, als ze niet op tijd klaar zijn, grote gevolgen hebben voor de waterstofketens, zowel lokaal als landelijk. Deze effecten manifesteren zich niet altijd op voor de hand liggende locaties; er zijn netwerkeffecten.
3) In eerste instantie heeft elektrolyse weinig invloed op de elektriciteitsprijzen. Zelfs een elektrolysecapaciteit die een orde van grootte lager of hoger is dan wat nu voor 2030 is gepland heeft geen significant effect op spotprijzen voor elektriciteit. Hierdoor zijn investeringen in grootschalige elektriciteitsopwekking, in ieder geval voor 2030, relatief ongevoelig voor wat er in het waterstofsysteem gebeurt. Het tegendeel is niet waar: de

hoeveelheid offshore wind die in het systeem aanwezig is, heeft een grote impact op het waterstofsysteem.

4) Lokale markten die niet verbonden zijn met nationale markten zijn moeilijk voorstelbaar zonder coördinatie. Alleen een grote hoeveelheid waterstofopslag kan vraag en aanbod lokaal in balans brengen als lokale stakeholders alleen hun eigen doelen nastreven. Bovendien zijn veel risico's veel groter in distributienetwerken.

Deze resultaten hebben een aantal belangrijke implicaties. Het belangrijkste is dat ze aangeven hoe belangrijk het is om expliciet rekening te houden met risico en onzekerheid in waterstofwaardeketens. Ze benadrukken ook het belang van gezamenlijke de-risking. Voor beleidsmakers benadrukken ze dat beleidsonzekerheid een belangrijke horde kan zijn voor de ontwikkeling van waterstofsystemen. Bovendien geven ze aan dat stochastische methoden en andere manieren om onzekerheid en risico mee te nemen in onderzoek een belangrijke meerwaarde hebben bij het analyseren van investeringen in waterstofsystemen.

Executive summary

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) 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 overdimensioned. 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.

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1. Introduction

1.1 Context

Hydrogen is generally expected to play an important role in the transition towards climate neutrality in The Netherlands, as a natural complement to the vast technical potential for intermittent renewable electricity production offered by the North Sea basin; see for example TKI Nieuw Gas (2018), Gasunie & TenneT (2019), Berenschot & Kalavasta (2020), TNO (2020).

Given the urgency of the transition, the magnitude of investment needed, and the long lead times, the timeline for hydrogen system development is pressing. Initial decision-making has already been undertaken, both in the public and private sectors. In industrial clusters, for instance, final investment decisions for a significant number of hydrogen import terminals have been taken or are due to be taken in the near future. Nationwide, Gasunie has been tasked with the rollout of a hydrogen backbone, with a first phase planned to be completed in the next five years. Nevertheless, a clear view on the system value (e.g., security of hydrogen and electricity supply, minimized infrastructural costs and spatial footprint) of hydrogen system development in the context of the integral energy system remains to be established. Moreover, we lack the methods to capture the underlying practicalities and barriers in policy-driven market-based transitional energy system development, including assessment of the risks, uncertainty, and the 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.

In the HyDelta project, WP2 looks at the value of hydrogen and at high-level deployment patterns that are optimal from a system perspective. In WP3, we focus more on how incentives for individual investors align with this system perspective. Together with our stakeholders, define and develop methods that can address additional factors that are crucial to understanding deployment strategies and policy. This includes investigation of

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

We address these factors with a mixed-methods approach, consisting of stakeholder workshops, quantitative modelling of energy systems and markets with a range of models, and qualitative analysis. With these methods, we aim to achieve three objectives.

1. Increase the understanding of the impact that power-to-hydrogen, hydrogen transport & storage and hydrogen consumption has on energy system stakeholders and market dynamics at multiple levels.
2. 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
3. Gain insights in potential mismatch between individual and system values and risks for the different stakeholders in the value chains.

In this report, we summarize the first conclusions of this analysis, together with a description of the methods that have been used to derive them.

1.2 Focus

We have started our analysis of risks, uncertainties and collaboration mechanisms with a series of stakeholder workshops with participants from a large part of the hydrogen supply chain. These workshops were used to formulate a longlist of risks and uncertainties; deliverable D3.1 summarizes some of the initial findings from the first of these workshops. Many of the risks and uncertainties on this longlist were related to each other, through common triggers, correlations, etc. To analyse them, they were therefore clustered into a smaller number of *risk events*, i.e. particular events whose occurrence is uncertain but which have a measurable impact on the objectives of hydrogen market participants or policy makers. These risk events can have many underlying risks that lead to them, and can have many impacts on stakeholders. We do not further analyse these underlying risks. We also do not focus on determining the probabilities of risk events, as this is an inherently subjective task. Instead, we focus on understanding the impact of the shortlist of risk events on stakeholders. Through this, we can also identify where collaboration might be a way to mitigate and reduce the impact of uncertain events, for instance, if particular risk events affect stakeholders in opposite directions.

Some of the risks lend themselves well to quantitative analysis. In this report, we therefore present results from a number of energy system and market models: the I-ELGAS integrated gas, electricity and hydrogen model which models optimal dispatch of all three networks for the whole of the Netherlands (including connections to neighbouring countries); the EYE electricity-hydrogen market model, which models markets in more detail at the expense of modelling infrastructure, and the ESSIM energy system simulation model, which simulates, rather than optimizes, operation of a local energy system. These models, though they necessarily make restrictive assumptions on the shape and functioning of the hydrogen system, help to cut through the complexity of risk in hydrogen supply chains in a way that qualitative analysis alone cannot do. Nevertheless, there are also risks that cannot be easily addressed quantitatively; these include, for instance, risks related to reputation, perceptions of hydrogen, etc. It is important to still include these in the analysis, as otherwise we would significantly understate the amount of risk and miss potential opportunities to reduce it. We therefore complement our qualitative analysis with a qualitative assessment of key risks and uncertainties.

In line with the general HyDelta 2 objectives, we focus on near-term risks and uncertainties, i.e. those relevant to decisions made between now and 2030. This means that risks and uncertainties that are only relevant for the longer term (e.g., related to technologies which are unlikely to enter the market before 2030, risks related to capacities of electrolysis significantly beyond current policy targets, etc.) are out of scope. In this deliverable, we also specifically focus on investment risk and uncertainty, i.e. related to decisions to invest in, for instance, hydrogen production capacity, infrastructure, storage, etc.

Virtually all risks events eventually affect more than one actor in a hydrogen supply chain, even if they are initially risks to a particular actor. For instance, delays to the installation of electrolysis capacity clearly affect the parties that are directly involved in the projects in question. However, a lower amount of electrolysis capacity can then also affect users of hydrogen (e.g., if hydrogen prices increase as a result of a lower amount of local supply), producers of electricity (e.g., if electricity prices decrease as a result of a lower amount of electricity demand), etc. We therefore do not pay much attention to the origin of risks and uncertainties. Instead, we look at their effects across the entire supply chain.

No discussion of risks and uncertainties in an emerging supply chain is ever complete, if only because of the presence of deep or Knightian uncertainties (the ‘unknown unknowns’) which by their very nature cannot be assessed. This report should not be read as a complete overview of all risks and uncertainties relevant to hydrogen systems. Instead, we aim to highlight a number of important conclusions which we can draw on the basis of the research undertaken, increasing understanding as per the objectives highlighted in the section above.

1.3. Layout of this report

In the next section, we first briefly present the main results of our analysis to date, with short explanations. Section 3 then outlines the methods which were used to derive these results in more detail. Section 4 has a fuller overview of results. Section 5 outlines some of the limitations of our research, recommendations for future research.

2. Main results

2.1 Result: Actors are aware of a large number of risks that directly affect them, but no single actor has a full overview of risks facing the hydrogen supply chain

During the course of this work, we have conducted a number of workshops with actors from across the supply chain for hydrogen. During the first two workshops, which had a more limited group of stakeholders, we identified 25 risks, which are summarized in deliverable D3.1. After consultations with more stakeholders, this list has grown to at least 85 distinct risks and uncertainties covering economic/financial, environmental, social, political/regulatory and technological factors. This list is still far from complete, so it is clear that **investors in the hydrogen supply chain face a wide variety of risk and uncertainty**. It is also clear that, **to get a wide-ranging overview of these risks and uncertainties, stakeholders need to collaborate**, as risks that affect one part of the supply chain typically indirectly affect all other parts; actors should consider not only the risks that they can easily see themselves. For example, for stakeholders in the mobility sector, the purity of hydrogen in the national infrastructure (and therefore, whether hydrogen is produced through electrolysis, steam methane reforming (SMR), etc.) is a major risk for investments in local infrastructure and storage. For other stakeholders, quality is a much less important dimension, and it might therefore not always be recognized as important, despite the fact that it has an indirect effect on, e.g., utilization rates of infrastructure. To some extent, intransparency of supply chain risk is not specific to hydrogen, but a feature of all supply chains. In hydrogen supply chains, however, it is arguably much more important, as they contain new technologies, new production methods, entirely new uses, and often also new companies. Moreover, hydrogen supply chains are currently highly dependent on the behavior of governments.

2.2 Result: Storage is important for the system but a risky investment

It is clear that storage is an important part of any hydrogen system. However, our models suggest that **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**. Storage revenues depend on variability of hydrogen prices, rather than the absolute levels which other components of the system rely on. If hydrogen production in The Netherlands, and particularly green production, is lower than anticipated, Dutch hydrogen prices would be mostly set by import prices. At least in our models, these are not highly variable. Figure 1 shows the results if a set of I-ELGAS energy system model runs where the amount of Dutch electrolysis capacity is varied. The lower lines show storage levels (where there is no difference between 1 and 3.5GW; hence the blue line falls entirely behind the orange line), the upper lines the hydrogen price. At low levels of electrolysis capacity, all local production is immediately directed to hydrogen demand; prices are set by import costs and therefore not highly variable. In this scenario, storage is virtually unused in 2030; the storage level remains at the initial level imposed on the model, without any withdrawals.

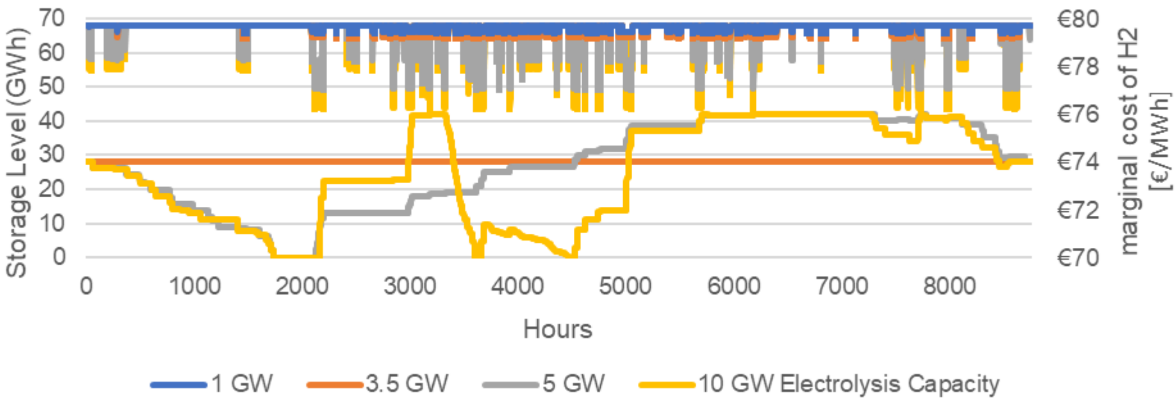


Figure 1 – Hydrogen prices and storage levels as a function of electrolysis capacity (I-ELGAS model)[1]

Figure 2 shows a load duration curve from the EYE market model2. This confirms that the low price variability seen in the I-ELGAS model results above is not just a feature of that particular model. The rationale is the same: green hydrogen production is small compared to demand, with imports or SMR setting prices.

