Assessment of policy instruments for hydrogen in the Netherlands

Contract details

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NL Ministry of Economic Affairs and Climate Policy

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Disclaimer

The conclusions in this report are based on results of a modelling exercise, complemented by qualitative research. Any modelling exercise uses assumptions. The assumptions in this research are primarily based on relevant literature and have been finalised in coordination with the client. If future developments differ significantly from the modelled assumptions, results may be different.

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I: Background & methodology

In this study, Trinomics and Quo Mare assessed the impact of different policy options considered by the Dutch government to facilitate domestic production of renewable hydrogen in electrolysers and its use in hard-to-decarbonise processes. This study is commissioned by the Dutch Ministry of Economic Affairs and Climate Policy (EZK) to inform the decision-making process with respect to national hydrogen policies. Currently, the Dutch industry uses about 50 TWh of hydrogen (180 PJ) annually, which makes the Netherlands among the countries with the highest hydrogen use in Europe. Virtually all current use is fossil-based (grey) hydrogen. In the future, low-carbon (e.g., blue) and renewable (green) hydrogen and other RFNBOs[1] can play a role in decarbonising hard-to-abate processes, not only by replacing current hydrogen use, but also current fossil fuel use. This study evaluates to what extent the considered policy options contribute to reaching two major targets for renewable hydrogen deployment. First, 4 GW domestic hydrogen production capacity with electrolysers in 2030. Second, 42% share of RFNBOs in the total hydrogen consumption in industry by 2030, and 60% in 2035. The first target is set nationally, while the second results from the recast Renewable Energy Directive (RED III) at EU level.[2] We assessed the impacts of the considered national policy measures on the installed renewable hydrogen capacity and production, industrial competitiveness, and decarbonisation in the Netherlands. The assessed policy mixes consist of different combinations of renewable hydrogen consumption subsidies, production subsidies and RFNBO consumption obligations for industrial hydrogen users, given the available budget (around € 5 bn) from the Dutch Climate Fund. The table below summarises the key characteristics of the different policy mixes (PM) and two sensitivity scenarios (S), which are identical to PM 2 and 3, except for the consumption obligation.[3]

<table>
<tr><th>Policy Mix</th><th>Consumption obligation</th><th>Consumption subsidy</th><th>Production subsidy</th></tr>
<tr><td>Policy Mix 1</td><td rowspan="2">42% (2030), 60% (2035)</td><td>capex+ opex (€ 2 bn)</td><td>capex+ opex (€ 3 bn)</td></tr>
<tr><td>Policy Mix 2</td><td rowspan="2">capex only (€ 1 bn)</td><td rowspan="2">capex+ opex (€ 4 bn)</td></tr>
<tr><td>Policy Mix 3</td><td rowspan="2">24% (2030), 60% (2035)</td></tr>
<tr><td>Policy Mix 4</td><td>capex+ opex (€ 4 bn)</td><td>capex+ opex (€ 1 bn)</td></tr>
<tr><td>Sensitivity 1</td><td>12% (2030), 30% (2035)</td><td rowspan="2">capex only (€ 1 bn)</td><td rowspan="2">capex+ opex (€ 4 bn)</td></tr>
<tr><td>Sensitivity 2</td><td>No obligation</td></tr>
</table>

The quantitative impacts of the different policy options were assessed using Quo Mare's Transition of the Dutch Energy System model (TDES), which is a techno-economic optimisation tool. TDES enables the estimation of interactions in the Dutch energy system; it simulates the most cost-efficient transition pathway for a given set of assumptions, limitations, and boundaries. The industrial end-users in scope are the most relevant industrial sectors (large existing and potential new industrial hydrogen users). For the decarbonisation effects, we focussed on the interaction between RFNBOs' use vs. electrification and carbon capture & storage (CCS, including low-carbon hydrogen). We first estimated the development of renewable hydrogen production and use in the Netherlands in the absence of the considered policy mixes, followed by an assessment of the policy mixes. The last modelling step was a sensitivity analysis. The modelling results were complemented by insights from qualitative research. Conclusions were formulated based on the results of both the quantitative and qualitative analysis.

[1] Renewable Fuels of Non-Biological Origin: Renewable liquid and gaseous fuels produced from renewable energy sources other than biomass. Gaseous renewable hydrogen produced with renewable electricity in an electrolyser is an RFNBO. Liquid fuels (ammonia, methanol, e-fuels) are considered RFNBOs if produced by renewable hydrogen.
[2] The recast has been adopted by the European Council on October 9, 2023. For more information, click here/here.
[3] Also, under PM 1, consumers can use subsidised RFNBOs to meet the consumption obligation, in contrast to PM 4.

II: Modelling assumptions and boundaries

The modelling results are based on a set of mutually agreed assumptions. Results should be interpreted with caution, and properly acknowledge the consequences of the assumptions and boundaries used, as well as the impact of (unforeseen) developments in other EU Member States and at global level. A single baseline scenario is used for modelling the effects of the policy mixes, with the research primarily geared towards understanding the dynamics of various policy mixes. This research is not a scenario study, in which each policy mix would have been tested under different negative and positive price sets. Instead, the scenarios are complemented by sensitivity analyses on specific (costs) assumptions, testing the baseline assumptions which are based on sources like II3050.[4] Key assumptions include fixed final demand volumes, which imply that the model generates pathways assuming the demand for final products and services (e.g., transport kilometres) remains constant.

The model assumes economic rational behaviour: investment and operational decisions are based on cost minimisation, taking into account legal obligations and constraints. Decarbonisation options that are not cost optimal according to our estimates are not selected by the model. However, some of these options are considered in practice. For instance, based on existing public information, the model projects that the steel sector will not decarbonise its activities by using renewable hydrogen, as other decarbonisation options (e.g., CCS and electrification) are expected to be more cost efficient without direct support for alternative decarbonisation options. Despite, various integrated steel mills in Europe developed plans to switch to hydrogen-based steel production, often with substantial national support. In this context, the Dutch government is in the process of designing tailor-made agreements (‘*maatwerkafspraken*’) with large industrial companies to make industrial processes more sustainable. Next to decarbonisation goals, these agreements could also take other considerations into account, like environmental and geo-political issues. Tailor-made agreements have not been considered in this study, as no final commitments have been communicated. However, tailor-made agreements with (potential) hydrogen users, e.g., steel and ammonia plants, can affect future hydrogen volumes significantly.

In the model, the RFNBO consumption obligation is always met at sector level, as the penalty for not respecting the legal obligation is assumed to outweigh the costs for compliance. In practice, the penalty could be set at a lower level, or the actual future costs could deviate from the assumed levels, which would further decrease RFNBO consumption the scenario outcomes. Similarly, if dedicated hydrogen infrastructure (for import and transport) would not be realised in time, the hydrogen uptake could be delayed. Lastly, the development of electricity infrastructure (renewable electricity generation capacity, reinforcement and extension of electricity networks) will affect the production and demand for hydrogen in the Netherlands.

III: Modelling results

The table below shows the key modelling results in the baseline (B), in the regular policy scenarios (PM 1-4) and in the sensitivity policy scenarios (S1-S2) for 2030. The 2035 results are described in the text below the table. The values shown for the policy mixes refer to the changes (+ or -) compared to the baseline values. The results do not take into account various national (hydrogen) policies, such as the refinery route, specific financial support for IPCEIs, ‘*maatwerkafspraken*’, ‘*subsidieregeling opschaling volledig hernieuwbare waterstofproductie via elektrolyse - OWE*’ and ‘*het groeifonds*’, nor policies from other EU Member States.

[4] Netbeheer Nederland and others (2023). *Het energiesysteem van de toekomst: de II3050-scenario’s.*

Key modelling results in the baseline (B) + impact of policy mixes (PM) and sensitivity analyses (S) in 2030.

	B	PM 1	PM 2	PM 3	PM 4	S 1	S 2	Unit
Renewable hydrogen production	**0**	*+5.9*	*+5.8*	*+5.0*	*+2.6*	*+5.0*	*+3.3*	TWh[5]
Low-carbon hydrogen production	**10**	*-6.7*			*-4.3*	*-6.7*	*-3.3*	
Fossil hydrogen production	**10**	*+0*			*-5.7*	*+0*		
Fossil ammonia production	**5**	*+0*			*-5.0*	*+0*		
Low-carbon ammonia imports	**28**	*+0*			*+5*	*+0*		
Other imports/production*	**0**	*+0*						
Electrolyser capacity	**0**	*+3.0*	*+2.9*	*+2.5*	*+1.3*	*+2.5*	*+1.7*	GW
Scope 1 CO_2 emissions NL (ETS)	**43**	*-0.6*		*-0.3*	*-0.7*	*-0.4*	*+0.2*	Mton CO_2

**Fossil/low-carbon/renewable/ ammonia/hydrogen production/imports, other than mentioned in the table.*

Without the considered hydrogen policies, renewable hydrogen/ammonia production/import is not foreseen by 2035. Significant amounts of domestically produced low-carbon hydrogen are foreseen. The baseline results show that renewable hydrogen and ammonia are not competitive with alternatives by 2035. As a result, no industrial renewable hydrogen/ammonia use is expected based on economic reasoning only. Due to this lack of demand, no substantial investments in production are foreseen in the baseline scenario. Towards 2035, the EU Emission Trading Scheme (and the national carbon levy for industry) make emitting CO_2 increasingly costly, while decarbonisation options become more economically viable due to decreasing costs. As a result, the model suggests that 10 TWh[5] of low-carbon hydrogen will be produced and used in the Netherlands by 2030 in the baseline. At the same time, fossil hydrogen and ammonia are still expected to be produced domestically. In 2035 however, no fossil ammonia/hydrogen is expected to be produced domestically. Instead, the level of low-carbon hydrogen production and use reaches 90 TWh. Low-carbon ammonia imports increase substantially, reaching 28 TWh in 2035. This increase is at the expense of domestically produced low-carbon ammonia. The costs and expected volumes of low-carbon hydrogen are affected by natural gas prices. Our sensitivity analysis shows that low-carbon hydrogen volumes in the baseline only decrease marginally if natural gas prices are increased by 25%. Even higher natural gas prices (which are not implausible, based on price fluctuations in recent years), and/or potential practical constraints to the number of new low-carbon hydrogen plants, could result in more modest growth of the low-carbon hydrogen production. Increased demand of low-carbon hydrogen would increase the demand for natural gas.

In the scenario runs with the considered hydrogen policy mixes (PM 1-4), we observed five key differences compared to the baseline (S1 and S2 are discussed further below):

1. **The considered policy options increase domestic production (and use) of renewable hydrogen** in all four policy mixes. The combination of the RFNBO consumption obligation, RFNBO consumption subsidies and renewable hydrogen production subsidies results in substantial domestic renewable hydrogen production and consumption in 2030 (3–6 TWh) and 2035 (3-7 TWh). This corresponds with electrolyser capacities of 1-3 GW in 2030 and 2-4 GW in 2035. Domestic renewable ammonia production is not foreseen in the scenarios.[6]
2. **The considered policy options result in a drop in total hydrogen use, driven by reduced hydrogen use in the fertiliser sector, which is an outcome primarily driven by a medium to high RFNBO consumption obligation in 2030 (24-42%).** Under the RFNBO consumption obligation, increased fossil and/or low-carbon hydrogen use *must* coincide with a proportional increase in RFNBO use. Instead, increased use of alternative fossil and/or low-carbon hydrogen derivatives does *not* require an increase in RFNBO use. This is a consequence of the RED III formula to calculate the RFNBO share in the hydrogen consumption by the industry, which

[5] 1 Terawatt hour (TWh) = 3.6 Petajoules (PJ)
[6] It is not possible to draw conclusions on reaching the RFNBO targets based on the modelling results, as the targets are in the modelling considered as a hard constraint (hence as model input).

discourages hydrogen use.[7] The results suggest that low-carbon ammonia imports replace domestic (low-carbon) ammonia production using hydrogen as input in the fertiliser sector. The type of ammonia (renewable, low-carbon, or fossil-based) is not affected by the policy mixes; industrial users purchase the most cost-efficient type. Between 2029 and 2035, this is expected to be low-carbon ammonia (due to e.g., the Carbon Border Adjustment Mechanism – CBAM). Relative to the baseline, total hydrogen use drops by -1 to -7 TWh in 2030 and by -70 to -76 TWh in 2035. Relative to current hydrogen use, drops by -3 to -9 TWh in 2030 and by -1 to -8 TWh in 2035.

3. **Under the assessed policy scenarios, the RFNBO consumption obligation is expected to drive the existing ammonia production units to shut down permanently.** The ammonia used for fertiliser production can be produced locally or imported. This price-sensitive decision can vary on a year-by-year basis. In the baseline scenario, the modelling results suggest a substantial decrease in domestic ammonia production. However, some domestic ammonia production is expected to remain sufficiently attractive to keep ammonia production units active. The switch to imported low-carbon ammonia (as explained in the key difference #2) reduces the hydrogen demand to the extent that ammonia production units in the fertiliser sector would be shut down completely. Reversing this situation would be hard, even if the price of renewable hydrogen would decrease to the point that the business case for restarting domestic ammonia production would become positive. It would require the necessary investments to restart the production, regain knowledgeable personnel, and a redevelopment of the client base. **The business case for domestic ammonia production is vulnerable, and highly dependent on the developments of (volatile) global prices.**
4. **The policy options with a medium/high consumption obligation delay decarbonisation of the industry and increase CO_2 emissions in 2035 (compared to the baseline scenario).** All policy options result in a slight decrease in CO_2 emissions in 2030. In 2035 however, CO_2 emissions are significantly higher in policy mixes P1-P4 compared to the baseline scenario (+21 to +23 Mton CO_2). Differences between policy mixes are small, because the consumption obligation reaches 60% in 2035 in each policy mix. In the baseline, electrification in combination with low-carbon hydrogen would be competitive, thereby replacing e.g., heat production with natural gas in the chemical sector. This would result in a sharp decrease in CO_2 emissions. Under the RFNBO consumption obligation, hydrogen users are forced to use a combination of low-carbon and renewable hydrogen, instead of low-carbon hydrogen only. As a result, industries are expected to continue using the current (fossil-based) production technologies longer, instead of investing in low-carbon hydrogen use, until the point that decarbonising through RFNBOs is more cost-efficient.
5. **The considered policy options result in substantial additional costs for industry (around €14 bn accumulated over all considered years), and government expenditures (€ 5 bn), as a result of a the medium/high RFNBO consumption obligation.** This is driven by increased energy-related costs for industry, which would only partly be compensated by subsidies. As the final demand volumes in the modelling are held constant, the impact of the different policies on output volumes cannot be estimated. Potential impacts along the value chain and consequences of these cost increases on a macro-economic level were not estimated.

A moderate RFNBO consumption obligation (S1, 12% in 2030) would reduce various negative consequences observed in the regular policy mixes, while still resulting in relatively high

[7] The RFNBO consumption obligation ensures that 'RFNBO use divided by hydrogen use must equal 42%'. As ammonia use is only included in the denominator of the formula, direct ammonia consumption is a way for industrial users to avoid a higher consumption obligation, and hence higher costs.

electrolyser capacities in 2030. The model run on policy mix 3, adjusted for a moderate (halved) RFNBO consumption obligation results 2.5 GW electrolyser capacity in 2030. Hence, the 2030 goal is still not reached, although other existing policies (e.g., IPCEI, OWE) are not taken into account in this study. In 2035 however, S1 results in 5 GW electrolyser capacity, which is the highest capacity reached under all scenarios.[8] The RFNBO share is expected to reach 31% in 2030 and 33% in 2035. The delayed decarbonisation compared to the baseline scenario is smaller than in the regular policy mixes. This is because low-carbon hydrogen remains more attractive than in scenarios with a high RFNBO consumption obligation. Yet, CO_2 emissions are still significantly higher than in the baseline scenario (without the policy options). The total energy/industry system costs are roughly halved in this scenario compared to the regular policy scenarios. Ammonia production units are still expected to shut down permanently.

Removing the obligation completely (S2) nullifies the negative effects, but results in less electrolyser capacity. S2 results in the lowest renewable hydrogen volumes, similar volumes of low-carbon hydrogen as in the baseline scenario, and negative costs for industry (as subsidies would be provided without any financial obligations). Ammonia production units remain active.

To test the robustness of the modelling results, four additional sensitivity runs were performed: lower investment costs (capex) for electrolysers,[9] a 25% increase in the natural gas price, increased (earlier) demand from Germany for sustainable fuels, and a lower price for RFNBO imports. The robustness of the results was tested for the baseline and for policy mixes 2 and 3. We conclude that:

- **The baseline results are only significantly affected by increased demand for sustainable fuels in Germany** (which further increases the domestic low-carbon hydrogen production by +50% in 2035) **and cheaper RFNBO imports** (resulting in substantial renewable hydrogen imports from around 2036, corresponding with less domestic production).[10]
- **While the 4 GW electrolyser target is not reached in any model run, certain developments would increase domestic renewable hydrogen production under policy mix 3.** These include higher natural gas prices and lower electrolyser investment costs. The highest electrolyser capacities are reached in the scenario with lower electrolyser investment costs (6 GW in 2035). We note that various hydrogen related policies (for instance IPCEI and the refinery route) were not included in the model runs, which should contribute to the hydrogen targets as well.

IV: Conclusions

In the absence of additional policies targeted at renewable hydrogen production and use, renewable hydrogen or ammonia production or import is not foreseen by 2035. Instead, significant volumes of domestically produced low-carbon hydrogen are foreseen to replace existing fossil hydrogen use and to supply new hydrogen users. In this baseline scenario, the Dutch industry is expected to reduce its CO_2-emissions mostly by using CCS and electrification (in combination with low-carbon hydrogen or derivatives), as renewable hydrogen will not yet be competitive. After 2035, low-carbon hydrogen could be complemented (or replaced) increasingly by RFNBOs, such as renewable hydrogen or ammonia, if production and/or import costs fall significantly. This conclusion is informed by the modelling results and additional qualitative insights. As the relevant industries are active in

[8] The lower RFNBO consumption obligation (S1) results in more investments in decarbonisation via low-carbon and renewable hydrogen use, compared to the scenarios with higher RFNBO obligations (PM 1-4). This is because the costs to decarbonise with hydrogen are lower (due to the lower RFNBO share). This results in an increase in hydrogen demand, for both low-carbon and renewable hydrogen.
[9] Implemented with a learning curve for electrolysers, assuming that costs gradually decrease from 99% in 2026 to 69% in 2035, relative to the (constant) costs in the other scenarios. In 2024 and 2025, higher costs are assumed.
[10] Dedicated policies to facilitate RFNBO-imports have not been modelled, such as H2Global.

international markets with fierce competition, voluntarily opting for substantially more expensive production methods seems highly unlikely. This conclusion is in line with international studies, which do not foresee the development of large electrolyser capacities in the Netherlands by 2035 without additional policies.[11]

Renewable hydrogen (and RFNBO) specific policies are justified to accelerate technology and market development as specific sectors and applications can only be fully decarbonised cost-efficiently with renewable fuels. Although we did not assess whether pursuing high national renewable hydrogen deployment targets would be justified for other (e.g., strategic) reasons, our assessment shows that the approach and pace as foreseen under policy mixes 1-4 may not be coherent with the energy and climate policy that aims to meet targets in a fair, cost effective and competitive way.

The pace and level of renewable hydrogen deployment in the Netherlands are affected by various (global) developments, which also impact the probability and cost of reaching the considered hydrogen targets. First, the electrolyser technology has not yet reached industrial maturity, affecting the availability and price of RFNBOs. Renewable hydrogen and derivatives are not yet produced at large scale, and further upscaling resulting in lower investment costs are expected in the coming decade. Technological learning curves depend on global developments; Dutch industrial actors can only contribute to a certain extent in reducing renewable hydrogen costs. Secondly, the demand for hydrogen in the Netherlands is affected by developments of markets and prices at global level. For instance, a substantial drop in the global ammonia price could halve the current hydrogen demand in the Netherlands. In the next few years, US industries are expected to determine the global price for RFNBOs, as a result of the Inflation Reduction Act (IRA). However, the US industries would not dominate the global price in the long run if the IRA subsidies would be scaled down (due to political/budget reasons), if the EU would react to the IRA via similar policy instruments, or if other producing countries set the price as “marginal” producer. At a more local scale, the availability and cost of alternative decarbonisation options (e.g., CCS and electrification) affect the renewable hydrogen demand.

The modelling results show that a medium to high RFNBO consumption obligation (24-42% in 2030, 60% in 2030) could harm industrial competitiveness significantly, while it would not guarantee that the RFNBO targets are effectively met and could even lead to *lower* RFNBO demand. To what extent industrial companies will make efforts to meet the obligation depends on the monitoring and compliance of the obligation, as well as the penalty level. While we assumed a high penalty in the modelling, companies may prefer not to comply if the penalty level is lower than the compliance cost. Moreover, the availability of RFNBOs is expected to be limited in the short to medium term, in particular in Central Western Europe where the business case for electrolysers using renewable electricity is less positive than in some other regions. There is a substantial risk that RFNBOs will not be sufficiently available by 2030. Hence, a strict RFNBO consumption obligation could expose industrial companies to higher risks and costs, thereby jeopardising their competitiveness. Such a legal obligation may reduce the affected industrial activities in the Netherlands, on the one hand by lower production levels in existing facilities, and on the other hand by lower investment levels in new assets. There is a risk that a strict obligation may hinder the development of new (sustainable) industries in the Netherlands, in particular if other EU or non-EU countries would not implement an obligation. Lastly, industrial companies may shift from hydrogen use to alternatives (e.g., ammonia) to meet the

[11] For instance: European Commission, DG Energy (2023). METIS 3 S5 - The impact of industry transition on a CO2-neutral European energy system.

obligation, thereby avoiding costs related to the obligation.[12] These different impacts are shown by the modelling exercise, in particular for the fertiliser sector. A strict RFNBO consumption obligation could ultimately lower the potential RFNBO demand, thereby reducing the investment certainty for RFNBO producers in the Netherlands.

To facilitate RFNBO consumption and to minimise the adverse impacts of a strict legal obligation, sufficient RFNBO availability needs to be developed first, before a legal consumption obligation can work effectively. All examined policy mixes containing a medium or high consumption obligation would result in less total hydrogen consumption (low carbon and renewable), delayed decarbonisation and competitiveness loss. This is driven by the design of the obligation and the absence of sufficient RFNBO volumes at competitive prices in the considered time horizon. As a result, sequencing the implementation of instruments, by first supporting domestic RFNBO production (and facilitating imports), may fit best with reality and various policy goals. Policy instruments that support RFNBO production and increase supply are expected to still contribute to renewable hydrogen targets, with less adverse effects. However, meeting the RFNBO target under RED III is unlikely without an RFNBO consumption obligation (in combination with the assessed subsidy levels). There is no public information available on the expected implementation of the RED III RFNBO consumption target in other EU Member States; future national policy initiatives in other countries will also affect the competitiveness of the Dutch industry. The prospect of a strict RNFNBO consumption obligation can have a paralysing effect on domestic investments in both RFNBO and low-carbon hydrogen production.

The design of support mechanisms should incentivise investments and (socially) cost-efficient choices for both production and consumption, as well as mitigate excessive risks for operators. Investment and operational support (or a combination of both) should be carefully considered, as they can be complementary and address the exposure to different risks but have specific disadvantages. Investment production or consumption subsidies trigger investments and lead to lower market distortions than operational subsidies — both regarding operational decisions of producers and consumers separately and by avoiding possible 'double subsidisation' of the same MWh RFNBO by operational production and consumption subsidies simultaneously. However, investment subsidies do not allow to adjust support according to market circumstances in the operational phase. Operational subsidies for production or consumption can mitigate the exposure of operators to market risks (for producers: the risk of low RFNBO prices, and for consumers: the risk of high RFNBO prices). However, operational subsidies influence operational decisions of producers and consumers, and could result in (hydrogen/electricity) market distortions affecting the business case of other market participants. Operational subsidies for production could e.g., disincentivise electrolyser operators to provide flexibility to the power system by reducing their electricity offtake in moments of electricity scarcity.

Operational subsidies should be properly designed to reduce market distortions and excessive subsidies. Operational subsidies can be granted via a tender with a fixed premium or with contracts for difference. A variable premium (i.e., contract for difference) is preferred over a fixed premium in terms of effectiveness and fairness. However, a variable premium is (administratively) more complex and depends on the existence of a liquid hydrogen market to provide a market price reference.

The introduction of production and demand subsidies should be coordinated with (neighbouring) Member States. Subsidies granted to hydrogen production in the Netherlands could indirectly support

[12] Respecting the RFNBO consumption obligation can be reached by decreasing the overall hydrogen use (denominator in formula) and/or by increasing RFNBO use (numerator).

renewable hydrogen exports rather than local consumption, while consumption subsidies could end up supporting imported RNFBOs, rather than local renewable production. The actual impact of production and demand subsidies will depend among other factors on support mechanisms implemented in other EU and non-EU countries.

If a smarter and lower RFNBO consumption obligation would be implemented, a domestic trading scheme could allow companies to meet their RFNBO consumption obligation in a flexible way. However, there are substantial risks. The considered RFNBO consumption obligation could involve issuing HWIs (*Hernieuwbare Waterstofeenheden voor Industrie)*, which are tradeable certificates for industrial companies. In theory, allowing to meet the RFNBO consumption obligation with tradeable HWIs, like in EU-ETS, is more efficient than an individual physical consumption obligation. However, given the expected market size and low number of market participants (including two market parties that currently dominate hydrogen use), it is unlikely that the HWI trading system would be sufficiently liquid and offer transparent price formation. There are risks of anti-competitive behaviour, creating artificial scarcity and driving up HWI prices, which may harm the functioning of a potential HWI market.

We note that other Dutch policies (not assessed in this report) will affect the attractiveness of investing in RFNBOs in the Netherlands. The decisions from the Dutch government on the development of a dedicated hydrogen network and related tariffs, as well as the design of the refinery route are relevant in this respect. The planning of suitable storage capacity is also an important factor. Moreover, the level of certainty offered by plans and commitments from the Dutch government will affect investment decisions from industrial companies. Clarity on the (broadly shared) vision of the Dutch government can lower the (perceived) risks, thereby contributing to unlocking investments. The national implementation of the upcoming EU gas package will affect the investment climate for hydrogen, thereby also determining the framework for cross-border cooperation at regional level. Lastly, based on costs-efficiency and competitiveness reasons, low-carbon fuels could play a transitional role. Policies on low-carbon hydrogen can affect renewable hydrogen deployment too.

Facilitating renewable hydrogen production and consumption is sensible political initiative to decarbonise society towards 2050. As renewable hydrogen technologies and markets have not yet reached industrial maturity, a strict consumption obligation for the Dutch industry by 2030 is unlikely to adequately facilitate renewable hydrogen uptake. To prepare and facilitate large-scale renewable hydrogen production and consumption beyond 2030, providing subsidies is required to close the cost gap with conventional technologies.

1 Introduction: objectives, scope & method

1.1 Reason for this study

Renewable and/or low-carbon hydrogen (and derivatives) are likely to have a substantial role in a fully decarbonised energy system. Renewable and low-carbon hydrogen (derivatives) are particularly relevant for mitigating hard-to-abate greenhouse gas (GHG) emissions in e.g., industrial processes and heavy-duty transport. For this reason, the European Commission (EC) and several EU Member States (MSs), including the Netherlands, are designing dedicated renewable hydrogen policies. The recast Renewable Energy Directive (RED III), as approved in March 2023, requires that 42% of hydrogen used in industry be renewable by 2030, and 60% by 2035.[13] For the transport sector, it sets a target for a 1% share of RFNBOs by 2030, as part of a combined target of 5.5% for advanced biofuels and renewable fuels of non-biological origin (RFNBOs).[14]

The Netherlands considers new policy options to contribute to the EU and national renewable hydrogen goals. These goals include a domestic electrolysis capacity of 4 GW in 2030, and the consumption goals for industry and transport resulting from the above-mentioned recast RED III.

1.2 Objectives of this study

This study supports the Dutch Ministry of Economic Affairs & Climate Policy in making informed decisions on future hydrogen policies. It does so by providing an impact assessment and a qualitative evaluation of different considered hydrogen policy mixes. We first assess the baseline situation; the expected developments in hydrogen production and use in the absence of additional policy measures. Then we assess the developments under four policy scenarios. The assessments are a combination of quantitative (modelling) exercises and qualitative research. **We assess the impacts of different policy scenarios on:**

1. **Volumes** - the expected developments on the hydrogen market under different scenarios in terms of demand and supply (separating local production and imports);
2. **Competitiveness** - the expected impacts of different policy options on the competitiveness of (new and existing) industrial hydrogen users; and
3. **Decarbonisation** – the expected impacts of different policy options on the CO_2 emissions in the Netherlands and on the deployment of other decarbonisation options.

1.3 Scope of this study

This study focuses on the production and industrial consumption of RFNBOs in the Netherlands in 2030 and 2035. The scope of this study is as follows:

- **RFNBOs and competing products:** for RFNBOs, the definition of the EU Renewable Energy Directive (RED-III) is followed. In practice, this entails hydrogen produced in electrolysers (using renewable electricity) and their derivatives, such as renewable ammonia. The study also assesses

[13] Council of the European Union (2023). Recast Renewable Energy Directive. The recast has been adopted by the European Council on October 9, 2023. For more information, click here or here.
[14] European Parliamentary Research Service (2023). EU rules for renewable hydrogen

key products directly competing with RFNBOs. These are primarily hydrogen and their derivative products produced from fossil fuels, or with application of carbon capture and storage (CCS).

- **Sectors:** this study focusses on the national goals regarding the domestic production and industrial consumption of RFNBOs in the Netherlands. While the consumption of RFNBOs and competing products in sectors other than industry (such as transport) is taken into account in the analysis, results on consumption of hydrogen and key derivatives are only presented for the industry. Production of RFNBOs is presented for the Netherlands as a whole.
- **Geography:** the study focuses on the Netherlands, but imports/exports of hydrogen and key derivatives are also taken into account. Potential interactions with other countries in the EU, particularly with neighbouring countries in Northwest Europe, are discussed qualitatively.
- **Time horizon:** the results are in this report presented for the current year (2023) and for 2030 and 2035. However, the model underpinning the quantitative results uses a time horizon until 2050 to consider long-term investment decisions.

1.4 Overarching research method & report structure

This study uses a mix of qualitative and quantitative research methods to assess and analyse the effects of selected policy mixes on the uptake of hydrogen in the Dutch economy and their impact on economic/industrial output and climate goals. The analysis is based on an extensive literature review, expert opinions and energy system modelling. The applied model (TDES), developed in-house by Quo Mare, is an energy system optimisation tool created to study the interaction between the entire Dutch economy (with a special focus on industry) and the local energy system. Within this study, this model is used to generate transition pathways for the Dutch economy based on selected policy mixes and a baseline scenario without any further governmental intervention. A comparative analysis is then carried out between the outputs of these different pathways. This report is structured as follows:

- **Chapter 2** provides the background of this study, summarising the relevance and future potential of hydrogen in Europe and the Netherlands based on literature, with the current policy goals of the Dutch government grounded in climate ambitions and international obligations.
- **Chapter 3** introduces the policy options considered by the government to achieve these goals and the combinations of options that are being assessed within this study.
- The description of the model used for this purpose is presented in **Chapter 4,** detailing the key assumptions and input parameters used in the modelling.
- **Chapter 5** contains the modelling outputs relevant for assessing the impact of the considered policy mixes on the future deployment and cost of hydrogen in the Netherlands, complemented with analyses on contracts, markets and cost components.
- **Chapter 6** informs on the impact of hydrogen deployment on the industrial competitiveness of the Dutch industry via the projected changes in energy-related costs, complemented with an analysis on the trade in RFNBO certificates and the risk for anti-competitive behaviour.
- **Chapter 7** shows the climate and energy impacts of the hydrogen policy options.
- **Chapter 8** gives an overview of the sensitivity of results on the investigated parameters, complemented by an overview of relevant conditions and facilitators.
- **Overarching conclusions are integrated in the Management summary & conclusions.**
- The **Annex** contains additional results (qualitative analyses on individual policy instruments).

2 Background: hydrogen deployment & policies

2.1 Why is deployment of (renewable) hydrogen relevant?

Renewable (and low-carbon) hydrogen is likely to play a role in a decarbonised energy system as *energy carrier* and as *feedstock* in hard-to-abate industrial processes and applications. Visions about the effective potential of renewable hydrogen in decarbonising energy use vary substantially. Advocates of hydrogen foresee a major role for renewable hydrogen in most sectors, including passenger cars and heating of buildings.[15,16] Critics instead point to the poor energy efficiency and high costs of the conversion processes, ultimately expecting a much more limited role for renewable hydrogen.[17] Based on our expertise, the starting point for this research is that renewable (and low-carbon) hydrogen will have *some* role in a fully decarbonised energy system on the medium/long term, at least in hard-to-abate sectors, such as certain industrial processes and heavy-duty transport. In addition, renewable (and low-carbon) hydrogen is likely to be used as backup fuel for electricity and heat generation, in particular during "Dunkelflaute" periods. For most other applications, competition with more energy-efficient and lower-cost alternatives (i.e., electrification) is strong and renewable (and low-carbon) hydrogen is likely to play a smaller role. To a large extent, our vision is in line with the Dutch government's (draft) *national plan energy system*.[18]

At present, hydrogen is almost exclusively generated from fossil sources and used in specific industrial processes as feedstock or energy carrier. The current global hydrogen use is modest (amounting to 3,102 TWh, or about 2.5% of the global final energy consumption[19]) and concentrated around a few industrial clusters. Virtually all (99% globally, as of 2022) hydrogen used today is produced either using natural gas in a steam methane reduction process (SMR) or as a by-product of the petrochemical industry[20] resulting in 900 Mt of CO_2 emissions annually.[21] There is no large-scale renewable hydrogen production capacity installed as of yet, though the existing global electrolyser capacity doubled between 2016 and 2021, reaching 300 MW in 2021.[22] In 2022, about 130 MW was commissioned; 45% less than in the previous year. However, the electrolyser manufacturing capacity increased by more than 25%, reaching nearly 11,000 MW per year in 2022. The realisation of all pipeline projects could lead to an installed electrolyser capacity of 170,000-365,000 MW by 2030.[23]

2.2 Current hydrogen use in Europe

Hydrogen use is currently concentrated in oil refineries, chemical industries to produce products such as plastics, ammonia (fertilisers), methanol **and** — to a smaller extent — **the steel sector**.[24] While the number of announcements made by (potential) market players on the installation of new production capacities for (low-carbon/renewable) hydrogen has been steadily increasing in the past few years, only a small fraction

[15] Hydrogen Europe (2022). Use of Hydrogen in Buildings.
[16] EC (2022). Hydrogen use in EU decarbonisation scenarios.
[17] See for instance: Michael Liebreich (2022). The Unbearable Lightness of Hydrogen.
[18] NL Ministry of Economic Affairs & Climate Policy (2023). *Nationaal Plan Energiesysteem - concept*. (in Dutch)
[19] IEA (2022). Global Hydrogen Review.
[20] IEA (2022). Hydrogen.
[21] IEA (2021). Global Hydrogen Review.
[22] IEA (2021). Global Hydrogen Review.
[23] IEA (2023). Electrolysers - Energy System.
[24] EC (n.d). Hydrogen.

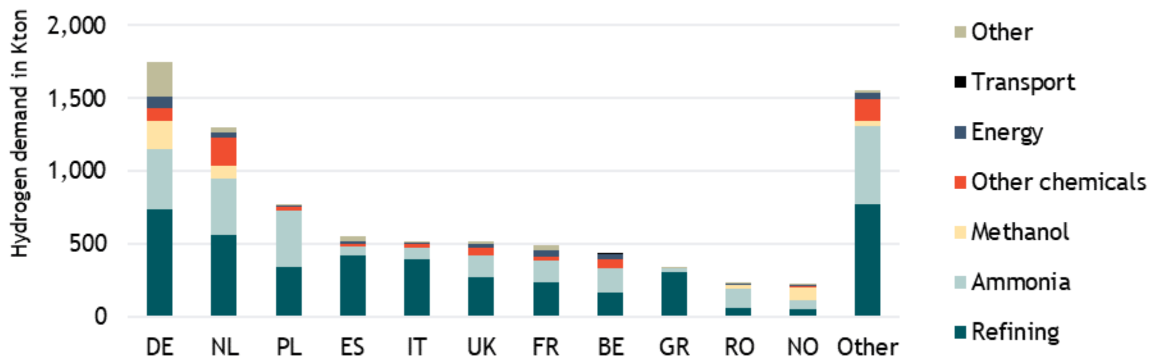
of these pledges involve a firm investment decision due to uncertainties in the expected evolution of demand, the lack of regulation and hydrogen infrastructure already in place.[25] There were about 350 projects under development globally as of 2021, together amounting to about 54 GW of potential future hydrogen production capacity.[26] The IEA in its 2022 Global Hydrogen Review predicts that global hydrogen demand could reach 3,795 TWh (115 Mt) by 2030 based on the already announced climate policy action points alone.

