50% green hydrogen for Dutch industry

Analysis of consequences draft RED3

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Content

Summary

As part of the Fit for 55 package, the European Commission has proposed a target for Member States to ensure that 50% of all hydrogen use in industry by 2030 is 'green hydrogen'. The Netherlands is a major consumer of hydrogen, and it is expected that the Dutch hydrogen demand will grow further due to existing industry plans in new applications such as steel. It will be a challenge for the Netherlands to realise the required volumes of green hydrogen by 2030, both with regard to scarce green hydrogen availability and the costs involved. Achieving this target by 2030 will become even more challenging if Dutch industry plans are realized for CO_2 emission reduction through decarbonization of fuel gases and fossil fuels with CCS (low-carbon hydrogen), and the resulting hydrogen must be included in the target setting for green hydrogen.

Green hydrogen has a crucial role to play in the transition towards a carbon neutral and circular economy by 2050. The European Commission has proposed an amendment of the Renewable Energy Directive (RED) to mainstream green hydrogen technology by including a target for Member States to cover 50% of all hydrogen use in industry with 50% 'green hydrogen' (more precisely: Renewable Fuels of Non-Biological Origin or RFNBOs) by 2030. For the Netherlands this target has significant implications given the high volumes of hydrogen use in industry – particularly in the refinery, fertilizer, and the chemical industry. Compared to other European countries, the Netherlands is the second-largest consumer of hydrogen.

This study examines three possible variants of the target. These variants explore the potential growth in hydrogen demand in the Netherlands (e.g. Tata Steel) and include the range of uncertainty with respect whether or not hydrogen from decarbonized fuel gases is included in the obligation. Green hydrogen demand for transport of about 30 PJ is included in all variants. This demand for transport results from other obligations to Member States that are part of the Fit for 55 package. These demand scenarios have been compared to supply potential, both domestic production and various import modalities.

The '**low' end variant of the target** (80 PJ green hydrogen) **is already highly ambitious, however attainable *if* immediate action across the hydrogen supply chain is taken** that provide investment security for the supply chain and for industrial use of green hydrogen. Regarding the low end variant of the target, the study finds that:

- At least 5 GW of additional renewable power production is needed (on top of existing plans for 10 GW additional offshore wind), to meet the green hydrogen target with only domestic production.
- The use of more renewable electricity for hydrogen production, *within* the existing national plans, will compete with demand for this electricity for other uses.
- Domestic production can be combined with import of green hydrogen.
- The additional national costs per hydrogen unit of 50% green hydrogen as compared to 100% fossil-based hydrogen range from +50% to +150%, depending on the price scenario. This results in additional costs of € 0.9 to 2.2 billion per year by 2030.

The **mid and high end variants are even more difficult to achieve** (110 PJ and 130 PJ green hydrogen, respectively). The higher targets of these variants result mainly from realization of Dutch industry plans for CO_2 emission reduction through decarbonization of fuel gases and fossil fuels with CCS (low-carbon hydrogen), when the resulting hydrogen must be included in the target setting for green hydrogen. The study finds that:

- Higher demand variants may be technically feasible but would require a much faster scale up of renewable electricity capacity (up to 11 GW by 2030 of additional offshore wind or equivalent production onshore) than currently foreseen, and dedicating the additional renewable electricity production to green hydrogen production. In that case the green electricity needs from other sectors cannot be met.
- Due to limits on the domestic supply potential, imports will play a crucial role in higher end demand variants. Whether this supply is realistic by 2030 is highly uncertain given that there is virtually zero capacity today.
- The ability of industry and refineries to 'take in' green hydrogen by 2030 is limited to about 50 PJ/y without substantial changes to processing facilities. Higher mandatory consumption levels of green hydrogen would require major adjustments to industrial installations, leading to higher costs and longer lead times to meet the target.