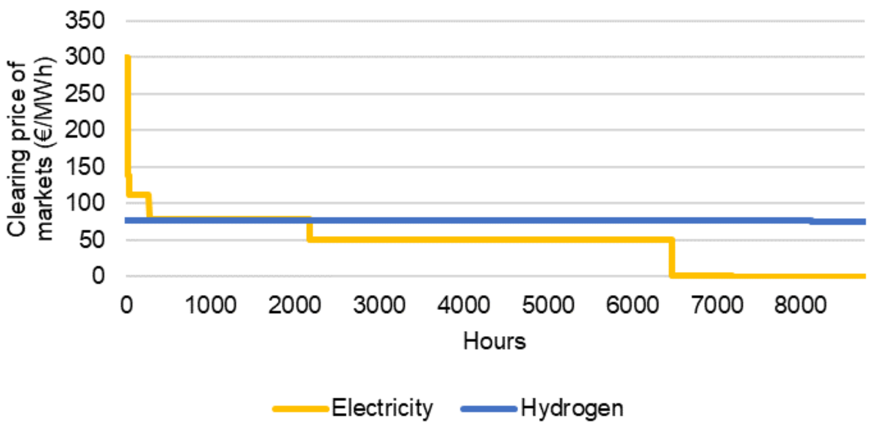


Figure 2 – Base case load duration curves for electricity and hydrogen (EYE model)

Nevertheless, storage has key system functions, some of which are not captured in our models. This includes contributions to security of supply. Moreover, it is clear that much more storage is needed after 2030 than before, and waiting until it is profitable may be too late. If storage is, along some dimensions, more risky than other types of investments but a key enabler of the system, this suggests that **collaboration on storage investment could be key**. This could include rewarding storage for its contribution to system security, e.g., through a TSO which books a fixed amount of the storage annually for security of supply / system integrity purposes, charging these costs to system users. This currently already happens with natural gas storage.

[1] To avoid differences in interpretation because of different energy densities of hydrogen, we report all quantities in MWh.

[2] Predicting prices far into the future is difficult; each model makes a significant number of restrictive assumptions. E.g., models which assume lower capacity for hydrogen imports, as used elsewhere in the HyDelta 2 project, will have more price variability.

2.3 Result: Infrastructure projected to be overdimensioned, so overall risks are low, but there are important regional effects

The planned national infrastructure for hydrogen, including the hydrogen backbone, is dimensioned for flows that are larger than those likely in 2030. **A uniform reduction in the capacity of infrastructure is therefore not a large 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**, so risks of incomplete infrastructures may be felt in unexpected places. Figure 3 shows the results of a what-if analysis using I-ELGAS, where the hydrogen backbone is constructed but the Groningen region is not connected. This causes a significant increase in hydrogen prices in a large bottleneck region, which includes Chemelot in the South-West of The Netherlands, because the circle of the backbone is broken and there is not enough remaining capacity connecting the South-West to the Rotterdam/Moerdijk area and the rest of the Netherlands, requiring the use of (more expensive) local hydrogen production. Hence, there is a significant price risk in a very different location than the location where the infrastructure is missing. In some cases, impacts are particularly high on particular parts of the supply chain. Figure 4 shows a set of load duration curves for an import facility, for a similar exercise in which Zeeland and Chemelot are disconnected. Although, in this scenario, impacts on prices are smaller, there is a major impact on import facilities, particularly those located in Rotterdam.

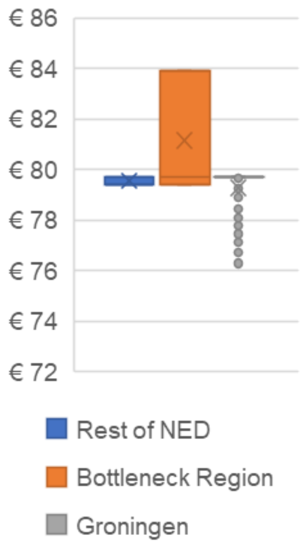


Figure 3 – Hydrogen marginal costs per MWh; Groningen disconnected. Bottleneck region occurs in the South-West of The Netherlands (I-ELGAS model)

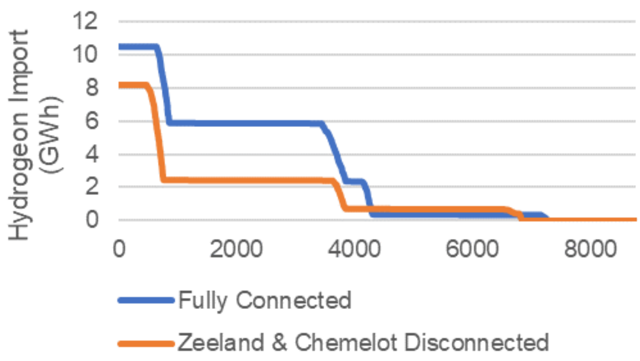


Figure 4 – Import load duration curves; Zeeland & Chemelot disconnected (I-ELGAS model)

Analysis with the EYE market model confirms that import infrastructure (e.g., import terminals), like storage, is more susceptible to price risk than other parts of the supply chain. Figure 5 shows the fraction of domestic hydrogen that is imported, as a function of relative import and SMR costs, for a large number of scenarios in which, among others, local electrolysis capacity and CO_2 prices are varied. As this figure shows, small variations in relative import prices have a very large effect on imports, and by extension, on the usage of import facilities. Infrastructure owners may be able to redirect this risk to market parties by requiring upfront bookings of capacity, so which party eventually bears this risk is a feature of the specifics of hydrogen market design. We do not attach probabilities to the scenarios, but it is also notable that import dominance occurs in the majority of scenarios.

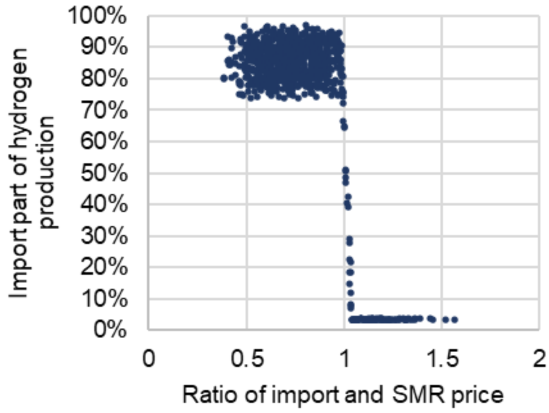


Figure 5 – Imports as a function of prices (EYE model)

2.4. Result: Hydrogen risks in 2030 do not yet easily spill over into electricity systems

As has been shown above, modelled 2030 hydrogen prices appear relatively stable, as local green hydrogen production is rarely price-setting. What is more, hydrogen-related risks do not easily spill over into electricity markets. Figure 6 shows a price duration curve for the electricity market, obtained from an I-ELGAS analysis where the amount of electrolysis capacity is varied. As this figure shows, **even an order-of-magnitude change in electrolysis capacity has no significant effect on (spot) electricity prices**[3]. This happens because electrolysis forms only a small part of the electricity system (with nearly 70GW of electricity production capacity); moreover, electrolyzers use electricity mostly when electricity prices are already low. This analysis assumes that prices are always equal to marginal costs and that market participants have perfect foresight. In reality, prices may respond more to variations in demand, but it seems unlikely that this effect is large before 2030, meaning that **investments in large-scale electricity generation capacity are, at least before 2030, relatively immune to what happens in the hydrogen system**. This is likely to change between 2030 and 2050, if much more electrolysis capacity comes online and SMR is phased out.

[3] Note that we do not model other markets, e.g., for imbalance or congestion management and therefore cannot draw any conslusions about these markets; opportunities for electrolysis in these markets is analyzed in WP2 of the HyDelta 2 project.

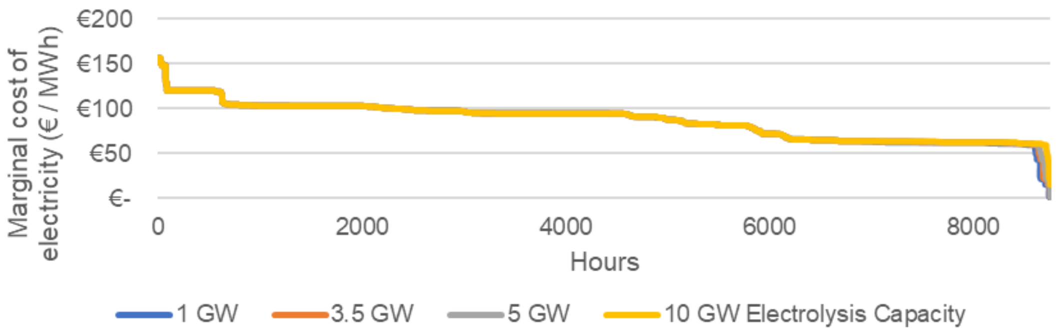


Figure 6 – I-ELGAS electricity prices by electrolysis capacity

2.5 Result: Risks in distribution networks are large

To analyse risks in distribution networks, we have used the ESSIM energy simulation model to analyse a small system with a local electrolyzer, fuel cell, renewable production, and small-scale storage. Unlike the other models used in this analysis, ESSIM does not optimize system operation, but simulates the behaviour of stakeholders even if these do not respect local constraints (e.g., thermal limits on electricity infrastructure or capacity limits of hydrogen pipelines). This is similar to current operation of distribution networks. The most striking conclusion from this analysis is that **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** than they are at national level. At a national level, the presence or absence of a single electrolyzer or consumer has little impact, at a distribution level it can make or break the business case for investment in a particular part of the local hydrogen infrastructure. While distribution network operators can certainly facilitate demonstrators such that they are ready for the transition to hydrogen, enable collaboration between specific local producers and consumers of hydrogen for coordinated one-off hydrogen projects, and make plans for an eventual conversion of (part of) their gas networks, a **larger transition of gas distribution network infrastructure to hydrogen significantly before 2030 seems excessively risky**. **Waiting for the development of a hydrogen backbone and the more clarity about the locations and characteristics of hydrogen demand, rather than investing in anticipation of it, is a less risky strategy.** This does not imply waiting until all uncertainty is resolved; infrastructure investments are always made under uncertainty. It does imply being cautious with large-scale investments until it is clear where demand will come from.

3. Summary of methodology: quantitative and qualitative investment risk analysis

3.1 Risk and uncertainty assessment process

The terms 'risk' and 'uncertainty' have different definitions in different contexts. In our case, following general usage of these terms in the risk management literature, we define a **risk** as an event or series of events that have a probability of occurring, and a positive or negative impact on a specified objective. The probability of occurrence must be quantifiable by the decision maker, at least to a certain extent. **Uncertainty** is similar; an uncertain event also has a probability of occurring and a positive or negative impact on a specified objective, but is very difficult or impossible to quantify. In some cases, the existence of the possible event might be unknown altogether; this is often referred to as a deep or Knightian uncertainty.