At present, Northwest Europe accounts for 5% of the global and 60% of European hydrogen demand.[27] About 60% of the 208 TWh (6.3 Mt) overall hydrogen demand of the region (home to 40% of the EU's chemical industry) is for pure hydrogen, 92% of which is used in the petrochemical industry and for ammonia production. While the petrochemical industry is expected to shrink by 25% in the coming years up to 2030[28], and steel production currently accounts for only a small fraction of the European demand, hydrogen is well-placed to take over the role of coal in steel production, generating significant new demand (about 22% increase)[29]. The bulk of this demand is expected to be in France and Germany, however, with the Netherlands' demand stagnating. The current hydrogen use is equivalent to less than 2% of Europe's final energy consumption, whereas electricity represents 22.8%, and natural gas 22.6%.[30] It can reasonably be assumed that hydrogen will replace natural gas to some extent in the future, also as a power system flexibility option. The estimations to what extent hydrogen may be used for electricity generation range between 5% and 15%, meaning a 210 TWh (6.4 Mt) additional hydrogen demand in Belgium, the Netherlands and Germany combined.[31]

The Netherlands is one of the largest hydrogen consumers in the EU. While numbers on hydrogen demand/consumption vary across sources, all sources rank the Netherlands among the top hydrogen consumers in the EU. According to JRC[32], Dutch hydrogen consumption reached 43 TWh (1.3 Mt) in 2020. According to the Fuel Cells and Hydrogen Observatory, the Netherlands is the second largest hydrogen consumer in Europe, just behind Germany. According to their estimates, 15% of all hydrogen consumed in the EU is consumed in the Netherlands. This is illustrated in Figure 2-1. In terms of production capacities, Hydrogen Europe reports 51 TWh (1.55 Mt)/year installed (conventional, non-renewable) in the Netherlands in 2020, corresponding to 13.5% of the EU-27's production capacity.[33]

[25] IEA (2022). Hydrogen.
[26] IEA (2021). Global Hydrogen Review.
[27] IEA (2021). Hydrogen in North-Western Europe.
[28] Trinomics (2022). Promotion of Hydrogen Value Chain and Open-access Network for Flanders. Not published.
[29] Trinomics (2022). Promotion of Hydrogen Value Chain and Open-access Network for Flanders. Not published.
[30] Eurostat (2023). Energy statistics - an overview.
[31] Trinomics (2022). Promotion of Hydrogen Value Chain and Open-access Network for Flanders. Not published.
[32] JRC (2022). The role of hydrogen in energy decarbonization scenarios.
[33] Hydrogen Europe (2022). Clean Hydrogen Monitor 2022.

Figure 2-1 Estimated hydrogen demand per country per end-use application in Europe, end 2020.



Source: Fuel Cells and Hydrogen Observatory (2022). Hydrogen demand.

Hydrogen consumption in the Netherlands is centred around three sectors: refining, ammonia production and chemical processes, accounting for 88% of the demand in 2020 (as shown in the figure). These industrial sectors have an international focus; most of their products are exported. Hence, even though the Netherlands consumes relatively large hydrogen volumes, it does so to manufacture products for the global market.

2.3 Potential future (renewable) hydrogen use in Europe

The most promising use cases for renewable (and low-carbon) hydrogen are in hard-to-abate sectors: specific industrial processes and heavy-duty transport where electrification is not feasible. As mentioned in 2.1, the production of hydrogen contains conversion losses and the production of hydrogen derivatives even more so. For that reason, other options (i.e., electrification) are often more efficient, both from an energetic as well as an economic perspective. As a result, the use case for renewable hydrogen is most robust in processes where alternatives are absent. There may be other (more niche) use cases, such as electricity generation during peak demand hours with limited renewable energy-based production. The use of hydrogen in individual commercial and residential buildings is not evident; other alternatives are more energy and cost-efficient.

For hydrogen to play a role in decarbonising the energy system, it must be produced without (substantial) GHG emissions. Box 1 provides an overview of the different production methods considered, commonly referred to as the different colours of hydrogen.

Box 1 Different types of hydrogen production

Hydrogen can be differentiated based on its production method and therefore its environmental footprint. In the energy industry jargon, different colours have been assigned. '**Brown**' or '**black**' hydrogen is produced from coal via gasification. This process is the most polluting method for hydrogen production with a 19 Mt CO_2/ MtH_2 emission factor. If hydrogen is produced from natural gas or oil without capturing the resulting GHG emissions, then the output is called '**grey**' hydrogen. If a form of carbon capture is applied preventing the CO_2 byproduct from entering the atmosphere, the emissions can be reduced from 10 $MtCO_2$/ MtH_2 to less than 1 $MtCO_2$/ MtH_2, and the resulting hydrogen is coloured '**blue**'. 'Grey' hydrogen is currently the most prevalent type of hydrogen in industrial utilisation. Pyrolysis is an energy-intensive process that makes it possible to split natural gas into gaseous hydrogen and solid carbon – meaning no GHG emissions into the atmosphere, therefore the first completely carbon-neutral hydrogen production method discussed here – resulting in '**turquoise**' hydrogen. The energy demand of this process, however, makes turquoise hydrogen a non-competitive alternative to grey, blue and any other, fossil-free hydrogen.

Hydrogen produced from water via electrolysis is classified based on the electricity used. If the electricity comes from the grid and is from both fossil and non-fossil origin, the resulting hydrogen is 'yellow'. If the electricity used in the electrolysis process comes from nuclear power plants, the resulting hydrogen is '**pink**', whereas if the electricity used comes from renewable energy sources, the resulting hydrogen is '**green**'. The carbon-neutral/low-carbon hydrogen production options are of particular interest to the decision-makers since these options provide alternatives for the future energy sector.

The EC adopted the Delegated Acts in February 2023, classifying hydrogen as renewable and non-renewable hydrogen — for both imported and of domestic origin — replacing the colour coding with official terminology. The new terminology labels hydrogen exclusively from renewable sources as 'renewable' hydrogen, whereas all hydrogen resulting from a production method with at least 70% less emissions than the use of natural gas across its full life cycle is labelled 'low-carbon' hydrogen. 'Green' hydrogen is therefore '**renewable**' hydrogen in the EC terminology, whereas 'blue' and 'pink' hydrogens are '**low-carbon**' hydrogen.

Box 2 Hydrogen and hydrogen derivatives (RFNBOs)

In the EU Renewable Energy Directive (2018 recast) RFNBOs are defined as liquid or gaseous fuels with an energy content derived from renewable but not biomass sources. Hydrogen and its derivatives are examples of RFNBOs (renewable liquid and gaseous fuels of non-biological origin). Hydrogen itself is complicated and expensive to store and transport in its pure form; it requires either high-pressure vessels, cryogenic tanks or dedicated pipelines. Hydrogen derivatives can be an attractive alternative, as they allow for the storing of hydrogen in the form of other molecules and are cheaper and easier to transport. Hydrogen derivatives include electro(e-)methanol, e-methane, e-ammonia, etc. The REPowerEU plan foresees half of the future hydrogen demand of the EU to be met via imports, and the hydrogen strategy of the Netherlands expects the country to play a major role as a hub for import and transport of hydrogen (and derivatives) to the rest of the continent.

The extent to which the different RFNBOs will be used in the medium to long term is uncertain. Yet, accommodating different RFNBOs requires appropriate policy decisions. Despite some concerns related to the toxicity and corrosiveness of ammonia, and the lack of experience using it as fuel for combustion engines – experts suggest that the future vector for hard-to-abate sectors might be ammonia rather than hydrogen.[34] Adapting to this scenario requires specific infrastructural investment decisions – i.e., import terminals and large-scale ammonia cracking plants, allowing to integrate the ammonia import into the hydrogen supply chain.

2.4 Hydrogen strategies and targets in the Netherlands

National hydrogen strategies and policies in the Netherlands

Hydrogen plans and strategies develop at a fast pace. In this section, we introduce the most relevant *existing* hydrogen policies in the Netherlands:

- **The Netherlands' Hydrogen Strategy (2020)** was the first dedicated Dutch hydrogen policy announcement. It states that a fully sustainable, flexible and affordable Dutch energy system will continue to rely on gaseous energy carriers in the future based on technological and economic arguments, thereby paving the way for hydrogen (derivatives).[35] According to the strategy, hydrogen will play a role in the decarbonisation of the industry and heavy-duty transport, as well as for energy storage, expecting that gaseous energy carriers (biogas and renewable hydrogen) will provide at least 30% of the final energy consumption by 2050. In this strategy, the role of low-carbon hydrogen is notably not detailed, despite its potential (transitional) role. The development of an international, Northwest European hydrogen market is deemed a crucial prerequisite for the competitiveness of the future economy, due to foreseen cost savings. Therefore, the strategy

[34] DNV (2022). Maritime forecast to 2050.
[35] Government of the Netherlands (2020). Government strategy on hydrogen.

proposes aligning regulation and decision-making among Northwest European governments. The strategy envisions a central role for the Netherlands as a distribution hub in the global hydrogen supply chain. Lastly, relying mainly on the offshore wind energy potential, a domestic hydrogen production capacity of 3-4 GW should be realised by 2030.

- **The Dutch Climate fund (under development)** aims to contribute to GHG emission reduction with a reserved budget of € 35 bn for 10 years. Indicatively, its resources are allocated to six categories: nuclear energy, carbon neutral gas plants, energy infrastructure, early phase development, sustainability of industry and innovation of SMEs and sustainability of the built environment.[36] The lion's share of the total budget (€ 15 bn) is allocated to the early phase development category, including the development of renewable energy carriers, such as renewable hydrogen. About € 9 bn is reserved for hydrogen-related developments.
- **The (draft) national plan energy system** shows the vision of the Dutch energy system in 2050, and the transition towards this. As such, it addresses the role of electricity, hydrogen, carbon and heat. With regards to hydrogen, the plan envisions hydrogen as a system role by 2050 and is used in both industry and (international) mobility. It advocates for a strong push for renewable hydrogen production, imports and storage. To realise this strong push of hydrogen production via electrolysis, a substantial increase in electricity production is required which will mainly be achieved by wind, solar and nuclear energy. The National plan foresees a major role for renewable hydrogen in the energy-intensive industry. Next to this, hydrogen is expected to be used for flexible electricity production during periods of low renewable energy supply and in the (international) shipping and aviation industry. However, it stresses that the hydrogen supply chain and its market are still in their early stages of development. This results in high uncertainties on international market conditions, prices, demand trends and competitiveness. To push for the transition, the plan envisions an important transition role for low-carbon hydrogen.[37]

Box 3 Hydrogen imports initiatives

Hydrogen can be imported directly in gaseous form via pipelines or in liquid form via ships or as a liquid derivative in the form of ammonia, methanol or liquid organic hydrogen carriers. The Netherlands actively seeks import policies too. In the long run, the Dutch government foresees to both import hydrogen (derivatives) and produce renewable hydrogen domestically (e.g., stated in the draft national plan energy system). Hence, the Dutch government also engages in various import-related policies. Regarding the development of trade (relations), deals are made in the form of Letters of Intent (LOI), Memorandums of Understanding (MoU), energy partnerships and/or trail shipments. The Dutch government developed bilateral trade agreements and MOUs with a broad group of countries for RFNBO imports already. As of June 2023, the Netherlands developed bilateral trade agreements and MOUs with Denmark, Indonesia, Japan, Saudi Arabia, Spain, United Arab Emirates, the United States of America, Norway, Namibia, Chile, South Africa, Canada, Uruguay, Oman, Morocco, Iceland, Portugal and Australia.[38]

Hydrogen targets relevant for the Netherlands

The following hydrogen-related goals are relevant for the Netherlands and this study.

[36] PBL (2023). Reflectie op voorstellen voor de inzet van middelen uit het Klimaatfonds.
[37] Ministry of Economic Affairs and Climate (2023). Nationaal plan energiesysteem Concept.
[38] National Hydrogen Program (2023). Internationale samenwerking

1. **Production goal**: 4 GW domestic hydrogen production capacity with electrolysers by 2030, and an ambition of 8 GW of electrolyser capacity in 2032, based on the 2030 goal set in the Climate Agreement and the elevated 2032 ambition set by the Dutch government in late 2022[39].
2. **Consumption goal in industry (industry goal):** 42% of the total hydrogen consumption in industry (defined as RFNBOs divided by total hydrogen usage excluding RFNBOs) for final energy use and non-energy purposes in 2030 should consist of RFNBOs, based on article 22a of the recast RED-III; and
3. **Consumption goal for mobility (transport goal):** 1% of final energy consumption in the transport sector in 2030 should consist of RFNBOs, also based on the recast RED-III.

[39] Rijksoverheid (n.d.). Stimulering gebruik van waterstof.

3 Assessed policy instruments & policy mixes

The Dutch Ministry of Economic Affairs and Climate Policy (EZK) considers three types of policy instruments, which should contribute to the aforementioned hydrogen targets:

1. A renewable hydrogen **consumption obligation** for (existing/potential) industrial hydrogen users;
2. A renewable hydrogen **consumption subsidy** for (existing/potential) industrial hydrogen users; and
3. A renewable hydrogen **production subsidy** for (potential) hydrogen producers.

EZK developed four policy mixes, combining different variations of the three instruments. These mixes are assessed in the main body of this report. In the sensitivity analyses, small changes within policy mixes (and other sensitivities) are tested. This chapter provides more information on the policy mixes. Section 3.1 details the individual policy instruments. Section 3.2 explores the potential effects when combinations of the three policies are used, as is the case in the policy mixes. In section 3.3, the criteria are presented, which are used in the assessment of policy mixes.

3.1 Individual policy options

3.1.1 *Industrial RFNBO consumption obligation*

The industrial RFNBO consumption obligation would require (existing and new) industrial hydrogen users to use a certain amount of RFNBOs as a share of their total hydrogen consumption. The implementation of the obligation is illustrated in Figure 3-1, and summarised below: [40]

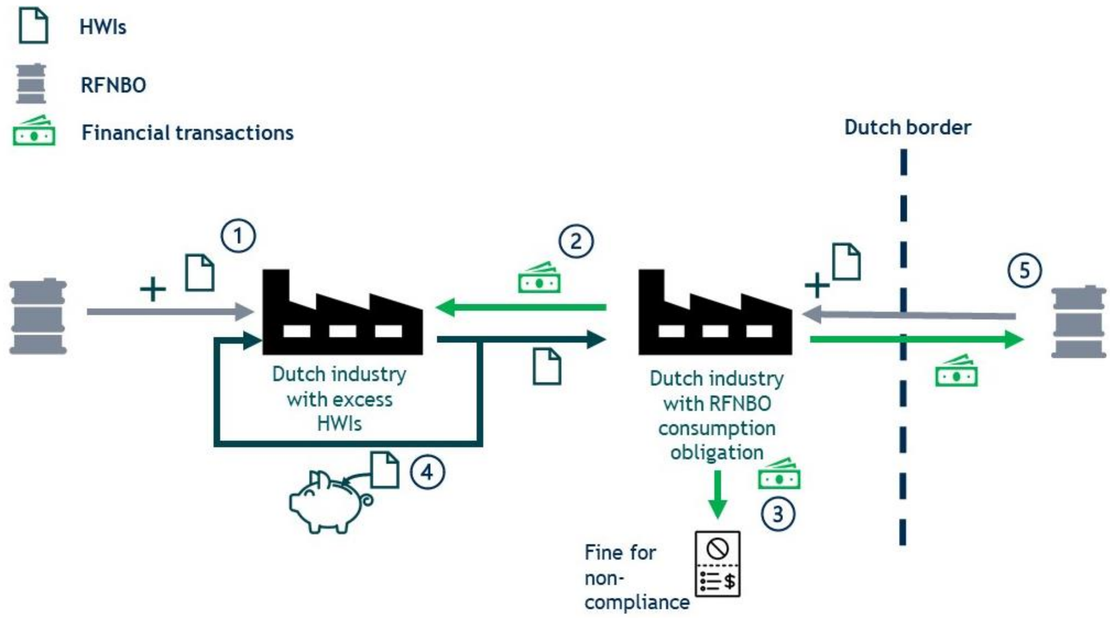
- When industrial companies use RFNBOs, they can register the amount and receive renewable hydrogen units for industry (HWIs; acronym for the Dutch denomination[41]). One unit of RFNBO (e.g., GJ or MWh) accounts for one HWI (visualised with #1 in Figure 3-1).
- Each year, hydrogen users must have y number of HWIs in their account, where:

$$y = x\% * total\ hydrogen\ consumption$$

- If users have insufficient HWIs in their account, they must purchase HWIs from others via a register (visualised with #2 in Figure 3-1), or pay a fine for non-compliance (visualised with #3 in Figure 3-1). If users possess more HWIs than required to meet their obligation y, they can bank them for future use (visualised with #4 in Figure 3-1) or sell them to other users.

[40] The HWI system is still under development; the implemented system may deviate from the system described here. We describe what assumptions we have used in our analysis, based on the information available at the start of this project.
[41] HWI: Renewable hydrogen units for industry *(Hernieuwbare Waterstofeenheden voor Industrie)*

Figure 3-1 Simplified overview of the consumption obligation and HWIs for the Dutch industry



This obligation is based on article 22a of the recast Renewable Energy Directive (RED-III), which sets a target for the use of RFNBOs in industry and therefore mandates EU Member States to ensure that 42% of their industry's total hydrogen consumption is based on RFNBOs by 2030.

The consumption obligation directly contributes to hydrogen target 2 (consumption goal in industry) and indirectly to hydrogen target 1 (production goal). The contribution to target 1 is indirect, as RFNBO consumption can either be based on domestically produced RFNBOs or imported RFNBOs (visualised with #5 in Figure 3-1). The obligation results in an increased willingness to pay for RFNBOs by the concerned industrial companies, as they would face a penalty if they do not fulfil their compliance obligation. Theoretically, the contribution to both targets increases when the obligation becomes more strict (higher target).

The impacts of an industry consumption obligation are in more detail presented in Annex I section I.1. This annex presents the effects of this policy instrument on the production and consumption goals as part of the Dutch hydrogen strategy and provides indications on the expected (price) developments of the HWIs.

3.1.2 Demand subsidy for RFNBOs

RFNBO demand subsidies provide an incentive to use RFNBOs in industry. As such, they directly contribute to target 2 and indirectly to target 1. Similar to the consumption obligation, demand subsidies directly affect the demand for renewable hydrogen in industry (though not as strict as a consumption obligation). Through this increased demand for renewable hydrogen, demand subsidies can contribute to domestic renewable hydrogen production capacities, though imported hydrogen may also be used.

There are different ways to design a demand subsidy, for instance: as a capex subsidy, opex subsidy or a combination of these. For the opex subsidy, potential forms include a premium, a single-sided CfD and a double-sided CfD. The next section first explains the designs for capex or opex based subsidies, after which the opex subsidy design option selected for this study (by the Ministry of Economic Affairs and Climate Policy) is detailed.

Capex demand subsidy

Capital expenditures (capex) subsidies can be used to cover part of the investment costs required to switch to RFNBOs based processes. Existing users can use this subsidy to convert their installations from using captive hydrogen (locally produced for internal use) to merchant hydrogen (produced on-site or in a remote production plant and sold to the user). This could be renewable or non-renewable merchant hydrogen, since there is no chemical difference between different types of hydrogen. Likewise, it can be used by new hydrogen users to cover the additional capex for a hydrogen-based process compared to a natural gas or oil-based process. Therefore, the capex subsidy would incentivise the use of hydrogen in general (not RFNBOs specifically).[42]

Opex demand subsidy

An opex demand subsidy covers the costs of using renewable hydrogen or other RFNBOs instead of (fossil-based) energy carriers. Therefore, the amount of subsidy depends on the amount of RFNBOs consumed. Consumers of RFNBOs are obligated to periodically report their actual RFNBOs consumptions in order to receive the opex subsidy.

An opex demand subsidy increases the price that a consumer is willing to pay for RFNBOs and/or lowers the procurement costs of RFNBOs, depending on the availability of RFNBOs:

- When the availability is limited, the opex subsidy increases the willingness of consumers to pay, thereby improving the business case for production. In the early stages, the availability of RFNBOs will be limited and their price will mainly be determined by (long-term) bilateral contracts between consumers and producers.
- In a situation with sufficient RFNBOs' availability, the opex subsidy serves as a discount on the market price. When the market for RFNBOs will have matured and the availability of RFNBOs will have increased, the price for RFNBOs will be determined through supply and demand of multiple market participants. An opex based RFNBO demand subsidy would hence serve as a discount on the market price for RFNBOs.

The opex based subsidy modelled in this study as a fixed premium. A single-sided CfD or a double-sided CfD are other suitable implementation methods and are described in Annex 0. These other methods have not been assessed in this report as they are not part of the policy mixes selected for the modelling. A fixed premium is a predetermined amount of subsidy granted to consumers to increase their willingness to pay.

[42] The capex subsidy could be designed in such a way that the consumption obligation for RFNBO is considered. If this condition is not met, the capex subsidy would have to be repaid. This would increase the complexity of this instrument with monitoring and reporting requirements, and mechanisms to enforce repayment.

The premium is predetermined and hence independent of the prices of fossil hydrogen and of RFNBOs.[43] In principle, the fixed premium is also granted for the consumption of self-produced RFNBO and is granted in the form of x €/kg RFNBO consumed, or x €/GWh if the RFNBO consumed is used for energy purposes.

3.1.3 Renewable hydrogen production subsidy

A production subsidy provides support to the (domestic) production of renewable hydrogen. Hence, it directly contributes to target 1, and indirectly to targets 2 and 3. Production subsidies directly improve the business case for domestic renewable hydrogen production. As such, they would also increase the availability of renewable hydrogen, thereby lowering the price and encouraging hydrogen use in both the industry and transport sectors. The production subsidy can be implemented in the form of a capex or opex based subsidy. Also, for the production subsidy, the potential forms of the opex subsidy include a premium, a single-sided CfD and a double-sided CfD. In this subsection, the design of these subsidy forms is explained and the selected form of the opex subsidy is detailed.

Design of production subsidy

A production subsidy can be in the form of a capex subsidy, an opex subsidy or a combination of both.

- Capex production subsidy: A capex production subsidy subsidises (part of) the investment costs required to build the electrolyser.
- Opex production subsidy: An opex production subsidy is based on the operating costs of the electrolysers, i.e., subsidy based on total renewable hydrogen produced.

The key difference is that a capex production subsidy is provided upfront, whereas an opex production subsidy depends on the total renewable hydrogen produced. Furthermore, a capex subsidy in principle does not exclusively incentivises the production of renewable hydrogen, but it may lead to more production of non-renewable electricity-based hydrogen.[44]

The opex subsidy investigated in this study takes the form of a single-sided Contract for Difference. A fixed premium or a double-sided CfD are other suitable implementation instruments, but they have not been assessed in this report as they are not part of the policy mixes modelled. Additional information on these other implementation methods can be found in Annex I.3. A CfD mitigates the market risks experienced by (potential new) producing companies of RFNBOs by paying them the difference between a predetermined reference price, which reflects fossil hydrogen, and a 'strike price' set at a value required for RFNBO production to be viable. The production costs of RFNBOs minus the market price of fossil hydrogen and its ETS costs are set as a maximum opex subsidy level. In a market situation in which the reference price (the price of fossil hydrogen) is lower than the strike price (set value for RFNBO production to be viable), the RFNBO supplier is paid the difference between the reference price and the strike price. This means that the supplier of RFNBO is granted the difference in price between fossil hydrogen and viable

[43] The fixed premium could be a short-term or long-term contract between the government and the RFNBO consumers. Short-term contracts would allow the demand subsidy to adjust quicker to new market developments but could make it more difficult for RFNBO consumers to establish long-term supply contracts with RFNBO producers. Long-term contracts provide more certainty to the RFNBO consumers who are unable to accommodate changes in fossil hydrogen and RFNBOs. The modelling uses a long-term fixed premium in the scenarios with an opex demand subsidy.

[44] The capex subsidy could be designed in such a way that only production of renewable hydrogen is allowed. If this condition is not met, the capex subsidy would have to be repaid. This would increase the complexity of this instrument with monitoring and reporting requirements, and mechanisms to enforce repayment.

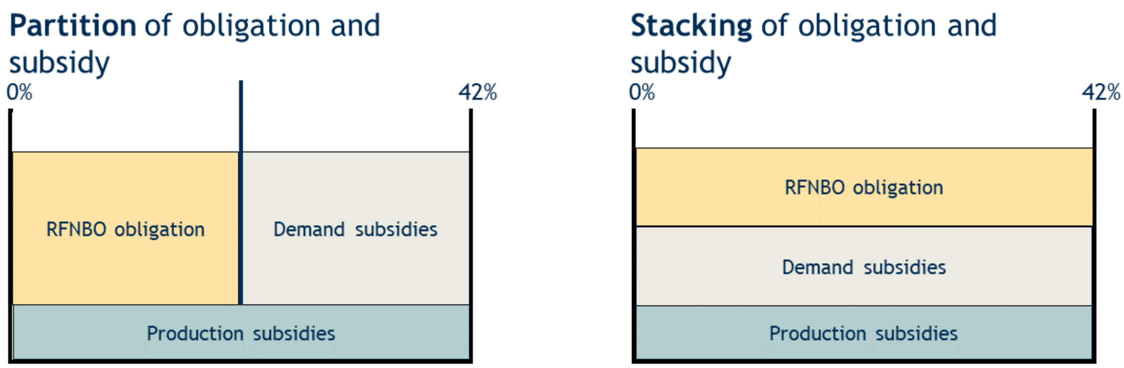
RFNBO production. In this way, the RFNBO producer receives a guaranteed minimum price for the duration of the CfD. Since subsidies are only paid when there's a difference between the strike price and the market reference price, no subsidies are granted if factors, such as the oil price, suddenly make RFNBO competitive with fossil hydrogen.

3.1.4 *Interactions when combining individual policy options*

Partition vs. stacking

The industrial RFNBO consumption obligation and demand subsidy are combined in two ways; either by using a partition of the obligation and the subsidies, or by 'stacking' the policy options (as shown in Table 3-1). Partition and stacking of the obligation and subsidies are visualised in Figure 3-2. The percentage of the RFNBO obligation that is reached is shown on the X-axis while the Y-axis shows the additional costs of using RFNBO compared to consuming fossil hydrogen.

Figure 3-2 Visualisation of implementation options combining consumption obligation and demand subsidies



The two implementation options differ in whether they allow RFNBO consumptions for which demand subsidy has been obtained to be used for meeting the industrial RFNBO consumption obligation:

- Under the partition option, RFNBO consumption for which demand subsidy has been obtained, cannot be used for the consumption obligation and vice versa. Thus, if a company uses the demand subsidy to buy RFNBO, this RFNBO cannot be used to earn HWIs, which are needed to fulfil the company's RFNBO consumption obligation. The RFNBO consumption obligation and demand subsidy work as two separate instruments to incentivise consumption of different tonnes of RFNBO. This means that the company's RFNBO consumption obligation can be set at a lower level than the national consumption goal for industry to still be able to meet that goal.
- Under the stacking option, a company that uses the demand subsidy to buy and consume RFNBOs can earn HWIs for these RFNBOs. Thus, the demand subsidy and RFNBO obligation work together to incentivise the consumption of the same tonne of RFNBO. The company's RFNBO consumption obligation will have to be set at the same level as the industry goal to ensure that goal is met.

Industrial RFNBO consumption obligation and renewable hydrogen production subsidy

Combining the consumption obligation with renewable hydrogen production subsidy is implemented by setting a cap on obtaining HWIs. This cap ensures that HWIs can only be obtained when a project has not obtained subsidies beyond a certain cap in order to lower risks of over-subsidy. RFNBOs produced by electrolysers that received more subsidy than this cap cannot be used to generate HWIs.

By setting this cap for obtaining HWIs, consumers of RFNBOs will receive HWIs until the moment that producers reach the subsidy limit. When reaching this point, the producers can then choose to either 1) continue to receive production subsidy for their production, for which there will be lower demand as consumers of these RFNBOs will not earn HWIs or 2) stop the production subsidy so that their RFNBOs can still earn HWIs upon consumption and be used for the consumption obligation. RFNBOs that cannot be used to earn HWIs and therefore not eligible for meeting the consumption obligation will sell at a lower price than RFBNOs eligible for the consumption obligation, creating two markets for RFNBOs in the Netherlands. The lower price for non-eligible RFNBOs could provide a stronger incentivise for exporting RFNBOs if producers could sell these non-eligible RFNBOs against a higher price abroad where such subsidy restrictions are not in place.

3.2 Policy mixes selected for assessment in this study

The impact of the different policy mixes is estimated by considering each policy mix as a separate scenario. We consider four policy mixes (summarised in Table 3-1):

- **Policy mix 1 - Balanced subsidy distribution with high obligation.** The consumption obligation is set at **42%** in 2030. Companies can use the demand subsidies (granted in the form capex and opex, € 2 bn budgeted) to fulfil their own consumption obligation (**stacking** of demand subsidy and consumption obligation). € 3 bn is budgeted for production subsidies, granted in both capex and opex form.
- **Policy mix 2 - Focus on electrolysis and RED-goal with high obligation**. **Only capex based subsidies are granted for demand** (€ 1 bn budgeted). The consumption obligation is set at **42%** in 2030. For production, both capex and opex based subsidies are granted (€ 4 bn budgeted). Because no opex based subsidy is granted for demand, there's **no interaction between the consumption obligation and the demand subsidies**.
- **Policy mix 3 - Focus on electrolysis and conservation of industry with lower obligation**. This policy mix is almost the same as policy mix 4, with the only difference being that it has a lower consumption obligation of **24%** in 2030 (slightly more than half of target set in recast RED).
- **Policy mix 4 - Focus on RED-goal and conservation of industry with lower obligation.** The consumption obligation is set at **24%** in 2030 (slightly more than half of target set in recast RED). However, in this policy mix, a **partition** is in place as the **demand subsidy cannot be used by companies to fulfil their own consumption obligation**.

In the modelling exercise, some policies are not included in the baseline, nor in the policy mixes. These include the IPCEI, SDE++, DEI+, VEKI and the refinery route.

Table 3-1 Policy mixes selected by EZK for further assessment

Policy Mix	Consumption obligation in 2030	Demand subsidy	Production subsidy	Combination of consumption obligation & demand subsidy
1: Balanced subsidy distribution with high obligation	42%	capex+ opex (€ 2 bn)	capex+ opex (€ 3 bn)	**Stacking** of demand subsidy and consumption obligation to reach industry target
2: Focus on electrolysis & RED-goal with high obligation	42%	capex only (€ 1 bn)	capex+ opex (€ 4 bn)	**Irrelevant**, no opex based subsidy granted for demand
3: Focus on electrolysis and preserving industry with lower obligation	24%	capex only (€ 1 bn)	capex+ opex (€ 4 bn)	**Irrelevant**, no opex based subsidy granted for demand
B: Focus on RED-goal & preserving industry with lower obligation	24%	capex+ opex (€ 4 bn)	capex+ opex (€ 1 bn)	**Partition** of demand subsidy and consumption obligation to reach industry target

3.3 Criteria for assessment

The four policy mixes described in the previous section have been assessed using the following criteria:

1. **Effectiveness of achieving the production goal**: As mentioned in previous sections, one of the three primary goals central to the Dutch hydrogen policy, is to have 4 GW domestic hydrogen production capacity with electrolysers by 2030, and an aspirational goal of 8 GW of electrolyser capacity by 2032.
2. **Effectiveness of achieving the industry goal**: As a second goal central to the Dutch hydrogen policy, 42% of the Dutch total hydrogen consumption (hydrogen derivatives are not included) in industry for final energy use and non-energy purposes needs to be fulfilled by RFNBO.
3. **Risk of displacing other decarbonisation options:** When policy instruments are in place to stimulate the uptake of a specific decarbonisation option (in this case the uptake of RFNBO consumption and production), this stimulated decarbonisation option becomes more attractive than other, often competing, decarbonisation options (e.g., electrification or CCS). The other options become less attractive and may be displaced by the supported option. Ideally, a policy instrument should be technology neutral to avoid competition distortion between different decarbonisation options.
4. **Risk of competitiveness loss and carbon leakage of Dutch industry:** National policy instruments influence the competitiveness of the local industry. When policy instruments have a negative effect on the competitiveness of the national industry, the country becomes less attractive for existing and new businesses. Any carbon related policy that leads to higher production costs for national industries, can in the short-term lead to lower production levels, and in the medium term to displacement of industrial production activities to countries where their carbon and hence production costs are lower.

5. **Risk of other undesired effects:** When implementing policies, undesired effects can occur. These effects are unintentional, could be hard to avoid and can occur in several forms:
    a. **Over-subsidising / societal costs:** When companies receive more subsidy than strictly required to bridge the cost gap between fossil /low-carbon hydrogen and RFNBO, they are over-subsidised. Over-subsidising should be avoided as results in unnecessary costs to society (i.e., the government giving more subsidies to companies than necessary to incentivise the desired behaviour). By linking the subsidy amount to factors that determine the price gap between fossil/low-carbon hydrogen and RFNBO (e.g., using a variable premium using CfDs), the risk of over-subsidy can be minimised.
    b. **Gaming:** This is also known as anti-competitive behaviour. This occurs when companies (either jointly or unilaterally) act to abuse or maintain a dominant position, negatively impacting competition or increasing the costs of national policies.
6. **Investment certainty:** Investment certainty is dependent on the regulatory framework and market risks. Investment certainty affects the likelihood and speed of a final investment decision. Investment certainty needs in this case to be assessed from both the producers' view as well as the industrial consumers' view.
7. **Administrative complexity:** This refers to the ease of implementing and complying with a policy instrument. When policy instruments require a lot of tracking of information and/or involve complex policy mechanisms, more time and resources are required to effectively implement the instruments. Depending on the policy mix, this includes monitoring and reporting on RFNBOs consumed or produced, setting up and maintaining a register for HWIs, developing, and conducting tenders for subsidy instruments, and providing guidance to companies. Generally, the more types of instruments or tracking of information required, the higher the administrative complexity.
8. **Coherence with other relevant policy instruments:** This refers to whether introducing the hydrogen policy mix is complementary to existing (hydrogen-related) policies and addresses an existing policy gap or strengthens the effects of existing policies or overlaps these policies with potentially undesired effects. A policy gap is, e.g., the current absence of policies to incentivise the consumption of RFNBOs. Examples of undesired impacts due to overlap with existing policy instruments are risks of double / over-subsidy.
9. **Strategic autonomy:** This assesses the extent to which the Dutch industrial consumers are incentivised through the policy instruments to use domestically produced RFNBOs rather than importing RFNBOs. Policy mixes with a limited or no direct incentive for using domestically produced RFNBOs may direct investments to the import infrastructure at the expense of infrastructure for domestic production, making the Netherlands more dependent on imports.

4 Our quantitative research method

4.1 Modelling philosophy

Quo Mare's Transition of Dutch Energy System (TDES) model is used as one of the key tools to answer the research questions in this study. TDES has been designed to better understand the energy dimensions, connections and dependencies within our economy and to support informed decision-making. TDES simulates different potential transition pathways to transform the current energy system towards a (net) zero-carbon energy system in 2050 under different constraints and assumptions. In other words, TDES identifies the economically most efficient transition pathway for a given set of conditions.

TDES covers the entire Dutch economy and energy system, with a specific focus on industry. For an energy system optimisation model to properly function, all (potential) energy supply (including domestic production, import and export), conversion and consumption within that particular system must be considered. As such, TDES covers all (energy consuming) sectors, including industry, agriculture, transport and the tertiary and residential sectors (e.g., energy consumption by households and in offices). While all energy consumption must be considered, it is not required to cover each sector with the same level of granularity. TDES focuses on industry; hence it provides a more detailed level of granularity for this sector.

TDES optimises transition pathways for a given set of policies (e.g., ETS), availability of resources (e.g., electricity and molecules) and fixed final demand volumes for products and services (e.g., steel). TDES identifies the techno-economic optimal pathway starting with the current and (assumed) future energy **resource availability**. Using these (processed) resources, various sectors can manufacture different **(intermediate) products**. These energy products are then used to meet **final demand volumes** for the manufacturing of products and services, such as steel or fertilisers and transport services. We note that the total energy demand is not fixed in the model: energy consumption in industry can vary, depending on how the demand for different products and services is met. Final energy demand for agriculture and households is fixed, for simplicity reasons. This implies that final demand volumes can be met in different ways. For instance, regarding transport, TDES assumes that a certain total amount of kilometres driven by passenger vehicles must be met, without making explicit assumptions on the share of internal combustion engine and electric vehicles; TDES is technology neutral. In other words: TDES finds the most efficient transition pathway, assuming that the final demand for products and services remains constant.[45] Also, the amounts of exported products and services remain fixed, illustrating the situation that the Netherlands will continue to export goods and services to the global market.