General findings across all variants are:

- Investment decisions across the hydrogen value chain need already to be taken before final adoption of the RED and subsequent formal transposition time. To provide for the required certainty of demand, a national target might be set in 2022 or 2023 already by the national government, together with appropriate market conditions and financial resources.
- Plans for decarbonised fuel gases and for low-carbon hydrogen production from natural gas with CCS *reduce* CO_2 emissions but *increase* the national target for green hydrogen, while those hydrogen volumes themselves cannot be made green, hence making the green hydrogen target even more difficult to achieve.
- Availability of green hydrogen for import plays an important role. Import is not a mere balancing item but requires concerted action as both import capacity and international production capacity has not yet been built up to scale.
- All variants require a massive and rapid scale-up of electrolyser and renewable electricity capacity in the Netherlands.
- All variants require developing an international green hydrogen market and related infrastructure for hydrogen imports.
- Coordination between Germany and the Netherlands might help to reduce uncertainty on future green hydrogen exports from the Netherlands to Germany. The same holds for Belgium.
- In case the costs associated with the 50% green hydrogen target has to be paid for by the hydrogen consuming Dutch industry (e.g. fertilizers, steel, chemical and oil products), it may deteriorate the competitiveness of these products in the international markets and may lead to production -, investment- and carbon leakage. CBAM does not protect all products equally and will also be based on CO_2 emission costs, not on the costs associated with green hydrogen.
- Stimulating import of 'green ammonia' (provided it is compliant with the RED criteria) together with subsequent direct use in the fertilizer industry, replacing ammonia production based on natural gas, will help to attain the Dutch national target.
- Stimulating alternative industrial production processes, not using hydrogen, will also help to attain the target.

Finally, to meet any of the variants the study finds the following **enabling conditions**:
- Domestic renewable power generation capacity needs to be significantly ramped up and this power should be allocated towards green hydrogen production. Given the many interdependencies, this requires a supply chain approach.
- Electrolyser manufacturing capacity needs to be further developed. The demand for electrolysers will grow significantly towards 2030, domestically and internationally, while global production capacity is still low.
- Hydrogen grid and storage capacity needs to be realized.
- Certification of hydrogen needs to be in place to support trade, import and export of physical flows.

Regarding the current process towards final adoption of the RED3, the study finds the following policy options to make the obligation more feasible:
- Provide clarity on the national target in absolute terms (i.e. obligated demand in PJ) rather than relative terms (% of green hydrogen use in industry). This provides more certainty for policy makers, industry, grid operators and renewable electricity developers and avoids creating a barrier for growth in the national hydrogen demand due to new hydrogen applications.
- Reduce the scope of the target setting, e.g. by excluding hydrogen rich by-product gasses and/or excluding decarbonized fuel gasses from the denominator (i.e. set the target towards the low end variant in this study).
- Allow for a lower percentage than 50% in 2030.
- Allow for a longer timeframe to meet the 50% target.
- Allow for a flexibility mechanism which enables green hydrogen use in other EU Member States to be counted towards the national target (statistical transfers).
- Allow for more full load hours for electrolysers, while connecting to renewable electricity sources.

In anticipation of the adoption of the RED3, regardless of which variant is applied, it is necessary to provide clarity to industry, since immediate action across the hydrogen supply chain is needed. This requires the following actions from the national government as soon as possible, so ***before*** final adoption of the RED proposal, provide investment security for the supply chain and for industrial use of green hydrogen by:
- Providing clarity on the national 2030 target as well as the instruments envisaged to achieve this target.
- Bringing into place policy instruments and financial resources that provide investment security for the supply chain and for industrial use of green hydrogen, in line with the objective of the RED to mainstream green hydrogen. These policy instruments need to allow for early build-up of green hydrogen production capacity, i.e. electrolysers and additional renewable electricity production.