In hydrogen value chains, different objectives can be at risk. The main objective we consider is the establishment of a long-term sustainable energy system in The Netherlands, in which hydrogen plays a welfare-optimal role. In practice, this requires investment decisions by private (and, sometimes public) investors along the value chain for hydrogen. We therefore focus on risks and uncertainties that affect returns on investment in different parts of the hydrogen value chain, either positively or negatively. These risks and uncertainties can affect investment costs, operational costs, production or consumption volumes, revenues, subsidy levels, etc. We focus particularly on worst cases, although the use of a discrete set of scenarios by its nature means that the definition of 'worst case' is limited to reasonable worst cases; other scenarios may exist.

The process to identify, cluster, and analysis of risks and uncertainties in hydrogen system has included the following steps:

1. A first workshop with internal TNO experts from a range of domains, including energy economics, hydrogen technology, infrastructure, energy finance, and business modelling. During this workshop, an initial list of risks and uncertainties was identified and ranked according to their likelihood of occurrence and likely impact.
2. A second workshop with experts from the HyDelta 2 consortium, including subject-matter experts from TNO, DNV, NEC, Gasunie, and the regional network operators. At this workshop, the initial list of risks and uncertainties was refined and added to. On the basis of these first two workshops, an initial shortlist of risks was compiled, which has been summarized in Deliverable 3.1. Figure 7 gives an overview of the initial categorization of risks.
3. A third workshop with a wide range of stakeholders from across the supply chain for hydrogen. Apart from representatives of the HyDelta 2 consortium partners, this included participants from, among others, ABM AMRO, Invest-NL, NAM, Shell, BP, Proton Ventures, TATA Steel, Ricardo, the Rotterdam School of Management, and the ministry of Economic Affairs. The results of the first two workshops were not initially presented to the participants; instead, they were asked to first give their own assessment of risks and uncertainties, in the categories economic/financial, environmental, social, political/regulatory technological. This yielded a set of 85 risks and uncertainties. Participants were then asked, for a limited number of these which had been identified by multiple participants, to indicate how severe these risks were in terms of probability and impact, and what mitigation options existed.
4. Their risks and uncertainties were subsequently analyzed to identify which common drivers or common consequences underlied them, and how they interacted. A shortlist of risk events was then selected for further analysis. The results of this step are summarized in Section 4.
5. This shortlist of risk events was then further split into risk events that could be (partly) analysed with quantitative models, and uncertainties that were more suitable for qualitative analysis. At this point, the risk events, which are general risks that can appear in multiple points of the supply

chain, were also mapped unto the supply chain, and specific scenarios were defined which would be analyzed quantitatively.

6. Three quantitative models were subsequently used to analyze these scenarios: a high-resolution integrated electricity-gas-hydrogen dispatch model (I-ELGAS), particularly to analyze the nationwide capacity and infrastructure risks, an electricity-hydrogen market model (EYE), particularly for price risks, and a regional energy system simulation model (ESSIM), particularly for risks specific to distribution networks. Section 3.2 below gives more detail on these methods.
7. Since focusing only on risks that can be quantified with models would be short-sighted and underestimate the real uncertainty in the market, we analyze the qualitative risks through a workshop with high-level decision makers. The results of this work will be reported in Deliverable 3.3.

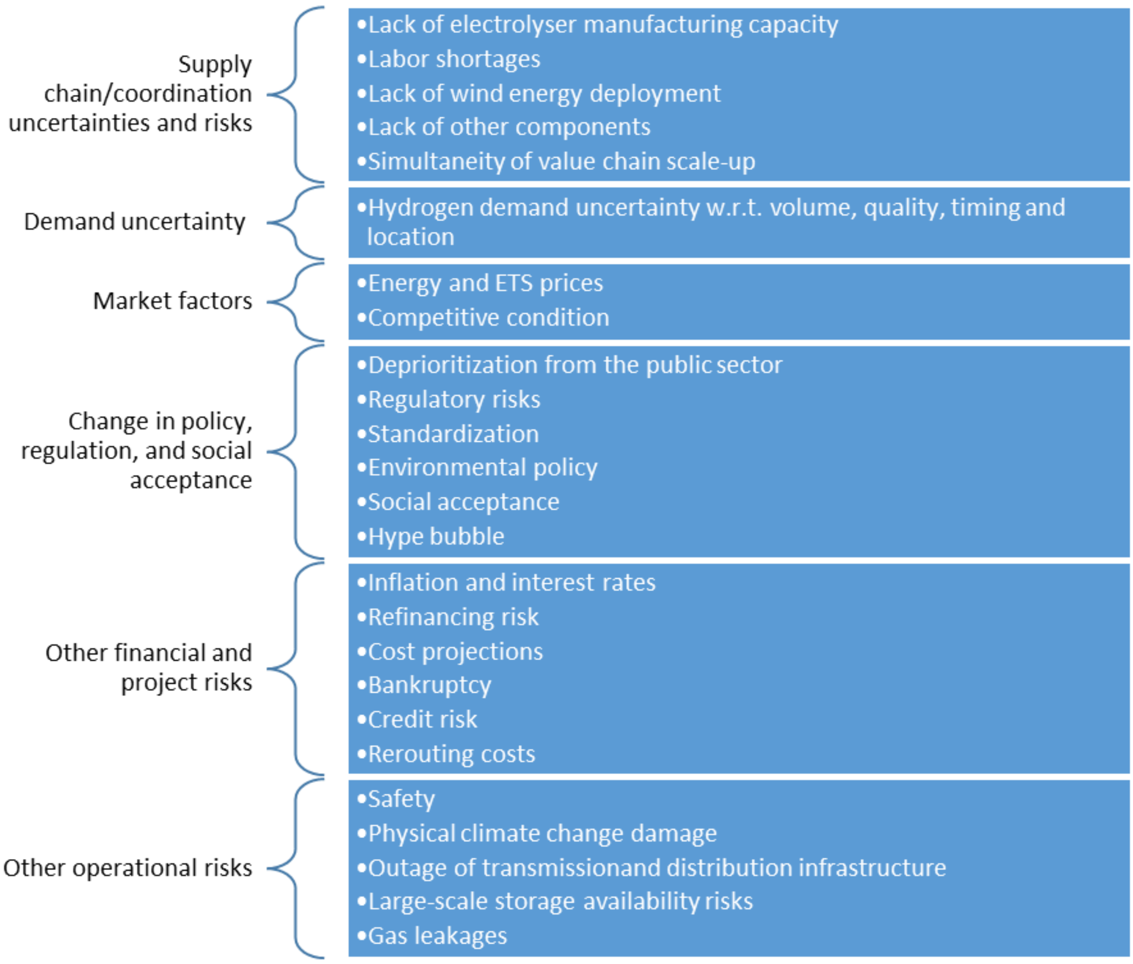


Figure 7 – Initial risk and uncertainty categorization

3.2. Quantitative assessment

I-ELGAS

I-ELGAS is an integrated electricity, gas, and hydrogen market model that was developed to analyze the interactions between these three energy carrier markets. Figure 8 shows a compact overview of the model. For a full description of the model formulation see [1].

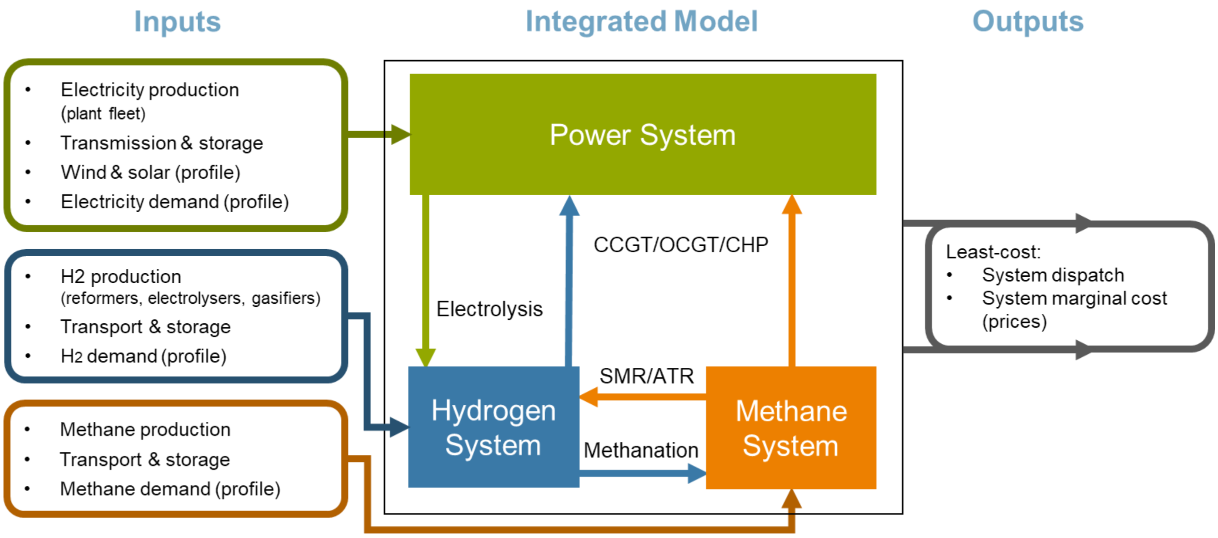


Figure 8 – An overview of the I-ELGAS model.

Structure

I-ELGAS minimizes the marginal cost of the combined market system and produces the optimal prices (marginal costs) and production dispatch. The optimization is on a yearly basis, with hourly market clearing granularity. I-ELGAS models the Netherlands with 35 electricity, 24 methane, and 19 hydrogen nodes, connected in their respective geographical grids. It also includes neighboring North Sea countries as single nodes that can trade with each other and with the Netherlands. Energy can move between the separate grids by means of conversion technologies, such as electrolyzers and power plants.

Assumptions

Since the year and system are optimized as a whole, the model assumes perfect foresight, meaning actors do not have any uncertainty about conditions and marginal costs later in the year. This means that, apart from the risk events that we model, there is no other risk present in the market. This is a common assumption in energy market models to ensure separability of time periods; in practice, this only has a major impact when modelling decisions that have to be taken a significant amount of time before the benefits of those decisions are realized. In our setup, this particularly concerns storage, which is present in limited quantities – the model will not use storage capacity to hedge, e.g., demand risk, and therefore generally have lower storage levels than could be expected in a real-world setting. The model only generates the system marginal cost of production, that may be taken as a proxy for commodity pricing under perfect competition. Dynamics of scarcity pricing or risk premia are not included in the model. For hydrogen, we also model an hydrogen-only market. If green hydrogen is required for some applications, a hydrogen market may be complemented with an additional market for green hydrogen certificates, enabling green hydrogen producers to generate additional income on top of the hydrogen price. This is not included in the model.

Hydrogen Infrastructure

Hydrogen transport within the Netherlands is based on the HyWay27 report, adapted to the nodal structure of I-ELGAS [2]. Energy carrier transport capacities between North Sea countries – including those for hydrogen – are based on the TYNDP2020 report [3]. Seaborne imports are also included, based on the REPowerEU value of 10Mt of hydrogen imports for all of Europe by 2030 [4]. The Netherlands portion of the 10Mt was estimated using Dutch industrial gas demand as compared to other North Sea countries.