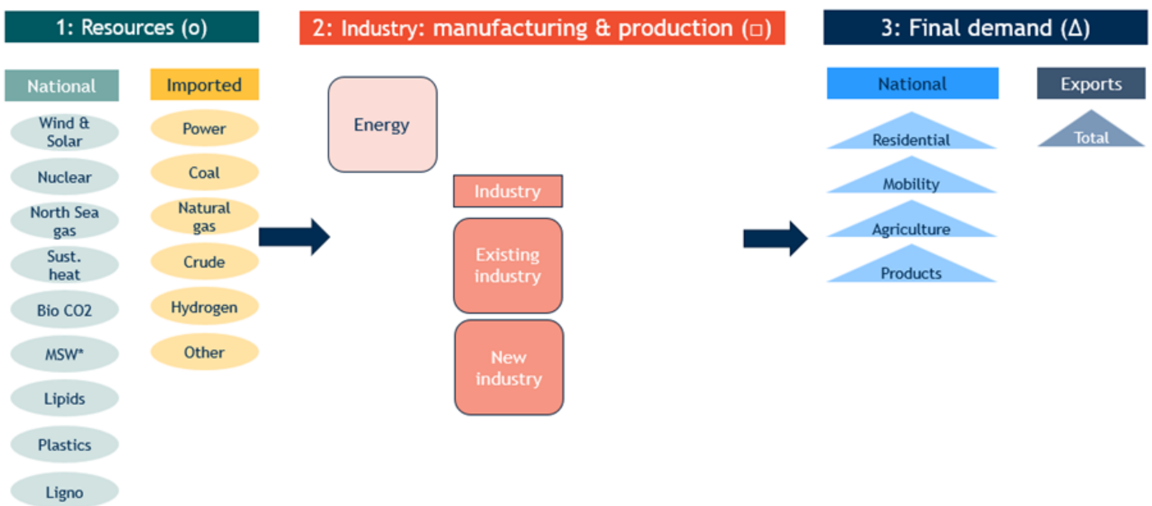
TDES generates a transition path, which means that it provides outputs for each year between 2020 and 2050, covering both existing and new industrial activities. TDES is a multiperiod optimisation model, covering each year between 2020 and 2050. Each year, the final demand volumes are met using the available resources. Each year, energy resource availability, costs for energy resources/products and

[45] There are arguments to assume fluctuating demand volumes. For instance, population growth (or growing income per capita) could lead to higher final demand volumes (e.g., the demand for transport services). However, lower consumption levels for certain products could also lead to lower demand volumes. TDES does not consider either and fixes the final demand volumes.

available technologies differ. These differences drive the energy transitions in the model. The way in which final demand volumes for products/services are met can be different each year. In 2020 for instance, most of the demand for passenger transport is met using (fossil) fuels. However, in later years, different resources and intermediate products will be used to meet the demand for passenger transport, replacing a certain share of the fossil fuels. In TDES, this can result from e.g., increased costs for fossil fuel and/or changing costs for electricity production. Even though each year can be shown separately, investment decisions are assessed using on a multiyear assessment of the business case in TDES.

Figure 4-1 provides a high-level overview of major components in TDES. This is a simplified picture as there are many subcomponents within each component shown. In the left column, the resources considered in TDES are shown, being nationally produced power (i.e., wind, solar, nuclear energy, gas, biomass, and coal), heat and molecules; and imports (of e.g., crude oil, natural gas, hydrogen, and other vectors). TDES also considers resources that are not available yet but will become available before 2050 (e.g., bio-CO_2/CCU). The right column shows the final demand components: demand for mobility, for products, for exported products and services and, agricultural and residential energy demand. In the centre, different industries are shown, which are described in more detail below.

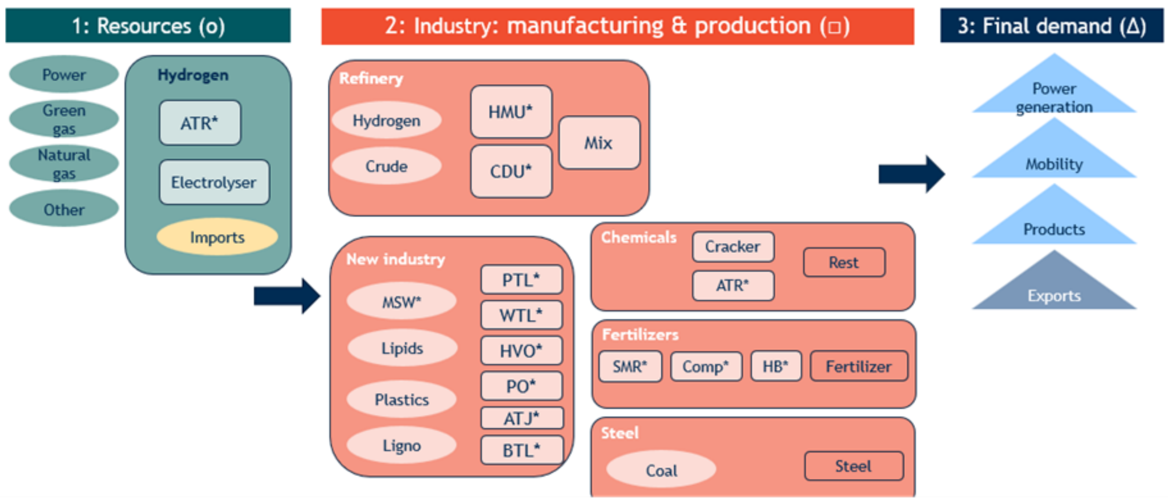
Figure 4-1 High-level overview of components in TDES model



* *MSW: Municipal solid waste*

Figure 4-2 zooms in on the central part of the model, the industry. On the left, it shows the resources. For hydrogen, some additional details are provided in the figure, such as hydrogen imports as a source, along with possible future national hydrogen production technologies (electrolysis and autothermal reforming). Two types of hydrogen are considered: hydrogen produced with electrolysis and low-carbon hydrogen. It also shows three industry blocks: refineries (which currently use hydrogen), new industry, and other (potential) hydrogen users, being fertiliser producers, the chemical sector, and the steel sector. On the right, the most relevant final demand blocks are shown.

Figure 4-2 High-level of industry component within TDES



* *ATR: Autothermal reforming, HMU: Hydrogen manufacturing unit, CDU: Crude distillation unit, PTL: Power to liquid, WTL: Waste to liquid, HVO: Hydrotreated vegetable oil, PO: Pyrolysis, ATJ: Alcohol to jet fuel, BTL: Biomass to liquid, SMR: Steam methane reduction, Comp: (hydrogen) compressor, HB: Haber-Bosch unit.*

TDES relies on publicly available input data whenever possible. In the absence of reliable publicly available data, or when there are strong reasons to deviate from public sources, input from experts can be used. Model inputs and assumptions are frequently updated, based on the latest (public) information available. For this research specifically, the most important source used for the input data is the TSO and DSO study II3050.[46]

4.2 Baseline scenario & inputs

The baseline simulates the economically most efficient transition pathway in the current regulatory and market framework and in the absence of new policies. As such, it serves as the basis for this research; any modelling scenario with new proposed policy mixes will be compared against the baseline to estimate the impact. In this section, we provide the most relevant assumptions that were made for the baseline, including (fixed) final demand volumes for products/services, energy resources availability per year, and resource/product costs per year.

In this research, final demand volumes are kept constant over time, including non-industrial energy demand, as well as the demand for certain products, services and exports (e.g., transport services and industrial products). Table 4-1 shows all (high-level) final demand volumes that were used. Note that residential heat demand can also be met by electricity, and that different resources and technologies can be used to meet e.g., the final transport demand.

[46] For a summary (in Dutch), please refer to Netbeheer Nederland (2023). *Het energiesysteem van de toekomst: de II3050-scenario's.*

Table 4-1 Fixed final demand volumes in baseline between 2020 and 2050

Group	Product/Service	Value	Unit	Source / comments
Residential energy	Heat demand	128	TWh	EBN (2020). Energy in numbers.
	Electricity demand	57	TWh	EBN (2020). Energy in numbers.
Agriculture	Heat Demand	30	TWh	EBN (2020). Energy in numbers.
	Electricity demand	10	TWh	EBN (2020). Energy in numbers.
Industrial products	Steel demand	7	Mton steel	Tata Steel (n.d.). Sustainability performance at our sites - Ijmuiden
	Fertiliser products (NH_3) demand	3	Mton fertiliser	PBL (2019). Decarbonisation options for the Dutch fertiliser industry
	Chemicals demand	10	Mton chemicals	PBL (2021). Decarbonisation options for large volume organic chemicals production, Sabic Geleen
Mobility	Light-duty vehicle kilometres	100	Gkm	CBS (2023). Traffic performance motor vehicles; kilometres, territory 1990-20202
	Heavy-duty vehicle kilometres	37.5	Gkm	Assumption: 1 M HDV at 40k km/year each
	Jet fuel demand*	27.8	TWh	Assumption: 2.5 Mton Jet fuel attributed to Dutch flights
	Marine fuel demand	27.8	TWh	Assumption: 2.5 Mton Marine fuel attributed to Dutch ships
	Fuels + feeds export demand	222.2	TWh	Assumption: 40% of Dutch refinery capacity (50 Mton/y) is export

** ≥14% of jet fuel is sustainable.*

In addition to the fixed demand volumes, TDES uses various constraints. Resource availabilities are an important constraint in the model. These availabilities refer to the maximum production levels (rather than expected consumption levels). Table 4-2 shows the resources constraints that have been implemented in TDES for the purposes of this research.

Table 4-2 Resource availability / constraints (i.e., no consumption forecasts).

Product	Origin	2020	2030	2050	Unit	Source / comments
Green gas*	National	30	35	45	TWh	CBS (2023). Biomassa; verbruik en energieproductie uit biomassa per techniek
Renewable power		17	137.3	378	TWh	RVO (2023). Offshore wind energy plans 2030-2050.
Plastics		0	1.3	4	Mton	RVO (2015). Sustainable biomass and bioenergy in the Netherlands
Municipal waste**		0	0.5	1.5	Mton	RVO (2015). Sustainable biomass and bioenergy in the Netherlands
Lignocelluloses		0	1	3	Mton	CBS (2023). Biomassa; verbruik en energieproductie uit biomassa per techniek
Lipids		0	2	6	Mton	CBS (2023). Biomassa; verbruik en energieproductie uit biomassa per techniek

*Notes: *North Sea gas available at 69.4 TWh per year in the period 2024-2033, unavailable in other years. ** Only covering municipal waste that can be used for waste to liquid (which is technology not yet available in 2020)*

While the baseline does not take into account the *new* hydrogen-related policy options considered in the context of this research, it does take the *existing* policies into account. These baseline policies are introduced in TDES either as constraints — for instance, if the use of a certain fossil fuel is prohibited from a certain year onwards — or as additional costs — for instance, due to carbon taxation. The most relevant existing policies and their model implications are:

1. **The European Emission Trading Scheme (EU ETS)** will force (scope 1 and 2) emissions covered under ETS to be zero by 2050. Scope 3 emissions will be restricted towards 2050 either via Court rules or via new policies. As the EU ETS will be broadened, it is assumed that EU ETS will be applicable to the entire economy (covering all sectors and households). For the new ETS sectors,

we use the same ETS price, which is introduced linearly from 0 in 2026 to the full amount in 2034 (166 €/ton in 2034). BECCS is considered; storing 1 Mton of biological CO_2 with CCS generates one ETS emission allowance.

2. **The Carbon Border Adjustment Mechanism (CBAM)** will increase the import costs of fossil hydrogen and ammonia compared to green alternatives. In addition, TDES assumes that CBAM will be extended to apply refinery products such as motor gasoline (mogas) even if it is not covered under the current CBAM scope. CBAM will be introduced linearly from 0% in 2026 to the full amount in 2034 (100%). The full amount is equal to the ETS costs corresponding to the CO_2 emissions that would have been incurred if the fossil hydrogen/ammonia/mogas were to be produced nationally using a steam methane reduction installation, a fertiliser installation, or a refinery respectively.
3. Importing **coal** and **lignocelluloses** for power generation is prohibited by 2030. Exporting[47] **non-sustainable fuels** (motor gasoline, diesel fuel, jet fuel & marine fuel) will be reduced to 0 by 2050 (linearly decreasing every year from 2035). Processing of light crudes to produce **naphtha** remains allowed after 2050.

Finally, TDES uses assumptions on costs for the different energy vectors to simulate the transition pathways. Note that this refers to the import costs (e.g., for fossil fuels) or the levelized costs of domestic production (e.g. for renewable energy) and does not contain assumptions on market prices. Table 4-3 and Table 4-4 shows the most relevant cost assumptions that have been implemented in TDES for the purpose of this research. Forecasting market prices is out of scope.

[47] Import or consumption of non-sustainable fuels is not restricted explicitly in the model, but implicitly they are restricted by ETS.

Table 4-3 Cost assumptions.

Product	Origin	2020	2030	2050	Unit	Source / comments
Natural gas	Import	14	31	15	€/MWh	II3050
Green gas	National	64	81	50	€/MWh	II3050
North Sea natural gas	National	14	14	14	€/MWh	Expert opinion
Coal	Import	7.9	8.9	6.6	€/MWh	II3050
Crude oil	Import	40.3	69.8	38.5	€/MWh	II3050
Renewable power	National	113	67	21	€/MWh	II3050
Nuclear power	National	157.3	157.3	157.3	€/MWh	Scenariostudie kernenergie 2022
Renewable Heat	National	18	5	5	€/MWh	Expert opinion
Fossil Hydrogen	Import	42.1	93	126.9	€/MWh	Natural gas costs for producing H_2 using SMR + CBAM costs + transportation costs (20 €/MWh)
Low-carbon Hydrogen	Import	95.1	122	96.7	€/MWh	Costs for fossil hydrogen + CCS costs - CBAM costs
Renewable Hydrogen	Import	233.3	164.3	95.3	€/MWh	Renewable electricity costs + capex (43.80 €/MWh) + transportation costs (20 €/MWh)
Bio CO_2	Import	250	250	250	€/ton	Expert opinion
Oxygen	National	45	45	45	€/ton	Expert opinion
Fossil Ammonia	Import	27.5	66.6	49.2	€/MWh	Natural gas costs for producing ammonia in fertiliser + CBAM costs + transportation costs (8.42 €/MWh)
Low-carbon Ammonia	Import	39.8	63	41.2	€/MWh	Costs for fossil ammonia + CCS costs - associated CBAM costs
Green Ammonia	Import	281.9	202.9	123.9	€/MWh	II-3050 (Fossil CO_2 in products remains allowed (e.g. naphtha derivatives)
Plastics	National	175	175	175	€/ton	II3050
Municipal waste	National	100	100	100	€/ton	II3050
Lignocelluloses	National	75	75	75	€/ton	II3050
Lipids	National	600	600	600	€/ton	II3050
Motor gasoline	Import	52.1	66.3	108.6	€/MWh	II3050
Sust. diesel fuel	Import	223.4	255	221.5	€/MWh	II3050
Sust. jet fuel	Import	228.8	262	226.8	€/MWh	II3050
Sust. marine fuel	Import	222.1	253	220.3	€/MWh	II3050
Sust. naphtha	Import	322	342.1	307.9	€/MWh	II3050

Notes: The above costs predictions are mostly based on II-3050. Although only giving price profiles for 2020, 2030 and 2050, this study was based on extreme cost profiles in 2022 due to the invasion of Ukraine which would cool off in the following years. To reflect this, we assume the relevant 2030 cost profiles to hold for the entire period 2022-2030. For these cost predictions, II-3050 was used in combination with expert opinions to correct for e.g., sustainability of fuels.

Table 4-4 Other relevant costs.

Variable	2020	2030	2050	Unit	Source / comments
ETS costs	25	137	251	€/ton	TNO Dec '22, corrected with the difference between predicted and actual ETS prices from '23.
CCS costs	*151.8*	*151.8*	*151.8*	*€/ton*	*Toetsing opslag CO_2 '22*
O_2 sale price	44	44	44	€/ton	Expert opinion

4.3 Key assumptions

In constructing the TDES model, various assumptions have been made. We distinguish between overarching TDES mechanisms and assumptions, and technology-specific assumptions and practical constraints. Below, we discuss the key modelling mechanisms (which have not yet been discussed in section 4.2) and the key assumptions. When relevant, we also discuss the justification for certain modelling choices and the relevant consequences. Assumptions on energy resource availability (and constraints) and costs are shown in this section.

Overarching TDES assumptions:

- Final demand volumes for products and services are fixed (and held constant over time). This also applies to final *energy* demand in the agricultural and residential sectors.
- TDES uses import costs (for fossil energy) and levelized costs of domestically produced energy, rather than market price predictions.
- Energy infrastructure is covered as a cost contribution; TDES does not consider geographical locations and there are no references to specific sites or companies.
- Only proven 'new technology' can be implemented; non-mature technological options — below technology readiness level (TRL) 7 — are not considered.
- Technology costs are fixed over time (learning effects are not considered). However, by following the available cost assumptions from II3050, the learning effects for renewable energy are implicitly applied. We assume fixed capex costs for electrolysers.
- Restrictions on available labour and space are modelled by limiting the maximum implementation speed of certain technological options.
- Fixed opex and Abandonment costs or Abandonment expenditure (abex) assets are not considered when deciding to keep or dismantle existing assets.
- Players are economically rational. Consequently, announced plans (and technology decisions) without a final investment decision which are not the most efficient according to the model are not selected in the modelling. For instance:
    a. Tata Steel is not assumed to switch to Direct Reduced Iron in Electric Arc Furnaces.
    b. New industry can be operational from 2028 onwards and the fuels and naphtha produced by new industry (e.g., pyrolysis and waste-to-liquid) are assumed to count as sustainable.
    c. Crackers are assumed to have access to sustainable naphtha from new industry as soon as it is available.

Technology-specific assumptions:

1. For **hydrogen**, no constraint on storage is considered. Regarding transportation, it is assumed that branches from the hydrogen backbone to the chemical industry will be completed seven years after completion of the backbone (for >90% of consumers). With regards to refineries, as the amount of current external hydrogen consumption is estimated at around 20% and only 10-15% of this amount is eligible for the sectoral targets, this current consumption is not considered. Refineries are thus assumed to be able to internally produce the full amount of hydrogen required for fuel treatment. Based on discussions with EZK, we assumed 2000 full load hours for electrolysers in the Netherlands and 4000 for electrolysers abroad.
2. **CCS** (e.g., steam methane reforming + CCS) will be available from 2027, with gradually increasing national and international capacities. Varying costs per project are not taken into account. We do not consider potentially forced phasing out of CCS. CCS of CO_2 from autothermal reforming installations has no capture costs and is therefore cheaper (76.8 €/ton instead of 151.8 €/ton).
3. **Nuclear** energy is not considered renewable energy. New nuclear power generation capacities will become available from 2035 onwards.
4. CO_2 emissions are set to reduce linearly from 181 Mton in 2020 to 0 by 2050. The Dutch **electricity grid** is assumed to be able to transport 120 TWh annually in the period 2020-2030. During the period 2030-2045, the grid capacity increases linearly to a maximum of 300 TWh in 2045.

5. (Imported) ammonia can be used as **sustainable marine fuel**. The corresponding investment costs on the marine side are not considered.
6. Power-to-liquid plants are allowed to use biological CO_2 from other sources through CCU for 40 €/ton in capture and transport costs.
7. Plastics can be converted to pyrolysis oil with no loss in mass.

Practical constraints:

Several constraints are added to represent practical infeasibilities and/or limit transition speeds:

1. Phase-out of non-sustainable mogas and diesel consumption by light-duty vehicles (LDV) and heavy-duty vehicles (HDV) is at most linear and will not reach zero before 2042. This represents the maximum transition speed of the entire Dutch light-duty vehicles and heavy -duty vehicles fleet.
2. Hydrogen consumption by heavy-duty vehicles is for the same reason set not to increase faster than linearly from 0 in 2024 to a maximum of 11 TWh in 2035. The maximum of 11 TWh represents one third of the Dutch heavy-duty vehicles fleet, which is the amount of hydrogen heavy-duty vehicles expected by the Ministry of I&W.
3. Hydrogen consumption in small industry is set to increase at most 10 TWh / year between 2027-2033 to represent realistic transition speed.
4. Electricity consumption for residential heat pumps is set to increase at most 1.5 TWh / year to represent realistic transition speed.
5. Sustainable marine fuel consumption is set to increase at most 1.4 TWh / year to represent realistic transition speed.
6. Hydrogen import is available up to 33 TWh per 2035, gradually increasing yearly to a maximum of 200 TWh in 2050. This represents the planning for the Dutch hydrogen backbone, as well as hydrogen-import-related (port) projects.
7. CCS will be phased in over the period 2027-2035 to a maximum of 22.5 Mton available CO_2 storage in Dutch fields and half that amount abroad. This is based on current planning of CCS projects; we assume another 5 Mton of CCS storage to become available each year after 2035.
8. Phase-in of renewable heat production availability over the next 30 years is assumed at a 6.6 TWh increase per year.
9. Phase-in of biological CO_2 import availability over the next 30 years is assumed at 0.3 TWh increase per year.

4.4 Translation of policy mixes into modelling scenarios - further assumptions

Details on **consumption obligation (HWIs)** considered in the assessment:

- The industrial use of 1 GJ renewable hydrogen yields 1 HWI for the user.
- In each year, all industrial hydrogen users must register X% of their total hydrogen consumption to HWIs, where X increases from about 0 in 2026 to 24/42% in 2030 and 60% in 2035 and beyond. See the table below for the value of X in each year and policy variant. There are two exceptions:
    - Refineries: 15% of the total hydrogen use is considered, proportional to the volume of output chemical feed that is produced rather than transport fuels. This means that at most 15% of the total hydrogen consumption can be used to generate HWIs and of this

15%, X% must be recorded each year to HWIs. E.g., when the obligation amounts to 24%, refineries are required to register 3.6% of their hydrogen consumption to HWIs.
    - New industry (hydrotreated vegetable oil/power to liquid/pyrolysis): Similarly, 15%/75%/100% of respective total hydrogen use is considered for this measure.
- HWIs are mutually tradable between industrial hydrogen users.
- If the obligation is not met, there is an exclusion clause under a certain price. It is assumed that the price of this buyout is sufficiently high to ensure that companies always prefer to fulfil the obligation.
- In each year, a certain percentage of the consumption obligation can be fulfilled in the following year instead.
- The option to bank HWIs and register them in the following year has not been included in the modelling.
- In line with the provisions in the recast RED, ammonia consumption is not included in the RFNBO consumption obligation and therefore does not have to meet any criteria (consuming hydrogen for the production of ammonia is included). However, consuming renewable ammonia does generate HWIs that can be used to meet the renewable hydrogen consumption obligation for that year.

Table 4-5 Assumed consumption obligation per year

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Consumption obligation 24%	0%	0.1%	0.1%	8%	16%	24%	32%	40%	48%	54%	60%
Consumption obligation 42%	0%	0.1%	0.1%	8%	16%	42%	45%	48%	52%	56%	60%

Details on the **production subsidy** considered in the assessment:

- Only electrolysers are eligible for this subsidy. Total **budget** ranges from € 1 bn in policy mix 4 up to € 4 bn in policy mix 2 and 3. Subsidies are disbursed over a period of 7 to 15 years (choice for applicant).
- Allocation mechanism: the budget is divided across different tender rounds.
- The opex subsidy is based on actual hydrogen production.
- For capex, the maximum subsidy equals 40% of investment costs. For opex, the subsidy is based on contracts for differences (CfDs, one-sided), in which case the reference price is the price for fossil hydrogen + ETS price.
- The subsidy is capped at € 9/kg (capex + opex).
- The height of the cap to limit generating HWIs for subsidised production is set at €2.5/MW electrolysis capacity.

Details on the **demand subsidy** considered in the assessment:

- Subsidy for industrial hydrogen users. Capex that can be covered are (conversion) costs of both existing and new industrial users of hydrogen. The 2025 **budget** ranges from € 1 bn in policy mix 2 and 3 to € 4 bn in policy mix 4.
- Allocation mechanism: the budget is divided across different tender rounds.

- For capex, the maximum subsidy equals 60% of investment costs. The opex based subsidy is granted in the form of a fixed premium of at most € 5/kg.
- The maximum subsidy is capped at € 9/kg (capex + opex).

5 Impacts on hydrogen volumes & prices

5.1 Hydrogen volumes under different policy options

5.1.1 Baseline results

The results of the baseline model run show that without any further policy intervention neither renewable hydrogen, nor renewable ammonia production/import is expected to take off by 2035. Table 5-1 summarises the results of the baseline scenario, indicating the renewable, low-carbon and fossil hydrogen and ammonia production and import of the Netherlands in the present (2023) and by 2030 and 2035. In the modelling results, domestically produced low-carbon RFNBOs refer to production with CCS. Under the EU definition, nuclear-based RFNBOs would also qualify, but production is not foreseen in the Netherlands before 2035. The modelling results support the hypothesis that renewable hydrogen requires further policy intervention to become (cost-)competitive with other forms of hydrogen. Our findings are in line with the findings from other studies. For instance, The METIS study "The impact of industry transition on a CO_2-neutral European energy system"[48] foresees very limited electrolyser capacities in the Netherlands and neighbouring countries, even in 2050.

However, while neither renewable hydrogen nor renewable ammonia production/use is foreseen until 2035, the results suggest that the Netherlands will ramp up low-carbon hydrogen production and low-carbon ammonia imports without additional policy intervention. The domestic production of low-carbon hydrogen, while being non-existent in 2023 (CCS being unavailable until 2027 as a modelling assumption), would achieve 10 TWh output by 2030, and 90 TWh output by 2035. In the discussion of the impact of the policy options, we will elaborate on the model dynamics that explain this substantial increase. For comparison, the Netherlands' current hydrogen demand is about 50 TWh (1.5 Mt)[49] and the expected RFNBO consumption of the country based on regulatory obligations (including the RED III) is at least 10.3 TWh (9.4 TWh originating from the industry and 0.9 TWh from transport).[50] Import of low-carbon hydrogen would not occur in the baseline scenario within the specified timeframe, while with regard to low-carbon ammonia, domestic production would remain non-existent and import would reach 27.9 TWh by 2030 (driven by CBAM), which is in line with the expectations found in the literature review that transport and trade of hydrogen is most efficient in the form of its derivatives. As low-carbon ammonia imports increase, the domestic demand for hydrogen to produce ammonia decreases naturally.

Domestic fossil hydrogen production will be replaced by low-carbon hydrogen production and low-carbon ammonia imports, with 10 TWh of fossil hydrogen in 2030 transitioning to low-carbon by 2035. The domestic production would fall by about 55% between 2023 and 2030 and disappear completely around 2033. According to the modelling results, this would not allow for the complete decarbonisation of the hydrogen use, and neither renewable, nor low-carbon hydrogen would be sufficiently competitive to completely displace fossil hydrogen by 2035. This could have consequences for the country's contribution to the EU's 2040 climate goals which are being discussed at the present.

[48] European Commission, DG Energy (2023). METIS 3 S5 - The impact of industry transition on a CO2-neutral European energy system.
[49] CBS (2020). The Dutch hydrogen balance and the current and future representation of hydrogen in the energy statistics.
[50] CE Delft & TNO (2023). Afnameverplichting waterstof. Unpublished.

Table 5-1 Baseline results - hydrogen + ammonia volumes in TWh (totals)

Indicator		2023	2030	2035	2023-2035
Domestic production	Renewable H_2	0			
	Low-carbon H_2	0	10	90	300
	Fossil H_2	22	10	0	167
	Renewable NH_3	0			
	Low-carbon NH_3	0		5	15
	Fossil NH_3	11	5	0	72
Imports	Renewable H_2	0			
	Low-carbon H_2	0			
	Fossil H_2	0			
	Renewable NH_3	0			
	Low-carbon NH_3	0	28	28	63
	Fossil NH_3	18	0		51

Ammonia includes applications of ammonia as sustainable marine fuel in the transport sector.
Methanol is excluded in the modelling exercise, as it is not expected to play a significant a role within the relevant timeframe (up to 2035) in the absence of additional policies not within scope of this project.
All tables in this report: no border between cells indicate that values are identical to the values from the previous cell.

5.1.2 *Impact of policy mixes*

All investigated policy mixes proved to be at least somewhat effective in increasing renewable hydrogen production. The following tables (Table 5-2 to Table 5-5) summarise the modelling results under different scenario assumptions (corresponding to different national policy mixes), in comparison with the baseline scenario's results detailed above. Table 5-2 summarises the domestically produced and imported renewable, low-carbon and fossil hydrogen/ammonia in 2030 and 2035, in the different policy mixes (PM 1, PM 2, PM 3, and PM 4) and the baseline scenario without additional intervention.

Table 5-2 Scenario results - hydrogen + ammonia volumes in TWh (totals, baseline results + difference with baseline)

Indicator		2030					2035				
Scenario		*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*
Domestic production	Renewable H_2	0	+5.9	+5.8	+5.0	+2.6	0	+5.9	+6.8	+7.2	+3.3
	Low-carbon H_2	10	-6.7			-4.3	90	-76			-79
	Fossil H_2	9.9	+0			-5.7	0	+0			
	Renewable NH_3	0	+0				0	+0			
	Low-carbon NH_3	0	+0				5	-5			
	Fossil NH_3	5	+0			-5	0	+0			
Imports	Renewable H_2	0	+0				0	+0			
	Low-carbon H_2	0	+0				0	+0			
	Fossil H_2	0	+0				0	+0			
	Renewable NH_3	0	+0				0	+0			
	Low-carbon NH_3	27.9	+0			+5	28.2	+5			
	Fossil NH_3	0	+0				0	+0			

The results show that policy mixes PM 2 and PM 3 would lead to the largest volumes of renewable hydrogen production, while policy mix PM 4 is estimated to result in significantly less renewable hydrogen production. In 2030, PM 1, PM 2 and PM 3 are estimated to increase renewable hydrogen production at a rather similar level (between +5 to 6 TWh). The largest volumes of renewable hydrogen are expected in scenario PM 1, while PM 4 only results in +2.6 TWh in 2030. This is likely to be a direct consequence of the differences in the available production subsidies, which are only €1 bn in PM 4, compared to €3 bn in PM 1 and €4 bn in PM 2 and PM 3. The higher budget for demand subsidy in PM 1 could explain the peak in renewable hydrogen production in 2030 compared to PM 2 and PM 3, as the industry would be incentivised to increase their hydrogen intake earlier in order to apply for subsidies. In 2035, the differences are slightly larger between the first three scenarios (+5 to 7 TWh). In 2035, PM 3 shows the largest volumes of renewable hydrogen, while PM 4 would lead to the most modest increase (+3.3 TWh). In all scenarios, no renewable ammonia is produced.

The increase in domestic renewable hydrogen production is expected to be realised at the expense of low-carbon hydrogen production. In the baseline, the substantial amounts of low-carbon hydrogen consumption are driven by the increasing ETS costs, as a result of which low-carbon hydrogen becomes more cost-efficient compared to e.g., heat generation with natural gas for the chemical industry. In all scenarios, there is a significant drop in low-carbon hydrogen production compared to the baseline. In scenarios PM 1, PM 2, and PM 3, the drop is identical (-6.7 TWh in 2030 and -76 TWh in 2035). In scenario PM 4, the drop is less substantial for 2030 while for 2035, the drop in PM 4 is slightly higher than in the other scenarios (-4.3 TWh in 2030, -79 TWh in 2035). For fossil hydrogen production, the only expected decrease is in 2030 for PM 4. This is explained by the lower RFNBO production subsidy, as a result of which the fertiliser sector will switch the ammonia imports in 2030 already, before the baseline switch from fossil to low-carbon ammonia production has been made. Regarding imports, the only changes compared to the baseline are observed for low-carbon ammonia, which would increase by +5 TWh in 2030 in PM 4 and by the same amount in all scenarios in 2035.

In all policy mixes, RFNBO shares range between 51% and 63% in 2030 and 65% and 66% in 2035. It is a given that the obligation is fully met, since the modelling inputs assume that the RFNBO obligation must be met at all costs. There are a few factors that cause the overshoot of the RFNBO percentages. First, the rising RFNBO consumption obligation and limited availability of production subsidies create an incentive to install electrolysis capacity before it is strictly necessary.[51] Second, the model contains flexible and non-flexible power sources. A share of power demand must be met flexible sources only. A share of the renewable power supply is hence a surplus, which can be either curtailed or used for electrolysis. Installed electrolyser capacity can thus use this surplus of renewable electricity to produce renewable hydrogen, at lower marginal costs than the low-carbon or fossil alternatives. Third, the consumption obligation creates an incentive to minimise overall industrial hydrogen consumption, which implies that the amount of renewable hydrogen from surplus power is already a large percentage of the total hydrogen consumption, reflected in the percentage.

[51] On the other hand, decreasing CAPEX are a reason to wait as long as possible. However, we assume fixed CAPEX costs in these scenarios. In the sensitivity analysis, decreasing costs are taken into account.

Table 5-3 reports on the relevant hydrogen targets, being the RFNBO share and domestic electrolysis capacity. Concerning the RFNBOs targets, all policy mixes exceed the required targets for 2030 set by the RED III article 22a, with a share ranging between 51% (PM 3) to 63% (PM 1 and PM 4). The policy mixes also exceed the required target set for 2035 (60%), with shares between 65% (PM 3 and PM 4) and 66% (PM 1 and PM 2). This is due to the modelling assumption that the penalty for not meeting the RFNBO consumption target exceeds the costs of meeting the target. The actual penalty is unknown.

The domestic electrolysis capacity is expected to reach 1.3 - 3 GW in 2030 and 1.6 - 3 GW in 2035. PM 1, PM 2 and PM 3 are expected to result in similar electrolysis capacities (2.5 - 3 GW in 2030 and 3-3.5 GW in 2035). Instead, the expected capacity in PM 4 is significantly lower (1.3 GW in 2030 and 1.6 GW in 2035). This suggests that the production subsidy budget is an important factor in establishing large electrolysis capacity; PM 4 has €1 bn dedicated to production subsidy, while the other policy mixes have a production subsidy budget of €3-4 bn These results also suggest that production subsidy is a more important factor with regards to electrolysis capacity than the strictness of the consumption obligation. Even though PM 3 uses a lower consumption obligation, the expected capacity is similar to that of PM 2, which uses the stricter obligation. An interesting observation is that PM 1 is expected to result in the most (and earliest) electrolysis capacity in 2030 among all variants, even though the production subsidy budget is slightly lower in this policy mix than in PM 2 and PM 3. Since PM 1 is more balanced between production and consumption subsidy, this could suggest that finding a balance between subsidising the production and consumption side of renewable hydrogen is a more effective strategy for establishing electrolyser capacity early, rather than focusing on the production side only.

Table 5-3 Scenario results – hydrogen targets (RFNBO percentages per scenario & additional [+] electrolysis capacity)

Indicator	2030					2035					Unit
Scenario	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	
RFNBO target %	0%	63.2%	54.2%	50.6%	63.1%	0%	65.6%		65.4%		%
Electrolyser capacity*	0	3	2.9	2.5	1.3	0	3	3.4	3.6	1.6	GW

** The capacity is determined based on the energy value of the produced hydrogen, assuming 2000 full load hours.*

Sector dynamics

Table 5-4 shows the resulting hydrogen production and consumption figures in greater detail and allows to disclose certain modelled sector dynamics. It shows for all considered forms of hydrogen (renewable, low-carbon and fossil) the production and consumption per sector, per policy, per year.

Table 5-4 Hydrogen (H_2) volumes in scenarios in TWh (totals, baseline results + difference with baseline)

Indicator		prod/ cons*	'23	2030					2035				
Scenario				*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*
Fossil H_2	Refineries (HMU**)	prod	6.4	4.1	+0				0	+0			
	Fertiliser (SMR**)	prod	12.1	5.7	+0			-5.7	0	+0			
	ATR**	prod	3.3	0	+0				0	+0			
	Import	n/a	0	0	+0				0	+0			
	Refineries	cons	5.1	4.1	+0				0	+0			
	Fertiliser plants	cons	12.1	5.7	+0			-5.7	0	+0			
	HVO**	cons	4.6	0	+0				0	+0			
	Total fossil H_2		21.8	9.8	+0			-5.7	0	+0			
Low-carbon H_2	ATR**	Prod	0	10	-6.7	+0		-4.3	80	-70			-73.3
	Fertiliser (SMR**)	Prod	0	0	+0				5.7	-5.7			
	Refineries (HMU**)	Prod	0	0	+0				4.1	+0			
	Import	n/a	0	0	+0				0	+0			
	Refineries	cons	0	0	+0				4.1	+0			
	Fertiliser plants	cons	0	0	+0				5.7	-5.7			
	Other industry	cons	0	0.6	-0.5				66.7	-66.7			
	HVO**	cons	0	5.6	-2.4			+0	6.3	+0			
	PO**	cons	0	2.3	-2.3				3.5	-1.8	-1.4	-1.2	-3.2
	HDV**	cons	0	1.5	-1.5				1.5	-1.5			
	Residential Heat	cons	0	0	_+0				2.1	+0	-0.4	-0.6	-1.9
	Total low-carbon H_2		0	10	-6.7			-4.3	89.8	-75.7			-79
Renewable H_2	Electrolysers	prod	0	0	+5.9	**+5.8**	+5	+2.6	0	+5.9	+6.8	+7.2	+3.3
	Import	n/a	0	0	+0				0	+0			
	Fertiliser plants	cons	0	0	+0				0	+0			
	Other industry	cons	0	0	+1.2	+1.2	+0.5	+0.4	0	+4	+5.3	+6	+0
	HVO**	cons	0	0	+2.4	+2.3	+2.4	+0	0	+0			
	PO**	cons	0	0	+2.3				0	+1.9	+1.5	+1.2	+3.3
	Total renewable H_2		0	0	+5.9	+5.8	+5.0	+2.6	0	+5.9	+6.8	+7.2	+3.3
Total H_2 consumption			21.8	19.8	-0.8	-0.9	-1.7	-7.4	89.8	-69.8	-68.9	-68.5	-75.5

**Production and consumption refer to national production and consumption, except when import is specified.*
*** ATR: Autothermal reforming, HDV: Heavy-duty vehicles, HMU: Hydrogen manufacturing unit, HVO: Hydrotreated vegetable oil, PO: Pyrolysis, SMR: Steam methane reduction.*

The modelling results suggest that renewable hydrogen consumption only takes place in certain chemical processes ("other industry") and industrial processes which are still non-existent today. Renewable hydrogen consumption is concentrated in new industrial processes in the policy mixes, such as pyrolysis (around 2 TWh) and hydrotreated vegetable oil (also around 2 TWh) in 2030. In 2035, no consumption is foreseen in hydrotreated vegetable oil. There are noticeable differences across scenarios. In the **other industry** (2030), a substantial increase is estimated in PM 1 and PM 2 (+1.2 TWh) and a smaller increase in PM 3 and PM 4 (around +0.5 TWh). In 2035, however, the increases in PM 2 and PM 3 are most substantial (+5 to 6 TWh), with a smaller increase in PM 1 (+4 TWh), and no change in PM 4. Regarding **pyrolysis** (2030), differences are minor across scenarios (+2.2 to 2.3 TWh). In 2035 however, differences are more substantial (+1.2 to +3.3 TWh).