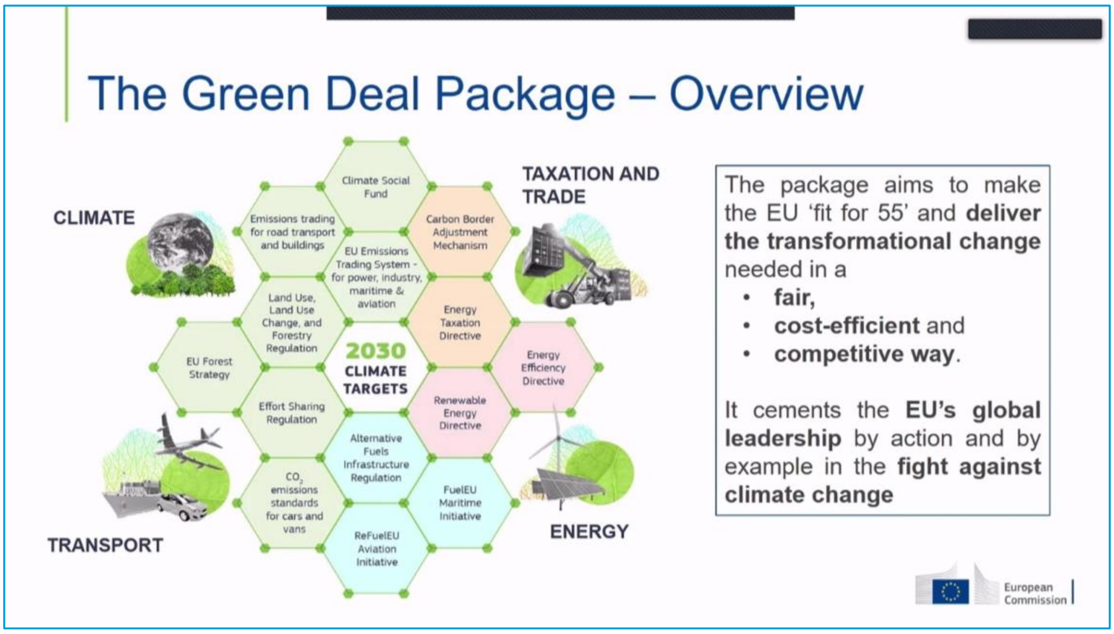
1 General introduction

1.1 Background

On July 14th, 2021, the European Commission adopted the Fit for 55 package, also known as the Green Deal package. A comprehensive and interconnected set of proposals to make the EU's policies fit for reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels, as laid down in the European Climate Law. By achieving these emission reductions in the next decade, Europe aims to be the world's first climate-neutral continent by 2050, making the European Green Deal a reality.

An overview of the package is shown in Figure 1. Part of the package are amendments to the existing Renewable Energy Directive (RED2). One of these amendments is Article 22a, which includes an obligation for Member States targeting the 'greening' of the hydrogen use of the industry. More precisely: *"Member States shall ensure that the contribution of renewable fuels of non-biological origin[1] used for final energy and non-energy purposes shall be 50% of the hydrogen used for final energy and non-energy purposes in industry by 2030."* This 'Article 22a' is the focus of this study.

Figure 1 – Overview of the Green Deal package. The Renewable Energy Directive is shown in pink