Base Scenario Data

All of the I-ELGAS analyses were conducted with comparison to a 2030 base scenario, which, with exception of the assumptions listed above, was based on the targets set out in the *Klimaat- en*

Energieakkoord 2030 as quantified in [5] and on [6]. While a scenario is comprized of many input parameters, the most pertinent are shown in Table 1.

Table 1 – Default values for I-ELGAS base case scenario.

Parameter	Base Case Value
CO2 Price	€ 110
SMR Capacity (NED)	5.5 GW
Electrolysis Capacity (NED)	3.5 GW
OffShore Wind Capacity (NED)	17.4 GW
OnShore Wind Capacity (NED)	7.1 GW
Solar Capacity (NED)	24.7 GW
Storage Capacity (NED)	42 GWh
H2 Shipping Import (NED)	18 GWh

EYE

EYE is a simulation tool that can simulate expected prices on wholesale markets based on a scenario. To do so, EYE is internally using bid ladders (merit orders) of supply and demand, coupled with a clearing mechanism (marginal pricing) that is comparable with the clearing mechanism of wholesale markets.

By means of this functionality, EYE can determine an expected price for a given time unit (typically hourly). It is possible to run simulations based on future energy system scenarios and, as a result, analyze the behavior of future energy prices. An overview of the EYE simulator and its inputs and outputs is shown in Figure 9; for full information see [7]

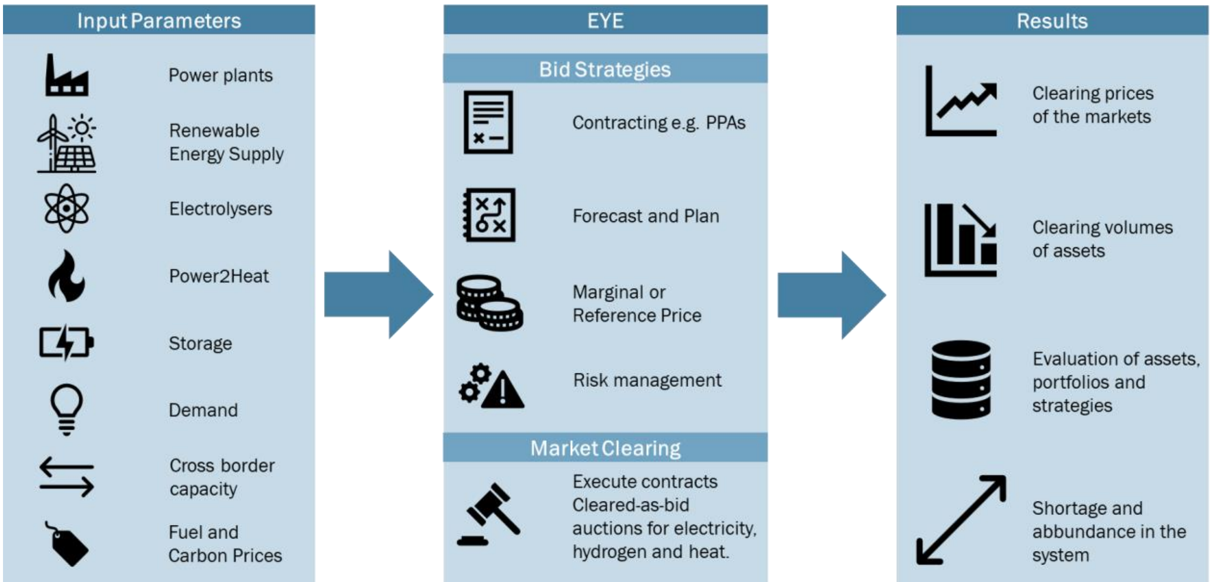


Figure 9 – Overview of the EYE model and its inputs and outputs.

In EYE multiple markets can be simulated: e.g. electricity and hydrogen. It requires little work to add other markets, such as ammonia and heat. There is an order in market clearing, e.g. first the electricity market is cleared, followed by the hydrogen market[4]. Based on this, assets can use the actual or

[4] This is an assumption. Since there is no hydrogen spot market yet, we do not know in which order markets will be cleared in the future. In general, this will only make a difference if there is significant amount of short-term uncertainty in either market.

forecasted prices of one market to determine their bids on other markets. This can be useful for assets which bid on both markets, such as electrolyzers.

The flexibility and short computation time of an EYE run allows us to perform Monte Carlo simulations. Random values are drawn from probability distributions for the input parameters. These result in distributions for output variables, such as the average clearing price on the electricity market. This provides insight in the uncertainties and risk for markets given uncertainties in e.g. the installed electrolyzer capacity.

ESSIM

Distribution networks for electricity and gas currently have much lower levels of control than transmission networks. At the transmission level, congestion can be predicted, monitored, and prevented through corrective action by system operators. In distribution networks, especially at lower voltage levels, prediction is harder and data scarcer. Moreover, distribution system operators currently have few options to actively address congestion through, for instance, active management of loads or distributed renewables, although this is an active area of research and demonstration. We therefore also use a model of a small (part of a) distribution network, in which there is no active control or optimization, but instead individual agents decide how to use the assets they own. For this, we use the Energy System Simulator (ESSIM) [8]. Figure 10 gives a graphical overview of the network used. This is a 'toy' network, rather than part of an existing network, as there are few examples of hydrogen networks available, and data at the local level is lacking. To test the feasibility of a local hydrogen system without a backbone, the network is not connected to a larger hydrogen system; there is an electricity connection but, again to test the feasibility of local operation, this is available for export only.

a) An electricity network (bottom left) with a grid connection (used only for export), a solar park, a wind farm, a battery, and electricity demand.
b) A hydrogen network (top right) with an electrolyzer, hydrogen storage facility and fuel cell. The electrolyzer uses electricity; the fuel cell produces electricity and heat.
c) A heat pump, using electricity to satisfy heat demand (together with the fuel cell)

There is no centralized control in this network. Each asset is operated by an individual agent, which uses exogenous local price thresholds to decide whether to produce or consume energy. For instance, the battery will never consume energy at grid prices, but will store energy if the price in the local electricity network is low because of high renewable production beyond what is consumed by the local electricity demand, etc.

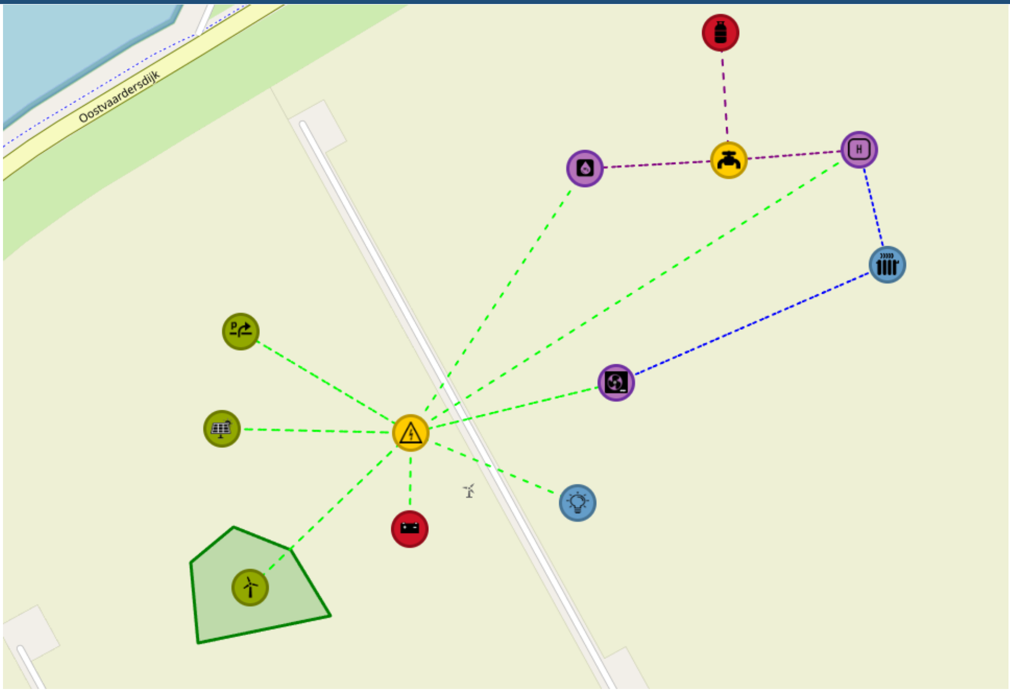


Figure 10 – Base case local energy network (ESSIM model)

3.3. Qualitative assessment

Not all impacts of risk can be quantified, and there are uncertainties which are fundamentally unquantifiable. We therefore separately also qualitatively analyze the key uncertainties that have been identified, through a workshop with key high-level decision makers. The results of this analysis will be reported in Deliverable 3.3.

3.4. Assessment of collaboration opportunities

We primarily assess collaboration opportunities through ex-post analysis of model results, and through analysis of workshop results.

4 Additional results

In section 2 above, we have presented the most important results. In this section, we present a more detailed overview of a number of additional results.

4.1 Risk and uncertainty identification: Overview of selected risk events

Risk events (RE) and uncertainties that may positively or negatively influence the overall objectives of the hydrogen value chain are numerous. Investment risks and uncertainties are identified by means of multiple workshops with key stakeholders in the value chain. The outcome shows a wide range of events. The long-list of identified risks and uncertainties can be found in Appendix A. This long-list has been clustered for the quantitative risk analysis in this study by mapping the relationship between the individual items and identifying the clusters of risks that lead to the same risk event. Table 2 summarizes this clustered set of risk events.

Table 2 - Risk events

Selected event	Event code	Description of event
Outperformed by competitor/competing technology	RE-O	The commercial competitiveness of the business of hydrogen supply chain stakeholders partially depends on the technology of choice of that stakeholder. The chosen technology can be outcompeted by other technologies in the market. E.g. hydrogen gas fired boiler may not be able to compete with electric boiler.
(In)sufficiency of installed technological capacity	RE-C	The installed and operational capacity of technologies throughout the hydrogen supply chain may be sufficient or insufficient in terms of volumes, mass flow rates etc. This (in)sufficiency has spatial and temporal characteristics. E.g. Dutch offshore wind farm capacity growth may be delayed multiple years beyond the targeted year of commissioning (2034 instead of 2030), leading to lower than expected/required amount of Dutch offshore wind electricity production in 2030 .
(Mis)alignment in timing of installed capacity	RE-T	The well aligned or misaligned commissioning date of technologies that depend on each other for successful operation may cause the hydrogen supply chain to function (in) successful. E.g. the presence of operational ammonia import jetty without an operational ammonia-to-hydrogen reconversion facility has consequences for the availability of hydrogen gas in the Dutch energy system.
(Non)renewable regulatory status of Dutch Hydrogen	RE-G	The market value and market demand for renewable hydrogen partially depends on the carbon intensity of that hydrogen and the corresponding compliancy to the regulatory definition of the renewable status. E.g. Dutch electrolyzers may solely use renewable power to produce hydrogen which leads to minimal environmental footprint per unit of hydrogen produced, making Dutch hydrogen an attractive product on the markets for decarbonization purposes.
Under or over utilization/performance of asset	RE-P	The technical performance assets may be higher or lower than assumed/expected by its user. E.g. the efficiency of the alkaline water electrolysis technology installed at a specific production side may be lower during actual operations than initially expected during the design phase, causing lower volume of hydrogen produced per annum.
Presence of liquid / open hydrogen market	RE-M	Hydrogen trade on bilateral level will lead to different market behavior of stakeholders compared to hydrogen trade on liquid/open market place. E.g. Multiple 10 year hydrogen delivery contracts may provide a low investment risk for hydrogen production facility investors to develop

		the facility, in contrast to shorter time horizon contracts and/or day ahead market bidding of the produced hydrogen.
Safety issues with hydrogen technology	RE-S	Safety incidents throughout the value chain may have effects on the (perceived) safety levels and consequentially the conditions in which hydrogen-based technologies are allowed to be operational. E.g. The leakage of hydrogen gas at the heavy duty truck filling station may lead to relocation of filling stations for mobility beyond cities as a safety incident prevention measure.