Low-carbon hydrogen is initially only produced using autothermal reforming in all scenarios, but by 2035 the refineries and fertiliser sector also internally produce low-carbon hydrogen only. In terms of consumption of non-internally produced low-carbon hydrogen, similar sectors are seen as for renewable hydrogen usage (other industry, hydrotreated vegetable oil, pyrolysis, heavy-duty vehicles and residential heat). In all scenarios, most consumption is expected in hydrotreated vegetable oil, both in the baseline as well as in the policy scenarios (from 3.3 to 5.7 TWh in 2030 to 6.3 TWh in 2035). For **pyrolysis** and **heavy-duty vehicles**, consumption is substantial in the baseline but would drop in the scenarios (in case of pyrolysis, even to zero, driven by price increases). For the **other industry**, the baseline estimates 0.6 TWh low-carbon hydrogen consumption in 2030, sharply increasing to 66.7 TWh in 2035. The modelling results suggest that the production of heat using natural gas will become less cost-efficient (mainly due to ETS costs) as a result of which heat production using low-carbon hydrogen becomes the techno-economic preferred option. Electrification of heat production also becomes more cost-efficient in the baseline in this sector, which is discussed in section 7.1. In the policy scenarios however, there is no low-carbon hydrogen consumption in the other industry in 2035. This is explained by the additional costs related to low-carbon hydrogen production resulting from the consumption obligation under the policy scenarios (as low-carbon hydrogen consumption increases the base of the obligation, thereby requiring companies to purchase more HWIs and therefore larger total volumes of renewable hydrogen). Regarding **residential heat**, no low-carbon hydrogen consumption is expected for 2030. For 2035, consumption in the residential heat sector is expected in all scenarios, with rather substantial differences between the scenarios (2.1 TWh in the baseline, and up to -1.9 TWh in the scenarios).

The observed drop in fossil hydrogen production and consumption in 2030 is due to changes in the fertiliser sector. In the baseline, a substantial reduction in consumption and production of hydrogen in the fertiliser sector is estimated between 2023 and 2030 (from 12.1 TWh to 5.7 TWh). In all policy scenarios, fossil hydrogen production and consumption would fall to zero in 2035 due to a transition towards low-carbon hydrogen. In policy mix PM 4, this drop is expected to occur in 2030 already. In the **refineries**, production drops as well in the baseline and in all scenarios (from 6.4 TWh in 2023 to 4.1 TWh in 2030). Fossil-based hydrogen produced by **autothermal reforming** drops to zero in the baseline and in all scenarios by 2030. On the consumption side, **refineries** show a moderate decrease in both the baseline and all scenarios towards 2030 to the extent that consumption levels match onsite production. **Hydrotreated vegetable oil** fossil hydrogen consumption is estimated to drop to zero in the baseline and all scenarios by 2030.

Table 5-5 shows the fossil, low-carbon and renewable ammonia production and consumption by application in the investigated timeline, depending on different policy mixes.

Table 5-5 Ammonia (NH_3) volumes in scenarios in TWh (totals, baseline results + difference with baseline)

	Location	prod/ cons	'23	2030					2035				
Scenario				*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*
Fossil NH_3	Fertiliser Plants (HB*)	Prod	10.6	5	+0			-5	0	+0			
	Import	n/a	17.5	0	+0				0	+0			
	Fertiliser Plants	cons	15.5	5	+0			-5	0	+0			
	Transport		12.6	0	+0				0	+0			
	Total fossil NH_3		**28.1**	**5**	**+0**			**-5**	**0**	**+0**			
Low-carbon NH_3	Fertiliser Plants (HB*)	Prod	0	0	+0				5	-5			
	Import	n/a	0	27.9	+0			+5	28.2	+5			
	Fertiliser Plants	cons	0	10.5	+0			+5	15.5	+0			
	Transport		0	17.4	+0				17.7	+0			
	Total low-carbon NH_3		**0**	**27.9**	**+0**			**+5**	**33.2**	+0			
Renewable NH_3	Fertiliser Plants (HB*)	Prod	0	**0**	**+0**				0	+0			
	Import	n/a	0	**0**	**+0**				0	+0			
	Fertiliser Plants	cons	0	**0**	**+0**				0	+0			
	Transport		0	**0**	**+0**				0	+0			
	Total renewable NH_3		**0**	**0**	**+0**				**0**	**+0**			
Total NH_3 consumption			**28.1**	**32.9**	**+0**				**33.2**	**+0**			

**HB: Haber-Bosch unit*

Renewable ammonia is expected to have no role, as production and consumption levels remain at zero, both in 2030 and 2035. Even though consuming renewable ammonia would generate HWI's for the consumer without increasing the total hydrogen consumption with regards to the consumption obligation, renewable ammonia does not appear in any scenario, most likely due to the high price.

Regarding non-renewable ammonia, the sector results disclose relevant dynamics: in the baseline, low-carbon ammonia imports result in lower demand for fossil-based hydrogen (produced by the SMR). A fertiliser plant can opt to produce ammonia using (fossil, low-carbon or renewable; domestic or imported) hydrogen, or it can opt to import ammonia. In the baseline, a decrease in fossil-based hydrogen production and use is observed in the fertiliser industry, as importing low-carbon ammonia turns more cost-efficient as ETS prices rise. Under all policy scenarios, the ammonia production plants in the fertiliser sector are shut down by 2035, after which all (low-carbon) ammonia is imported. In PM 4, this change is observed in 2030 already. We note that the decisions for producing ammonia domestically or importing it are very price-sensitive and can hence vary on a year-by-year basis.

Regarding low-carbon ammonia, the modelling results show that the increased low-carbon ammonia imports are destined for fertiliser plants and transport and replace fossil ammonia. In the **transport sector**, consumption would increase from zero in 2023 to 17 TWh in 2030 (and remain relatively stable, with 18 TWh in 2035). In contrast, fossil ammonia use would decrease in the same period by 13 TWh. There are no differences between the baseline and policy scenarios. In the **fertiliser sector**, low-carbon ammonia use would increase from zero to 15.5 TWh in 2030 and 2035 in the baseline. In 2035, consumption would increase by another +5 TWh in all policy scenarios, thereby replacing fossil ammonia consumption.

5.2 Hydrogen contracts, markets & cost components

5.2.1 Contracts & markets

The global installed electrolysis capacity amounted to 690 MW in 2022. The deployment of electrolyser capacities dedicated to hydrogen production only started to accelerate in the late 2010s, and the global installed capacity is expected to reach almost 2.9 GW by the end of 2023.[52] The world's largest operating electrolyser producing renewable hydrogen is currently operated in China: Shell's power-to-hydrogen electrolyser in Zhangjiakou has a 20 MW nominal capacity and operates on electricity provided by onshore windfarms.[53] The largest upcoming project currently under construction is located in Saudi Arabia. The Helios plant will have a 2.2 GW nominal capacity and is designed to produce renewable hydrogen (650 t/day) for the global market, exported in the form of ammonia. It is expected to become operational by 2025.[54] The largest renewable hydrogen project within the EU is under construction in Sweden. With an 800 MW installed capacity, the H_2 Green Steel project is meant to decarbonise the operation of the country's steel industry using locally produced renewable hydrogen (starting operation by 2025), while also exporting the surplus hydrogen.

Large renewable hydrogen projects face high risks: sizeable renewable hydrogen production projects are not yet operational and the costs to produce renewable hydrogen are still substantially higher than for fossil fuel-based hydrogen. Functioning markets constitute a precondition for the successful development of a hydrogen industry. They will give consumers access to hydrogen and hydrogen derivatives, such as ammonia and methanol, which they can then trade directly with the relevant producer. Non-discriminatory trading markets create confidence in hydrogen as an increasingly important energy source. This is based on transparency in pricing, the publication of trading volumes as well as the number of trading participants and transactions. The pre-energy crisis production cost of fossil hydrogen was around 1.7 USD/kgH_2 in Europe.[55] Since the natural gas price makes up about 70% of this, the energy crisis contributed to a large extent to a more favourable business case for renewable hydrogen. However, the ramp-up of electrolyser production capacities and a drop of about 70% in installation costs (as estimated by the IEA) by 2030 is still necessary to bring the production cost of renewable hydrogen down in the range of 1.3-4.5 USD/kgH_2, making it competitive at least in regions where renewable energy is abundantly available.[56] The current market context still poses significant risks for investors in renewable hydrogen.

For industrial projects that face high risks, developers (producers) seek ways to limit their exposure to these risks. One way to do this is by concluding long-term procurement and/or supply agreements with (credible) counterparts. Long-term agreements with electricity suppliers on the one hand and hydrogen

[52] IEA (2023). Electrolysers.
[53] Shell (2022). Shell starts up hydrogen electrolyser in China with 20 MW production capacity.
[54] IEA (2022). Hydrogen project database.
[55] IEA (2019). The Future of Hydrogen.
[56] IEA (2022). Global Hydrogen Review 2022.

users on the other hand can contribute to revenue certainty for operators of electrolyser plants. The revenue uncertainty which electrolyser operators would face if buying electricity and/or selling hydrogen only on short-term markets decreases significantly with long-term agreements. In general, this decreased uncertainty improves the business case and makes it a more bankable investment for lenders. At the same time, hydrogen users are protected from fluctuating energy prices resulting from an increasing deployment of intermittent renewable electricity generation capacities, and therefore, renewable hydrogen.

As a result, long-term contracts are an adequate instrument, in particular in the initial phase of renewable hydrogen deployment. This is confirmed by most stakeholders we have consulted within this research. The investment decisions for larger electrolysers will only be confirmed if there is sufficient certainty about the project revenues, which in practice implies that long-term contracts between producers and consumers must be in place.

In the longer run, if risks decrease and if more producers and users of renewable hydrogen enter the market, the liquidity of the market will gradually increase. A liquid market is however not expected to exist before 2030. Only a small share of the produced hydrogen is currently traded in open markets. Most of it is produced by a few actors and consumed locally. Hydrogen is at present mainly traded via over-the-counter contracts, rather than via an organised market platform which would allow transparent price formation. In global trade, pure hydrogen's turnover amounts to € 130 million only, making it an almost non-existent share of global trade and the 3834th most traded product. Ammonia (the most traded hydrogen derivative) has a somewhat higher turnover amounting to € 6.3 bn, still only the 413th most traded product.[57] While hydrogen has been historically mainly produced on-site to cover local demand, some early signs of the development of global hydrogen trade can be identified. National governments show increasing activity in facilitating bilateral or multilateral agreements. Germany, Japan and the Netherlands have been the most active in this area, as explained in Box 3. By 2050, about ¼ of the global hydrogen demand is expected to be internationally traded, 55% of which would be transported via hydrogen pipelines, mainly on the European market, and 45% shipped as ammonia (or other derivatives, like methanol, LOHCs, etc.) globally.[58] This is expected to amount to about 40% of the current global, internationally traded natural gas market. The hydrogen trade itself is limited by the large concentration of demand for hydrogen derivatives (i.e., ammonia) and products made with hydrogen (i.e., steel) – 75-90% of which is covered by the top 10 countries of demand.

The envisioned HWI system may create a national market, rather than a regional or even global market. The envisioned HWI system is explained in section 3.1.1, and assessed in section 6.2.1.

5.2.2 Hydrogen prices & cost components

With regard to hydrogen prices and costs, we separate between market prices and production costs, as well as between fossil, renewable and low-carbon hydrogen. The price of hydrogen, like any other commodity, is influenced by a variety of factors, including costs of production, transport, distribution and conversion, and supply-demand dynamics. In general, the main cost components of hydrogen production

[57] JRC (2022). The role of hydrogen in energy decarbonization scenarios.
[58] IRENA (2022). Global hydrogen trade to meet the 1.5 C climate goal: Trade outlook for 2050 and way forward.

can be broken down into the same main sub-components for all types of hydrogen – these are related to investment (capex) and operation (opex) including energy/fuel used to produce hydrogen. However, the cost components can be further differentiated based on the production method.

In the case of fossil fuel-based hydrogen, the feedstock is almost always natural gas, sometimes other hydrocarbons, including coal. This differentiates the cost of fossil fuel-based hydrogen from other forms (low-carbon and renewable hydrogen) based on:

- The fuel component being largely the price of natural gas (in the case of 95% of the produced volume).
- The capex component being the price of reactors, gasifiers, pyrolysis units, etc.; and
- The operational costs include the price of carbon emissions (EU-ETS and/or national levy).

Low-carbon hydrogen is similar in its cost formation to fossil hydrogen with an added cost for carbon capture and storage or re-use. Important to note is that all existing carbon-capturing technologies lead to energy efficiency losses and some remaining CO_2 emissions. Hydrogen produced via the use of electricity from nuclear power plants is also considered to be low-carbon. This differentiates the cost of derived hydrogen from other forms (fossil and renewable hydrogen) based on:

- The operational costs still include a (greatly reduced) price of residual GHG emissions (EU-ETS and/or national levy);
- The price of electricity can be higher when it originates from nuclear generation due to the significant capex of nuclear power plants, whereas the load factor of electrolysers can be higher than with using renewable electricity due to the more stable nuclear electricity generation;
- The capex component inflated by the investment costs of carbon capture facilities;
- The opex component inflated by the operational costs of carbon transport and storage.

The production of renewable hydrogen depends on a number of different factors. This means that the price formation of renewable hydrogen varies based on:

- The capex component made up largely by the price of electrolyser units and supporting facilities. In principle this cost component will be similar for all production areas;
- The availability and cost of water, which will be different depending on the production area;
- The related carbon emissions being zero, and therefore imposing no further carbon surcharges; and
- The availability and cost of renewable electricity used in the process, which will also be different depending on the production area.

5.3 Relevance of (inter)national market developments and policies for renewable hydrogen deployment and prices in the Netherlands

5.3.1 Introduction

The focus of this analysis is on market policies at the EU level and in North-Western countries which could affect the renewable hydrogen deployment and prices in the Netherlands. Interactions between hydrogen sectoral policies for industry and transport in the Netherlands are also addressed. Policies which are prerequisites or facilitators for such deployment are covered in section 8.2, such as those related to infrastructure planning and operation or certification of renewable hydrogen.

5.3.2 *Policies relevant for hydrogen deployment*

Relevant policies at EU level

The European Commission (EC) has developed various hydrogen-related policies and initiatives, in particular to facilitate and stimulate renewable hydrogen production, transport and use, and to avoid market fragmentation. In the EC's Communication on the European Hydrogen Bank[59] for instance, the EC underlines the importance of preventing early market fragmentation — such as divergent terminology and certification of hydrogen, or different market pricing rules —, and highlights the necessity of harmonised approaches in regulation and market development tools instead.

Renewable hydrogen is expected to play a central role in the decarbonization of processes and applications where electrification is not a suitable or feasible option.[60] This is, for instance, stated in the EC's hydrogen strategy and REPowerEU plan.[61] As renewable hydrogen has however still a significantly higher production cost than fossil fuel based hydrogen without CCS, production and use of renewable hydrogen in the EU is at present virtually non-existent. To stimulate the role of renewables hydrogen in the decarbonisation processes, the EU regulatory framework for hydrogen is currently being adapted.[62] This includes:

- **Renewable Energy Directive** (RED III): In March 2023, an agreement was reached between Member States and the EC on the revision of the RED II, adopting the increased REPowerEU target of 42.5% (aiming for 45%) renewable energy consumption share by 2030.[63] Part of this target is to be achieved by the promotion of RFNBOs (renewable hydrogen and its derivatives, instead of fossil fuel based hydrogen) in the transport sector and in industry, i.e. for producing fertilisers and fuelling high-temperature processes.[64] More importantly, the recast RED III comprises a binding 42% national target for industry and a 1% target for transportation for the share of renewable hydrogen in their final hydrogen consumption within the EU by 2030.[65]
- **Hydrogen and decarbonised gas markets package**: The EC proposed in 2021 a revised Gas and Hydrogen Directive, replacing the current EU Gas Directive 2009/73/EC. [66] Among others, the recast Directive intends to accelerate investment in renewable hydrogen production[67], thereby aiming to ramp up the production of green gases.[68] In February 2023 the European Parliament's Committee on Industry, Research and Energy adopted its final report, and the Parliament is now in interinstitutional negotiations with the Council and the Commission about the proposal. The new Gas and Hydrogen Directive sets the definition of renewable and low-carbon gases. Furthermore, it promotes the unbundling and certification of hydrogen system operators and sets the rules for the organisation of hydrogen markets. This includes refining provisions on market access, the free

[59] EC (2023). European Hydrogen Bank.
[60] EC (2020). A hydrogen strategy for a climate-neutral Europe.
[61] EC (2022). REPowerEU Plan.
[62] EC (2021). Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen.
[63] EC (n.d). Renewable energy directive.
[64] EC (2023). European Green Deal: EU agrees stronger legislation to accelerate the rollout of renewable energy.
[65] EC (2023). European Green Deal: EU agrees stronger legislation to accelerate the rollout of renewable energy.
[66] EC (2021). DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal markets. in renewable and natural gases and in hydrogen.
[67] EC (2023). Net Zero Industry Act.
[68] EP (2023). EU Directive on Gas and Hydrogen Networks.

choice of supplier, market-based pricing, public service obligations and the promotion of regional cooperation. As part of the above-mentioned package, the Gas Regulation 715/2009 is currently also being revised to align it with the new energy and climate ambitions.

- **Projects of Common European Interest** (IPCEI): This initiative is a framework for Member States to provide State aid in the form of financial support for projects that further strategic European goals – such as sustainability, digitalisation, sovereignty, and a level playing field for companies. As such, cross-border renewable hydrogen projects may also be eligible for IPCEI support. The Netherlands is participating in 4 IPCEIs on hydrogen, covering important fields, such as:
    1. Technology value chain (Hy2Tech) – with a budget of €5.4 bn, provided by 15 participating Member States, €35 million coming from the Netherlands;
    2. Production/electrolysis (Hy2Use) – with a budget of €5.2 bn, by 13 participating Member States, €784 million coming from the Netherlands;
    3. Import and storage (RHATL) – with a maximum budget of €595 M from the Netherlands. Decisions at the Dutch and EU levels are pending, and;
    4. Application (Mobility and Transport) – with a maximum budget of €199 M from the Netherlands. Decisions at the Dutch and EU levels are pending.
- **European Hydrogen Bank** (EHB): The EHB was set up in 2023, with the aim to offer financial support for renewable hydrogen projects, increasing the return on investment and thereby lowering the risks. Two new financing instruments will be implemented through the EHB. Launching the EHB's domestic leg, the EC is advancing with the design of the first pilot auctions in a competitive bidding mechanism planned to take place in the autumn of 2023 already. The auction will award production subsidies on renewable hydrogen in the form of a **fixed premium** per produced quantity for a maximum of 10 years of operation. The indicative budget for this auction round is € 800 million based on already performed market testing and will be adjusted in later auctions based on the lessons learned in the first round.[69] The EHB should also facilitate transparency and coordination by providing increased demand visibility and links to existing financing instruments on EU and international scale. Via these mechanisms, the EC aims to contribute to early market creation, while maintaining that the bulk of the investment in the upscaling hydrogen sector must come from private investors. Furthermore, to prevent fragmentation of the EU market and unnecessary administrative costs in developing differing hydrogen support schemes across Member States, the EC's Communication proposes to extend this platform later by offering 'auctions-as-a-service' to EU Member States, running a single auction in the entire European market.
  According to the terms and conditions published by the European Commission on 30 August 2023, eligible projects will have five years to be commissioned from the time of award, the ceiling price of the premium has been set at €4.5 per kilo of hydrogen and the completion bond is set at 4% of expected revenue.[70]
- **Delegated Acts on the production of renewable liquid and gaseous transport fuels of non-biological origin:** The Delegated Acts present the developed standard EU methodology ensuring that the electricity used to produce renewable liquid and gaseous transport fuels of non-biological

[69] EC (2023). European Hydrogen Bank.
[70] Hydrogen Europe (2023). Hydrogen Bank terms and conditions published.

origin (RFNBOs) is of renewable origin. These DAs already provide a guideline for uniform certification of renewable hydrogen across the EU, applicable for both domestic production and imports.[71]

- **Revised TEN-E Regulation**: The Trans-European Networks for Energy (TEN-E) is the EU policy focused on necessary interlinkages between the energy infrastructure of EU Member States. Recognising the importance of energy infrastructure in the realisation of its climate and energy independence goals, the EC adopted in 2020 its proposal for a revision of the TEN-E regulation, and in 2022 a new version of the legislation entered into force as a result.[72] The revised regulation updates the infrastructure categories eligible for support emphasising decarbonisation and adding a new focus on offshore electricity grids, hydrogen infrastructure and smart grids. The Regulation identifies 11 priority corridors (geographic regions where interconnection is most important) and 3 priority thematic areas (smart electricity and gas grids, and a cross-border CO_2 transport network) for further support in the optimisation of the EU electricity and gas infrastructure. One of the identified priority infrastructure gas corridors is the hydrogen interconnection in Western Europe (HI West), connecting the Netherlands to Belgium, Germany, Luxembourg, and further France, Ireland, Denmark, Czechia, Austria, Spain, Portugal, Italy and Malta.[73] The financing of projects that fall into these categories will be done largely through projects of common interest (PCIs) and projects of mutual interest (PMIs), financed by the Connecting Europe Facility (CEF) until 2027. 147 projects related to EU hydrogen infrastructure were already submitted for consideration through the PCI and PMI instruments.[74]

Relevant policies in Northwest Europe[75]

Hydrogen strategy & policy in Germany

The German government considers the large potential of offshore wind energy on the northern coastline as an opportunity to develop significant domestic renewable hydrogen production capacity. As such, Germany acknowledges the need for public measures, such as grants, to incentivise investments. In June 2020, the Federal Government published its national hydrogen strategy, indicating renewable hydrogen to be an important component of the country's energy future. Moreover, the strategy states that the current framework is not appropriate to facilitate economically viable renewable hydrogen production.[76] The German government argues that the competitive environment makes it impossible for producers to pass the higher costs associated with renewable hydrogen projects through to end-users. In July 2023 the German National Hydrogen Strategy was updated to reflect the necessary changes brought on by the RED III.[77] In this revision, the German government committed to a more ambitious, 2% target for the RFNBO share (instead of the RED III target 1%), replacing kerosene in aviation[78] and therefore significantly increasing the expected demand (and competition) for hydrogen. Furthermore, in September 2023, the

[71] EC (2023). Detailed rules for the production of RFNBOs.
[72] EC (2022). Trans-European Networks for Energy.
[73] EC (n.d.). Projects of Common Interest - Selection process.
[74] GIE (2023). Applications to first PCI and PMI list under revised TEN-E Regulation underline European hydrogen infrastructure's potential.
[75] This section has been written in the summer of 2023. Given the pace at which governments announce new/updated hydrogen policies, new policies may have been announced by the time of publication.
[76] Federal Government of Germany (2020). The National Hydrogen Strategy.
[77] Freshfields (2023). At a glance - the updated German National Hydrogen Strategy
[78] Transport and Environment (2023). First binding target to supply green H2 and e-fuels to the transport sector

British and German governments signed an agreement of cooperation to establish a new ‘international hydrogen industry’. The parties agreed to coordinate research, the promotion of trade, planning and investment and to establish international leadership in the hydrogen markets by setting safety standards and regulations.

To stimulate hydrogen production via electrolysis, the German government announced to launch a pilot programme targeting the steel and chemical industries introducing a Carbon Contracts for Difference (CCfD) programme. By February 2023, the planned hydrogen generation capacity in Germany coming online before 2030 increased by more than 44% (from 5.6 GW to 8.1 GW) compared to the expectations of the previous year, as a result of the energy crisis and the increased targets.[79]

Through H_2Global, the German government will facilitate the trade of renewable hydrogen aiming to accelerate the creation of a well-functioning European hydrogen market. It will do so by contracting production capacities on international markets (via 10-year supply contracts) and selling them to market parties via a double public auction process. The first procedure was approved in 2021 with a € 900 million budget, and by 2023 the Federal Government is planning to provide a further € 3.5 bn covering the period up to 2036.[80]

In July 2023, the German government published a revised version of its original hydrogen strategy (2020) recognising the increasing demand generated by the accelerated energy transition. In this new revision, the government doubled the original (5 GW) domestic electrolyser capacity goal to 10 GW by 2030. Furthermore, the German government expects that this will only cover 50-70% of the increased hydrogen demand by 2030, and pledges to develop a dedicated import strategy.[81] Through a mix of newly-built and repurposed pipelines, the emerging 1800 km hydrogen grid will connect all major suppliers and customers - in industry, in heavy-duty commercial vehicles and increasingly in aviation and shipping - by 2030. The government recognises that the increased goals will require further financial adjustments (compared to the 2020 allocations) but makes no specific mention of an indicative budget.

Hydrogen strategy & policy in Belgium

Belgium expects a limited role for domestic renewable hydrogen production due to the country’s relatively low renewable electricity potential, and its priority to use the available renewable electricity for direct applications. Belgium aims, similar to the Netherlands, to become a hydrogen import and transit hub in Europe.[82] In 2021, the Federal Government adopted the country’s hydrogen strategy, and revised and updated it in 2022. In an effort to solidify its position as a transit and trading hub, and to establish a unified European hydrogen market, Belgium has a stated ambition to build an interconnected hydrogen transport network with at least Germany, France and the Netherlands by 2028.

[79] E.ON (2023). H2-Bilanz.
[80] German Ministry of Economic Affairs & Climate Action (2022). Launching first auction procedure for H2Global
[81] Federal Government of Germany (2023). Fortschreibung der Nationalen Wasserstoffstrategie (in German)
[82] The Federal Government of Belgium (2022). Hydrogen vision and strategy.

The Belgian federal government deems common market rules and market coupling important. As such, Belgium welcomes the initiative of the EC to achieve this, as proposed in the Hydrogen and decarbonised gas markets package. The government's proposed approach is built on four pillars:

1. Belgium's role as European transport hub for hydrogen;
2. Obtaining leadership in hydrogen technologies;
3. Establishment of a common and robust hydrogen market; and
4. Cooperation with European and international partners.

The Belgian government has not yet defined specific measures for supporting domestic hydrogen production and refers in its strategy only vaguely to demand-inducing measures, which would indeed be rather part of the regional competencies. The federal strategy's emphasis is on establishing the necessary physical connections for a common European market, and Belgium's role as a hub by building international connections and import capacities, and by setting up a market platform that facilitates the trade of hydrogen molecules.

In July 2023 Belgium adopted the hydrogen transmission law ('*Wet betreffende het vervoer van waterstof door middel van leidingen*')[83], setting the regulatory framework for hydrogen transport through pipelines in the country. The law defines the process for the designation of a hydrogen network operator that will be responsible for the development and operation of new hydrogen pipelines (this procedure is ongoing[84]), unbundling and third-party access requirements, competencies of the federal regulator CREG, as well as other aspects.

Next to the federal hydrogen law, which will regulate the transport of hydrogen via pipelines at high pressure, the Flemish region is working on a decree to regulate the distribution of hydrogen at a regional level, similar to the distribution of electricity and natural gas. The decree has a similar approach as its federal counterpart: one 'hydrogen distribution system operator' would be designated in Flanders and regulatory provisions are foreseen regarding the independence and (vertical and horizontal) unbundling of the operator, 'third party access', grid tariffs to be approved by VREG, and monitoring of the hydrogen quality. Furthermore, the Flemish government approved in 2020 the regional hydrogen strategy; its ambitions and priorities are in line with the vision of the federal government.[85]

Hydrogen strategy & policy in France

France aims to achieve 6.5 GW electrolysis capacity in 2030, which is higher than the Dutch target, while reserving a lower budget and indicating that hydrogen deployment is mainly a 'European matter'. In 2020, the French Innovation Council identified decarbonised hydrogen as a priority among 11 markets that are considered key to the sustainable development of the country. The National Strategy for the

[83] Belgisch Staatsblad (25/07/2023). *Belgisch Staatsblad*.
[84] Publication CREG 13 July 2023 Nota betreffende voorwaarden voor certificering en evaluatiecriteria voor aanwijzing als waterstofvervoersnetbeheerder respectievelijk overeenkomstig de artikelen 10 en 11 van de wet betreffende het vervoer van waterstof door middel van leidingen. | CREG : Commissie voor de Regulering van de Elektriciteit en het Gas. (in Dutch)
[85] Vlaamse Waterstofvisie "Europese koploper via duurzame innovatie"

Development of Decarbonised and Renewable Hydrogen in France was adopted in 2020.[86] The strategy emphasises the importance of cooperating with European partners through the IPCEI platform, and of removing regulatory, technical (lack of standards) and financial barriers, thus promoting the emergence of a sustainable European value chain. France aims to accelerate and accommodate the deployment of low-carbon hydrogen within three priority areas by:

1. Decarbonising the industry via the development of the necessary electrolyser capacities;
2. Developing heavy-duty hydrogen-fuelled transport; and
3. Supporting research and skills development.

The overall budget amounts to € 7 bn budget, of which € 3.4 bn was allocated for these purposes in the period 2020-2023 already. To achieve the goals, the strategy specifically envisages the introduction of a **guarantee of origin mechanism** for renewable and low-carbon hydrogen, as well as production subsidies.[87] The French government's hydrogen strategy, compared to its Dutch counterpart, has a more ambitious domestic production goal (6.5 GW electrolyser capacity by 2030, compared to the Dutch goal of 3-4 GW), with a somewhat lower budget (€ 7 bn compared to the Dutch budget of € 9 bn) - but without the Dutch perspective on import. The French government announced an additional € 2 bn budget for its hydrogen goals in 2021, bringing its overall budget to € 9 bn as well. The government also reiterates the country's advantage in the production of low-carbon hydrogen – based on the high share of nuclear energy in the French electricity mix.

Hydrogen strategy & policy in the United Kingdom

The UK foresees a significantly larger role for hydrogen than EU countries, with low-carbon hydrogen covering 20-35% of its final energy consumption by 2050.[88] In comparison, most EU scenarios expect a 10% share in the EU's final energy demand, and the EC's Fit-for-55 predicts a 20% share for hydrogen in the same time horizon.[89] The UK government published its hydrogen strategy in 2021; it foresees an important role for hydrogen in transport, industry, and also (residential) buildings. The strategy emphasises the importance of domestic production to ensure energy supply security, rather than relying on imports. The strategy also expects the development of global, large-scale hydrogen markets. The Ten Point Plan for a Green Industrial Revolution, published in 2020, foresees 5 GW of low-carbon hydrogen production capacity in the UK by 2030. The implementation of this strategy by 2030 is built on five pillars:

1. **Supporting research and innovation** including a GBP 60 million (€ 70 million) package allocated to launch the Low-carbon Hydrogen Supply Competition, aiming to supply solutions;
2. **Establishing an appropriate CCUS infrastructure** supported by the CCS Infrastructure Fund with a GBP 1 bn (€ 1.2 bn) budget;
3. **Developing a hydrogen business model funded through the existing Net Zero Strategy** (GBP 100/€ 120 million) with stakeholder consultation, including a framework for commercially viable investment opportunities that also meet the government's low-carbon hydrogen objectives – introducing price support through variable premiums bridging the gap between the production cost

[86] French Government, (2020). *Stratégie nationale pour le développement de l'hydrogène décarboné en France* (in French)
[87] Ibid.
[88] HM Government (2021). UK Hydrogen Strategy.
[89] JRC (2022). The role of hydrogen in energy decarbonisation scenarios.

and the (potentially lower) market price of hydrogen, and a volume support through a sliding scale approach in the price support (higher premium for lower offtake volumes);

4. **Creating a net zero hydrogen fund**[90] containing a GBP 240 (€ 280) million package to act as a government co-investment in low-carbon hydrogen production capacities, which is supposed to unlock a further GBP 4 (€ 4.7 bn) in private investments by 'de-risking' early projects[91]; and
5. **Creating a low-carbon hydrogen standard** setting the acceptable level and calculation methods for GHG emissions of low-carbon hydrogen production.

Compared to the Dutch plans, the UK relies heavily on low-carbon hydrogen (and specifically CCUS technologies) in the early development of the hydrogen supply chains. This is also illustrated by the difference between the UK budget for low-carbon hydrogen production (€ 280 million) and the Dutch Climate Fund (€ 9 bn). In its 'twin track' approach, the UK government intends to develop the production of renewable and low-carbon hydrogen simultaneously, aiming to meet any level of hydrogen demand on the path of decarbonisation, while also hedging the risks and uncertainties in the different technologies' development. Especially during the early stages, throughout the 2020s, the government expects that the currently cheaper carbon capture option (in steam methane reduction processes) will pave the way for higher hydrogen uptake in the future. The UK government estimates that approx. 15 GW of low-carbon and renewable hydrogen production capacity is already in the pipeline within the UK. The Net Zero Hydrogen Fund, offering capex support for selected hydrogen investments, is being implemented in two stages; eligible projects were invited to apply until 31 May 2023 for round 1 and 7 June 2023 for round 2.

Hydrogen strategy & policy in Norway

The Norwegian hydrogen strategy (2020) recognises hydrogen as an energy carrier 'with a significant potential for reducing local, national and global emissions, and for creating economic value for Norwegian businesses'.[92] The government foresees a role for hydrogen in industry and transport – especially in heavy-duty road and maritime transport – while also reflecting on the uncertainty resulting from the low technology readiness level of these applications. The Norwegian railways are largely electrified, and the evaluation of the possibility of replacing the remaining diesel trains (making up 20% of the network) with hydrogen-fuelled trains, is stalled for safety reasons. The government expressed similar concerns and considerations regarding the use of highly flammable gases (like hydrogen) in aviation. Norway is in a somewhat unique position within Europe with its large and already realised potential for hydropower, meaning there are significant benefits from integration with the EU electricity system. The Norwegian power system can provide flexibility in 'wet' years,[93] while interconnections with the EU help guarantee supply adequacy in dry years. Despite being a large fossil gas producer, natural gas does not play a role in residential heating, and it makes up only 1% of the domestic final energy consumption[94] of Norway. The retrofitting of existing natural gas networks for dedicated hydrogen use, or the role of hydrogen as flexibility option for balancing the energy system are, therefore, not of interest to the Norwegian government.

[90] Rijksoverheid (2023). Kabinet investeert fors in opschaling waterstof. (in Dutch)
[91] HM Government (2020). The Ten Point Plan for a Green Industrial Revolution.
[92] Norwegian Ministry of Petroleum and Energy, Norwegian Ministry of Climate and Environment (2020). The Norwegian Government's hydrogen strategy.
[93] FME CenSES (2018) Norway's role as a flexibility provider in a renewable Europe;
DTU et al. (2019) Flexible Nordic Energy Systems
[94] IEA (2022). Norway Natural Gas Security Policy.

The government considers both renewable and low-carbon hydrogen pathways for future applications. Especially in the early stages of market development, the role of CCS is emphasised in the hydrogen strategy, as a way to avoid investing in expensive hydrogen transport pipelines without the certainty of sufficient demand in Europe. The government explicitly states that long-term continued production of oil and gas on the Norwegian shelf, and export of natural gas for the production of hydrogen – rather than exporting hydrogen itself – is the most realistic scenario for Norway. The government, therefore, pledges to make natural gas reforming combined with CCS a competitive alternative to water electrolysis. The Northern Lights project of the Norwegian government provides an opportunity for partnering governments and companies to transport and store captured CO_2 byproducts of industrial activities under the seabed in saline aquifers serving as permanent storage facilities.[95] Such a working agreement already exists (since 2022) between Northern Lights and the Dutch ammonia and fertiliser plant, Yara Sluiskil — which will become active from 2025 onward.[96]

With regard to international cooperation, especially harmonisation of standards and regulations, information-sharing regarding value chains, research partnerships and safety have been identified as important issues. The Norwegian strategy also highlights the importance of the existing Nordic cooperation (between Norway, Denmark, Sweden, Iceland and Finland) in hydrogen development.