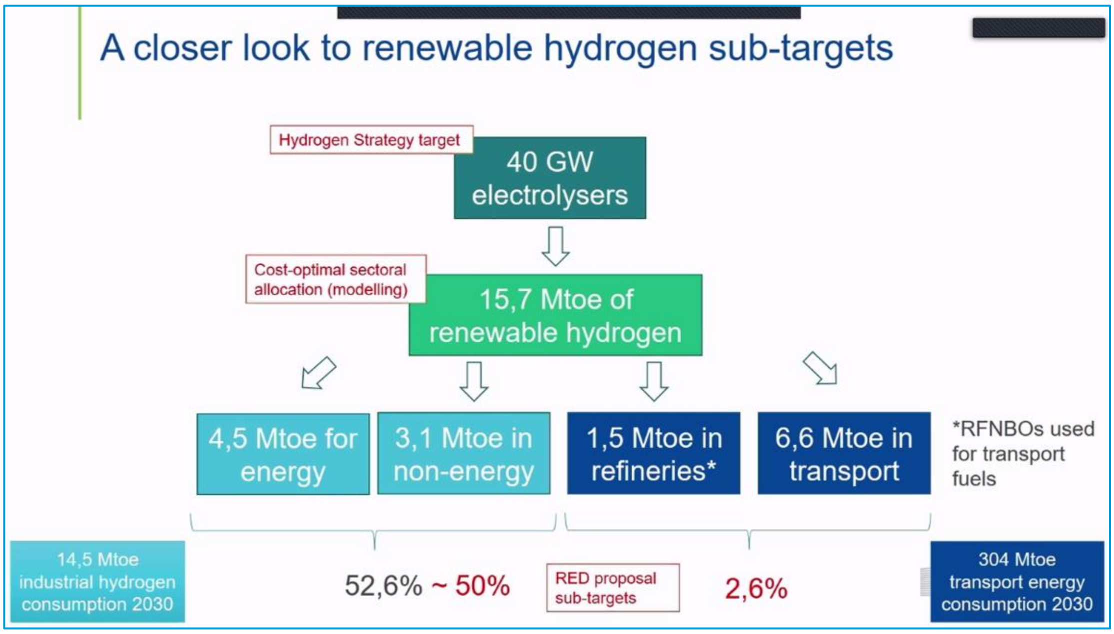


Source: Public presentation by Mr Van der Schouw, DG ENER, December 10th, 2021.

[1] Renewable fuels of non-biological origin, or RFNBO for short, is the formal term that is used to describe 'green hydrogen' and green hydrogen carriers. It is defined as: liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass.

Green hydrogen fulfils an essential role in the CO_2-neutral energy and feedstock supply towards 2050 and beyond. The overarching aims of the Commission are to mainstream renewable energy in hard-to-decarbonise sectors like the hydrogen using industry, and to realise the European hydrogen strategy (EC, 2020a) that has set target of 40 GW of electrolyser capacity within the EU by 2030. Article 22a and its 50% target is a means to realise this overarching aims. See also Figure 2 that shows the interrelation between the target and sub targets.

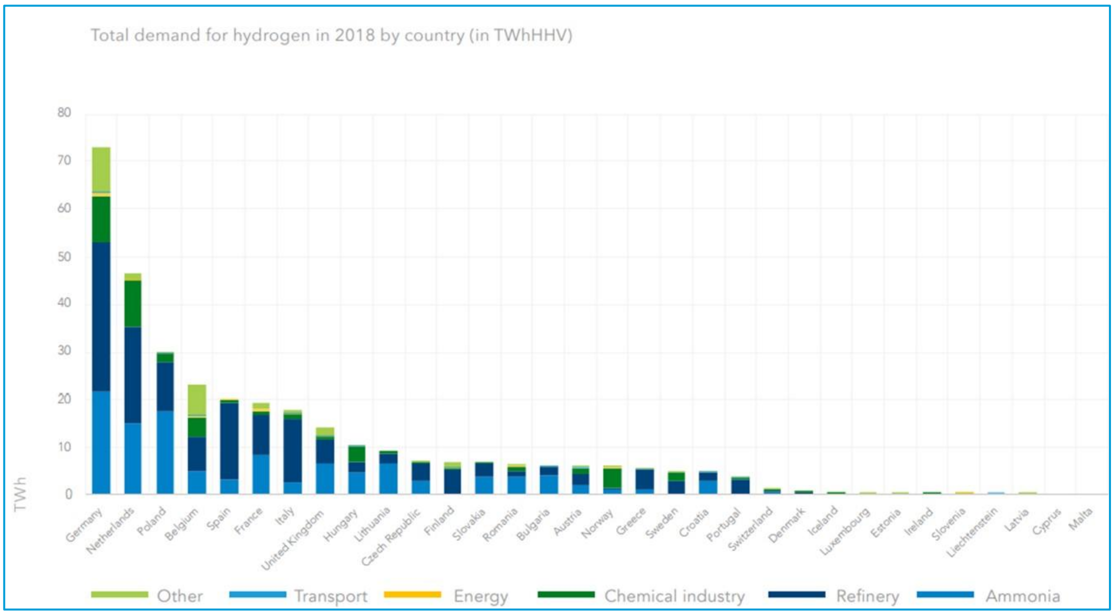
Figure 2 – Schematic representation the European hydrogen strategy, translated into targets (1 Mtoe = 42 PJ)



Source: Public presentation by Mr Van der Schouw, DG ENER, December 10th, 2021.