Risk events and uncertainties often have causal relations with each other. Figure 11 illustrates the causal relations between the selected risk events that are considered in scope in this study. Each relationship, as is depicted with an arrow, indicates an expected influence of a 'fired risk', i.e., a risk event that occurs, at one variable onto the next variable.

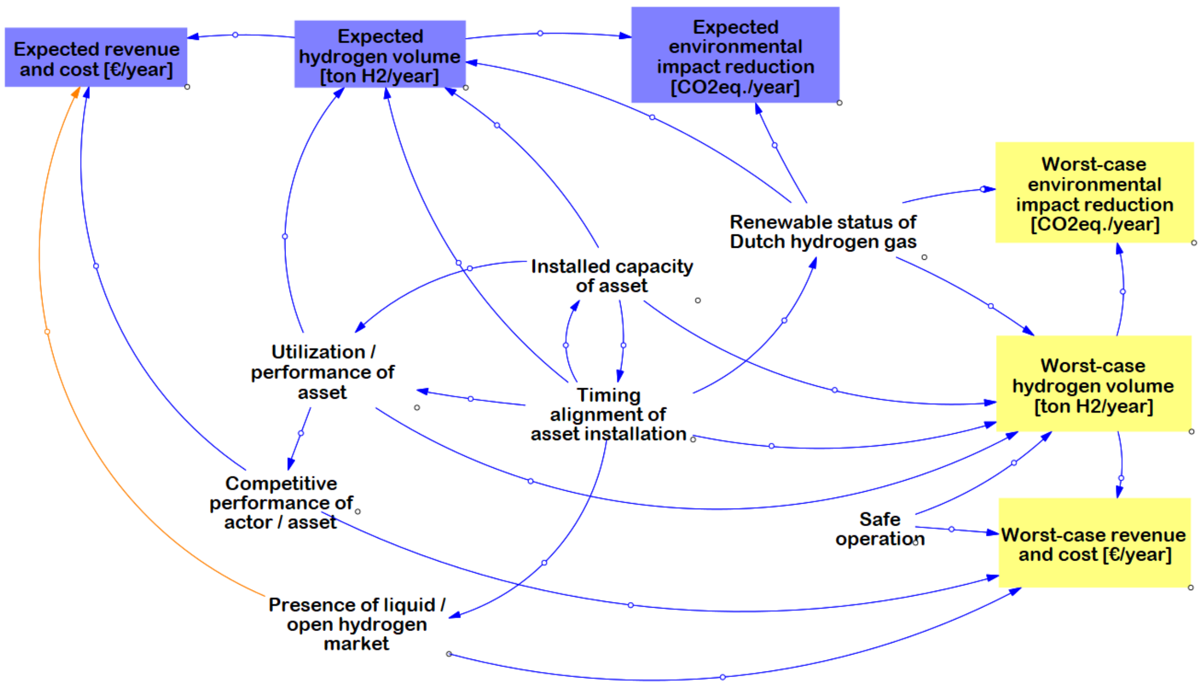


Figure 11 – Risk events and their relationships, both with each other and with average (blue) wors-case (yellow) objectives at risk.

The selected risk events will have numerous causes and consequences, both direct and indirect. In this study the risk identification is limited to the identification of events. Probability estimates are not included. The potential consequences for individual actors as well as the hydrogen value chain and/or the energy system as a whole are quantified in the next paragraph for risk events RE-C, RE-G, RE-M and partially for risk event RE-T.

4.2 Risk analysis: Overview of quantitative results

(In)sufficiency of installed technological capacity / (Mis)alignment in timing of installed capacity

One of the most important category of risk events, if not the most important, that has been identified in the workshops is the (in)sufficiency of installed technological capacity of different parts of the supply chain for hydrogen. If this is temporary, this falls under misalignment in timing of installed capacity. We have analyzed a number of different types of capacity insufficiency: offshore wind and solar capacity that generate the electricity used by renewable hydrogen producers; electrolysis capacity itself, and infrastructure capacity (including import capacity). Hydrogen consumption capacity is kept constant throughout the analysis, such that changes in the other parameters can be interpreted as changes relative to demand.

First, we consider the effect of a lower or higher amount of electrolysis capacity than planned. Figure 12 shows the results from I-ELGAS model runs. As this figure shows, there is some cannibalization risk: additional electrolysis capacity reduces the usage of all electrolyzers, as expected. However, this effect is small until the total amount of capacity increases to 5-10GW. This implies that **a smaller than expected amount of electrolysis capacity does not significantly change usage levels of planned electrolyzers**, as imports adjust, **but if capacity is much higher than anticipated, this would affect electrolyzer investment negatively.** Conventional hydrogen production with SMR is more linearly affected by additional electrolysis capacity, so **for SMR capacity, the risk of less/more electrolysis is more balanced**. All these effects are a result of the relatively stable price for hydrogen in all scenarios, caused by the dominance of imports and SMR[5]. Additional electrolysis capacity has some cannibalization effect, but remains a relatively small part of the hydrogen system compared to SMR and import; substitution between the different categories has some effect, but this effect remains small. It is relatively more pronounced and definitely more asymmetric for electrolysis than for SMR, because the former also affects the availability of cheap (renewable) energy (i.e., there is an input and output price risk), whereas the latter is only directly affected through varying hydrogen prices. Although, as mentioned earlier, electricity prices are not significantly affected by electrolysis on average, electrolysis does reduce the number of hours in which prices are very low.

[5] Note that we do not differentiate between different types of hydrogen. If policies to, e.g., mandate a certain amount of green hydrogen are implemented, green hydrogen might warrant a premium. This is not considered here.

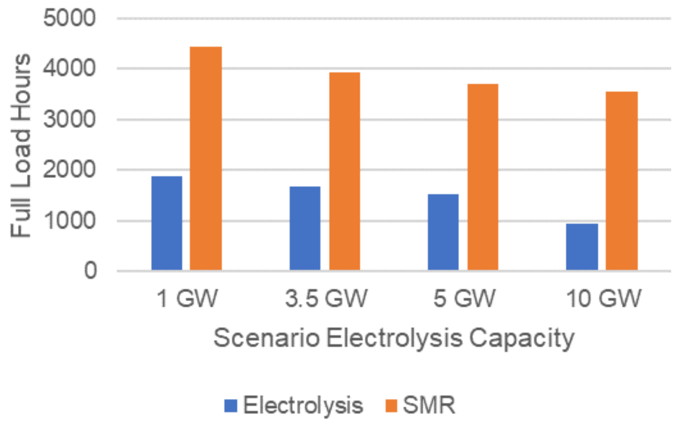


Figure 12 – Hydrogen production full load hours as a function of electrolysis capacity, everything else equal

Figure 13 shows a similar exercise using the EYE market model; here, because of shorter computation times, electrolysis capacity can be varied continuously. Moreover, interactions with other risks can be shown. The figure shows the results of 1000 model runs, where, besides electrolyzer capacity, offshore wind capacity, natural gas prices, and import prices are also varied. Remarkably, the fraction of electrolysis in the hydrogen mix is mostly a function of its own capacity, with a mild amount of cannibalization happening (i.e. the points not being on a 45 degree line). At least in the model, there are **therefore no significant interactions between electrolysis capacity risk (to other electrolyzers) and other uncertainties**. In other words, the amount of cannibalization does not appear to be a factor of other uncertain parameters.

So, while electrolysis investment may experience little risk from (temporary or longer) deviations in electrolyzer capacity, as Figure 12 above has shown, this does not mean that other parts of the system are also relatively unaffected by the amount of electrolysis capacity. **Storage use, in particular, is much more severely affected**.

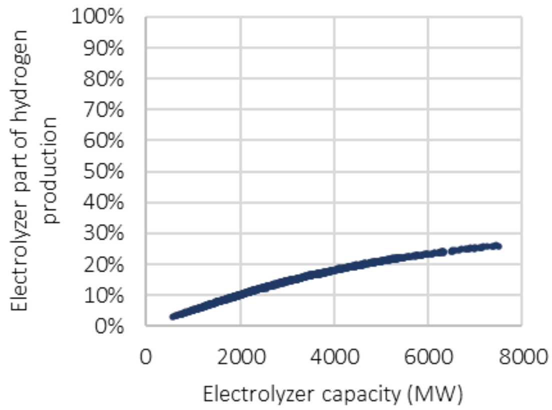


Figure 13 – Electrolyzer use as a function of capacity

Figure shows offshore wind capacity does significantly affect hydrogen production income, and especially electrolysis. A higher than expected amount of offshore wind significantly reduces both average electricity prices and the number/length of low-price periods, which makes electrolysis more attractive. Less than expected offshore wind has a negative effect on electrolysis. This suggests that **(in)sufficient offshore wind capacity is a major risk for electrolyzer investors.** SMR is not directly affected by low electricity prices, but is indirectly affected at at very high levels of offshore wind capacity because gas prices decrease in response to the substantially lower use of gas in the power sector.

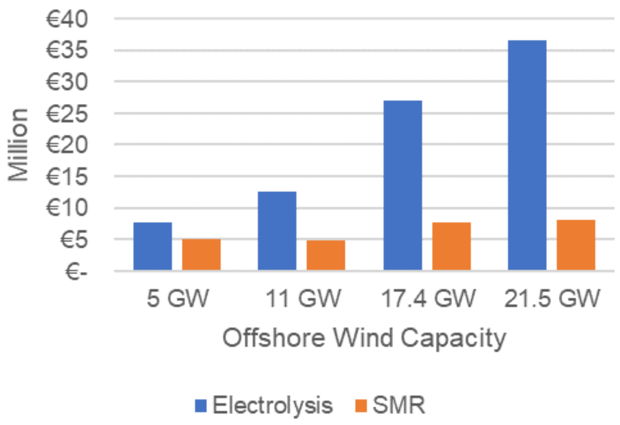


Figure 13 - Hydrogen production income as a function of offshore wind capacity

Figure 14 shows a similar, though less pronounced, effect for solar capacity; one of the reasons that this effect is less pronounced is the lower capacity factor of solar (i.e. 1GW of solar produces less electricity than 1GW of offshore wind), combined with the fact that solar capacity only generates electricity during the day (when prices, on average, are lower), and therefore does not affect prices throughout the night.