5.3.3 Interactions and alignment with international developments

The future market for (renewable) hydrogen is very likely to become an international market, similar to the markets for most other energy vectors. The (North-west) European electricity market is largely integrated, with the Netherlands trading electricity with e.g., Germany, Belgium, France, the UK, and the Nordics. For natural gas, the market is also highly physically and virtually interconnected, with significant amounts of natural gas (around a quarter of the European gas consumption[97]) imported from Norway and distributed across the EU, among others via the Netherlands. Moreover, there is a *global* market for liquified natural gas (LNG).[98] Given this international component, understanding and properly taking into account international developments and policies is crucial to develop effective hydrogen policies, in particular for trade-oriented countries, like the Netherlands.

Projects exist for the interconnection of the Dutch hydrogen backbone with neighbouring countries already before 2030. An example is the Hyperlink project being developed by Gasunie Germany.[99] The European Hydrogen Backbone initiative foresees an interconnected hydrogen pipeline system in North-Western Europe by 2030, with multiple cross-border links between the Netherlands, Belgium and Germany. However, most development plans have not yet reached a final investment decision and, as there are still uncertainties regarding the effective demand and hence use of the new infrastructure, as well as regarding the regulatory framework, the timing seems quite ambitious and may be subject to delays.

[95] Northern Lights (n.d.). Northern Lights Project - What we do.
[96] Equinor (2022). Important step to decarbonise Europe.
[97] Norwegian Ministry of Petroleum and Energy, Norwegian Ministry of Climate and Environment (2020). The Norwegian Government's hydrogen strategy.
[98] This does not mean that a large share of the total hydrogen production will be traded globally: international trade comes at a (transport) cost, which can make (more) national or regional more attractive.
[99] https://www.hyperlink-gasunie.de/ueber-hyperlink/hyperlink-1-2

The METIS study "The impact of industry transition on a CO_2-neutral European energy system"[100] assesses the development of a cross-border hydrogen infrastructure in 2050. Under the METIS assumptions, establishing large hydrogen interconnectors between the Netherlands on one hand and the UK and Norway on the other would be economically efficient. Furthermore, Germany and Belgium would focus on importing renewable hydrogen through pipelines from elsewhere (such as France, the UK, Norway and Spain) due to limited domestic production potentials, while the Netherlands would reach an electrolyser capacity from 12 to 14 GW depending on the scenario. Therefore, according to the METIS study, the Netherlands would not trade hydrogen with Belgium and Germany in significant volumes, and thus no new hydrogen cross-border capacities would be required with these countries.

In addition to cross-border hydrogen trade by pipelines, the Netherlands would rely on imports of derivatives by ships to complement domestic production, as shown in section 5.1. Moreover, some trade in hydrogen and derivatives may take place with Belgium and Germany through other modes such as barges and trains – but the volumes are likely to be limited and have a modest influence on prices. Therefore, the Dutch hydrogen market would to an important extent rely on derivatives' imports by ships and become interconnected through pipelines to neighbouring countries at some point, although there is still uncertainty about the timing.

In comparison to other Northwest European countries, the Netherlands would focus on renewable (rather than low-carbon) hydrogen and reserve a relatively high budget to stimulate its development. This contrast seems to be the most visible with Norway's hydrogen strategy, which aims to build on the already established natural gas production and export value chain — especially in the 2030 time horizon — and promotes CC(U)S technologies rather than water electrolysis. The important North Sea offshore wind energy potential provides an opportunity for setting up significant domestic renewable electricity/hydrogen production capacities in the Netherlands. Furthermore, the Dutch government sees the role of the country somewhat similarly as — and potentially in competition with — Belgium as an import and distribution hub for the rest of the continent. The dedicated budget for hydrogen development in the Netherlands in the 2030-time horizon seems to be in the same order of magnitude as in the rest of the region (especially Germany). France and the UK have presented more ambitious goals related to domestic production capacities but have allocated somewhat smaller public budgets. The publicly available information is summarised in Table 5-6 below.

[100] European Commission, DG Energy (2023). METIS 3 S5 - The impact of industry transition on a CO2-neutral European energy system.

Table 5-6 Hydrogen strategies & policies in the EU and some Northwest European countries by 2030

Jurisdiction	Type of H_2	Origin of H_2	Production capacity goal	Indicative budget [€]	Proposed instrument
Netherlands	**renewable**	**mixed**	**3-4 GW**	**9 bn**	
EU	renewable	mixed	40 GW	34-49 bn	Investment support (e.g., Horizon2020), coordination (through the EHB)
Belgium	mixed	import	150 MW*	N.A.	Investment support (e.g., IPCEIs)
Germany	renewable	mixed	10 GW	9 bn**	Investment support (e.g., IPCEIs), pilot CCfD, tax exemption (EEG surcharge reduction), double auction model
France	low-carbon	domestic	6.5 GW	9 bn	Investment support (e.g., IPCEIs)
UK	mixed	mixed	10 GW	6.3 bn	Variable premium, volume support, DEVEX and capex
Norway	low-carbon	domestic	N.A.	N.A.	N.A.

**By 2026, the Belgian government sees a limited role for domestic hydrogen production, as the renewable electricity potential is going to be taken up almost exclusively by the necessary electrification.*
***Indicative budget presented in the original (2020) hydrogen strategy, not reflecting the updated goals (2023, from 5 GW to 10 GW). The 2023 revision of the German hydrogen strategy recognises the necessity for further funding but makes no concrete mention of additional budget allocation.*

Early development of a cross-border hydrogen network should also be driven by long-term electricity (input for electrolysers) and hydrogen sales agreements between the concerned market parties. As detailed in section 5.2, the initial development of the renewable hydrogen market in the Netherlands would rely on long-term contracts. A liquid hydrogen market with significant short-term trade is not expected before 2030. Thus, while hydrogen price benchmarks already exist, the price of hydrogen would in the short- to medium-term mainly be set by bilateral trades (also considering eventual supply- and demand-side support and obligations). This will to some extent provide certainty not only for investors in supply and demand assets but also in domestic and cross-border transport infrastructure.

The Netherlands is expected to rely on imports of renewable hydrogen and derivatives to complement its domestic production. Thus, domestic hydrogen will have an advantage over imports regarding transport costs, which must be weighed against eventual higher production costs. However, while some other countries may have a competitive advantage in production costs, this will not be the case for most Dutch neighbours, which have similar challenges in terms of availability and cost of renewable electricity electrolysers. In the medium- to long-term Nordic countries may become relevant hydrogen exporters, but it can be expected that policies will not aim to provide supply-side subsidies in this case.

Neighbouring demand-side policies may incentivise the export of hydrogen produced in the Netherlands, but this would require that demand-side support in those countries would be significantly more generous or consumption obligations stricter than in the Netherlands, to create more important incentives for neighbouring consumers compared to Dutch ones to purchase Dutch renewable hydrogen. The use of measures such as destination clauses in supply-side support mechanisms to restrict export of subsidised renewable hydrogen produced in the Netherlands is likely not allowed, at least for EU Member

States, as it would restrict free of movement of goods in the internal market. Double-sided auctions for hydrogen production plants with a delivery point in the Netherlands could serve nonetheless to help match domestic supply and demand in this regard. Alternatively, if desired such trade could be promoted by cooperation between the Dutch government and Neighbouring Member States

Hence, it is unlikely that demand-side policies in neighbouring countries would distort the Dutch hydrogen market significantly in the medium term, as such policies are not expected to be significantly more ambitious than in the Netherlands. There is nonetheless an important role for infrastructure eventually connecting the regional hydrogen market, to increase market liquidity, leverage the lowest-cost renewable energy potential and enhance security of supply.

Compatibility with the neighbouring countries' vision of hydrogen development is important to facilitate cross-border market integration and to avoid competition distortion, where such risks exist. National approaches should also be compatible with EU developments, so that a regional hydrogen market can be created, and market fragmentation can be avoided. The Dutch government recognises the importance of a harmonised approach in (Northwest) Europe in its hydrogen strategy. This is also illustrated by the hydrogen backbone initiative, which is expected to connect the main industrial clusters in the Netherlands, Belgium and North Rhine-Westphalia. A particular point of attention will be the impact on the Dutch renewable hydrogen production of the interaction and competition with other European and non-European hydrogen markets. Monitoring of hydrogen policies of neighbouring countries and close cooperation to integrate networks and markets while avoiding eventual distortions are relevant policy priorities, also considering the long lead time for developing cross-border projects.

5.4 Key takeaways on the impact of policy options on hydrogen volumes & prices

Main takeaways from modelling regarding hydrogen (& derivatives) volumes.

Based on the modelling results presented in section 5.1, we summarise here the main takeaways regarding the impact of the policy options on the hydrogen (& derivatives) deployment:

1. **No renewable hydrogen or ammonia production, nor import is expected prior to 2035 in the absence of the considered hydrogen policy options (baseline)**. Both the RFNBO share of 0% and the absence of electrolysis capacity indicate that there is no expected domestic renewable hydrogen production in the baseline, nor will (imported) RFNBOs be used in the industry. Renewable hydrogen or ammonia is far too expensive compared to alternatives to be consumed by industry voluntarily. The lack of demand results in a lack of investments in production. However, **all policy scenarios are expected to result in renewable hydrogen production** in 2030 and 2035 (3.3 – 7.2 TWh). The renewable hydrogen produced domestically in the policy scenarios uses low-cost renewable electricity as input, during periods of abundant electricity supply. Domestic renewable ammonia production or import does not occur in 2030 or 2035 across all scenarios. We note that the decisions for producing ammonia domestically or importing it are very price sensitive and can hence vary on a year-by-year basis.
2. In the **baseline, significant amounts of low-carbon hydrogen are produced using autothermal reforming (80 TWh in 2035)**, driven by increasing ETS costs (and hence increasing costs of heat production with natural gas and fossil hydrogen production). In the absence of the considered

hydrogen policy options, significant decarbonisation (of heat generated with natural gas) in the (rest of the) chemical sector is expected, using both low-carbon hydrogen and electrification (more information in section 7.1). Large volumes of low-carbon hydrogen use (90 TWh in 2035) become cost-efficient as ETS prices increase and CCS becomes available. **In the policy scenarios, low-carbon hydrogen production only reaches 11 – 14.2 TWh in 2035.** This is because new hydrogen (including hydrogen) off-takers are forced to comply with the consumption obligation. The chemical sector would thus be forced to partially use a combination of low-carbon hydrogen and renewable hydrogen if it were to use hydrogen as decarbonisation option, instead of low-carbon hydrogen only. As the costs of the combination of renewable and low-carbon hydrogen outweigh the costs of natural gas + ETS, the sector does not opt for decarbonisation with hydrogen until 2040-2045. In the policy mixes, some of the domestic low-carbon and fossil hydrogen is replaced by renewable hydrogen, but the overall hydrogen consumption would still decrease, which is discussed in the next point.

3. In the **baseline, low-carbon ammonia imports increase substantially over time at the expense of imported and domestic fossil and ammonia production** , amounting to 28.2 TWh of low-carbon ammonia in 2035, while domestic fossil ammonia production would be phased out (from 17.5 TWh to zero in 2030). In the baseline, the fertiliser industry is expected to keep its SMR units active (but at a lower production level) to produce part of its ammonia using natural gas, while importing the majority of its ammonia depending on the price. This is driven by cost savings related to production process integration and by reacting to global market conditions. Fossil-based low-carbon hydrogen and ammonia production only remains for onsite consumption. **In the policy mixes, imported low-carbon ammonia completely replaces domestic (fossil) ammonia production using hydrogen as input and SMR units are expected to be decommissioned**. This is related to the fact that ammonia use is only included in the denominator of the RFNBO consumption obligation. Therefore, direct ammonia consumption is a way for companies to avoid higher obligations, and, hence avoid higher costs. Using low-carbon hydrogen instead of direct ammonia would increase costs as the consumption obligation then forces companies to use renewable hydrogen as well. The type of ammonia (renewable, low-carbon fossil-based) is not affected by the policy mixes; companies purchase the most cost-efficient type, low-carbon after 2029. Using renewable ammonia while selling HWIs is not cost-effective under the current assumptions. **The switch to low-carbon ammonia imports reduces the hydrogen demand substantially**. Such a large decrease would imply that companies shut down their domestic ammonia production and directly import fossil or low-carbon ammonia instead to make fertilisers and chemicals. Reversing this situation would come with difficulties, even if the price of renewable hydrogen would decrease to the point that the business case for restarting domestic ammonia production becomes positive. It would not only require the necessary investments to restart the assets but also regaining knowledgeable personnel, and a redevelopment of the client base. All policy mixes lead to a shutdown of Dutch low-carbon SMRs, increase in import of low-carbon hydrogen/ammonia, and no increase in renewable ammonia import.
4. **Policy mixes PM 2 and PM 3 result in the largest volumes of domestic renewable hydrogen production.** This is in line with the expectations, as these policy options offer the largest production subsidy (€4 bn). In 2035, PM 3 results in more electrolysis capacity than PM 2 (7.2 TWh and 6.8 TWh respectively), which implies that for the given subsidies, a higher consumption obligation results in less electrolysis capacity. PM 1 — with higher demand subsidies and lower production subsidies compared to PM 2 and PM 3 — results in less electrolysis capacity (5.9 TWh) than PM 2 and PM 3,

which is also in line with the expectations: with demand subsidies, domestic production competes with imports. This conclusion is confirmed by the results for policy mix PM 4 (even more demand subsidy and less production subsidy), which is expected to result in significantly less renewable hydrogen production (3.3 TWh). The impact on low-carbon hydrogen is mirrored.

5. Despite the uptake of domestic renewable hydrogen production, the **electrolysis targets are not expected to be reached** (maximum 3.6 GW in 2030 and 2035).
6. **It is not possible to draw on the basis of the modelling results conclusions on reaching the RFNBO targets,** as reaching the target is modelled as a hard constraint (hence a model input). The basis for this constraint is the assumption of a significant penalty to be in place in all policy mixes. The penalties are assumed to be high enough to discourage violating the RFNBO targets. In practice, reaching the target will depend on the costs for not reaching the target (penalty), and the physical availability of RFNBOs.
7. In the policy mixes, the expected RFNBO shares would exceed the industrial targets for 2030 and 2035 (with shares of 65%-66% by 2035) set by the RED III article 22a because of the interaction between subsidy and electricity balancing.

Main takeaways from analyses on volumes, contracts, costs and international developments

Based on the analysis presented in section 5.2, we have derived the following takeaways regarding hydrogen (& derivatives) prices and contracts:

1. Large renewable hydrogen projects face high risks: sizeable renewable hydrogen production projects are not yet operational and the costs to produce renewable hydrogen are still substantially higher than for fossil or low-carbon hydrogen. Project developers seek ways to limit their exposure to these risks. Long-term contracts are an adequate instrument to limit exposure. Even if production subsidies mitigate the price exposure, they will likely not cover the full production costs, but only the profitability gap. And in any case, producers will want to ensure the offtake of their production, in the context of a less liquid market with comparatively few consumers. Hence, **long-term contracts are expected to be the dominant contract type in the initial phase of renewable hydrogen deployment**.
2. If risks decrease and if more producers and users of renewable hydrogen enter the market, the liquidity of the market will gradually increase, and different contract types will be used. **A liquid market is however not expected to exist before 2030, and probably even by 2035.**
3. **Different hydrogen types have different cost structures.** Fossil hydrogen production is characterised by a high share of operational costs (input fuel and ETS costs). Low-carbon hydrogen production is specifically affected by the avoided ETS costs and additional costs for CCS (capex and opex). In the case of hydrogen produced via electrolysers, the capex represents a high share of the overall costs, while the operational costs mainly consist of the input electricity (network tariffs) and is hence depending on the source (nuclear, renewable) and electricity market situation.

Based on the analysis presented in section 5.2.2, the following key takeaways can be mentioned regarding international developments:

1. The future market for (renewable) hydrogen will not be a national market; plans for interconnecting the Dutch hydrogen backbone with the pipelines in neighbouring countries are at present being explored. The relevance of cross-border trade and infrastructure is confirmed by

other studies. **Compatibility of the Dutch hydrogen strategy and policy with the neighbouring countries' approach is important to facilitate cross-border market integration and to avoid competition distortion.**

2. In comparison to other Northwest European countries, **the Netherlands mainly focuses on the development of renewable hydrogen (and not also on low-carbon hydrogen) and reserves a relatively high budget** to stimulate its development. In addition, The Netherlands is expected to rely on imports of hydrogen derivatives to complement its domestic production.
3. **Demand-side policies in neighbouring countries may incentivise export of hydrogen produced in the Netherlands to these countries**, but this **risk is considered low** in the medium term under the considered policy options.

Assessment of the considered policy options against selected evaluation criteria

The assessment of the considered policy mixes leads to the following preliminary conclusions:

- **Effectiveness in achieving production target:** The production capacity targets (4 GW in 2030) would not be achieved by the policy scenarios under the modelling assumptions. Policy mix 1 would lead to the highest capacity in 2030 with 3 GW, while PM 4 would result in the lowest capacity. The combination of a consumption obligation with production subsidies is expected to result in the highest hydrogen generation capacities.
- **Effectiveness in achieving the industry consumption goal:** In the modelling approach, the industry consumption targets are met under any policy, as the penalty for not meeting the obligation is set at a higher level than the costs to meet the obligation. In other words, this is a modelling assumption. In practise, the uptake of RFNBOs in industry will depend on (1) the relative costs of meeting the obligation vs. the costs of not meeting the obligation (penalty), (2) the (physical) availability of RFNBOs, and (3) developments and/or actions that affect the basis (denominator) of the RFNBO obligation, such as a lower overall hydrogen consumption level. It is noted however, that the higher consumption obligation (in combination with stacking it with demand subsidies, PM 1) provides more certainty for reaching the industry goal than a partition where the industrial consumption obligation is lower, and the remainder of the industry goal has to be fulfilled through the demand subsidy (PM 4). Since companies with a demand subsidy are not obligated to make use of it and would only do so if it makes economically sense, the contribution of a demand subsidy is inherently less certain than a consumption obligation.
- **Administrative complexity:** The consumption obligation has a higher administrative complexity than the other policy instruments, given the need to create a flexible trading scheme for HWIs. Between the different types of the obligation, a partition of demand subsidy and consumption obligation (PM 4) is more complex than stacking (PM 1), since strict monitoring is required to implement the partition and to ensure that HWIs are not used for RFNBO volumes that receive opex demand subsidy. Also, the stricter the obligation, the higher the cost of meeting that obligation, and hence the higher the risk that companies would try to avoid costs affiliated with the obligation. As such, it is assumed that a stricter obligation requires closer monitoring. Lastly, CfDs for demand and/or production subsidies are administratively more complex than fixed premiums. In all options, 1-way CfDs have been used for this assessment.

Table 5-7 Assessment of the considered policy mixes against selected evaluation criteria

#	Criterion	PM 1	PM 2	PM 3	PM 4
1	Effectiveness of achieving production goal	Lower	Low	Low	Lowest
2	Effectiveness of achieving the industry goal	Higher	High	Low	Low
7	Administrative complexity	Complex	Complex	Least complex	Most complex

6 Impacts on industrial competitiveness & risk for anti-competitive behaviour

6.1 Estimated impacts on procurement costs of current and potential industrial hydrogen users

6.1.1 *Baseline results & Impacts of policy mixes*

The impacts of the policy mixes on the energy-related production costs show that these costs vary substantially across scenarios, involving both large energy cost increases and decreases (driven by demand subsidies). Table 6-1 shows the absolute changes in the energy-related production costs in different sectors in 2030 and 2035 under the different policy scenarios, compared to the baseline. The costs already take into account the available subsidies. We note that output levels are kept at a constant level (as can be noticed from the output volumes in Table 6-1). These results serve as proxy for the competitiveness impacts of the considered policy options.

Table 6-1 Scenario results - production costs related to energy contents Δ (mln €/year) and output volumes (totals, baseline results + difference with baseline) in Mton of product

Sector		2030					2035				
Scenario		*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*
Δ Production costs	Steel	n/a	-21	+0	+0		n/a	+83	+83		+92
	Chemical	n/a	+516	+523	+417	-200	n/a	+216	+289	+330	-80
	Fertiliser	n/a	+30	-26	+30	n/a	n/a	n/a			
	Pyrolysis	n/a	+369	+369	+372	-104	n/a	+225	+144	+108	+442
	HVO**	n/a	+357	+357	+361	-75	n/a	-36	-55	-56	-57
	PTL**	n/a	+0				n/a	+0			
Output	Steel	7	+0				7	+0			
	Chemical	10	+0				10	+0			
	Fertiliser	3	+0				3	+0			

*** HVO: Hydrotreated vegetable oil, PTL: Power to liquid.*

Regarding impacts **per sector**, we note that:

- In the **steel sector**, the energy-related costs are expected to increase compared to the baseline in all scenarios in 2035, ranging between € 83 and € 92 million per year. In 2030 however, energy costs are slightly in PM 1 (€ -21 million per year) and the same as the baseline in the other scenarios. The changes in the steel sector are not resulting from direct effects (i.e., policy mixes leading to different choices with regard to production options) but are driven by indirect effects. For instance, a decrease in low-carbon hydrogen production opens up CCS capacity for other emitters of CO_2, such as the steel industry, changing their price profile. The yearly differences in costs are relatively small when compared to, for example, the cost component of iron ore.
- In the **chemical sector**, the policy options are estimated to result in different decarbonisation decisions, thereby delaying certain investments in decarbonisation that were estimated to take place in the baseline in 2030 and 2035 (through low-carbon hydrogen use and electrification). As a result, heat production with natural gas remains the dominant heat option, complemented by the

use of RFNBOs (see explanations in chapter 5). The increase in energy-related costs in scenarios PM 1, PM 2 and PM 3 (ranging between € 216 and € 523 million per year) reflect the cost differential between electrification and low-carbon hydrogen use on the one hand, and heat production with natural gas (incl. ETS costs) and RFNBOs on the other hand. In policy mix PM 4, the energy costs are lower compared to the baseline (€ -78 to € -226 million per year), due to the (higher) demand subsidy that is allocated to the chemical industry and lowers the costs for RFNBOs, if only temporarily.

- In the **fertiliser sector**, energy-related costs are estimated to decrease by € 26 million per year in PM 2 and to increase by € 30 million in PM 1 and PM 3 (2030). For 2035 (and PM 4 in 2030) there are no estimated energy-related costs for the fertiliser sector, as the modelling results suggest that the policy options (in combination with international competition) would result in a non-profitable situation for SMR installations in the Netherlands which leads to the use of strictly imported ammonia. In other words, ammonia production units would be closed down in the Netherlands (only the last step – producing fertiliser from ammonia – remains).
- Regarding the **new (circular carbon) industry**, the observations are similar in 2030 for **pyrolysis** and **hydrotreated vegetable oil production.** In all scenarios, the energy-related costs increase compared to the baseline, except for PM 4. The cost increases (ranging from € 357 - € 372 million per year) are driven by the RFNBO consumption in these sectors (rather than low-carbon hydrogen in the baseline), which is not fully compensated by the available demand subsidies. In PM 4, the large demand subsidy results in lower costs for RFNBO consumption, thereby resulting in a decrease in energy-related costs compared to the baseline.

The cost differences between PM 4 and other scenarios indicate that allocating the available demand subsidies is a sensitive issue. The impact of different policy options on the energy-related costs per sector confirms that the costs decrease in all sectors that are foreseen to use RFNBOs in all years as the budget of the demand subsidies increases. In PM 4, which contains the most generous demand subsidy (€ 4 billion instead of € 1 or € 2 billion), there are cost savings compared to the baseline in all sectors in 2030.

6.2 Considerations for HWI market & general risks for anti-competitive behaviour

6.2.1 Considerations for the HWI market

The envisioned HWI system should allow for domestic trade in RFNBO certificates, which should enable hydrogen consumers under the consumption obligation without (sufficient) physical access to RFNBOs to meet the obligation. Theoretically, this market mechanism should lead to the most efficient allocation of resources under certain conditions. The envisioned HWI system has been explained in section 3.1.1. It decouples the physical RFNBO production and consumption from the compliance with the consumption obligation. A company that does not physically consume certified RFNBOs (or not sufficiently to meet the obligation) can purchase HWIs from a company consuming RFNBOs exceeding its obligations to comply with the HWI obligation. If certain conditions are met, such a market system should result in the most efficient allocation of resources. These conditions include (amongst others) having sufficient HWI market liquidity and a sufficient number of buyers and sellers, so that individual operators do not have excessive market power.

Large trading systems, such as the EU ETS, have proven to be efficient in reaching targets in a cost-efficient manner. The European Emission Trading System (EU ETS) should ensure that the GHG emission targets of the sectors in scope are met, by limiting and gradually reducing the allowed GHG emissions of all sectors in scope at EU level.[101] Not all participants are technically or economically able to reduce their GHG emissions to the same extent. Instead, all participants are required to cover their GHG emissions with ETS allowances, which they receive for free from the authorities (based on benchmarks) or can purchase on the ETS market.[102] Thus, if company A can reduce its GHG emissions at lower costs than company B and at lower costs than the market price for ETS-allowances, company B can purchase company A's emission allowances to cost-effectively reduce the total GHG emissions in the system. At system level, this results in the most cost-efficient emission reduction pathway, irrespective of countries and sectors. The trading mechanism in EU ETS functions relatively well because of its size. The GHG emissions of more than 11 thousand companies are regulated under EU ETS. As a result, there are numerous potential buyers and sellers, which contributes to the liquidity of the market, and to the fact that individual buyers do not have excessive market power, minimising the risk of market manipulation.

In the Netherlands, national trading systems are used, such as the national carbon levy for industry. EU ETS should in principle ensure an efficient decarbonisation pathway at EU level, as it does not consider geographical borders within the system. To meet national climate targets for industry, the Netherlands implemented a national system on top of EU ETS, which includes a trading mechanism: the national carbon levy for industry. Under the carbon levy, companies need to have sufficient dispensation rights to cover their emissions (similar to the EU ETS) or else pay the levy. As this national levy only covers Dutch ETS companies[103], it covers significantly fewer companies than the EU ETS (around 400). The Herfindahl-Hirschman index for the emissions of the Dutch stationary sources subject to the ETS for 2022 was 380 (out of 10 000).[104] The ACM indicates that when assessing company fusions, an HHI under 1000 is considered not to be a concern from a competition perspective.[105]

Against this background, the envisioned HWI system, which essentially is a domestic market of tradable RFNBO certificates, may not provide sufficient liquidity to function well in the near future due to high market concentration or low trade volumes. The envisioned HWI system will only cover new and existing industrial hydrogen users. While the exact number of future market participants is unknown, a significant growth in hydrogen users would need to be achieved to increase competition. The current hydrogen use is concentrated in oil refineries and chemical industries to produce products such as ammonia (as mentioned in section 2.2). There are two fertiliser producers in the Netherlands responsible for the large majority of the current national hydrogen demand. The modelling results in section 5.1.2 indicate that the policy mixes would not lead to domestic renewable ammonia production for the fertiliser sector. However, such a possibility cannot be excluded as actual investment decisions will be influenced by other factors, and considering recent announcements.[106] As hydrogen and derivatives will be employed only in cases where

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[101] In fact, EU, Iceland, Liechtenstein, and Norway.
[102] ETS allowances are distributed in two ways: by auctioning and by distributing free allowances to sectors with perceived risks of carbon leakage.
[103] And a handful of non-ETS companies.
[104] Own calculations based on Nea data. NEa (2023) Rapportages en cijfers EU ETS
[105] NEW (2013) Uitkomsten Economische Detectie. Het economisch detectie instrument toegepast op de Nederlandse economie in 2009
[106] See for example Yara wil in 2030 1,5 megaton minder CO2 uitstoten

there are no other suitable (cheaper) decarbonisation alternatives such as direct electrification available, it can be expected that the number of companies participating in the HWI system will be much smaller than the ones currently subject to the ETS Regulation or the Dutch carbon levy for industry. According to modelling results, the renewable hydrogen market volume under all policy mixes would be smaller than current fossil-based hydrogen production. Hence, among the relatively few market players on the demand side, two companies could have substantial market power if they ultimately decide to produce or purchase domestic renewable ammonia – and if they don't, this would significantly reduce the size of the market, which could also have negative impacts on liquidity.

On the supply side, it can also be expected that there will be very few national producers, in particular in the period towards 2030. The production would be strongly linked to the availability of subsidies and/or the consumption obligation, given the short-term lack of competitiveness vis-à-vis fossil hydrogen and the lead time necessary to implement the projects. As such, the HWI trading system is hence not expected to be liquid in the short-term and would involve a risk of market power on the demand (especially) but also to some extent on the supply side. In the long term (by or after 2035) HWI prices could incentivise new market entrants and the market could become more liquid.

This is also reflected by stakeholders, who voiced their concerns about a strict (42%) RFNBO consumption obligation, with virtually no availability of RFNBOs as of yet. Also, there seems little confidence in the tradability of HWIs. The key concern raised by stakeholders is the limited availability of RFNBOs. The consumption obligation should contribute to more revenue certainty for (future) RFNBO producers, thereby lowering risks for producers and enhancing positive investment decisions in the coming years. The essential question is to what extent the consumption obligation would effectively lower the risks for RFNBO producers. If the obligation would be too strict — i.e., if (potential) hydrogen users decide to lower their hydrogen consumption to reduce the obligation — it would not contribute to a better business case for renewable hydrogen producers. On the other hand, if designed well, the consumption obligation can contribute to an improved business case for RFNBO producers. The second concern is the (perceived) risk that the trading system would be illiquid for the reasons indicated above. In a worst-case scenario, this would imply trading would not occur and each industrial consumer targeted by the industrial obligation must physically consume RFNBOs, even if this is not the most efficient outcome at system level. Market power is very likely to be expressed on the demand side if large fertiliser producers switch to domestic renewable ammonia, and likely even on the supply side in the short-term at least, as mentioned. Lastly, there are uncertainties about the value of HWIs and the renewable energy units for the transport sector (HBEs). Under the HBE-obligation (as discussed below in Box 4), transportation fuel suppliers face penalties if they do not meet the HBE-obligation. However, the level of the penalty can vary (only the maximum penalty value is set[107]). In interviews, stakeholders mentioned that they value HBEs lower than the German counterpart, due to the penalty level, which is set at a lower level in the Netherlands, making companies more willing to pay the penalty. If the HWI-system were to follow the HBE-system, HWIs may be valued low in business cases of RFNBO producers, which may affect investment decisions in the coming years.

[107] For more information, we refer to this document.

Lastly, for industrial companies which are targeted by the HWI obligation but cannot use RFNBOs for technical reasons, purchasing HWIs from third parties is their only option to meet the obligation. If HWI trade does not materialise, these companies cannot meet their target. And in case HWI trade does materialise, these companies do not have a good negotiating position. Potential sellers can be aware that such company only has one option to meet the obligation, and thus should be willing to pay a high price. In addition, HWIs may not be sufficiently available for such companies, in case the larger users (e.g., fertiliser producers) purchase all available HWIs.

The lack of sufficient size and liquidity of a national HWI market could potentially be addressed by allowing trade of HWIs or corresponding certificates with other Member States. Cross-border trade systems would increase the overall supply and demand of HWIs and mitigate competition concerns. However, while Member States are required to recognise each other's guarantees of origin, it is uncertain whether such HWI trade would be allowed by the revised RED III in order for Member States to meet their RFNBO consumption goals for industry, as article 22a does not mention such possibility. On the basis of the current EU legislation, it seems that Member States would need to physically meet the RFNBO consumption goals for their industry.

Box 4 Interaction of the HWI and HBE market and price

HWI prices under the industrial RFNBO consumption obligation could be influenced by the HBE-mechanism for the Dutch transport sector ('*Hernieuwbare Brandstofeenheden*'). To meet the national goals for the transport sector under the REDII as well as the Dutch national climate agreement, the Netherlands has implemented the HBE-mechanism ('*Hernieuwbare Brandstofeenheden*' — Renewable Fuel Units).[108] This is a market-based instrument with tradable HBE units under the Energy for Transport ('*Energie voor Vervoer*') system on which the HWI mechanism under the industrial RFNBO consumption obligation is based. Under the Energy for Transport system, a certain share of transportation fuel delivered by fuel suppliers needs to be renewable, which is monitored through the quantity of HBEs that the fuel supplier has. Companies can earn HBEs for the renewable fuel, including RFNBOs, and renewable electricity they have supplied to the transport sector in the Netherlands. They can use these HBEs to meet their own compliance obligation or sell them to fuel suppliers with a shortage of HBEs. Since the delivery of RFNBOs to transport generates HBEs, HBE prices can affect HWI prices and vice versa.

The Dutch government intends to use the HBE mechanism to meet the 2030 renewable hydrogen consumption goal for mobility. Therefore, dependencies between HWI and HBE prices would increase. To meet the consumption goal of 1% RFNBOs in final energy consumption in the transport sector in 2030, the Netherlands is considering introducing the so-called *refinery route* ('*raffinageroute*').[109] Under the refinery route, refineries can earn HBEs for renewable hydrogen consumed to produce oil products. These HBEs would be used to determine the progress towards the RFNBO transport goal. The additional renewable hydrogen demand from refineries for meeting the transport goal could increase HWI prices. Similarly, the demand for meeting the industrial RFNBO consumption goal would decrease RFNBOs available for the transport goal, which could drive up HBE prices.

Both the transport (HBE) and industry (HWI) targets increase the demand for RFNBOs, thereby the willingness to pay, or the value. Thus, HBEs affect the value of RFNBOs, and therefore HWIs. The interactions between HWI and HBE prices occur when their value is higher than the cost differential between renewable and unabated or low-carbon hydrogen. In that situation, if HBE prices are higher than HWI prices, refineries would be willing to pay more than industrial facilities for renewable hydrogen to generate HBEs. This could, in turn, drive up HWI prices as industrial facilities would need to purchase HWIs instead of renewable hydrogen to meet their RFNBO consumption obligation. Similarly, if HWI prices are higher than that of HBEs, industrial facilities would be willing to pay more for renewable hydrogen to generate HWIs, which could drive up HBE prices up to the point that the RFBNO transport goal is achieved. These interactions could result in HBE and HWI prices converging, were it not for other factors that also impact HWI and HBE prices.

[108] For more details, see NEa (2023). Marktmechanisme hernieuwbare Energie voor Vervoer en HBE's.
[109] Rijksoverheid (2022). Kamerbrief over hernieuwbare waterstof in raffinageprocessen vanaf 2025.

Demand for HWIs should be larger than for HBEs but in a similar order of magnitude, considering the sectoral sub-targets and expected energy consumption. 1% of the assumed fuel consumption in the mobility sector in the Netherlands as defined in the modelling assumptions (see section 4.2) is 2.2 TWh, while the model results indicate that the policy mixes considered should lead to renewable hydrogen production in the range of 2-7 TWh (section 5.1.2). Hence, the interaction effects between the industrial and transport hydrogen demand detailed above should not be disregarded.

HWI and HBE prices are also driven by different factors beyond each other's prices, making it difficult to predict their degree of interaction in the future. For this reason, the HBE-mechanism is not in scope of our quantitative analysis. These factors may have a stronger influence on the HWI and HBE prices than interactions between them:

- **Biofuel and electricity prices:** since HBEs can also be earned from supplying sustainable biofuels and renewable electricity to the transport sector, the HBE price also depends on the cost differential between biofuels and fossil fuels, electricity prices and uptake of electric transportation.
- **Availability and price of domestically produced RFNBOs versus imports:** in the current HBE mechanism, HBEs can only be generated from the consumption of RFNBOs produced in the Netherlands. If this rule is extended to the refinery route, this would mean refineries can only generate HBEs from domestically produced renewable hydrogen. In contrast, HWIs can also be earned from the consumption of imported RFNBOs, which may have a different price than domestically produced RFNBOs.
- **Refinery route ending in 2030:** the refinery route for earning HBEs is expected to only be in place until 2030,[110] limiting any long-term impact this route would have on HWI prices.
- **Other design aspects and market expectations regarding the HWI mechanism and refinery route:** HWI and HBE prices are affected by the design details of the underlying mechanisms, such as banking and borrowing rules, as well as expectations on how the HWI and HBE may develop.

6.2.2 Risks for anti-competitive behaviour

Anti-competitive behaviour (gaming) is defined as behaviour by companies (either jointly or individually) that act to abuse or maintain a dominant position, negatively impacting competition and/or increasing the costs of the national hydrogen policies. As anti-competitive behaviour reduces the exposure of the companies to (competitive) market incentives, it can result in higher margins for companies, at the expense of increased costs for certain consumers (and the government). In the end, anti-competitive behaviour is problematic as it leads to higher societal costs.

Anti-competitive behaviour is relevant in the context of this study as substantial subsidies are considered within the policy mixes; anti-competitive behaviour could hence result in ineffective spending of public resources. We consider three main risks of anti-competitive behaviour in the considered policy options:

1. **Anti-competitive bidding strategies** by participants in tenders;
2. **Manipulation of the HWI market** to influence prices; and
3. **Other market manipulations,** such as the parameters setting the reference price for CfD-based subsidies.