The impact of Article 22a on the Netherlands will be larger than on most other EU Member States, due to the concentration of hydrogen using industries (e.g. ammonia, chemical, refineries) in the Netherlands. In terms of current hydrogen demand, the Netherlands comes second behind Germany, see Figure 3. Current hydrogen demand is almost entirely met by hydrogen made from fossil fuels. An overview of current hydrogen consumption in the Netherlands by industry and refineries is provided in Annex A.

Figure 3 – Hydrogen use by EU countries, the Netherlands being second in row



Source: Hydrogen Europe (2020).

One other important piece of background information for the Dutch situation lies in another part of the Green Deal Package, with a specific objective of 2.6% for the use of 'green hydrogen' (i.e. RFNBO) as fuel in the transport sector. Bunkering of these fuels is an important economic activity in the Netherlands, for example in the Port of Rotterdam which is one of the largest harbours of the world and at Schiphol as large European airport.
The two targets coincide for the Netherlands in terms of effect on green hydrogen demand.

1.2 Objective of this study

The Dutch industry has asked CE Delft and TNO to provide:
- clarification of the policy terms of Article 22a;
- understanding of the impact of the article on physical realisation, on competitiveness of the Dutch industry, and on policy options for implementation.

The insights from the study will be used for industry stance, for European decision-making and to provide ideas for national policy making on how to achieve the objectives.

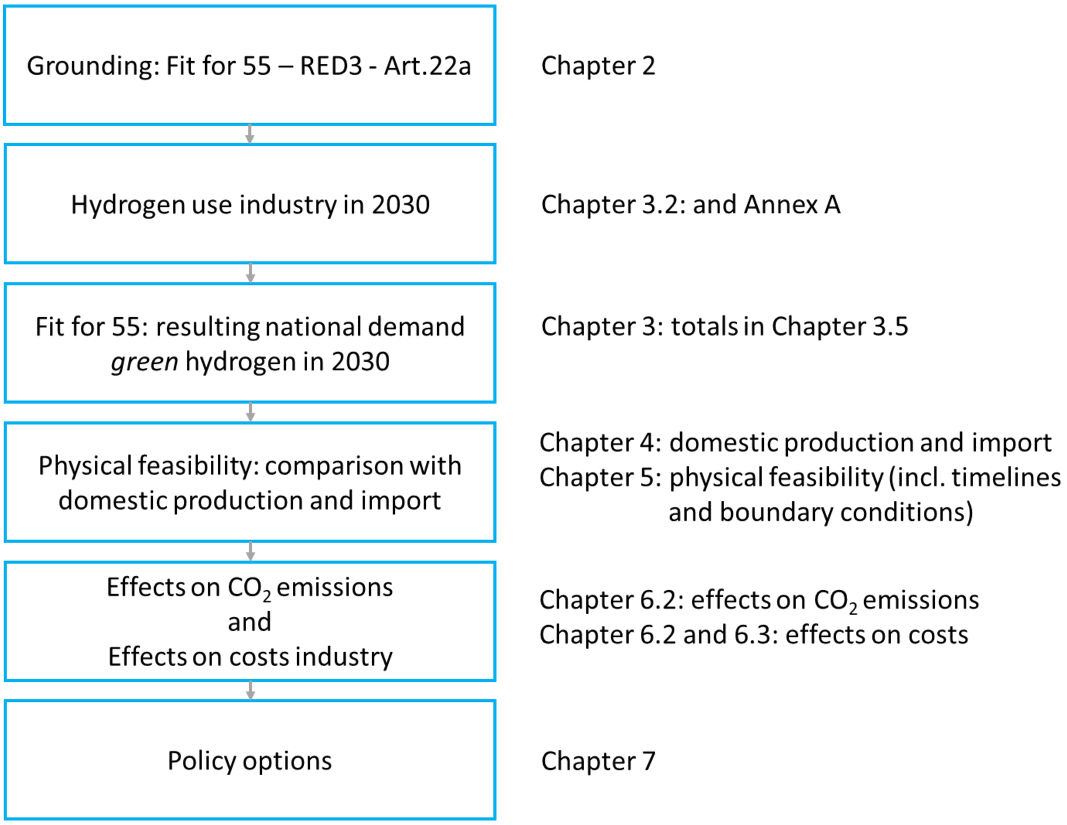
1.3 Research questions

The main research questions are:
- What is the specific meaning of the policy terms of Article 22a? ('grounding')
- What are the quantitative implications of the objective of Article 22a?
- How does the objective relate to current plans and ambitions?
- What is needed to realise the target by 2030?
- What are the consequences of the target?
  - Physical consequences.
  - What are the costs? What is the impact on competitiveness of the Dutch industry?
  - What are the policy options for implementation and what boundary conditions have to be provided by policy to be able to meet the objectives?