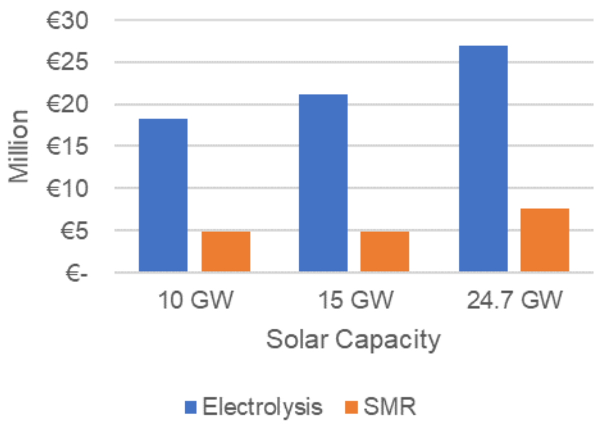


Figure 14 – Hydrogen production income as a function of solar capacity

Renewable capacity does not only pose a risk to electrolysis, but also to import/export facilities. Figure 15 shows how offshore wind capacity changes the patterns of import and export. The maximum amount of electrolysis and export demand are indicated on the horizontal axis, the top with imports. When offshore wind capacity is low, import of hydrogen is cheaper during around half of the year; The Netherlands also exports part of the imported capacity to Germany. When the amount of offshore wind capacity increases, imports become less attractive and cease altogether for very high offshore wind capacity levels. **Offshore wind capacity risk is therefore an important category of risk for import/export terminals and pipelines.** This is in line with the results of HyDelta 1, where the ratio of

RES to electrolysis capacity was found to be an important parameter for imports [9], although it was not extensively analyzed there.

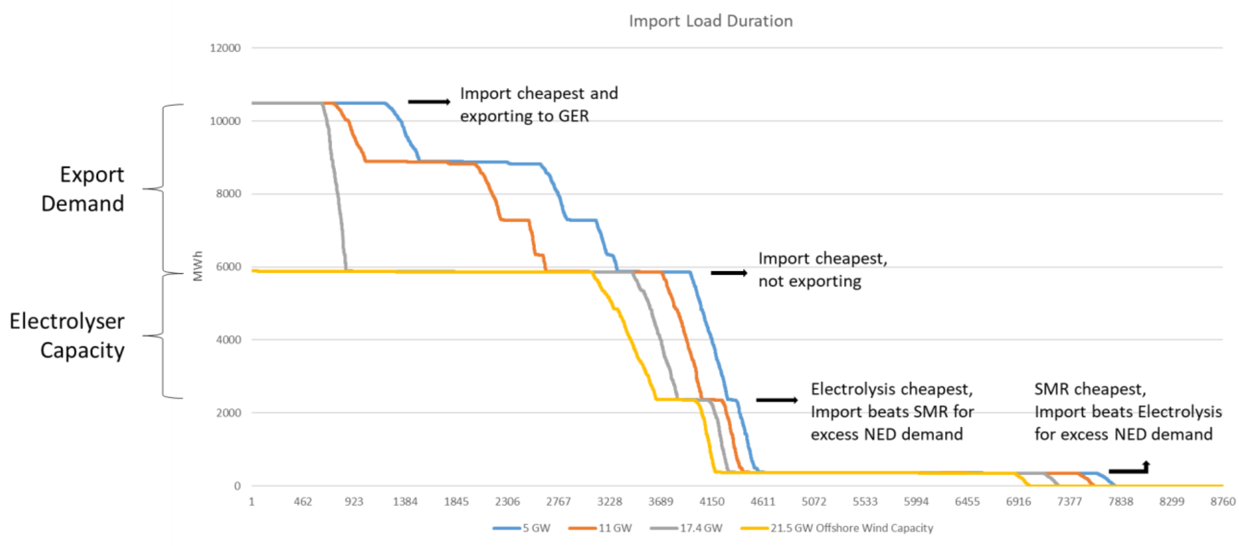


Figure 15 – Hydrogen imports/exports as a function of offshore wind capacity

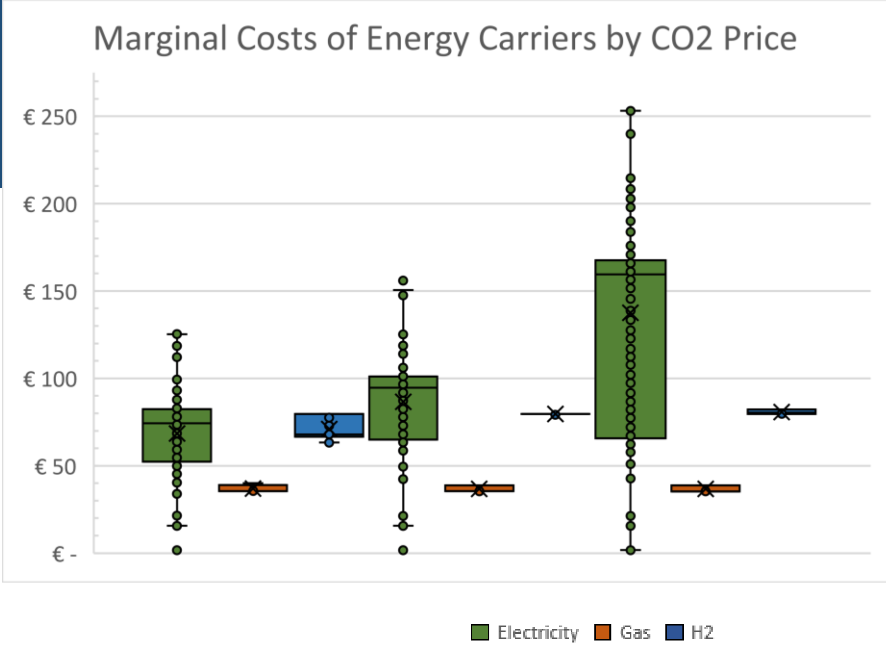
We have also examined the risks of hydrogen transmission infrastructure being lower than expected across the board. However, because in 2030 transmission infrastructure will be significantly oversized in expectation of growth in demand and supply towards 2050, smaller transmission capacities across the board have little to no effect on any part of the system. Disruptions to import facilities and the complete absence of infrastructure in particular locations does have an effect; this will be discussed in the section on liquid and open markets below.

These results all apply at a national level. Distribution networks face very similar risks. These risks are often more likely to occur (e.g., at a local level, personnel shortages are more likely to affect construction activities, as smaller-scale investments are relatively more labour-intensive). In addition, there are locational risks that are present in distribution networks but not in distribution networks. We have used the ESSIM energy system simulator to consider these. However, for a realistically sized local network, we have found that a significant reduction in supply or demand at a specific location almost always results in an network that cannot maintain energy balances for all vectors, i.e. a network which is not within its safe operation window. Only if the local network has both electricity and hydrogen import and export connection to an external network (e.g., a hydrogen backbone and electricity transmission network) can networks be balanced. This suggests **that locational risks are very large in distribution networks**. A local system that (including storage) is sized for a particular configuration of supply and demand is not flexible enough to deal with large variations. Coordination between supply and demand can solve imbalances, but this is not current practice in distribution networks.

(Non)renewable regulatory status of Dutch Hydrogen

As the analysis above has already shown, competition between imports of hydrogen, hydrogen produced through electrolysis, and hydrogen produced through SMR, determines a large part of the dynamics of the hydrogen system. In all of our models, hydrogen demand is a single commodity, with no specific distinction between green and non-green hydrogen. In reality, some applications (e.g., mobility) require green hydrogen. Other applications may, for instance through regulation, be required to use (a fraction of) green hydrogen, or there may be a separate market for green hydrogen certificates where green hydrogen producers can make additional revenues.

One way to look at this is to consider a higher CO2 price, which increases the marginal cost of SMR. As Figure 16 shows, this has little effect on hydrogen prices, as there is a substitution from SMR to imports, which in terms of cost are assumed to be close to domestic production. **Policies that make SMR less**



risk to the domestic hydrogen sector if , lower use of SMR implies higher imports, s the that, in 2030, current targets for import

ere is a significant effect on import. **The s and domestic production do present a** HyDelta 1 [10].

€50 €110 €300

Figure 16 – Marginal costs of energy carries by CO_2 price

Figure 17 - Hydrogen storage use (bottom) and marginal cost (top) as a function of CO2 prices

Presence of liquid / open hydrogen market

If liquid and open hydrogen markets exist, this implies that hydrogen can be traded freely between a large number of buyers and sellers. This means that both physical infrastructure needs to exist to make trade flows possible, that market mechanisms exist for buyers and sellers to find each other, and that there are enough different buyers and sellers. The market aspect is difficult to consider in optimization-based models. Here, we therefore focus on two dimensions: the ability to import hydrogen from abroad, and the ability to flow hydrogen between the different parts of The Netherlands.

The ability to import hydrogen from a worldwide market has a significant impact on the hydrogen value chain. Figure 18 shows that a larger than planned amount of infrastructure has little effect on hydrogen prices (the grey and orange lines overlap); however, if import capacity is not available at all, hydrogen prices increase substantially during over half of the year. **Import availability is therefore a key risk, which affects electrolyzers and consumers in opposite directions.** A lack of import creates possibilities for electrolyzers, but increases costs for consumers of hydrogen**.** As a further illustration, Figure 19 shows what this means for production levels of electrolyzers and SMR facilities. Electrolyzers profit from higher prices as a result of lower import capacities, but still produce roughly the same amount. SMR facilities are especially positively affected, profiting both from higher prices, but also from a large increase in production, as electrolysis capacity is insufficient to meet demand. **In 2030, SMR in particular wins if import is unavailable, even more than electrolyzers.**

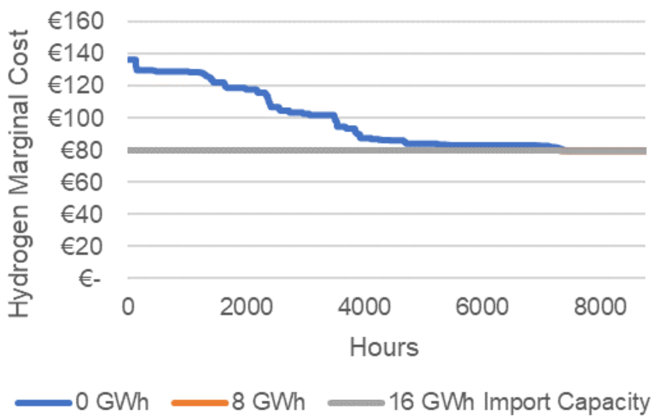


Figure 18 - Hydrogen marginal costs as a function of import capacity

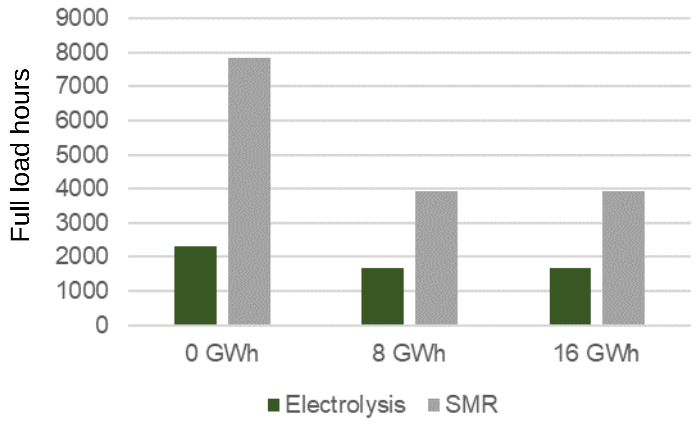


Figure 19 - Hydrogen production as a function of import capacity

Next, we consider the ability to trade hydrogen within The Netherlands, using national infrastructure. Since we have already established that a decrease in the total amount of transport, and therefore trade capacity, has little effect because there is excess capacity, we look at two scenarios where regions are disconnected: one where Zeeland and Chemelot are disconnected, and one where the Groningen is disconnected, In both cases, local markets with local prices form, rather than a single market for The Netherlands. Figure 20 shows the marginal prices of hydrogen in the two scenarios, and in the fully connected base scenario.