In theory, companies may be incentivised to exert anti-competitive behaviour, as it can result in higher benefits for them (at the expense of higher societal costs). Anti-competitive behaviour could aim to achieve a number of objectives. It can increase perceived supply- or demand-side subsidies or impede competitors from receiving subsidies or cost-efficiently meeting their own consumption obligations. Also, it can create unduly arbitrage between the supply/demand-side subsidies and the HWI market, aiming to:

[110] Rijksoverheid (2022). Kamerbrief over hernieuwbare waterstof in raffinageprocessen vanaf 2025.

- Make excessive profits from simultaneously producing subsidised renewable hydrogen and selling HWIs on the supply side;
- Purchase HWIs at a price lower than perceived subsidies on the demand side; and
- Perceive capex subsidies and then fail to produce/consume renewable hydrogen.

All strategic behaviour should not necessarily be considered anti-competitive. Companies will need to make decisions regarding their required subsidy levels, the future renewable hydrogen (domestic and imports) and HWI prices, and level of competition in any tenders for supply- or demand-side subsidies. This means they will need to consider the actions of their competitors for their own decision-making, without this necessarily constituting anti-competitive behaviour.

We consider three driving factors influencing whether market actors have the opportunity to exercise anti-competitive behaviour. First, the number and concentration of participants for supply/demand-side support tenders (relative to available support budget). Second, the design aspects of the supply or demand-side support (i.e., use of competitive bidding or not, requirements to participants and penalties for non-delivery, segmentation of tender into capex categories, and limitations on supported volume/capacity per company). Third, the size and concentration of the HWI market.

Exploring gaming risks in the assessed policy options

Participation in demand-side tenders could be highly concentrated given the large share of fertiliser producers in total hydrogen demand. As mentioned before, current hydrogen use is dominated by two fertiliser companies. As a result, their share in demand-side tenders would be rather large should they rely in the future on domestic renewable ammonia (as discussed, modelling results indicate they would rely on low-carbon imported ammonia, but there are significant uncertainties in this regard). In tenders with a low number of participants, larger participants can bid strike prices significantly above the cost gap to adapt their process and consume renewable hydrogen, and still be awarded support. This is because a large part of the budget would be available for large consumers, even if smaller participants would bid lower strike prices for the demand-side support as these smaller participants can only untap a share of the budget due to their low demand. Moreover, smaller participants may have an incentive to anticipate and exceed the bid levels of the larger (marginal) participants, thus increasing the cost of support for the government. Segmenting the tenders into capex categories would not mitigate this risk and possibly worsen it, as the fertiliser industry would likely be grouped in the same category.

The demand-side concentration for RFNBOs could lead to anti-competitive behaviour in tender-based demand-side subsidies, particularly for policy mixes 1 and 4, which also provide opex subsidies for demand. On one hand, policy mix 4 foresees demand-side subsidies of around 4B € – the highest value among all options, which could lead to lower competition and hence a higher risk of gaming for that option. Current large hydrogen consumers in the Netherlands could be the only parties capable of fully utilising the subsidy volumes (should they participate), depending on tender design. On the other hand, policy mix 1 would allow the stacking of the demand opex subsidy and the demand obligation, which could be detrimental for the reasons detailed in Box 5 below.

Some measures could be taken to mitigate this risk. Primarily, an allocation of support using other mechanisms than tenders could be envisioned for the fertiliser industry (should they aim to consume domestic renewable hydrogen), with competitive bidding being reserved for actors from other industrial sectors (and transport). If tenders would still be employed for allocation of support to industrial sectors, the Dutch government could:

- Establish a minimum number of subscribed participants/volumes, e.g., 1.5 to 2 times the target supported hydrogen consumption;
- Set reserve prices based on an assessment of adaptation (for capex-based subsidies) and substitution (for opex-based subsidies) costs per industrial sector;
- Limit the hydrogen consumption supported per company (with an assessment needed to avoid the risk of not meeting the consumption targets); and
- Require participants to bid their true adaptation and substitution costs, to be verified ex-post with the realisation of investments.

The concentration on the demand side also results in risks for anti-competitive behaviour in the envisioned HWI market. Large market participants can influence prices. The general caveats of the HWI market have been explored in section 6.2.1. These caveats are also related to anti-competitive behaviour: large companies on the demand side can manipulate the market, by using their market power to affect prices. This could even lead to further market concentration. Even the perceived risk of market manipulation by certain market participants can prevent such market from functioning well.

Participation in supply-side tenders would expectedly be somewhat higher than in demand-side tenders (if the offered support is sufficient to attract interest), given the large number of announced projects for the production of renewable hydrogen in the Netherlands. However, there could be concerns particularly up to 2030. Planned hydrogen production projects in different maturity stages number over 40 projects for a total installed capacity of over 7 GW, if all projects were to be commissioned. The project size ranges considerably from a few MWs or lower to the GW scale. [111] Hence, if tenders' conditions are adequate, they could attract significant interest, possibly with participation being multiple times higher than tender contracting targets and thus leading to competitive behaviour from the participants. Depending on the number of tenders, the larger GW-scale projects could win a majority or even the totality of the offered support. As long as the bid ranking is done according to the lowest price (for example through a descending clock auction until the offered strike prices lead to the requested support matching the available subsidy volumes) this could prevent anti-competitive behaviour in the tendering phase (although suppliers could still unduly influence the HWI market as discussed in section 6.2.1).

The high number of announced renewable hydrogen projects in the Netherlands could reduce the risk of gaming in supply-side tenders, which is considered medium for all policy options, except for policy mix 4 where risks are lower. The actual room for gaming in supply-side tenders is dependent on how many projects would reach sufficient maturity to participate in the tenders, and thus the risk of gaming in any first supply-side tenders cannot be eliminated. Policy mix 4 has lower production subsidies, which could lead to higher competition in the tenders. In any case, despite the lower risks compared to demand-side

[111] TKI Nieuw Gas (2022).

tenders, the Dutch government could take measures to mitigate any potential risks, such as limiting the hydrogen installed capacity and/or production volumes supported per project to e.g., a few hundred MWs (weighed against benefits of economies of scale).

Undue arbitrage between the supply/demand-side subsidies and the HWI market leading to supramarginal profits to certain companies should also be considered. As indicated, depending on the supply-side tender design, a single or few large producers could receive all the available support. This would increase their competitiveness and likely make them some of the first large-scale producers of renewable hydrogen in the Netherlands. They would hence perceive a large share of HWIs in the absence of (non-subsidised) other producers under some of the policy mixes, at least until the resulting high HWI prices would incentivise other renewable hydrogen projects. Nonetheless, large projects participating in supply-side tenders would very likely already have an off-taker for the renewable hydrogen, with a hydrogen sale agreement already signed (possibly conditional on the receipt of subsidies) and with the off-taker also receiving HWIs for complying with its consumption obligation. Thus, the supply and demand for 'free' HWIs would be rather low in the beginning, while in later stages both supply and demand of HWIs would gradually increase — although even then, many or even the majority of hydrogen production projects will still rely on long-term hydrogen sale agreements to bank the investments.

Hence, the risk of undue arbitrage between the supply/demand-side subsidies and the HWI market is low for all policy options. Anyway, if mitigation options are still deemed necessary, they could include for example ex-post monitoring of the HWI market to identify potential market abuse.

Regarding the risk of manipulation of the reference price used to define payments in CfDs, first the way the reference price is set must be considered. The reference price can be set administratively, for example by authorities calculating a reference based on electricity market prices, electrolyser capex and the cost of capital, or it can be defined using a market-based approach, for example according to forward hydrogen price benchmarks. Market-based approaches for setting the reference price should theoretically better reflect the actual value of hydrogen but may be more subject to market manipulation if the hydrogen market prices can be influenced by e.g., a few large producers. However, although hydrogen price benchmarks are already available, a liquid market with transparent price formation will probably not exist before 2030. Hence, it is likely that initial support for hydrogen supply and consumption using CfD approach would set reference prices administratively. In this case, the risk for gaming is limited, although other challenges exist, particularly for the authorities to define the appropriate calculation method for the reference price.

Box 5 Stacking and partition and anti-competitive behaviour risks

Stacking (PM 1) and partition (PM 4) result in different dynamics concerning anti-competitive behaviour risks due to the interactions between the opex based demand subsidy and the HWI system. The risk for anti-competitive behaviour is present in both options but appears to be more profound in stacking compared to a partition. A partition only indirectly creates an uneven level playing field as companies with demand subsidies can average out their RFNBO cost that is needed to meet the consumption obligations. Since companies with demand subsidies have the flexibility to choose between receiving subsidies or earning HWIs, there is a risk of market manipulation by these companies. However, market manipulation may be more difficult due to the more complex interactions between HWI prices, demand subsidies, and cost differential of RFNBOs and fossil hydrogen. In case of stacking, an uneven playing field is created by directly lowering the costs of companies with demand subsidies to meet the consumption obligations. This creates more market distortion as companies with access to the cheapest RFNBOs will generally be the ones receiving demand subsidies, while companies without subsidies may face much higher costs for their RFNBOs to meet the consumption obligation. There is even a risk of over-subsidy for companies with subsidies as they can sell their excess HWIs to companies without a subsidy and a shortage of HWIs.

In both options, the smaller the group of companies with subsidies, the higher the risks of market manipulation of HWI prices, which in turn can affect RFNBO prices. This uneven playing field in both options can be reduced if all industrial hydrogen consumers are eligible for RFNBO subsidy if they effectively substitute their (existing) fossil hydrogen use, but this has a price-driving effect on RFNBO. All companies would be "willing" to pay more for RFNBOs. RFNBOs would then become more expensive for other users such as refineries that do not receive a similar subsidy. To what degree the increase in RFNBO price leads to an increase in price of the final products depends on how much of the costs for RFNBOs compared to fossil hydrogen a company could pass on in the first place. Furthermore, a larger subsidy budget would be needed (if the subsidy intensity is too low, the subsidy would not have any impact in Option A) and thus higher costs for the government. Also, providing subsidies for substituting fossil hydrogen with RFNBOs for all users risks causing a greater displacement of other GHG emission abatement technologies that may be more cost-effective from a climate perspective in reducing GHG emissions compared to tendering.

It should be noted that in either option, companies with access to the cheapest RFNBOs will likely be the ones willing to bid the lowest at the tenders. The only exception may be companies that expect that they are able to absorb the additional costs or pass these on, which may also bid for a lower subsidy to increase their chances of obtaining subsidy. For example, if bidders can secure customers willing to pay a premium for renewable hydrogen used in their products or could afford to request less subsidy. In this case, the tendering process would favour the conversion applications that require the least subsidy (and therefore cheapest for the government), but these may not necessarily be the ones with the lowest adaptation costs for the companies. Hence the industries with the highest adaptation costs may end up without subsidies, and therefore face a much higher cost burden than the ones that have the lowest costs of meeting the consumption obligation in the first place. From an economic perspective, this may be the most cost-effective way of achieving the industry goal. However, it is also more prone to market manipulation and risk of over-profits if there are only very few companies that earn excess HWIs to sell as they have more market power to set the HWI prices.

6.3 Investment certainty

Generally, the more subsidies are provided, the higher the investment certainty becomes for assets and operations that are being subsidised. A capex subsidy provides more investment certainty than an opex subsidy. An opex subsidy depends on the amount of renewable hydrogen produced or RFNBO consumed, which is uncertain, whereas a capex subsidy depends on the investment costs. Normative policies, such as the compliance obligation, also increase investment certainty for both the renewable hydrogen producer and consumer side (unless the penalty for not meeting the obligation is low), although probably less compared to subsidies due to the uncertainties around how the price of HWIs may develop.

Under a consumption obligation, the higher the obligation, the higher the investment certainty as long as the obligation is not set that high that investment leakage will occur:

- For producers, demand for RFNBOs is created that would have not been there without the obligation. This increases the investment certainty for electrolyser capacity as there is more certainty that there will be demand for renewable hydrogen. However, since the consumption obligation can also be fulfilled by imports, the consumption obligation may not necessarily increase investment certainty on its own for producers. If the business case for electrolysers outside the Netherlands and exporting the renewable hydrogen (or processing the renewable hydrogen outside the Netherlands and exporting its derivative due to the multiplier) to the Netherlands is better than the business case for domestic electrolysers, a consumption obligation would not significantly improve investment certainty. This depends on the presence of other mechanisms such as

production subsidies in the Netherlands compared to other countries and the available infrastructure for imports.
- For existing hydrogen consumers, a consumption obligation improves the investment certainty to adapt their installations to be able to use RFNBOs.
- For potential new hydrogen consumers, the consumption obligation could discourage investments in hydrogen use as it would come with the obligation to consume renewable hydrogen which is generally more expensive. If there is a desire to incentivise new hydrogen consumers to stimulate the (renewable) hydrogen market, an option is to differentiate the consumption obligation between existing and new users, with new users receiving lower/no consumption obligation in the early years.

6.4 Key takeaways on competitiveness of industrial hydrogen users and the risks for anti-competitive behaviour

Main takeaways from the modelling exercise regarding the competitiveness impacts

Based on section 6.1, the main takeaways regarding the impact on competitiveness are:

1. In general, the hydrogen policy options result in additional energy-related costs compared to the baseline situation (in which ETS is the driving policy). A portion of the cost increases are mitigated (or even reversed) as a result of demand subsidies. The demand subsidy in PM 4 is substantially more generous than in other policy scenarios, which results in cost savings in various sectors, compared to the baseline. Allocation of the available demand subsidies is a sensitive issue.
2. The SMR installations in the fertiliser sector are foreseen to close permanently, as a result of the consumption obligation.
3. **The modelling results do not provide a full picture of competitiveness impacts.** By definition, the final demand volumes (for e.g., steel) are held constant. As such, a decrease in production output volumes as a result of cost increases cannot be estimated. Lastly, other potential impacts along the value chain have not been estimated.

Main takeaways from the qualitative analyses regarding the impacts of the policy options on the competitiveness and the risks for anti-competitive behaviour

Based on section 6.2 the additional takeaways regarding the impact on competitiveness and the risks for anti-competitive behaviour are:

1. **The consumption obligation is likely to have significant (and varying) impacts on companies that are targeted by the obligation.** While the HWI system — which should allow HWI trade — can theoretically serve as a way to lower the overall costs to meet the obligation, there are various concerns. 1: The envisioned HWI system (a domestic market of tradable RFNBO certificates) is not likely to provide sufficient liquidity to function well. 2: Current RFNBOs' availability is low and future RFNBOs' availability is uncertain; a strict obligation exposes targeted companies to large risks. 3: Due to the high market concentration (if the two incumbent fertiliser companies switch to domestic renewable ammonia) or low trading volumes, there are risks for market manipulation, which could negatively affect the confidence of market participants in the HWI system. 4: Industrial companies which are targeted by the HWI obligation

but cannot use RFNBOs for technical reasons, purchasing HWIs from third parties is their only option to meet the obligation. If an HWI market does not properly materialise due to constraints in the production of RFNBOs, these companies cannot meet their target.

2. **The lack of sufficient size and liquidity of a national HWI market could potentially be addressed by allowing trade of HWIs or corresponding certificates with other Member States.** In addition, (starting with) a relatively low obligation decreases competitiveness risks. However, it is not certain such trade of certificates is allowed under the revised RED III.
3. **The impact of the RFNBO obligation heavily depends on the level of the penalty which is faced when the obligation is not met.**
4. **The highest risk for anti-competitive behaviour is related to possible manipulation of demand-side tenders and of the HWI price**, which may occur due to the limited number of hydrogen users which would be subject to the consumption obligation or eligible for demand-side subsidies:
   a. For the **demand side tenders**, various mitigation options are proposed in case tenders would be the preferred approach for allocating these subsidies, particularly the possible obligation for participants to bid on the basis of their true adaptation (for capex-based subsidies) and substitution costs (for opex-based subsidies), to be verified ex-post with the realisation of investments.
   b. Regarding the possible **manipulation of the HWI price**, both the risk for and impact of manipulation of the HWI price is higher with a high RFNBO consumption obligation.
5. **Risks also exist concerning the use of opex-based demand subsidies**, as they could distort competition between companies subject to the demand obligation (if stacking is allowed)

Assessment of the considered policy options against selected criteria

The assessment of the considered policy mixes leads to the following preliminary conclusions:

- The **risk of competitiveness loss and carbon leakage of the Dutch industry** is present in all policy options, as various sectors are estimated to face increasing costs compared to the baseline scenario. In practice, the competitiveness loss differs between sectors and even within sectors. This is driven by the fact that certain companies will be granted subsidies, while others will not.
- **Risk of other undesired effects - gaming risks. The risk that tenders for allocating production subsidies would be manipulated is considered medium.** While the number of participants would in principle be higher than in consumption subsidy tenders, it is still highly dependent on how many projects would be sufficiently mature to participate. **The risks of undue arbitrage between supply/demand side subsidies and the HWI market and manipulation of the reference price in CfD-based support are considered low**. This assessment applies to all policy mixes considered in this study. **While stacking increases the likelihood of reaching the RFNBO target, it also increases the risk of anti-competitive behaviour and market manipulation.** Regarding the possible **manipulation of the HWI price**, both the risk for and impact of manipulation of the HWI price is higher with a high RFNBO consumption obligation. Hence, these risks would be higher in policy options PM 1 and PM 2.
- **Investment certainty** in electrolysers and converting existing assets or building new assets to be able to consume RFNBOs is affected by availability and form of the subsidies and the

(strictness) of the consumption obligation (in combination with the penalty). The key difference between the policy options in this respect are the levels of the consumption obligation and types of subsidies provided. Since the consumption obligation in 2035 is 60% for all policy mixes, a higher obligation in 2030 shows a stronger commitment to reaching the 60% target and therefore provides more certainty. Also, a capex subsidy provides more certainty to invest (or not invest) than one combined with an opex subsidy. PM 2 is therefore rated as the policy option with the highest investment certainty and PM 4 the lowest.

Table 6-2 Assessment of policy mixes against selected criteria

#	Criterion	PM 1	PM 2	PM 3	PM 4
4	Risk of competitiveness loss and carbon leakage of Dutch industry	High risk	High risk	High risk	Moderate risk
5	Risk of other undesired effects (gaming risks)	High risk	Moderate risk	Moderate risk	High risk
6	Investment certainty	Medium	High	Medium	Low

7 Climate & energy impacts

7.1 Estimated impacts on energy & climate indicators

7.1.1 Baseline results

Without any further policy intervention, CO_2 emissions are estimated to decline sharply, CCS to ramp up and power consumption to almost double by 2035. Table 7-1 shows how different climate and energy indicators develop towards 2035 in the baseline. The decline in scope 1 CO_2 emissions in the Netherlands is driven by the ETS price (not by the ETS cap). EU-ETS emissions should be zero in 2039, which is the reason for the modelling assumption that the Dutch EU-ETS emissions decline in a linear path between 2020 and 2039. The other parameters disclose relevant information on the expected decarbonisation pathways in the absence of additional policies.

- Concerning **CCS**, significant amounts of CCS are estimated, reaching 29 Mton CO_2-equivalent in 2035.[112] Roughly half of this CCS is related to the domestic production of low-carbon hydrogen (90 TWh). This is the result of the pressure from ETS (and the national CO_2-levy), as well as the availability of mature CCS technologies by 2035.
- Concerning **electrification**, a moderate increase (of about 10%) is expected towards 2030. Between 2030 and 2035 however, a substantial increase (of almost 50% compared to 2030) is estimated in the baseline. For electrification, the maximum (grid) capacity is fully met. In other words, while further electrification might be cost-efficient, the assumed limited grid capacity prevents further electrification in the baseline.

In combination, CCS and electrification, and the uptake of new industry replacing fossil-based transport fuels with sustainable transport fuels are expected to decrease the Dutch scope 1 ETS emissions to 4 Mton CO_2 in 2035. The extent to which emission reduction may be partially offset by imported CO_2 emissions is out of scope.

Table 7-1 Baseline results – other relevant results (totals)

Indicator	2023	2030	2035	2023-2035	Unit
Scope 1 CO_2 emissions NL (ETS)	61	43	4	496	Mton CO_2
CCS applied	0	1	29	89	Mton CO_2
CCU applied	0				Mton CO_2
Power consumption for electrolysis	0				TWh
Total power consumption	108	120	177	1673	TWh

7.1.2 Impact of policy mixes

Under all policy options, scope 1 CO_2 emissions (ETS) in the Netherlands are substantially higher (+21 to 23 Mton CO_2eq by 2035) than in the baseline. This is due to delayed implementation of decarbonisation measures under the policy scenarios, as the consumption obligation forces end-users to use less cost-efficient decarbonisation technologies. Table 7-2 shows the same energy and climate

[112] The maximum (storage) capacity in 2035 is set at 38 Mton, which is hence not reached.

indicators as the table above, indicating the impact between the baseline and the policy scenarios in 2030 and 2035. In addition, the total public support (capex and opex) as well as the Δ net present values (NPV) are presented. The Δ NPV refers to the total additional costs made in the model relative to the baseline, using discounting to express the costs across the years in scope in current costs. This indicator therefore indicates the additional costs caused by the policy scenarios, excluding the subsidies. The highest increase in national scope 1 CO_2 emissions compared to the baseline is expected under PM 4 (+23.2 Mton), whereas the increase in PM 3 is more modest (+21.1 Mton). This is driven by a drop in CCS use under all policy options compared to the baseline situation in 2035, with a -13.9 Mton CO_2eq decrease in scenarios PM 1, PM 2, and PM 3 and a larger decrease of -14.6 Mton in PM 4. Also, the power consumption decreases in the policy scenarios, which is related to delayed or cancelled investments in electrification. While the domestic renewable hydrogen production results in additional electricity demand, the net effect is negative: in the scenarios, a very substantial amount of electrification in the chemical sector in the baseline is no longer cost-efficient under the proposed policies and is only partially replaced by renewable hydrogen production and consumption. The remainder of the foreseen electrification in the baseline is replaced by heat generation with natural gas (the current technology). In the policy scenarios, a large amount of heat in the chemical sector is decarbonised later (beyond 2035), compared to the baseline scenario.

Table 7-2 Scenario results - other relevant results (totals, baseline results + difference with baseline)

Indicator	2030					2035					Unit
Scenario	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	
Scope 1 CO_2 emissions NL	42.6	-0.6		-0.3	-0.7	3.9	+21.7	+21.3	+21.1	+23.2	Mton CO_2
CCS applied	0.8	-0.8			-0.8	29.2	-13.9			-14.6	
CCU applied	0	+0.4	+0			0	+0				
Power consumption, excl. electrolysis	120	+0				176.8	-26	-25.5	-25.2	-27.7	TWh
Total power consumption	120	+8.9	+8.8	+7.6	+3.9	176.8	-17.2	-15.3	-14.5	-22.8	TWh
Accumulated capex support	0	+3 235	+3 048	+2 736	+1 749	0	+3 236	+3 330	+3 832	+2 599	€ mln
Accumulated opex support	0	+1 174	+1 327	+1 168	+1 894	0	+1 174	+1 670	+1 168	+2 401	€ mln
Δ Net present value*	n/a	n/a				n/a	+14.1	+14.3	+14.3	+14.7	€ bn

** Δ NPV of the energy system, which refers to the total extra costs to the industry in each scenario relative to the baseline (excl. subsidy budget) across the years in scope of this project using discounting to express in current costs.*

The support and NPV indicators show that the policy options result in substantial additional costs in the considered timeframe (until 2035), amounting to €5 bn of subsidies plus around €14 bn of additional costs in the industry. In the model, the different subsidies are available from 2025 onwards; the year in which subsidies used are decided by the techno-economic optimisation. The results show that significant amounts of the subsidies are used by 2030 (accumulated subsidies ranging between €3.5 bn and €4.4 bn). By 2035, the full amounts of the available subsidies have been used. The NPV ranges between €14.1 and €14.7 bn, indicating that there are little differences between the policy options in terms of total costs for industry at national level. We note that this NPV indicator is not a macro-economic indicator and should not be interpreted as such. **The macro-economic effects of the policies have not been measured.**

Sector dynamics

Zooming in on CCS, the figures regarding power generation and consumption and CO_2 emissions disclose some underlying dynamics. Table 7-3 shows the model dynamics in more detail. We observe:

- Regarding **CCS**, no changes are observed between the baseline and the policy scenarios for CCS use in steel production and refineries (all changes are related to autothermal reforming). In scenario PM 4, the CCS uptake in autothermal reforming is slightly higher than in the other policy scenarios. We also note that (while not visible in the table), the policy options create more capacity for CCS in other processes due to the sharp decrease in production of low-carbon hydrogen.
- Regarding **power generation**, large increases in renewable electricity generation are expected between 2023 and 2035 in both the baseline and (all) policy scenarios. In 2030, an increase in renewable power generation is expected in all policy scenarios, compared to the baseline (+ 4-9 TWh). The policy scenarios have very limited impacts on other electricity generation technologies.
- Regarding **power consumption**, increases are estimated between 2023 and 2035, mostly for road transport (light-duty vehicles and heavy-duty vehicles), in the rest of the (chemical) industry and in the new industry (to a smaller extent). Electricity consumption for households, offices, public spaces and agriculture is fixed by assumption. The policy mixes have an impact on power consumption in electrolysers, autothermal reforming, and in the rest of the (chemical) industry. While the first two are in line with expectations (more electrolysis, less CCS), the latter is counterintuitive. The reason has been explained above: the negative decarbonisation effect in the policy scenarios compared to the baseline results in a net decrease in electricity use as heat production with natural gas remains cost-effective in more cases than the baseline.
- Regarding **CO_2 emissions**, national scope 1 ETS emissions are estimated to drop to zero by 2035 in fertilisers, refineries, steel production, and heat and energy generation based on natural gas. The remaining emissions are related to cracking naphtha. Under the policy scenarios, the only difference compared to the baseline is expected to occur in the rest of the (chemical) industry. Under the policy scenarios, electrification in the chemical sector is expected to take place beyond 2035, but to a smaller extent than in the baseline, which may also be related to the subsidising of renewable hydrogen.

Table 7-3 CCS (Mton CO_2eq), electricity (TWh) and CO_2 (Mton CO_2eq) volumes in scenarios (baseline value and difference compared to baseline)

	Location		'23	2030					2035				
Scenario			*B*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*	*B*	*PM 1*	*PM 2*	*PM 3*	*PM 4*
CCS use	ATR**		0	0.8	-0.8				15	-13.9			-14.6
CCS use	Steel production		0	0	+0				4.1	+0			
CCS use	Refineries		0	0	+0				9.7	+0			
CCS use	**Total CCS***		**0**	**0.8**	**-0.8**				**28.8**	**-13.9**			**-14.6**
Electricity generation & consumption	Coal	*Generation*	22.3	20	+0	+0.2			20	+0			
Electricity generation & consumption	Natural Gas	*Generation*	36.7	0	+0				-	+0			
Electricity generation & consumption	Renewables	*Generation*	47.5	96.5	+7.7	+8.8	+7.6	+4	152.1	-18.8	-17.2	-17.3	-22.8
Electricity generation & consumption	Rest	*Generation*	0.9	3.5	+0				4.7	+0			
Electricity generation & consumption	Electrolyser	*Consumption*	0	0	+7.7	+8.8	+7.6	+4	-	+7.7	+8.8	+8.8	+5
Electricity generation & consumption	Households	*Consumption*	24	24	+0				24	+0			
Electricity generation & consumption	Offices	*Consumption*	4.5	4.5	+0				4.5	+0			
Electricity generation & consumption	Public Space	*Consumption*	28.5	28.5	+0				28.5	+0			
Electricity generation & consumption	LDV**	*Consumption*	0	4	-0.9	-1.1	-0.9		24	+0			
Electricity generation & consumption	HDV**	*Consumption*	0	6.8	+1.1				14.8	+1			
Electricity generation & consumption	Agriculture	*Consumption*	10	10	+0				10	+0			
Electricity generation & consumption	Other industry	*Consumption*	39	39.3	+0				65	-24.9	-24.4	-24.5	-26
Electricity generation & consumption	PO**	*Consumption*	0	0.5	+0				0.8	+0			
Electricity generation & consumption	HVO**	*Consumption*	1.4	1.7	+0				1.9	+0			
Electricity generation & consumption	BTL**	*Consumption*	0	0.3	+0				0.3	+0			
Electricity generation & consumption	ATR**	*Consumption*	0	0.3	-0.2				3.0	-2.6			-2.8
Electricity generation & consumption	**Total electricity**		**107.4**	**120**	**+7.7**	**+9**	**+7.6**	**+4**	**176.8**	**-18.8**	**-17.2**	**-17.3**	**-22.8**
CO_2 emissions	Fertiliser Plants	*Generation*	0.9	0.4	+0			-0.4	0	+0			
CO_2 emissions	Refineries	*Generation*	13.8	10.9	-0.5	-0.4	-0.5	-0.4	0	+0			
CO_2 emissions	Naphtha Crackers	*Generation*	4.8	4.2	+0				3.9	+0			
CO_2 emissions	Steel Production	*Generation*	4.1	4.1	+0				0	+0			
CO_2 emissions	Heat generation (chemical industry NG)	*Generation*	23.2	22.9	+0.2			+0.1	0	+21.7	+21.3	+21.1	+23.2
CO_2 emissions	Energy generation (NG)	*Generation*	14.5	0	+0				0	+0			
CO_2 emissions	**Total CO_2**		**61.3**	**42.6**	**-0.3**	**-0.6**	**-0.3**	**-0.7**	**3.9**	**+21.7**	**+21.3**	**+21.1**	**+23.2**

**CCS refers to CO_2 emissions effectively captured and stored (taking into account efficiency losses in capture process)*
*** ATR: Autothermal reforming, BTL: biomass to liquid, HDV: Heavy-duty vehicles, HVO: Hydrotreated vegetable oil, LDV: Light-duty vehicles, PO: Pyrolysis.*

7.2 Key takeaways on the climate impacts of the considered policy options

Main takeaways from the modelling regarding climate and energy impacts

Based on the modelling results discussed in section 7.1, we present here the main takeaways regarding the policy options and the broader energy (system) and climate impacts:

1. **Without any further policy intervention, scope 1 CO_2 emissions (ETS) are estimated to decline sharply, CCS would ramp up while the power consumption is estimated to almost double by 2035** (due to electrification of transport and heat in the chemical sector, to the full amount of the electricity grid capacity). **Under all policy options, scope 1 CO_2 emissions in the Netherlands are substantially higher (+21 to 23 Mton CO_2eq) than in the baseline,** because of a decrease in CCS use and electrification compared to the baseline. However, the RFNBO consumption obligation would force the industry to decarbonise using renewable hydrogen rather than low-carbon hydrogen, which is less cost-efficient in the short run. Hence, industries are expected to stick longer to the current (fossil-based) production technologies, until the moment that decarbonising through RFNBOs is more cost-efficient. The investments in decarbonisation are estimated to occur beyond 2035.
2. **Regarding the impact of the different policy scenarios, most CO_2 emission reduction is reached in PM 3, but the differences are minor (range of 2 Mton) compared to the difference between the baseline and the policy options (more than 20 Mton).**
3. **All policy mixes lead to substantial additional costs at (energy/industry) system level of around €14 bn (accumulated over all considered years), and to government expenditures (€5 bn in total).** The macro-economic effects of the policies have not been estimated.

Assessment of the policy options against selected criteria

The assessment of the considered policy options against selected criteria leads to the following conclusions:

- **Risk of displacing other decarbonisation options in the short run:** The modelling results suggest that there is a high risk that the policy options delay investments in other decarbonisation options (in particular electrification and deployment of low-carbon technologies), as it forces less cost-efficient measures to be implemented. As such, more cost-efficient options would be displaced. In the short term, this would lead to less (or delayed) CO_2 emission reduction and higher system costs. This is not only a result of the modelling results, but also in line with expectations. Moreover, various researchers have warned about this, also in the light of the ambitious hydrogen-related targets under REPowerEU.[113] This risk is driven by the industrial consumption obligation, which is included in all policy mixes and only differs significantly in 4 years, having a modest impact on investment decisions. Hence, we conclude that the risk that the considered policy options displace other more cost-efficient decarbonisation options is high.
- **Risk of other undesired effects of the considered policy options:** Relevant undesired effects are related to **climate effects**, **system costs** (and potential excessive subsidies). The forecasted increase in CO_2 emissions in the short term (towards 2035) can obviously be considered an undesired consequence of the policy options. Whether or not the policy options would ultimately lead to more (accumulated) CO_2 emissions in the long run cannot be assessed based on the results. It is likely that pushing RFNBOs in a relatively early stage leads to more (cost-efficient) decarbonisation of hard-to-abate emissions in a later stage, which cannot be achieved with electrification. This (and whether or not that justifies the push for RNBOs now) has not been assessed in this research. The additional (system and governmental) costs related to the policy

[113] Battaglini & Ceglarz (2023). The role of hydrogen in a future, low-carbon, and secure European energy system.

options can also be considered undesired consequences. There are no major differences between the policy options, but all options lead to significant additional costs. This also implies that excessive subsidies at system level seem not to be an issue, compared to the costs related to the RFNBO consumption obligation.

- **Strategic autonomy:** The most relevant indicator of strategic autonomy is the domestic renewable hydrogen generation capacity (and production). Hence, the scores follow this indicator. Indirectly, the extent to which the Netherlands remains attractive for the production of various energy-intensive industrial products (where energy is used as fuel or feedstock), is also relevant for the strategic autonomy.
- **Coherence with other energy & climate policies:** There are several policies and strategies that are somewhat related to the specific goals of the considered hydrogen policy options. In this section, we consider the policy options related to the **climate goals.** The considered hydrogen-related policy options are not in line with the decarbonisation targets in the short run (towards 2035), as all assessed policy options would force industries to use less cost-efficient decarbonisation technologies. Investments in decarbonisation may hence be postponed until the moment that the costs of the decarbonisation options with added consumption obligations are more cost-efficient than using the fossil-based alternative (and ETS-costs). This is estimated to result in higher CO_2 emissions in 2035. However, in order to reach full decarbonisation in 2050, RFNBOs will have to play a major role: certain processes cannot be electrified, and CCS is likely to be for several industrial processes not the most cost-efficient option in the long run. To reach full decarbonisation, vast upscaling of renewable energy based and low-carbon technologies (both on the production, storage and consumption side) will be required. In the absence of timely upscaling (and related cost reductions), the existing decarbonisation options may not be sufficient to timely reduce and ultimately phase out the hard-to-abate emissions, as RFNBOs may be insufficiently available and/or expensive. **Hence, policies to support RFNBO production and consumption are necessary, but should be designed and implemented taking into account their short term (climate) cost impacts,** as well as other costs and benefits. Alignment with the approach and pace in neighbouring countries (and at EU level) seems logical, given the relevance of international developments and trade in RFNBOs.

Table 7-4 Assessment of the considered policy mixes against selected criteria

#	Criterion	PM 1	PM 2	PM 3	PM 4
3	Risk of displacing other decarbonisation options	Higher risk	Higher risk	Higher risk	High risk
5	Risk of other undesired effects (CO_2 emissions, system costs, over-subsiding)	Highest risk	Higher risk	High risk	Highest risk
8	Energy independence	Positive	Positive	Most positive	Negative
9	Coherence with other relevant policy instruments (from energy/climate perspective)	Long term CO_2 emissions cannot be estimated, which are required to score this criterion. However, the increased emissions in the baseline are a serious concern.			

8 Robustness of the of results

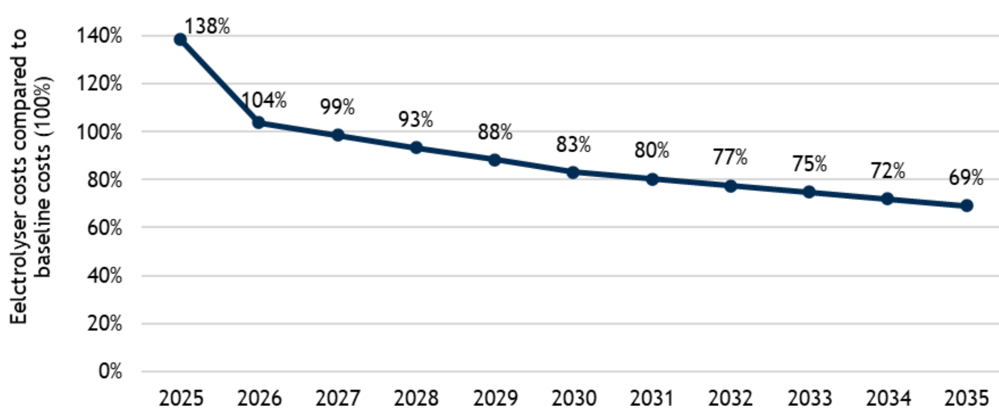
8.1 Quantitative sensitivity analysis

Based on the initial results presented above, EZK requested 6 additional model runs, 2 of which explore different changes with respect to the RFNBO consumption obligation, and 4 'regular' sensitivity analyses exploring the presented results' robustness to a change in external parameters. The model runs are set up as follows:

- **S1 - Light obligation:** The RFNBO consumption obligation is set 50% lower compared to the values of PM 3 and 4 (i.e., 12% in 2030).
- **S2 - No obligation:** The RFNBO consumption obligation is set equal to zero.
- **S3 - Lower investment costs for electrolysers (with learning curves):** The capex costs for electrolysers are affected by a learning curve. This also impacts the global renewable hydrogen and ammonia prices.
- **S4 - Higher price for natural gas:** The global natural gas price is increased by +25%. This also causes an increase in global fossil and low-carbon hydrogen and ammonia prices.
- **S5 - Faster decarbonisation of German transport sector:** Export of non-sustainable fuels to Germany decreases to zero over the period 2025-2040 (rather than 2035-2050), which increases the demand for RFNBOs and low-carbon fuels in Germany.
- **S6 - Cheaper RFNBO imports:** The costs for RFNBO imports are lowered, by applying the learning curve for electrolysers from S3 and assuming lower electricity prices abroad (factor 1.65). Foreign electrolysers are assumed to have a load factor of 4000 FLH.

The lower investment costs for electrolysers are implemented based on the learning curve as shown in Figure 8-1. For S3 and S6, a yearly capex learning curve profile was used, which is in line with a study from CE Delft and TNO[114], commissioned by EZK. In addition, a "balance of plant" factor of 1.4 was added (accounting for costs associated with AC/DC conversion, water treatment, storage of oxygen/hydrogen and processing of rest heat). The graph below shows the total electrolyser investment costs resulting from this learning curve compared to the electrolyser investment costs in the other scenarios.

Figure 8-1 Electrolyser costs in S3 and S6 (as percentage, relative to the baseline costs of 100%)



[114] CE Delft & TNO (2023). Afnameverplichting waterstof. Unpublished.

The results show the differences between the original baseline and the sensitivity adjusted baselines, and the difference between policy mix 3 (PM 3) and the sensitivity adjusted PM 3. Table 8-1 and Table 8-2 show the results of the sensitivity analysis on the hydrogen and ammonia domestic production and import volumes for 2030 and 2035 respectively. Table 8-3 and Table 8-4 show the impact on other key indicators, being the installed electrolyser capacities, scope 1 ETS CO2 emissions, CCS use, power consumption and the net present value NPV. 'B' refers to the regular (first column) and adjusted baselines (e.g., the baseline result with increased natural gas prices for S4). The impacts (indicated by + or -) are relative to the original baseline for S1 and S2, or relative to the adjusted baselines for S3-S6. The NPV is relative to the original baseline.

The amount of renewable hydrogen produced increases in case of light (S1) or no (S2) RFNBO consumption obligation by 2030, compared to the baseline (without subsidies). Compared to policy mix 3, the 'S1 light obligation' results in an increase in renewable hydrogen production and 'S2 no obligation' in a decrease. Under the light consumption obligation, decarbonisation with hydrogen use in the chemical industry turns cost efficient five to ten years earlier, compared to the scenarios with higher obligations. This translates into an earlier demand for renewable hydrogen to meet the (light) consumption obligation in this sector, explaining the increase in renewable hydrogen production and increased electrolysis capacity (5 GW in 2035). The light obligation also results in a lower decrease in low-carbon hydrogen production under the policy scenarios (compared to the baseline) which explains the overall increased demand for hydrogen described above. The RFNBO share is expected to reach 31% in 2030 and 33% in 2035 in this scenario.

Without the obligation, renewable hydrogen production is only supported by production and consumption subsidies. This results in a low amount of electrolysis capacity. No additional capacity is expected after the subsidy budget has been used. Aside from the small increase in renewable hydrogen production compared to the baseline, the scenario results without consumption obligation are very similar to the baseline scenario results. Low-carbon hydrogen production remains the preferred option, only partly replaced by the aforementioned subsidised renewable hydrogen. Fossil hydrogen volumes stay at baseline level, hydrogen import figures, and ammonia imports/production figures are unchanged. Lastly, the uptake of CCS and CO_2 emissions are similar to in the baseline scenario. The total energy related costs for the industry (NPV) are significantly lower under the light obligation. Without the obligation, the relative NPV is negative since the only change relative to the base case is the provided € 5 billion in subsidies.

The modelling results confirm that introducing decreasing capex values (learning curve) for electrolysers (S3) leads to more domestic renewable hydrogen production around 2035-2040, but not in the baseline. One remarkable result is the relative decrease in renewable hydrogen production in 2030 in S3 compared to other scenarios. This is explained by the yearly capex decrease for electrolyser capacity, which incentivises postponing the construction of electrolysers. As a result, the electrolysis capacity only reaches 1.3 GW in 2030; the 4GW electrolyser target for 2030 is not within reach. The production of renewable ammonia in 2030 is incidental and negligible in this scenario; renewable ammonia production is consistently less attractive than the alternatives and only occurs in 2030. The effects on fossil and low-carbon hydrogen are marginal and mostly consequences of the pattern described above. It is noted that the baseline results do not change: even with decreasing capex values for electrolysers, no domestic renewable hydrogen production is foreseen by 2035. The hydrogen import figures, and ammonia imports/production figures are largely unchanged.

A 25% increase in natural gas prices (S4) would lead to higher renewable hydrogen production under the policy scenarios (by more than 50%), but not in the baseline. In other words, a substantial increase in gas prices increases the demand for renewable hydrogen as early as 2030 as it makes the alternatives more attractive. Higher natural gas prices would also lead to increased low-carbon hydrogen use in 2030 (both in the baseline and PM 3). In 2035, there is no difference with respect to fossil hydrogen volumes in the scenario with increased natural gas prices. The hydrogen import figures, and ammonia imports/ production figures are unchanged.

Earlier decarbonisation of the German transport sector (S5) results predominantly in increased low-carbon hydrogen production in the Netherlands in the baseline, which is offset in the policy scenarios. The increased demand for sustainable fuels leads to slightly increased ammonia imports and investments in technologies such as hydrotreated vegetable oil (HVO), pyrolysis and power-to-liquid. To meet the demand for sustainable fuels from Germany, low-carbon hydrogen production is also increased in the baseline, which is counteracted if the RFNBO consumption obligation is introduced. In the scenario with the obligation, the demand for sustainable fuels is met with technologies with less impact of the RFNBO obligation (such as HVO) or direct imports.

Lower costs for RFNBO imports (S6) drastically lowers domestically produced renewable hydrogen. Assuming lower costs for RFNBO imports (i.e., applying lower costs for electrolysers and assuming low electricity prices abroad) results in large-scale imports of renewable hydrogen, starting around 2036. Although electrolysis capacity is comparable to S3 in 2030 and 2035, the dominant strategy after 2035 is importing renewable hydrogen in S6 and domestic production of renewable hydrogen in S3. Before 2035, reducing overall hydrogen consumption remains more economically attractive than importing RFNBOs. The baseline results are largely unaffected, since RFNBOs remain economically inefficient without subsidies or a consumption obligation.

The main takeaways of the sensitivity analysis are:

- **Baseline results are marginally affected at most, except for the low-carbon hydrogen volumes which increase significantly with increased demand for sustainable fuels from Germany.**
- **Various developments could lead to increased domestic renewable hydrogen production volumes (higher natural gas prices and lower electrolyser investment costs), but the 4 GW electrolysis target in 2030 is not within reach.**
- **A lighter RFNBO consumption obligation leads to better results, in terms of electrolysis capacities, CO_2 emissions, and industrial competitiveness, due to new hydrogen consumption (e.g., in the chemical sector) being less costly.**

Table 8-1 Results of the sensitivity analysis: volumes and changes in hydrogen and ammonia domestic production and imports in 2030 (in TWh)

Scenario		B	PM 3	S1	S2	S3		S4		S5		S6	
						B	PM 3	B	PM 3	B	PM 3	B	PM 3
Domestic production	Renewable H_2	0	+5.0		+3.3	0	+2.7	0	+7.0	0	+5.0	0	+4.6
	Low-carbon H_2	10	-6.7		-3.3	10	-3.3	13	-3.3	13	-6.7	10	-6.7
	Fossil H_2	10	+0			10	-1.3	10	-1.3	10	-0.1	10	-0.1
	Renewable NH_3	0	+0			0	+1.2	0	+0				
	Low-carbon NH_3	0											
	Fossil NH_3	5	+0			5	-1.2	5	+0	5	+0	5	+0
Imports	Renewable H_2	0											
	Low-carbon H_2	0											
	Fossil H_2	0											
	Renewable NH_3	0											
	Low-carbon NH_3	28	+0			28	+0	28	+0	28	+0	28	+0
	Fossil NH_3	0											

The table first shows the regular baseline and PM 3 results (for comparison), followed by S1 and S2. For S3-S6, both the impacts on the baseline results are shown (B) and the impacts on PM 3. The impacts (indicated by + or -) are relative to the relevant baselines (which is the original baseline for S1 and S2, and the new baselines for S3-S6).

Table 8-2 Results of the sensitivity analyses: volumes and changes in hydrogen and ammonia domestic production and imports in 2035 (in TWh)

Scenario		B	PM 3	S1	S2	S3		S4		S5		S6	
						B	3	B	3	B	3	B	3
Domestic production	Renewable H_2	0	+5.9	+10.0	+3.3	0	+9.6	0	+9.3	0	+5.8	0	+9.5
	Low-carbon H_2	90	-75.7	-55.7	-3.3	90	-72.4	87	-69	139	-125.8	90	-72.4
	Fossil H_2	0											
	Renewable NH_3	0											
	Low-carbon NH_3	5	-5.0		+0	5	-5.0	5	-5.0	5	-5.0	5	-5.0
	Fossil NH_3	0											
Imports	Renewable H_2	0											
	Low-carbon H_2	0											
	Fossil H_2	0											
	Renewable NH_3	0											
	Low-carbon NH_3	28	+5.0		+0	28	+5.0	28	+5.0	35	+2.4	28	+5.0
	Fossil NH_3	0											

The table first shows the regular baseline and PM 3 results (for comparison), followed by S1 and S2. For S3-S6, both the impacts on the baseline results are shown (B) and the impacts on PM 3. The impacts (indicated by + or -) are relative to the relevant baselines (which is the original baseline for S1 and S2, and the new baselines for S3-S6).

Table 8-3 Results of the sensitivity analyses: other indicators in 2030

Scenario	*B*	*PM 3*	*S1*	*S2*	*S3*		*S4*		*S5*		*S6*		Unit
Indicator					*B*	*3*	*B*	*3*	*B*	*3*	*B*	*3*	
Electrolyser capacity*	**0**	*+2.5*	*+2.5*	*+1.7*	**0**	*+1.3*	**0**	*+3.5*	**0**	*+2.5*	**0**	*+2.3*	GW
Scope 1 CO_2 emissions NL (ETS)	**43**	*-0.3*	*-0.4*	*+0.2*	**43**	*-0.1*	**41**	*-0.9*	**43**	*-0.6*	**43**	*-0.2*	Mton
CCS applied	**1**	*-0.8*	*-0.8*	*-0.6*	**1**	*-0.8*	**1**	*-0.8*	**1**	*-0.8*	**1**	*-0.8*	CO_2
Total power consumption	**120**	*+7.6*	*+7.6*	*+5.0*	**120**	*+4*	**120**	*+10.6*	**120**	*+7.6*	**120**	*+6.9*	TWh
Δ NPV**	**n/a**	*14.3*	*6.6*	*-3.1*	*0.0*	*7.3*	*24.1*	*37.2*	*14.7*	*32.9*	*0.0*	*5.2*	€ bn

The table shows the regular baseline and PM 3 results (for comparison), followed by the S1 and S2 results. For S3-S6, both the impacts on the baseline results are shown (B) and the impacts on PM 3. The impacts (indicated by + or -) are relative to the relevant baselines (which is the original baseline for S1 and S2, and the new baselines for S3-S6).
** The capacity is determined based on the energy value of the produced hydrogen, assuming 2000 full load hours.*
*** NPV relative to the original baseline. The values do not refer to 2030, but to the entire period.*

Table 8-4 Results of the sensitivity analyses: other indicators in 2035

Scenario	*B*	*PM 3*	*S1*	*S2*	*S3*		*S4*		*S5*		*S6*		Unit
Indicator					*B*	*3*	*B*	*3*	*B*	*3*	*B*	*3*	
Electrolyser capacity*	**0**	*+3.6*	*+5.0*	*+1.7*	**0**	*+4.8*	**0**	*+4.7*	**0**	*+2.9*	**0**	*+4.8*	GW
Scope 1 CO_2 emissions NL (ETS)	**4**	*+21*	*+14*	*+0*	**4**	*+18*	**4**	*+20*	**4**	*+22*	**4**	*+20*	Mton
CCS applied	**29**	*-14*	*-10*	*+0*	**29**	*-13*	**29**	*-13*	**35**	*-23*	**29**	*-14*	CO_2
Total power consumption	**177**	*-25*	*-2*	*+4*	**177**	*-10*	**178**	*-11*	**180**	*-18*	**177**	*-10*	TWh

The table shows the regular baseline and PM 3 results (for comparison), followed by the S1 and S2 results. For S3-S6, both the impacts on the baseline results are shown (B) and the impacts on PM 3. The impacts (indicated by + or -) are relative to the relevant baselines (which is the original baseline for S1 and S2, and the new baselines for S3-S6).
** The capacity is determined based on the energy value of the produced hydrogen, assuming 2000 full load hours.*

8.2 Conditions & facilitators for hydrogen deployment in the Netherlands

Economic support or obligations for domestic production and consumption of renewable hydrogen in the Netherlands alone will not be sufficient to meet the stated Dutch policy goals. Various additional initiatives will have to be taken, supported by a diverse set of policies at EU and national levels. Moreover, reaching the goals is also dependent on exogenous developments, which are not under control of the Dutch government.

In this section, the main developments and associated policies are discussed, which are pre-conditions or facilitators to developing large-scale hydrogen production and consumption in the Netherlands, in addition to the supply- and demand-side measures assessed in this report. It must also be noted that for most of these elements, it is not fully clear whether they can be considered as a pre-requisite (a sine qua non condition for achieving the goals) and/or as a facilitator (an element which helps but can possibly be missed, at the expense of higher costs to achieve the policy goals).

Guarantees of Origin (GOs) and certification

To adequately value renewable (and low-carbon) hydrogen, a system of Guarantees of Origin (GOs) and certifications will be required, as defined in the Article 19 of the RED II. A GO provides information to energy suppliers and consumers on the quality of the energy supplied/used (including hydrogen) – indicating that it is obtained from renewable sources. The EU-wide implementation of such a system is necessary to guarantee that the development of hydrogen does not actually compromise the broader climate goals, and a worldwide implementation would contribute to the development of a global market.

The facilitation of cross-border trade of hydrogen will also require the mutual recognition of certificates between countries. Experience regarding cross-border trade shows that mutual recognition of standards even between EU member states is not straightforward and requires further attention. Furthermore, the EC's REPowerEU plan envisions 10 million tonnes of renewable hydrogen imported from third countries, constituting about 50% of the EU's consumption by 2030. The absence of a global certification system (and the corresponding lack of confidence in the climate-neutrality of this imported hydrogen and derivatives) would significantly compromise the EU bloc's climate goals. Mutual recognition of certificates with neighbouring countries, however, would be less relevant given such cross-border trade could be limited in the short- to medium-term compared to imports from major hydrogen and derivatives producers in the Nordics, Southern Europe and non-European countries. HyXChange, launched in October 2022 by Gasunie, is the first European pilot project of such a GO certificate for hydrogen, currently only valid in the Netherlands.[115]

In view of the creation of **global standards and certification processes within the hydrogen value chain**, the H2GLOBAL STIFTUNG (based in Hamburg) has in collaboration with HYDROGEN EUROPE published in September 2023 a Policy Brief entitled "STANDARDIZING HYDROGEN CERTIFICATION: ENHANCE TRACEABILITY, TRANSPARENCY, AND MARKET ACCESS". This publication describes the need for, and benefits of globally harmonised standards and certification processes across the hydrogen value chain. The currently starting market ramp-up is based on an increasing need for sustainability. While certification is a major tool supporting policies allowing monetizing the sustainability value, it is associated with major challenges: lack of globally aligned cross-sector certification standards and lack of integration among existing certification services.[116]

Safety standards

The implementation of adequate and consistent safety standards will be required for the safe production, transport, storage and consumption of hydrogen and its derivatives. Hydrogen production and use are already well-established in industry for chemical and metallurgical applications, but it has not been used as a fuel in significant quantities (other than fuelling rockets) since the early 20th century (when city gas lighting was replaced by electricity). For hydrogen to be used on a large scale, adequate safety standards corresponding to the requirements and expectations of the 21st century need to be established. These safety considerations will play a significant role in determining the economics and global tradability of hydrogen by defining which hydrogen derivatives can be transported over long distances, and through which transport modes.

Hydrogen is a colourless, odourless, tasteless and non-poisonous, however highly flammable gas in normal condition. Hence, strict safety standards must be (and have been) respected to reduce the risks. Ignition can occur at a much wider range of volumetric hydrogen-to-air ratio (between 4-75%)[117]

[115] IEA (2023). Hydrogen Guarantee of Origin Scheme.
[116] H2Global-Stiftung-Policy-Brief-05_2023-EN.pdf (hydrogeneurope.eu)
[117] Dagdougui et al. (2018). Hydrogen infrastructure for energy applications.

compared to natural gas (which is only flammable within the 5-20% range), making the combustion of hydrogen much harder to control. In line with its hydrogen strategy, the Dutch government launched the Hydrogen Safety Innovation Programme in 2020 (expected to end by 2024), which will be implemented as a public-private partnership between the national government and other stakeholders, such as the network operators, emergency services, knowledge institutes and private companies. The aim of the programme is to identify safety issues concerning hydrogen and to propose the necessary policies that will allow these issues to be adequately addressed. For the establishment of an international hydrogen market (see section 5.2.2) this work needs to be carried out on a European/global level as well. The lack of regulatory clarity, and specifically the lack of technical and safety standards still poses a risk for investors.[118] Many countries already started amending the existing regulatory framework to include hydrogen.[119] However, this led to inconsistencies (i.e., the German Federal Land Utilisation Ordinance restricts hydrogen storage to industrial sites, however, allows refuelling stations – also storing hydrogen – in residential areas as well). When reviewing and possibly amending the existing Dutch safety regulation, authorities should ensure that established applications are not prioritised at the expense of novel applications (such as transport through repurposed pipelines). Certainty regarding safety standards is necessary to enable the timely rollout of dedicated hydrogen infrastructure.

Hydrogen infrastructure & storage

Development of dedicated hydrogen and derivatives infrastructure will be necessary to enable physical cross-border and domestic trade of hydrogen. The already existing extensive infrastructure used for import-export (or just storage and transportation) of gases (including natural gas and hydrogen) and derivatives needs to be refurbished/repurposed and expanded. This infrastructure includes:

- **Hydrogen and derivatives import terminals:** Hydrogen is a much smaller molecule than natural gas, making the gas leakier and requiring more robust storage tanks and pipes. Its boiling point is also much lower, meaning that hydrogen tanks and pipes would also have to be much more efficiently insulated. The derivatives of hydrogen (e.g., ammonia) are better suited for transportation and storage but require additional technology and the existing terminals to be retrofitted otherwise (e.g., with ammonia cracking plants where required). This retrofitting is a technologically complex and expensive process, and in some cases only possible for the elements of the infrastructure that were initially designed with this potential change of use in mind (taking it into account during the material selection).[120]
- **The Dutch hydrogen backbone:** which is a national rollout plan to create a transport grid that covers five major industrial clusters (Northern Netherlands, North Sea canal area, Rotterdam-Moerdijk, Zeeland-Western Brabant and Chemelot/Limburg), connecting them, providing access to storage facilities and connecting the Netherlands with neighbouring countries. Realising this national transport network is of importance for the development of a sustainable hydrogen chain and thus the sustainability of the Dutch energy and resource use.[121] The network is being built in several phases, with the goal to have the initial network configuration completed by 2030. To realise this planning, the Dutch government emphasises a flexible, adaptive and phased approach

[118] EIB (2022). Unlocking the hydrogen economy – stimulating investment across the hydrogen value chain.
[119] OECD (2023). Risk-based Regulatory Design for the Safe Use of Hydrogen.
[120] Fraunhofer (2022). Conversion of LNG Terminals for Liquid Hydrogen or Ammonia.
[121] Ministry of Economic Affairs and Climate (2022). Ontwikkeling transportnet voor waterstof

because the development of the production, demand and infrastructure must be considered in conjunction and still has its uncertainties. In mid-June 2022, the Netherlands approved its first plans for the developments of this network. This first phase is planned to be realised by 2025, which includes developing the network in coastal industrial clusters and in the northern region of the Netherlands, linking with northern Germany by then.[122] Ultimately, it is expected that 85% of the national hydrogen backbone would consist of repurposed natural gas pipelines, the remaining 15% would be newly constructed.[123]

- **Cross-border pipelines with Belgium and Germany (and through them other EU Member States) as well as the UK and Norway:** The Port of Rotterdam estimates that the amount of hydrogen (derivatives) coming in through Rotterdam could rise to as much as 18 Mt (594 TWh) by 2050.[124] Much of this import is intended for other European countries and therefore a cost-efficient way of transportation is necessary. The 2022 energy crisis resulted in an acute transport capacity shortage in the North-West European gas market and natural gas infrastructure.[125] ACER in its recent report recommends 'careful consideration' for further investment in the bottlenecks where operational optimisation is not sufficient, and the capacity shortage would prevail for a prolonged period. The future transportation of hydrogen cuts into this issue as well, since (barring the limited possibilities of transportation of natural gas-hydrogen blends) it will require additional infrastructure capacities. The METIS 3 study ordered by the EC[126] concluded that a pan-European hydrogen transport infrastructure realised by 2030 would be economically reasonable, as it would facilitate:
    - cost (and therefore price) reduction of hydrogen by the reallocation and optimisation of renewable electricity and hydrogen production,
    - convergence in hydrogen prices across EU member states,
    - reduction of the produced hydrogen's carbon-content,
    - lowered needs for additional electrolyser and storage capacities by enabling better utilisation, and therefore lowered overall investment costs,
    - increased system flexibility.

  The study found that in the optimal scenario (lowest cost, based on a number of assumptions as detailed in the study itself) 27 GW of newly built, and 44 GW of repurposed (from the existing natural gas infrastructure) pipeline capacity would be necessary across the continent by 2030.
- **Large-scale underground hydrogen storage:**
  The volatile production of renewable energy plants and the mismatch between the generation and consumption profiles make storage of energy (and other flexibility options) a crucial component in the ongoing energy transition. One of the main reasons why hydrogen is being considered an important energy vector in the future energy system is the relative simplicity of hydrogen storage on an industrial scale for extended time horizons compared to the storage of electricity. It is indeed more economical to convert surplus electricity in times of peak generation into hydrogen, and to store it in repurposed salt caverns, oil and gas fields, or aquifers, than to store the electricity.[127] For hydrogen to fulfil its strategic role as a flexibility option, these large-scale

[122] Tweede Kamer der Staten-Generaal (2021). Kamerstuk 32813, nr. 756
[123] HYnetwork (n.d.). Hydrogen network Netherlands
[124] Port of Rotterdam (n.d). Import of hydrogen.
[125] ACER (2023). Addressing congestion in North-West European gas markets.
[126] EC (2021). METIS study on costs and benefits of a pan-European hydrogen infrastructure.
[127] Andersson et al. (2019). Large-scale storage of hydrogen.

storage capacities need to be established. Gasunie is currently working on a pilot project (HyStock) in the Netherlands establishing the first large-scale hydrogen storage in the salt caverns of Zuidwendig, with a plan of storing 6.000 tonnes of hydrogen (in the first storage unit, with a possible extension up to 4 units and 20.000 tonnes overall capacity, after 2030 based on demand), starting commercial operation by 2028.[128]

Electricity supply and transmission infrastructure

The availability of sufficient renewable electricity supply beyond the direct electrification needs, as well as adequate (offshore and onshore) transmission capacity to transport electricity to the electrolysers' location is an important pre-condition and facilitator for the deployment of electrolyser capacities. The efficiency of the current, commercially available electrolysis technologies ranges between 50 and 80% (depending on the type of electrolyser).[129] This means that for the production of 1 kg of hydrogen with an energy content of 33.6 kWh, 42-67.2 kWh of electricity is necessary. The Northern Netherlands alone aims to have an 18 TWh annual hydrogen production by 2030[130] - requiring the transmission of 22.6-36.1 TWh of electricity to electrolyser facilities (which constitutes about 20-30% of the entire Netherlands' yearly electricity consumption). As large-scale hydrogen transport is in general less expensive than electricity transmission, electrolysers should preferably be located near to the concerned electricity generation facilities, also to reduce congestion in the electricity network. The high-voltage grid in the Netherlands is indeed coming under increasing pressure, and is already nearing its maximum capacity in areas like the Port of Rotterdam, especially because of the number of applications to connect electrolysers to the grid.[131] The capacity map of Netbeheer Nederland[132] shows that in large parts of the country (in the provinces Utrecht, Noord-Brabant and Limburg), the grid has reached its limits even with congestion management. Wind energy production already results in high congestion and related costs in Germany's landing points of the North Sea electricity infrastructure.[133] Investments in electrolysers can to some extent reduce electricity grid congestion and mitigate investment needs for network reinforcements and extensions.

[128] HyStock (n.d.). HyStock.
[129] Kumar et al. (2022). An overview of water electrolysis technologies for green hydrogen production.
[130] RVO (2021). Excelling in hydrogen - Dutch technology for a climate neutral world.
[131] TenneT (n.d.). Studies on congestion management.
[132] Netbeheer Nederland (2023). *Capaciteitskaart invoeding elektriciteitsnet*.
[133] TNO (2022). Offshore hydrogen for unlocking the full energy potential of the North Sea.

Annex I – Additional results & consulted experts

This annex details the three individual policy instruments for incentivising RFNBO production and/or consumption investigated in this study with regards to their contribution to and certainty of achieving the production and industry consumption goals, i.e., the effectiveness of the policy instrument type. In assessing the contribution and certainty:

- Green indicates largely positive/certain,
- White somewhat positive/certain and negative/uncertain
- Red largely negative/uncertain.

Section I.1 details the effects of the consumption obligation, section I.2 demand subsidies and section I.3 production subsidies. In addition, section I.4 provides more information on the options companies have in the case of a partition vs. in the case of stacking. Lastly, section I.5 provides a list of experts and stakeholders consulted in this study.

I.1 Industrial RFNBO consumption obligation

The industrial RFNBO consumption obligation can be summarised as follows:

- All industrial hydrogen consumers (both existing and new users of hydrogen) have a consumption obligation of $X\%$ renewable hydrogen.
- When consumers use RFNBOs (renewable hydrogen or derivatives such as ammonia), they can have it registered (booked in). When they register their RFNBO consumption, they get HWIs credited to their account (1 GJ use of RFNBO = 1 HWI).
- Each year hydrogen consumers must have y number of HWIs in their account, where:
$$y = X\% * Total\ hydrogen\ consumption$$
- If consumers have insufficient HWIs in their account, they will have to purchase HWIs from others or pay a fine for non-compliance; if consumers have more HWIs than their obligation y, they can bank them for future use (with potential limits to banking) or sell them to others.

In theory, the price of HWIs is the difference between the cost of renewable and fossil hydrogen but several factors can affect the HWI price. HWI prices can be higher or lower than the renewable-fossil H_2 price differential in practice depending on the physical storage costs of H_2 and the banking restrictions of HWIs (that do not have storage costs):

- The price of HWIs can be lower than the H_2 price differential when the supply of HWIs is greater than the demand, i.e., when more renewable H_2 or other RFNBOs have been booked in than needed to meet consumption obligations. If banking of HWIs is not allowed, the price of HWIs could drop to zero for a certain year if the hydrogen consumers have already fully met their compliance obligation for that year. However, if banking is allowed for future use, the price of HWIs would not drop to zero, but the actual price decrease will depend on the banking restrictions of HWIs. If banking of HWIs is allowed without restrictions, the price of HWIs would be close to that of the H_2 price differential or could even exceed the H_2 price differential (see next point).

- The price of HWIs may be higher than the renewable-fossil H_2 price differential when it is expected that there will be a future shortage of renewable H_2 to meet the consumption obligation and banking of HWIs is allowed. More certainty on the longer-term consumption obligation and an expected increase in the consumption would also contribute to a higher HWI price. How much higher will depend on whether there are any restrictions on HWI banking (the more banking is allowed, the higher the HWI price) as well as the cost of physically storing renewable H_2 (the higher the storage costs, the higher the HWI price). The price may also be higher because some industrial customers do not have access to renewable hydrogen or other RFNBOs and thus must always purchase HWIs to meet their obligation. The maximum price of HWIs in this case is the penalty the consumers would face if they failed to meet their RFNBO obligation.

The different drivers of the HWI price described above makes it more difficult for industrial hydrogen users to predict the HWI price and incorporate it in their business decisions. This becomes even more difficult as the market expands to predict how much HWI demand has already been fulfilled and what the banking behaviour might be of industrial hydrogen users.

The consumption obligation has a positive contribution to the industry goal but its impact on the production goal is uncertain. The effect of the different situations in case of a high and low RFNBO availability, the interaction with the HWI price and the renewable-fossil H_2 price differential and their effects on the production and industry goals are shown in Figure 8-2. Building on the effects identified in Figure 8-2, Table 8-5 provides a summary of the potential effects of the RFNBO consumption obligation on the effectiveness of achieving the production and industry goals. A red coloured row in this table indicates a negative effect on the assessed goal while a green coloured row indicates a positive effect on the assessed goal.

Figure 8-2 Visual mapping of the effects of the RFNBO consumption obligation on the production and industry goals

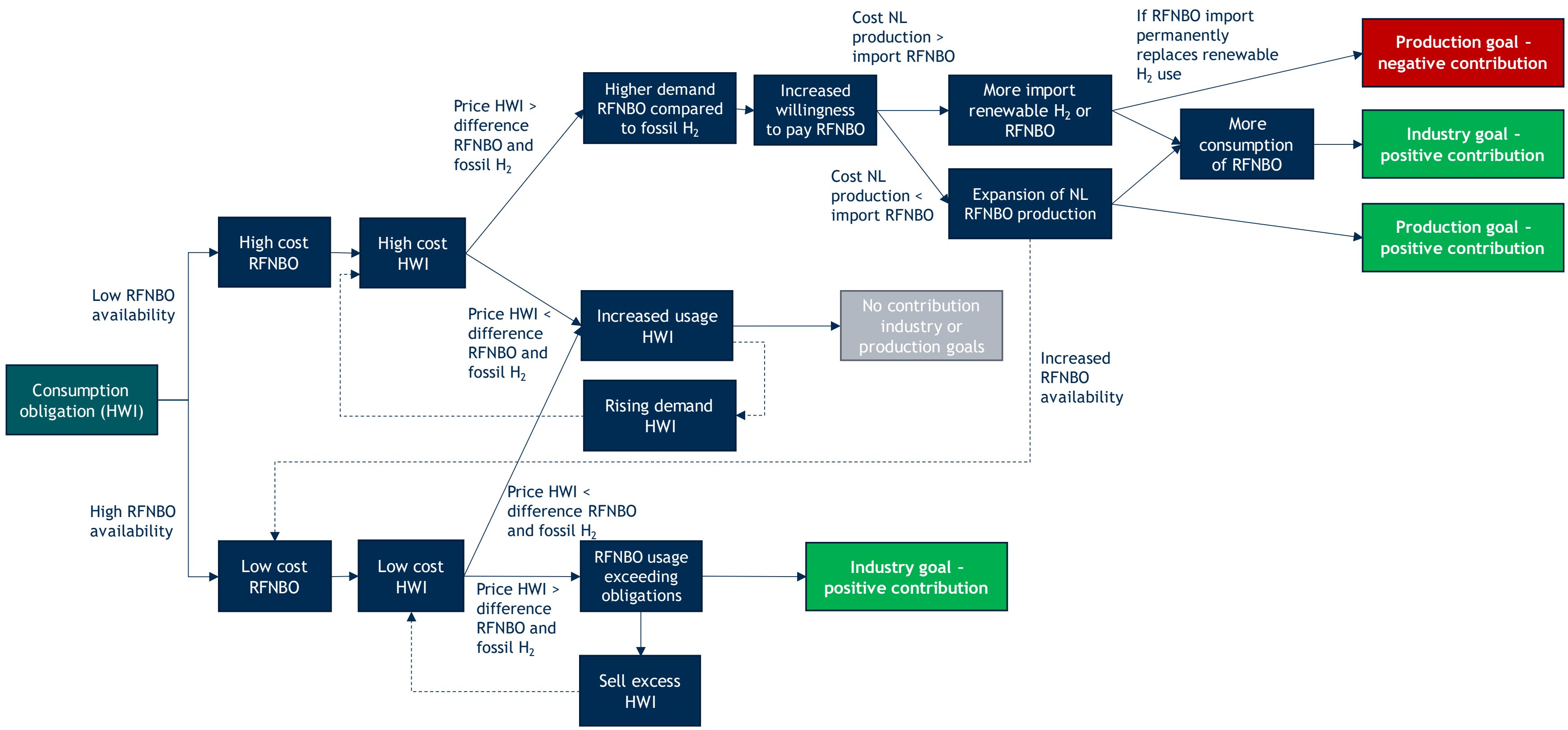


Table 8-5 Summary of the effects of the RFNBO consumption obligation on the production and industry goals

Goals	Effects
Production goal - contribution	• In principle positive effects on the production goal. The higher the consumption obligations, the stronger the contribution to the goals. High consumption obligations automatically require more production (domestic but also from import) of RFNBO. This results in an increase of the willingness of consumers to pay for RFNBO as they would otherwise face a penalty, which could improve the business case for domestic RFNBO production. • Even with high availability of RFNBO, the consumption obligation has a positive contribution to the production goal. The revenues consumers can receive for selling their excess HWIs supports the demand for RFNBO, and thus production. • While importing RFNBOs does not directly contribute to the production goal, it could increase the market for RFNBO. As long as domestic RFNBO production can be competitive with imports on the long term, imports incentivised through the consumption obligation could also contribute to the production goal. • However, if the consumption obligation leads to imports of renewable H_2 derivatives permanently reduce the domestic demand for H_2, this could negatively affect the production goals. For example, if the consumption obligation leads to companies shutting down their domestic ammonia production and directly importing renewable ammonia instead to make fertilisers and chemicals, the domestic demand for (renewable) H_2 would permanently be reduced. The drop in H_2 demand could negatively impact the business case for domestic renewable H_2 production. • The consumption obligation could also lead to H_2 consumers reducing or completely moving their operations abroad, resulting in an overall reduction in H_2 demand including RFNBOs, which would negatively affect the business case for domestic RFNBO production.
Production goal - certainty	• The consumption obligation indirectly contributes to achieving the production goal; the more stringent the obligations, the higher the HWI price and thus the more investment in RFNBO production is incentivised. • The consumption obligation can also be achieved through imports. Since the general expectation is that importing RFNBOs is cheaper than domestic production, especially on the short/medium term, the certainty of achieving the production goal via a compliance obligation is limited. • The risk of the consumption obligation causing H_2 consumers to reduce or completely move their operations abroad increase the uncertainty of achieving the production goal with this instrument further.
Industry goal - contribution	• The consumption obligation directly contributes to the industry goal by creating a demand for RFNBOs. • The option to trade HWIs enables consumers with access to cheaper RFNBOs than others to use RFNBOs beyond their obligation, incentivising further use of RFNBOs. • By allowing HWIs to be earned from imported RFNBOs including derivatives of H_2, this policy instrument further contributes to achieving the industry goal. Consuming imported RFNBOs other than renewable H_2 decreases the total hydrogen consumption (denominator of the obligation) while it counts towards to the achievement of the obligation (numerator), resulting in a multiplier effect.
Industry goal - certainty	• The consumption obligation increases the certainty of achieving the industry goal as long as it is set in line with the industry goal. • Only if the costs of using RFNBOs or HWI prices are higher than the penalty for non-compliance, the certainty of achieving the industry goal would be jeopardised. • The industry goal in our analysis focuses on 2030, but if there is more visibility of the consumption obligation beyond 2035 and this is expected to increase, this could increase the investment certainty to adapt processes to be able to consume RFNBOs, which would have a positive impact on the certainty of achieving the industry goal for 2030.

I.2 Demand subsidy for RFNBOs

In this section, the capex and opex demand subsidies are discussed separately as they affect the production and industry goals differently.

I.2.1 Capex based demand subsidy for hydrogen and/or its derivatives

The capex subsidy in this study is as a subsidy on investment costs to make a plant suitable for use of renewable H_2 or other RFNBOs in the form of % of total investment cost. Since chemically there is no distinction between renewable H_2 or fossil or low-carbon H_2, a capex subsidy incentivises the use of H_2 in general. Practically, the capex subsidy can be for:

- **Existing users:** convert installation from using captive H_2 (H_2 produced by the consumer for internal use) to merchant H_2 (H_2 produced on-site or in a central production plant sold to a consumer), where a part can be with low capex and part has high capex. For installations to switch from merchant fossil H_2 to merchant renewable H_2, no capex is expected other than any new infrastructure connections that would be needed, assuming that the purity of the fossil and renewable H_2 are the same.
- **New users:** convert the plant to use merchant H_2 as fuel instead of fossil fuel. This is not technology neutral and therefore creates an uneven playing field compared to other technologies, which may not be the most cost-effective from a climate perspective.