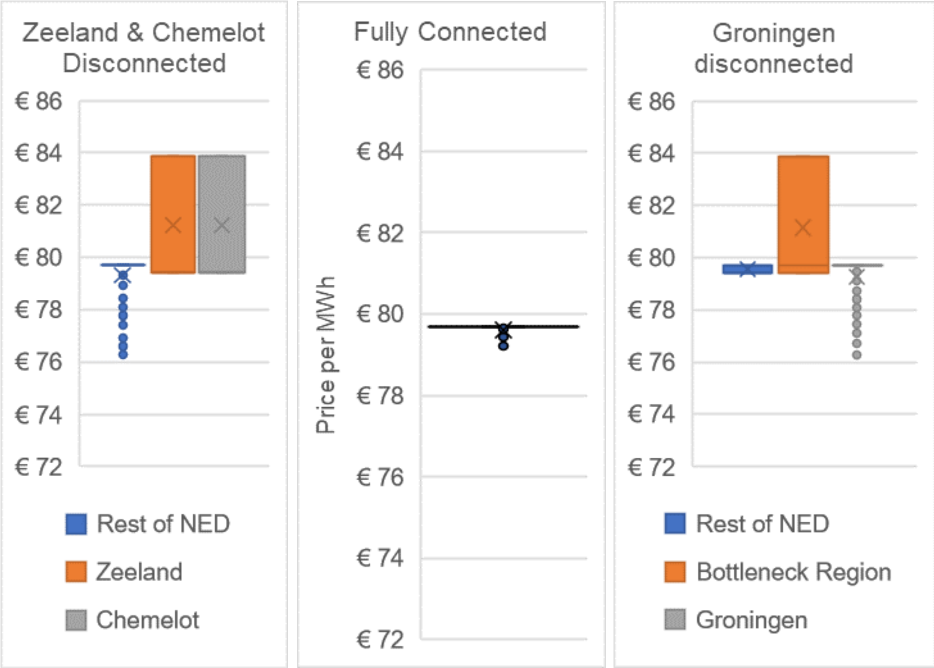


Figure 20 - Hydrogen marginal costs for different connection scenarios

As this figure shows, if Zeeland and Chemelot are disconnected, prices of hydrogen increase substantially in these regions, because of local scarcity. The rest of the country is relatively unaffected. If Groningen is disconnected, however, a much larger bottleneck region forms, which also includes Chemelot in the South-East of The Netherlands. Part of the hydrogen flowing to Chemelot in the base scenario came via the North; moreover, there is storage capacity which is now no longer accessible, so disconnecting Groningen has a much wider effect. This shows how **hydrogen infrastructure risk can have a much wider impact than the immediate region in which infrastructure is delayed or disrupted.**

Even though, in the scenario in which Zeeland and Chemelot are disconnected, prices increase only in these regions, this does not mean that investments in the rest of the country are unaffected. Figure 21 shows how the number of full load hours for electrolyzers in the Zeeland actually increases (to compensate for the lack of imports from other regions), but full loads in the other regions decreases sharply. This underscores how **infrastructure risks propagate beyond their immediate location, to losers but also winners elsewhere**.

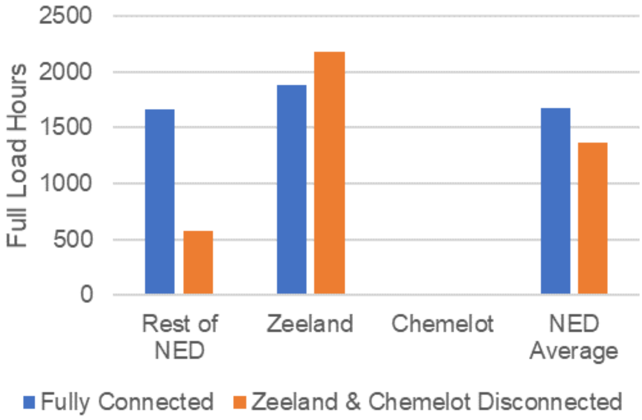


Figure 21 - Electrolysis full load hours - Zeeland and Chemelot connected/disconnected

Figure 22 and Figure 23 show how imports are affected in the disconnection scenarios. In both cases, a lack of domestic infrastructure decreases imports substantially, although they are also more constant across the year. **Domestic infrastructure risk therefore also propagates to import infrastructures, and to the worldwide market for hydrogen**.

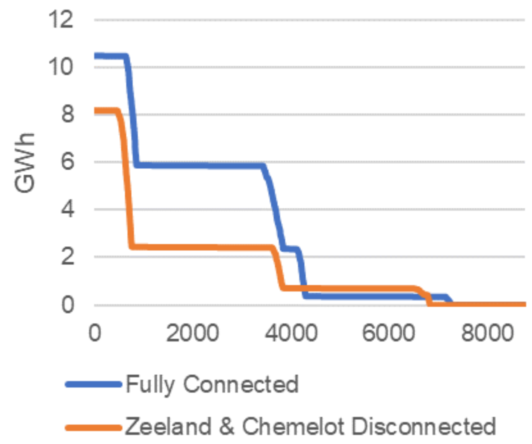


Figure 22 - Import load duration curves - Zeeland and Chemelot connected/disconnected

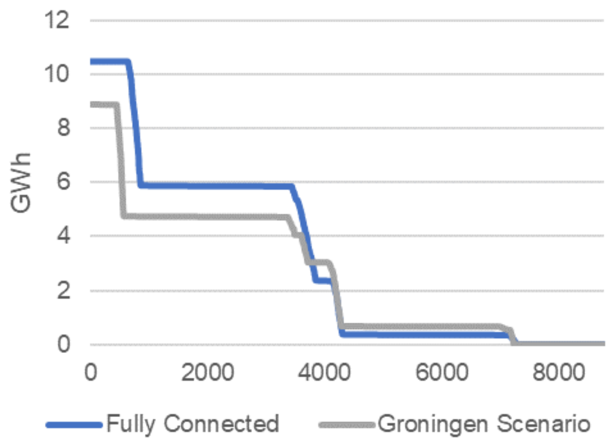


Figure 23 - Import load duration curves - Groningen connected/disconnected

The analysis above has already shown the importance of imports for determining the operation of the domestic hydrogen system, but also the risk that import facilities face by changing prices. Figure 24 has shown that the ratio between import prices and SMR prices determines import levels. Figure 24, from a Monte Carlo run of the EYE model, further illustrates how clearing prices for hydrogen determine Dutch prices in 2030. At low import prices, Dutch clearing prices are virtually only determined by import prices in a 1:1 relation, because domestic production facilities cannot compete, give the assumptions of the model. If import prices are high enough for imports to be relatively unattractive, uncertainties about CO2 prices and electrolysis capacity start to make a difference. CO2 prices become particularly important, as they directly influence the marginal costs of SMR; electrolysis also becomes a larger part of the hydrogen production mix. This implies that **if imports are cheap, prices are relatively certain. If imports are expensive, there is a higher degree of price risk.**

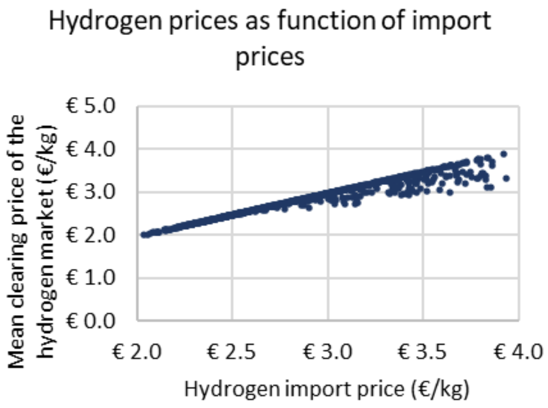


Figure 24 - Hydrogen prices as a function of import prices

As has already been explained above, small local systems designed for a particular configuration of hydrogen supply and demand are not very robust to changes in the system unless there is a high degree of local coordination. Although local markets are certainly feasible if there is local coordination, imbalances are hard to avoid if there is none. In a range of simulations with the ESSIM model, finding points where electricity, hydrogen and heat networks were all in balance was difficult. Small deviations in magnitudes of hydrogen supply and demand would immediately throw one of the networks out of balance. In general, **local energy markets have a much smaller number of participants, meaning that small deviations at a single point cannot easily be accommodated**. A full discussion of local risks and uncertainties for islanded systems is outside the scope of this report.

4.3 Collaboration as a risk mitigation strategy

In deliverable 3.1, a number of mechanisms for coordination between market participants has been outlined. From the results above we can draw a number of conclusions about when which collaboration strategy might be appropriate. Collaboration is useful if:

a) Uncertainties affect different parties in the value chain differently, e.g., when a particular realization of an uncertain factor is financially beneficial for one party but affects another one negatively. Typical examples include electricity and hydrogen price risk, which affects buyers and sellers in opposite directions. This implies that collaboration through mechanisms such as joint ventures, PPAs, swaps, etc. can reduce risk.

➔ The quantitative analysis has shown that this can mitigate risk in several circumstances. Deviations or delays in the planned amount of import capacity are a good example here; a reduction in imports affects consumers and producers of hydrogen in opposite directions, so if this risk is seen as particularly probable, combining both sides of the market can be an effective hedge. Deviations or delays in offshore wind capacity are another example, although here, the risk is unidirectional: electrolyzers are affected by offshore wind capacity, but not the other way around. This means that, although collaboration can help, offshore wind investors will benefit much less than electrolysis investors, and hence, the latter will need to pay more for, for instance, a PPA that in a symmetric situation. Our results have also shown that collaboration between investors in different locations can help, even if they are in the same place in the supply chain. This can reduce risks posed by unavailability of particular parts of the national infrastructure. In all of this, it is important to realize that locational differences can appear even in responses to risk events fired in very different places in the country.

b) Uncertainties can be reduced or hedged by a particular parties, even though other parties also see the benefits of this reduction or mitigation. Some of the safety and supply chain risks fall into this category, e.g., when particular stakeholders can increase the reliability of the entire system at a small private cost. This again implies that either collaboration through joint operation and/or planning, or through financial contracting, would be beneficial. Enforced collaboration, e.g., through standards, is another potential mechanism.

➔ This is particularly relevant when it comes to the status of renewable hydrogen. This is the domain of policy makers (and, perhaps, very large consumers), who can substantially reduce this risk by giving more policy certainty. It is also relevant when it comes to large national infrastructures; overdimensioning key components of infrastructure, as well as making sure there is redundancy in the system, benefits everybody.

c) Uncertainties that can be reduced through better coordination between parties. This includes coordinating investment and construction, such that all parts of the value chain are in place at the same time, but may also include coordination on human resource issues to avoid human resource risks becoming even bigger than they already are. This implies that sharing information and facilitation of coordination would help.

➔ This is particularly relevant for local systems, where coordination is key to ensuring a resilient system. It can also be relevant for storage and import infrastructures, both of which are relatively risky, but both of which are crucial to the secure functioning of the system. Coordination, for instance by the national government, can ensure that risks are reduced and the socially optimal levels of import infrastructure and storage are present when needed.