A capex-based demand subsidy can have both a positive and negative contribution to the production and industry goals. The effects of a capex-based demand subsidy for H_2 and its derivatives on the production and industrial goals are shown in Figure 8-3. Building on the mapping of effects in Figure 8-3, Table 8-6 provides a summary of the potential effects of a capex based demand subsidy for H_2 and its derivatives on the effectiveness of achieving the production and industry goal.

Figure 8-3 Visual mapping of the effects of a capex based demand subsidy for H_2 and its derivatives on the production and industry goals

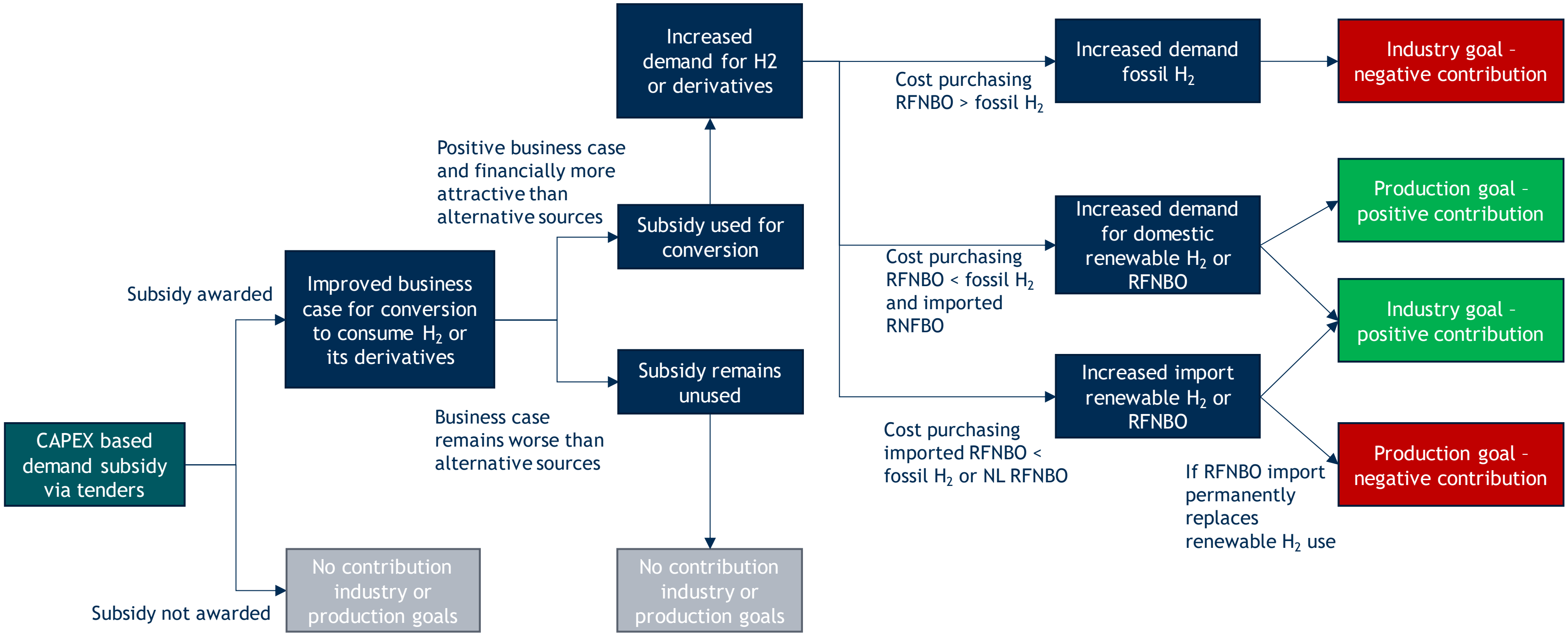


Table 8-6 Summary of the effects of a capex based demand subsidy for H_2 and its derivatives on the production and industry goals

Goals	Effects
Production goal - contribution	• Only parties awarded with a capex demand subsidy would additionally contribution to achieving the production goal; the situation for parties without subsidy remains unchanged. The more subsidy available, the higher the potential contribution. • Contribution strongly dependent on the price of RFNBOs compared to fossil H_2, as well as the price difference between domestic and imported RFNBOs. Only if the cost of domestically produced RFNBO < fossil H_2 or imported RFNBOs, the subsidy incentivises domestic RFNBO production. • Imports of H_2 derivatives could permanently reduce the demand for H_2 if it leads to domestic facilities to process H_2 into derivatives shutting down and processing occurring abroad, which could negatively affect the production goals (see consumption obligation for an example). This risk increases if the subsidy also supports conversions that enable the direct use of H_2 derivatives.
Production goal - certainty	• Very limited impact on certainty that production goal will be achieved as it depends on the price of domestic RFNBOs compared to imported RFNBOs and fossil (and low-carbon) H_2. • There is no guarantee that the investment to convert installations to be able to use (renewable) H_2 will be made with subsidy as companies can decide not to make use of the subsidy if the business case remains negative. The higher the subsidy provided, the more certainty that the business case will be positive.
Industry goal - contribution	• Only parties awarded with a capex related hydrogen demand subsidy would additionally contribute to achieving the industry goal; the more subsidy available, the higher the potential contribution. • Contribution strongly dependent on the price of RFNBOs compared to fossil H_2, as well as the price difference between domestic and imported RFNBOs. ▪ If price of RFNBO < fossil H_2 it contributes to the industry goal. If imported RFNBOs other than renewable H_2 replace fossil H_2 use, there is an additional contribution due to the multiplier effect. ▪ If the price of RFNBO > fossil H_2, the capex demand subsidy could lead to an increase in fossil H_2 use compared to the absence of the subsidy where the H_2 consumption was less (i.e., the subsidy resulted in new H_2 users), negatively contributing to the industry goal as more RFNBO is needed to meet the industry goal.
Industry goal - certainty	• Limited effect on certainty that industry goal will be achieved as it depends on the price of RFNBOs compared to fossil (and low-carbon) H_2. • There is no guarantee that the investment to convert installations to be able to use (renewable) H_2 will be made with subsidy as companies can decide not to make use of the subsidy if the business case remains negative. The higher the subsidy provided, the more certainty that the business case will be positive.

I.2.2 Opex based demand subsidy for hydrogen and/or its derivatives

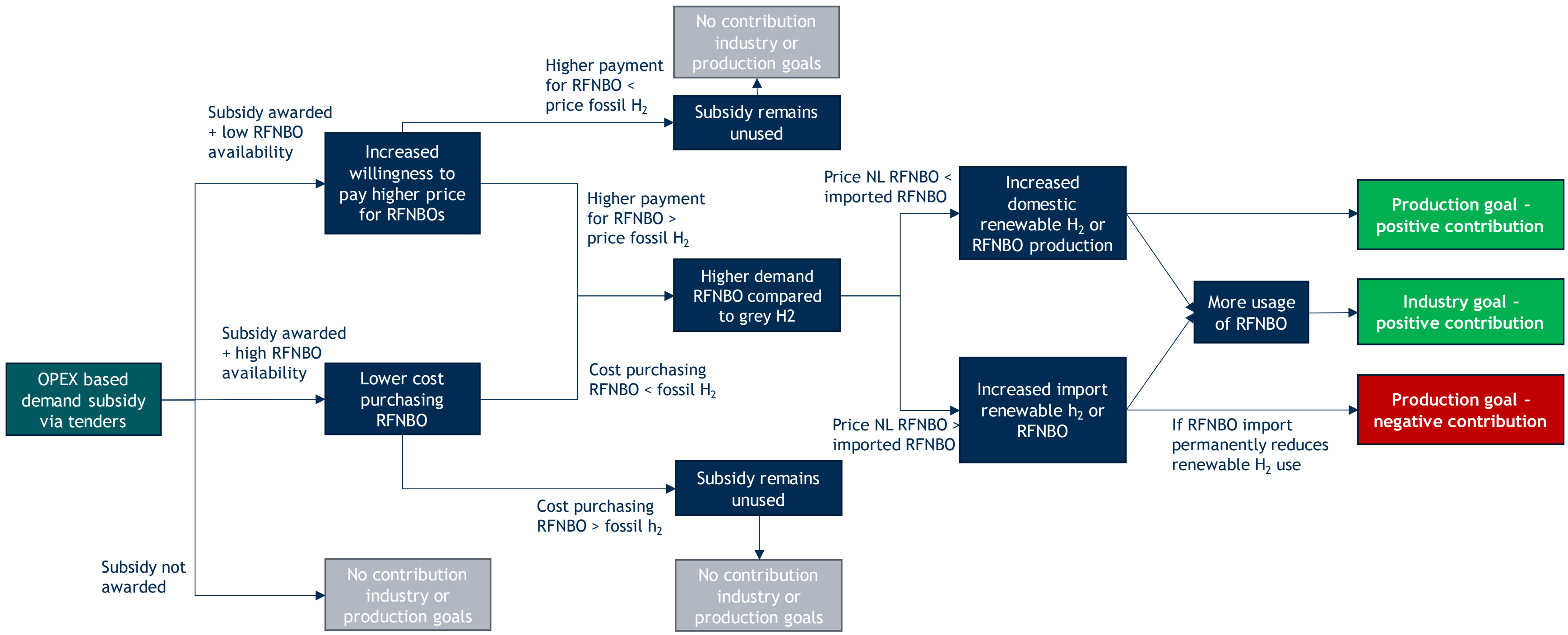
The opex based RFNBO demand subsidy is a subsidy based on the opex and amount of RFNBO consumed. The impact of an opex subsidy varies depending on the availability of RFNBOs:

- In the early stages, the availability of RFNBOs is limited. The price of RFNBOs would mainly be determined by (long-term) bilateral contracts between consumers and producers of RFNBOs. An opex based renewable hydrogen demand subsidy would increase the price that consumers are willing to pay for RFNBOs, which in turn improves the business case for producers.
- When the market for RFNBOs will have matured and the availability of RFNBOs will have increased, the price for RFNBOs would be determined through supply and demand of multiple market participants. An opex based RFNBO demand subsidy would hence serve as a discount on the market price for RFNBOs.

Unsuccessful bidders would not contribute to the achievement of the production or industry goals.

An opex based demand subsidy will have a positive contribution to the industry goal but its contribution to the production goal is uncertain. The effect of an opex based renewable hydrogen demand subsidy on the production and industry goals are shown in Figure 8-4.

Figure 8-4 Visual mapping of the effects of a opex based RFNBO demand subsidy on the production and industry goals



Implementation options for an opex based RFNBO demand subsidy

There are various ways an opex based RFNBO demand subsidy can be implemented, which all follow the effect pathways as shown in Figure 8-4. For this study, we have investigated three variants, all combined with a tender system, with one modelled and assessed in detail in the report:

- Fixed premium (**modelled in this study**)
- Contract for difference (CfD), single-sided
- Contract for difference (CfD), double-sided

For the CfD in combination with a tender system, we identified two options for this could be implemented:

1. **Option I CfD** (shown in Figure 8-5 and Figure 8-6): The subsidy award is based on the highest price that the customer is willing to pay for RFNBOs: the subsidy amount is the difference between the strike price (the price the customer is willing to pay – WTP) and the market price of RFNBOs. If the price of RFNBOs increases, the subsidy amount also increases and vice versa, as shown in Figure 8-5). A risk is that if the price of RFNBOs sharply rises, the government has to subsidise a large amount. The buyer has certainty at what price RFNBOs can be purchased and there is greater certainty that the goal will be met, but limited incentive to find the cheapest provider of RFNBOs (incentive depends on how the reference market price is determined for the subsidy: the more conservative the market price, the stronger the incentive). To mitigate the risk that the government would need to subsidise a large amount, it can implement a subsidy cap (e.g., absolute based on maximum amount of subsidy received, or relative based on maximum € per MWh or kg renewable H_2 (as shown in Figure 8-6). When the cap is reached, it could in theory incentivise the consumer to find a new and moreover cheaper provider of the RFNBOs, although in practice consumers will likely switch over to cheaper sources such as fossil or low-carbon H_2. Setting a low cap might deter potential consuming parties, impeding the effectiveness of the subsidy. Setting soft caps, where a certain percentage of the additional costs are covered (e.g., 80%) while the consumer is still exposed to some proportion of the higher costs for RFNBOs, could be a way to balance the risk of subsidising large amounts with deterring potential consuming parties. For this option, it also needs to be noted that the market price of RFNBOs will have to be defined based on assumptions given the absence of the liquid market, hence implying an uncertainty risk. The price of long-term consumption contracts between producers and consumers could be used, but this could be susceptible to gaming as the subsidy would cover the price gap between the price the producer would set and the price the customer is willing to pay.

Figure 8-5 Contract for difference option I

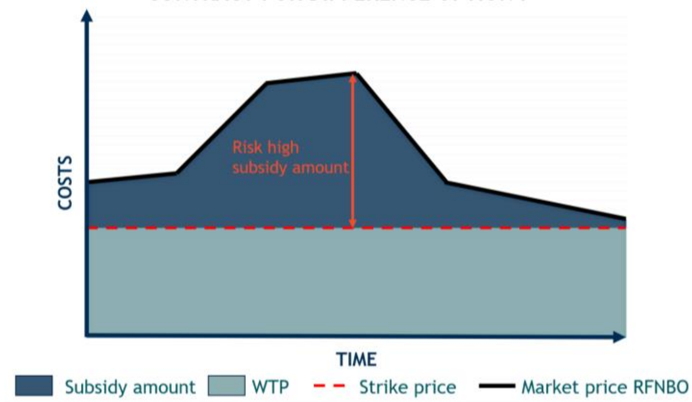
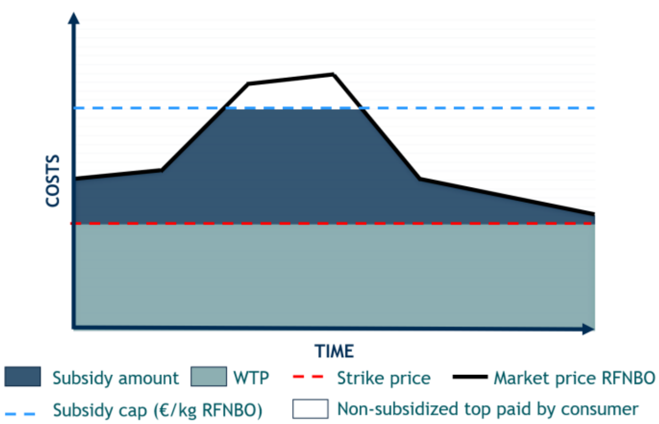


Figure 8-6 Contract for difference option I with subsidy cap



2. **Option II CfD** (shown in Figure 8-7 and Figure 8-8): Subsidy award based on the lowest price at which a consumer can enter into a RFNBO supply contract: the subsidy amount is the difference between the strike price (the price at which the consumer will buy RFNBOs) and the market price of the current alternative (e.g., fossil H_2). If the price of fossil H_2 increases, the subsidy amount decreases and vice versa. The buyer has the incentive to find the cheapest supplier of RFNBO after the subsidy has been awarded and the strike price fixed. The difference between the actual RFNBO price and the strike price would be a profit for consumer (as shown in Figure 8-8). Option II could increase the risk of over-subsidy if the strike price is very high, but this risk is lowered through tendering as consumers would bid against the lowest possible strike price to increase their chances of the subsidy being awarded. However, there is risk that consumers are unable find suppliers willing to sell RFNBOs against the strike price that the subsidy was awarded. This risk could be mitigated by only awarding subsidies to consumers that have (long-term) contracts with suppliers. On the other hand, this could deter potential consumers from bidding.

Figure 8-7 Contract for difference option II

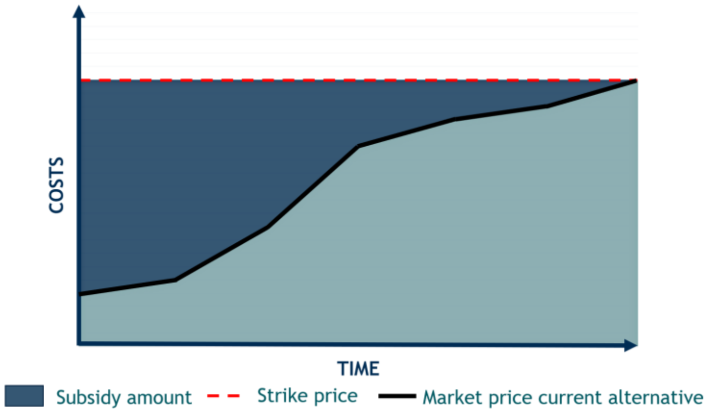
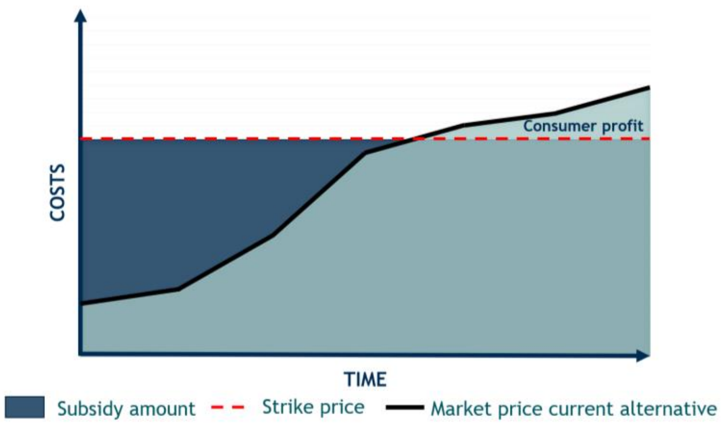


Figure 8-8 Contract for difference option II with consumer profits



The main advantages and disadvantages of the three types of opex based RFNBO demand subsidy can be summarised as follows:

- **Fixed premium**: this is the least complex to implement and there is more certainty on how much the government hands out in subsidy compared to CfDs as there is only one unknown instead of two (subsidy per MWh or kg hydrogen is known, quantity remains unknown). However, there is more uncertainty (due to fluctuation of price of RFNBO as well as fossil H_2) on whether the fixed premium can bridge the price difference or leads to over-subsidy. This could make Final Investment Decisions (FIDs) less likely.
- **Single-sided CfD:** less complex compared to a double-sided CfD and no repayment obligation by the beneficiaries of the subsidies. This leads to higher risk of over-subsidisation.
- **Double-sided CfD**: a double-sided CfD generally limits risks for over-profits through repayment obligation if the subsidy amount would be negative in the calculation on the difference between the reference market price and strike price. However, in case of a demand subsidy, other effects need to be considered:
    - Under Option I, there would be a repayment obligation if the price of RFNBOs falls below the strike price. However, if the repayment obligation could lead to higher costs for RFNBO compared to alternatives (e.g., fossil or low-carbon H_2), the beneficiaries of the

subsidies could decide to use the alternatives instead (if their contract have sufficient flexibility on the offtake amount), making the subsidy instrument less effective in contributing to the industry and production goals.

- Under Option II, the risk of using alternatives identified in Option I would be mitigated. There would be a repayment obligation if the price of fossil or low-carbon H_2 would be higher than the strike price of RFNBOs. Since the alternatives are more expensive than RFNBOs and the repayment is determined by the price differential between the strike price and the alternative, there is no incentive to switch to the alternative.

The main advantage of CfDs over a fixed premium assumes that there will be a variable price for the RFNBOs. However, in practice, most industrial RFNBO consumers are expected to establish long-term consumption contracts at fixed prices for the majority of their consumption. Otherwise, the supply and price risks would be too high to justify the adaption investments. Under these circumstances, a fixed premium and a CfD under Option I could have the same effect.[134] Under CfD Option I, producers and consumers could fix the reference price (price of renewable H_2) in long-term contracts. The producer would, in turn, purchase renewable electricity through long-term contracts to hedge its price risk. As the most important cost components would be fixed in long-term contracts, the CfD does not add any additional benefit compared to a fixed premium and would only have the disadvantage of being more complex to administer.

Table 8-7 provides a summary of the potential effects of an opex based RFNBO demand subsidy on the effectiveness of achieving the production and industry goals.

Table 8-7 Summary of the effects of an opex based RFNBO demand subsidy on the production and industry goals

Goals	Effects
Production goal - contribution	**Overall** • Only parties awarded with an opex based RFNBO demand subsidy would additionally contribute to achieving the production goal; the more subsidy available, the higher the potential contribution. • Imports of RFNBOs other than renewable H_2 could permanently reduce the demand for H_2, which could negatively affect the production goal. This risk increases if the subsidy also supports the use of renewable H_2 derivatives in addition to renewable H_2. **Option I CfD** • Potentially good contributions to production goal as the subsidy for the RFNBO consumers can cover increases in purchasing costs for RFNBOs. • In case of a double-sided CfD, the repayment obligation could lower the demand for RFNBOs if alternatives such as fossil /low-carbon H_2 are cheaper than RFNBOs after repayment, which could negatively affect the production goal. • However, if domestic production is more expensive than imports and the CfD market price is based on import prices, there is no contribution to the production goal and the demand would be fulfilled by imports. **Option II CfD** • Potentially limited contributions to production goal if RFNBO consumers may not be able to establish contracts with domestic producers at the strike price.

	• RFNBO consumers may establish contracts with importers if domestic production is more expensive, which does not contribute to the production goal. **Fixed premium** • If the purchasing costs of fossil (and low-carbon) H_2 > RFNBO after taking into account demand subsidies, this would increase RFNBO demand and could thus indirectly improve the business case for domestic RFNBO production. • If fossil (and low-carbon) H_2 remains cheaper than RFNBOs after demand subsidies, then there is no contribution to the production goal.
Production goal - certainty	**Overall** • Certainty depends on whether the subsidy is sufficient to incentivise more demand for RFNBOs and thus indirectly improving the business case for domestic production sufficiently. • Limited contribution to certainty that production goal will be achieved as it depends on the price of domestic RFNBOs compared to imported RFNBOs, where it is generally expected that imported RFNBOs will mostly be cheaper than domestic ones, especially in the early phases. **Option I CfD** • Certainty of contributing to achieving the production goal depends on the market prices used for RFNBOs, information that is scarce in an illiquid market. The higher the prices used, the more certainty of contributing to the production goals (but also more risk of over-subsidy). **Option II CfD** • Uncertain whether RFNBO consumers can establish a supply contract with domestic producers. In the early phase, this risk will be higher as there will only be very few domestically producing companies. **Fixed premium** • Uncertain whether the fixed premium can bridge the price difference between RFNBO and fossil (and low-carbon) H_2 to incentivise domestic RFNBO production (and imports, but these do not contribute to the production goal).
Industry goal - contribution	**Overall** • Only parties awarded with an opex based renewable hydrogen demand subsidy would additionally contribute to achieving the industry goal; the more subsidy available, the higher the potential contribution. **Option I CfD** • Potentially good contributions to industry goal as the buyers of the RFNBO has certainty as what costs they can purchase RFNBOs and the CfD subsidy fully or partly closes the cost gap between RFNBOs and fossil H_2, as price rises of RFNBOs (up to a certain limit if a cap is imposed) do not need to be covered by consumers but is covered by subsidies. • In case of a double-sided CfD, the repayment obligation could lower the demand for RFNBOs if alternatives such as fossil/low-carbon H_2 are cheaper than RFNBOs after repayment, negatively affecting the industry goal. **Option II CfD** • Potentially good contributions to the industry goal if the buyer of the RFNBO is able to establish supply contracts, which can be from domestic production or imports, as it allows RFNBOs to be purchased at a fixed price. **Fixed premium** • If the costs of fossil (and low-carbon) H_2 > RFNBO after taking into account demand subsidies, this would increase RFNBO demand. • If fossil (and low-carbon) H_2 remains cheaper than RFNBOs after subsidies, then there is no contribution to the industry goal.
Industry goal - certainty	**Overall**

	• Certainty of achieving the industry goal depends on the available subsidy budget and the levels (prices) at which the subsidy is set, which have to be sufficient to bridge the cost gap between RFNBOs and fossil H_2 (taking into account any potential green premium for RFNBO industry is willing to pay), and able to cover the subsidy needs up to the industry goal. **Option I CfD** • Certainty of contributing to achieving the industry goal depends on the market prices used for RFNBOs, information that is scarce in an illiquid market. The higher the prices used, the more certainty of contributing to the production goals (but also more risk of over-subsidy). **Option II CfD** • Uncertain whether RFNBO consumers can establish a supply contract with domestic producers or importers. In the early phase, this risk will be higher as there will be few producing companies. **Fixed premium** • Uncertain whether the fixed premium can bridge the price difference between RFNBO and fossil (and low-carbon) H_2 to incentivise RFNBO consumption.

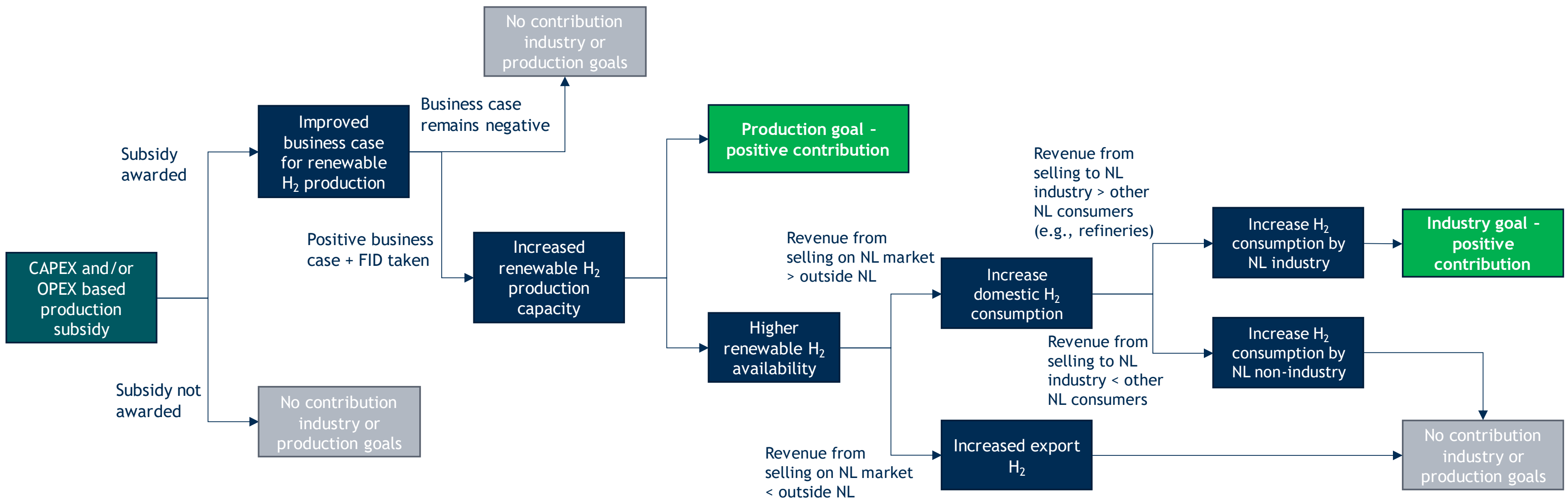
I.3 Renewable hydrogen production subsidy

In the policy mixes of this study, production subsidies are only provided for renewable hydrogen production in the form of combined capex+opex subsidy:

- **Capex:** subsidy on investment costs to build the electrolyser, i.e., a subsidy based on the % of total investment costs; and
- **Opex**: subsidy on the opex of operating the electrolysers when these come into operation, i.e., subsidy based on total renewable H_2 produced.

Both a capex and opex based renewable hydrogen production subsidy improve the business case for electrolysers and therefore have the same effects on the production and industry goals. The key difference is that a capex production subsidy is provided upfront, whereas an opex production subsidy depends on the total renewable H_2 produced. Furthermore, a capex production subsidy does not only incentivise the production of renewable H_2, but the production of H_2 through electrolysis in general; this could include electricity from fossil sources or nuclear energy. H_2 produced from fossil- or nuclear-based electricity would not contribute to the industry goal. By using an opex production subsidy instead, the subsidy could be limited to only renewable H_2 while still (partially) covering investment costs. Nonetheless, since the effects of a capex and opex based renewable hydrogen production subsidy on the production and industry goals are otherwise similar, they are shown in one figure in Figure 8-9.

Figure 8-9 Visual mapping of the effects of a renewable hydrogen production subsidy on the production and industry goals



Implementation options for an opex based RFNBO production subsidy

There are various ways the opex component of the renewable hydrogen production subsidy can be implemented, which all follow the effect pathways as shown in Figure 8-9. For this study, we have investigated three variants, all combined with a tender system, with one modelled and assessed in detail in the report:

- Fixed premium
- Contract for difference (CfD), single-sided **(modelled in this study)**
- Contract for difference (CfD), double-sided

The main advantages and disadvantages of the three types of opex component of the renewable hydrogen production subsidy can be summarised as follows:

- **Fixed premium**: more insight on how much is distributed in subsidy but brings in more uncertainty on whether the fixed premium can bridge the price difference between renewable H_2 and low-carbon /fossil H_2 or just leads to over-subsidy. Thus, no certainty for the producer whether the price at which the renewable H_2 can be sold leads to a positive business case. This is mainly due to fluctuation of the market price of hydrogen (which is determined by fossil H_2 in the early phases) and the price of electricity. This may make FID less appropriate compared to CfDs.
- **Single-sided CfD**: The subsidy amount is the difference between the market price of H_2 and the strike price (price at which the producer needs to sell the renewable H_2 for a positive business case). However, it may be difficult for producers to determine a fixed strike price to guarantee a positive business case. In this case, the strike price could be indexed against the costs of producing renewable H_2, or in absence of transparency on the costs, the electricity price as the main determinant for the opex of renewable H_2. This provides more certainty for the producer that it can cover the costs of renewable H_2 production but increases the complexity of the CfD. However, producers can also enter into long-term power purchasing agreements (PPAs) to limit the risks related to the variability of the electricity price. In that case, an indexation of the subsidy amount would not be necessary. Finally, as with any single-sided CfD, there is a risk of over-profit if the market price of H_2 (regardless of fossil or renewable) rises above the submission amount.
- **Double-sided CfD**: limits over-profits through repayment obligation but more complex than a single-sided CfD. Repayment would occur if the market price of H_2 is higher than the strike price.

The main advantage of CfDs over a fixed premium assumes that there will be a variable market price for (renewable) H_2. However, in practice, most industrial RFNBO consumers are expected to establish long-term purchasing contracts at fixed H_2 prices for the majority of their consumption. For this reason, the European Commission is providing renewable H_2 production subsidies in the form of a fixed premium, as mentioned in Section 5.3.2.

Table 8-8 provides a summary of the potential effects of a renewable hydrogen production subsidy on the effectiveness of achieving the production and industry goals.

Table 8-8 Summary of the effects of a renewable hydrogen production subsidy on the production and industry goals

Goals	Effects
Production goal - contribution	• Only parties awarded with renewable hydrogen production subsidy would additionally contribute to achieving the production goal; the more subsidy available, the higher the potential contribution. • If the subsidy (irrespectively if the opex component is a CfD or fixed premium) is high enough for a positive business case, it directly contributes to the production goal.
Production goal - certainty	**Overall** • Certainty of achieving the production goal depends on the available subsidy budget and the levels at which the subsidy is set, which have to be sufficient for a positive business case. **CfD** • Certainty of contributing to achieving the production goal depend on expectations of how market prices develop relative to the strike price and the ability of potential producers to mitigate market price risks for electricity. **Fixed premium** • Uncertain whether the subsidy is sufficient for a positive business case, which is largely dependent on the ability of potential producers to mitigate market price risks for H_2 and electricity.
Industry goal - contribution	• Increasing production capacity of renewable H_2 will help increase its availability on the market and/or lower the price of renewable H_2, which contributes to achieving the industry goal. • If the subsidised renewable H_2 would mainly be exported abroad, the production subsidy would not contribute to the industry goal. The magnitude of this risk depends on the available cross-border network infrastructure and additional transportation costs. Currently, this risk is limited as the existing (private) cross-border hydrogen network does not provide third-party access. However, if a cross-border infrastructure for hydrogen would be expanded and further developed, e.g., through the Hydrogen Backbone Initiative[135] or Delta Rhein Corridor[136] the risk of export increases.
Industry goal - certainty	**Overall** • Contribution to the industry goal is highly uncertain and depends on market factors. A positive business case for producers means that renewable H_2 can be competitive against fossil/low-carbon H_2. However, market price fluctuations could make renewable H_2 more expensive than originally anticipated and not competitive anymore (after taking into account any potential premium for renewable H_2 industry is willing to pay), and thus not contribute to the industry goal. • Only if selling the H_2 from the subsidised electrolysers to domestic industry leads to more revenue compared to compared to selling it to consumers outside the Netherlands and other domestic users (e.g., refineries), does the production subsidy contribute to the industry goal. This does not only depend on the price that consumers are willing to pay, but also the costs of transporting the H_2 produced by the subsidised electrolysers. **CfD** • Certainty of contributing to achieving the industry goal depend on whether the subsidy can maintain the competitiveness of renewable H_2 against fossil/low-carbon H_2, which largely relate to the ability of potential producers to mitigate market price risks for electricity. **Fixed premium** • Uncertain whether the subsidy is sufficient to maintain the competitiveness of renewable H_2 against fossil/low-carbon H_2, which is largely dependent on the ability of potential producers to mitigate market price risks for H_2 and electricity.

[135] EHB (n.d.) The European Hydrogen Backbone initiative
[136] RVO (2023). Delta Rhine Corridor

I.4 Actions in case of partition vs. in case of stacking

In case of a partition, companies would face a level playing field under the share of consumption obligation in theory. However, in a tendering system for demand subsidy part, an uneven playing field is created because companies with demand subsidies have more flexibility in how they fulfil their consumption obligation and could lower the renewable hydrogen costs under the consumption obligation (additional earnings for the green premium for using RFNBOs omitted for simplicity, which effectively lowers the RFNBO costs):

- **Companies without subsidies face the following choice**:
  - If cost RFNBO < cost fossil H_2 + HWI cost: use RFNBOs and earn HWIs to cover their consumption obligation, or
  - If cost RFNBO > cost fossil H_2+ HWI cost: use fossil H_2 and purchase HWIs to cover their consumption obligation.
- **Companies with the option to use demand subsidies face the following choices with more flexibility:**
  - (A) For the share to fulfil their consumption obligation:
    - *If cost RFNBO < cost fossil H_2+ HWI cost*:
      - If demand subsidy < HWI costs: use RFNBOs without demand subsidy and earn HWIs to cover their consumption obligation, or (2)
      - If demand subsidy > HWI costs: use RFNBOs with demand subsidy, and purchase HWIs to cover their consumption obligation.
    - *If cost RFNBO > cost fossil H_2+ HWI cost*:
      - If cost RFNBO – demand subsidy < cost fossil H_2+ HWI cost: use RFNBOs with demand subsidy, and purchase HWIs to cover their consumption obligation, or
      - If cost RFNBO – demand subsidy < cost fossil H_2+ HWI cost: use fossil H_2, and purchase HWIs to cover their consumption obligation.
  - (B) For the share exceeding the consumption obligation: (1)
    - If HWI earnings > demand subsidy, and cost RFNBO – HWI earnings < cost fossil H_2: use RFNBOs without demand subsidy and earn HWIs to sell to others, which effectively lowers the average costs of using RFNBO,
    - If HWI earnings < demand subsidy, and cost RFNBO – demand subsidy < cost fossil H_2: use RFNBOs with demand subsidy, with the demand subsidies effectively lowering the average costs of using RFNBO, or
    - If cost RFNBO after demand subsidy or HWI earnings > cost fossil H_2: keep using fossil H_2.

Under the current design of the demand subsidy (CfD), firms have the possibility to shift in the part of the RFNBO they request demand subsidy for, and the demand subsidy depends on a reference price that companies can influence. As such, companies could put RFNBO with a high reference price under the subsidy, and cheaper RFNBO under the consumption obligation. Such a risk would not be present with a fixed premium demand subsidy, but at the expense of less certainty of meeting the industry goal if the level of the premium demand subsidy is too low or over-profits if the premium is too high.

In case of stacking, there will also be companies with and without subsidies. Companies with demand subsidies can generally pay more for RFNBOs than companies without demand subsidies. Thus, “companies with” can indirectly enhance production and infrastructure because they can pay a higher price than “companies without”. This also enables “companies with” to meet their consumption obligation, as well as more easily earn excess HWIs to sell to “companies without”, particularly if the subsidised volume of RFNBO exceeds what is needed for meeting the consumption obligation. This is mostly applicable in the early phases when there is a lack of infrastructure and illiquid market, and “companies with” would be driving the HWI price. In the later stages in a liquid market, the subsidy would act as a discount on the RFBNO price for “companies with”, providing them with a competitive advantage compared to the “companies without”. Depending on how many companies are selling excess HWIs and the degree of banking of HWIs allowed, the HWI price could be higher than the demand subsidies, resulting in excess profits for the “companies with”.

I.5 Consulted experts & stakeholders

For this project, we consulted experts and stakeholders from the following organisations:

- Air Liquide
- CE Delft
- Energie Nederland
- HyCC
- NL Hydrogen
- OCI
- RWE
- Shell
- TNO
- VNCI

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