5. Limitations of work and recommended future research

5.1 Limitations of work

Naturally, our approach has its limitations. Three limitations, in particular, are worth highlighting. First of all, our lists of risks and uncertainties, and the resulting clustered risk events, are unlikely to be exhaustive. It is likely that discussions with more stakeholders would yield additional risks. Moreover, we are, by definition, limited to the uncertainties and risks that are already on the radar of stakeholders. In addition to these, there are deep uncertainties (the 'unknown unknowns') which nobody anticipates but which can have a major impact. Unexpected geopolitical events, such as the Fukushima disaster or the war in Ukraine have, for example, had a bigger impact on our energy system than most of the anticipated risks; it is not impossible that similar unexpected events can dwarf the risks events described in this report. Similarly, hydrogen systems are highly impacted by policy and market design decisions; indeed, these are some of the key uncertainties that were identified through our stakeholder workshops, and many of the risk events we have analyzed can be caused by policy actions or market design decisions. However, it is always possible that policies on hydrogen, but also in adjacent areas (including mobility, industrial decarbonization, carbon capture and storage, and many others) will drive the behaviour of hydrogen supply chain actors in ways that we have not analyzed.

Second, the quantitative models that we have used have clear limitations. Throughout the analysis, we have assumed that market participants are fully rational, have perfect foresight, and that there is no additional uncertainty except for the particular what-if analysis we were conducting. In reality, both investment and operational decisions are made under a great deal of uncertainty, and decision makers often do not match our ideal of perfectly rational and forward-looking agents. For example, in our models, gas or hydrogen storage facilities are generally used optimally; this means that storage levels are sometimes low or zero, without this having a major effect on prices. In reality, low storage levels are an important indication of scarcity, which can spook risk-averse market participants and lead to prices far beyond what our models would predict. Moreover, financial markets are not explicitly modelled in this study, as they are assumed to not affect the real economy. In practice, financial markets pose both real constraints on the energy system, but also opportunities to hedge risk at a price. Markets for green hydrogen certificates, or other means for green hydrogen to capture additional returns, have also not been modelled. The computational intensity of the models also limits the number of what-if analyses that were performed, and the number of scenarios. We have used a single base scenario, based on current plans for the hydrogen and electricity systems in The Netherlands; although we have analyzed a large number of variations around this base scenario, a very different base scenario would yield different results.

Finally, have considered the impact of the risks on a one-by-one basis, without discussing their probability of occurrence, because these probabilities are inherently subjective. Nevertheless, because the risk events can have common drivers, it is likely that their probabilities are correlated. We have not studied the effect of multiple risk events firing at the same time, and may therefore have understated (or overstated) their impact.

All of this means that our exact quantitative results should be interpreted as having large error bars. Nevertheless, we do expect the qualitative insights derived from our quantitative results to carry over to a real-world setting. In deliverable 3.3, we will add further qualitative analysis to these results.

5.2 Suggestions for future work to industry, government, academia and RTOs

Industry	1 **Identify risk collaboratively**. When decision makers from across the supply chain collaborative to identify risks and uncertainty, they get a much better and broader understanding of what can happen, as well as its magnitude and probability of occurrence. 2 **De-risk collaboratively**. Identifying risk collaboratively can already help to de-risk, as previously unknown probabilities and effects can be made tangible. In addition, there are ample opportunities for actors to collaborate to de-risk further, e.g., through formal contracts such as PPAs and joint ventures but also through more informal coordination. 3 **DNOs should get ready for hydrogen through facilitating trials and small-scale hydrogen projects with local suppliers and consumers.** Large-scale conversion of distribution networks is still very risky, but since DNOs can play a key role to coordinate local hydrogen markets, they need to be ready for this.
Government	1 **Explicitly consider the effect of policy uncertainty**. Policy makers affect risk perceptions in the market long before policies are implemented. The effects of anticipated and real policy and the resulting level of uncertainty should be explicitly considered. 2 **Seek to provide long-term clarity on definitions of green hydrogen**. Investors need to know on which basis imports, SMR and electrolysis compete. This is one of the major risks that policy makers can reduce. 3 **Consider the needed amount of import capacity**. Imports are an important determinant of the Dutch hydrogen market, at least until 2030. A significant amount of import capacity is currently proposed in the Cluster Energy Strategies. Policy makers should consider which level of import capacity is optimal from a societal perspective, i.e. which level still provides incentives for investment in a domestic hydrogen system, but also provides security of supply and a hedge against high local prices. 4 **Think about the needed incentives (long-term) storage**. Storage is necessary but risky; this is especially true for long-term storage, which therefore might require more additional investment incentives than other technologies. Large-scale storage has long lead-times, so making sure private and public incentives align should be a priority.
Academia	1 **Develop more stochastic models of hydrogen systems in The Netherlands**. Risks and uncertainties are important; we need more stochastic methods to determine optimal responses. 2 **Develop agent-based/other non-optimal solutions**. Actors in hydrogen supply chains are not all forward-looking, perfectly rational agents participating in a perfectly competitive market with perfect access to finance. Studying

	perceptions of risk and uncertainty, and decision making in an equilibrium setting would be a useful addition to the currently available toolset.
Research & technology organizations	1 **Take a whole-system approach to evaluating risks and uncertainty** when analysing particular projects, looking beyond a particular investment to risks and uncertainties in the rest of the supply chain that can propagate. 2 **Ex-post evaluation of investment decisions.** RTOs are ideally placed to not just consider new projects and methods, but also to look back and evaluate what has happened. Doing this for hydrogen investment projects (e.g., considering which risk events fired and what responses were made) would likely yield valuable insights. 3 **Applying stochastic methods**. Risk and uncertainty matter. Although deterministic methods are sometimes still appropriate, stochastic methods should be considered. 4 **More research on the business cases for (long-term) hydrogen storage**.

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Appendices

Appendix A Risk and uncertainty identification

Outcome of Workshop #3 with 13 hydrogen ecosystem subject-matter experts from industry and governmental bodies (1/3):

ECONOMIC / FINANCIAL	ENVIRONMENTAL	SOCIAL	POLITICAL/REGULATORY	TECHNOLOGICAL	OTHER
Undefined market	Nitrogen issue as barrier to transition	No alternatives once things go very wrong	Speed of development&construction of new infrastructures	Electrolyser technology not available / still immature / not operating according to specificaitons	no urgency to include arbitrage
No spotmarket	Discovery of additional GHG emission potential of H_2 in case of leaks	Safety	No import terminals on time	technological suply chain bottlenecks	infra should be its own category
H_2 is too expensive related to alternatives	Leaks of H_2 to atmosphere decreasing the impact to climate change (as H_2 is a GHG)	Jon market - upskilling	No pipelines on time	is there enough green electrons in time?	
H_2 import outcompetes domestic H_2 production	Major leak event of ammonia, hydrogen in the ocian or air near populated area	Major leak event of ammonia, hydrogen in the ocian or air near populated area	No storage on time	breackthrough technology disrupts already heavy invested infrastructure for H_2	
lack of economic drivers to establish Dutch strategic H_2 production capacity (despite potential outcompeted by import) and thereby establish partial energy independency	too much focus on hydrogen, slows other options	too much focus on hydrogen, slows other options	No enforcement of legislation	international port bunkering infrastructure does not align (eg. Port of brazil - port of Rotterdam	
Impact of IRA in US on H_2 imports	justification principle/EIA for new sites of ammonia crackers/import export facilities	justification principle/EIA for new sites of ammonia crackers/import export facilities	Defining colours / shades of H_2+subsidies	Technology readiness levels -> demand	
the (lack of) security of supply is not valuated	NIMBY approach to onshore electrolysers	Lack of spending power to finance H_2 transition / Questions to who will finance 'socialize risks, privatise rewards'	True colour determination	underestimated complexity of roll-out (change frrom natural as to hydrogen)	
Customer premium for 'fossil free' production over low CO_2 (green) production	Determining true carbon content	safety is unknown to public > negative messages	Lack of eu policy alignment (e.g. too late implementation of EU frameworks)	storage on a regional or local level is needed but not developed yet	
speed of getting down the cost curve. Is USA (1-1-1) ambition realistic?		acceptance of public H_2, no acceptance renewable power	Unclear EU or National policies> waiting	reliance on scarce raw materials for electrolysers available in politically challenging countries	

Outcome of Workshop #3 with 13 hydrogen ecosystem subject-matter experts from industry and governmental bodies (2/3):

ECONOMIC / FINANCIAL	ENVIRONMENTAL	SOCIAL	POLITICAL/REGULATORY	TECHNOLOGICAL	OTHER
Timing misalignment of infrastructure, production (H2, ren. Power) and demand		social support for subsurface activities might be lacking (> subsurface H2 storage only possible offshore: expensive!!) (>or not possible at all)	social support for subsurface activities might be lacking (> subsurface H2 storage only possible offshore: expensive!!) (>or not possible at all)	electrolysers and balance of plant are too immature	
Needed acceleration is not met (=stranded investments)		no social support for blue H2 (>opportunity to kickstart H2 economy lost)	no social support for blue H2 (>opportunity to kickstart H2 economy lost)	a safety incident early in the deveopment of hydrogen value chains	
price and tracking possibilities & green certificates			securing demand for H2: will energy intense industry require extra support? And will it get this on time?	massive improvements in battery storage that drives H2 to more niche volumes, below initial mass for hydrogen economy	
Quality of blue vs green vs cost/price			Insufficient monetization of H2 for its added value as a possible energy carrier, which should come from regulations	lack of materials	
H2 offtake risk => major H2 demand in NLs industry will move somewhere else (e.g. NH3 production) where renewables->H2 is cheaper			Political willingness to support hydrogen	lack of skilled people	
Investors avoid immature market / unproven technology			conflicting international policies on H2 adoption	underestimated material degradation effects when exposed to hydrogen	
Lack of bankability in general			Maritime industry has not adopted/approved/compiled adequate directives (e.g. through IMO) to allow massive fuel volumes to be traded	availability manufacturing capacity (of electrolysers etc) for ambitious capacity plans	
Too few investments in renewable power generation (or too late)			competition for existing pipelines / national transportation networks	technology supply chain electrolysers	

Outcome of Workshop #3 with 13 hydrogen ecosystem subject-matter experts from industry and governmental bodies (3/3):

ECONOMIC / FINANCIAL	ENVIRONMENTAL	SOCIAL	POLITICAL/REGULATORY	TECHNOLOGICAL	OTHER
Labour shortage			lack of market / subsidy mechanism to make switch to hydrogen (exempt(???) MBEs, a good but temporary start)	admixing of h2 in gas grid is not considered (is seen as a waste of H2) while there will be side streams (e.g. freom purification) that may add more value in the gas grid then after another purification in the H2 grid)	
Lack or depletion of mineral resources to support growth volumes of hydrogen technologies (e.g. platinum catalysts mined in south africa)			not choosing for the obvious first steps (delay -> missing the window of opportunity)	scaling production to mega size (green)	
untrustworthy government			claims about where hydrogen should be used hinder other sectors	no consensus on H2 quality in the backbone (98% vs 99.99..%) (>socially suboptimal solution with purification needed in many places: expensive)	
			REDII vs IRA	intermittency of wind power generation	
			additionality principle results in electrolyser projects waiting on wind offshore	too late decision on infrastructure standards on quality (purity), pressure, etc...	
			additionality is too restrictive		