1.4 Structure of this report and guidance to the reader

The structure of the report is depicted in Figure 4. Conclusions are given in Chapter 8.

Figure 4 - Schematic structure of the report



In this general introduction and in the summary, we use 'green hydrogen' instead of the term 'renewable fuels of non-biological origin' (RFNBO) used in the RED. Throughout the rest of the report we use RFNBO[2] where possible. In the summary and also in the conclusions, we also rounded the figures of hydrogen demand and production to tens of PJ.

In the rest of the report, we use 'low-carbon' and 'decarbonized' hydrogen instead of 'blue' hydrogen.

We use RED2 as abbreviation for the current version of the Renewable Energy Directive, and the recast of the RED2 as proposed by the EC will be indicated by RED3 (European Commission, 2021).

[2] It is expected that in practice the term RFNBO will largely coincide with green hydrogen. But RFNBO includes more, such as green ammonia, provided it result in emissions reductions of 70% or more over the conventional fossil fuel.

Throughout this report, we use the energy content of hydrogen as unit, expressed in PetaJoule (PJ) and based on lower heating value (LHV). The values are within one year (i.e. more precisely PJ/y), mostly by 2030. Other sources also use weight as unit (Mton), or energy content expressed in TWh. 1 Mton (i.e. 1 billion kg) of pure hydrogen is equivalent to 120 PJ of energy (LHV). 1 TWh is 3.6 PJ, by definition[3].

[3] This is the energy content of hydrogen, not to be confused with the amount of electricity that is needed to produce hydrogen with an electrolyser, which is more, due to conversion losses.

2 Explanation of RED3 Art. 22a

2.1 Introduction

The Renewable Energy Directive (RED) has historically aimed at promoting renewable energy in electricity, transport and heating and cooling. The current proposal for revision of the RED2 (often referred to as RED3) includes for the first time - in Article 22a - a provision on consumption of RFNBOs in industry (European Commission, 2021).

Article 22a is delineated in rather broad terms without specifying all categories that are involved in industrial hydrogen consumption. However, the Netherlands is a big consumer of hydrogen (second in the EU after Germany; see Figure 3) and this consumption takes place in various compositions and under a range of conditions, not exactly spelled out in Art. 22a.

In this chapter we will elucidate the content of Art. 22a (see following text box).
The definitions used in the Article are analysed in relation to hydrogen consumption in industry.

RED2 revision proposal, Article 22a: Mainstreaming renewable energy in industry

1. Member States shall endeavor to increase the share of renewable sources in the amount of energy sources used for final energy and non-energy purposes in the industry sector by an indicative average minimum annual increase of 1.1 percentage points by 2030.

   Member States shall include the measures planned and taken to achieve such indicative increase in their integrated national energy and climate plans and progress reports submitted pursuant to Articles 3, 14 and 17 of Regulation (EU) 2018/1999.

   Member States shall ensure that the contribution of renewable fuels of non-biological origin used for final energy and non-energy purposes shall be 50% of the hydrogen used for final energy and non-energy purposes in industry by 2030. For the calculation of that percentage, the following rules shall apply:
   (a) For the calculation of the denominator, the energy content of hydrogen for final energy and non-energy purposes shall be taken into account, excluding hydrogen used as intermediate products for the production of conventional transport fuels.
   (b) For the calculation of the numerator, the energy content of the renewable fuels of non-biological origin consumed in the industry sector for final energy and non-energy purposes shall be taken into account, excluding renewable fuels of non-biological origin used as intermediate products for the production of conventional transport fuels.
   (c) For the calculation of the numerator and the denominator, the values regarding the energy content of fuels set out in Annex III shall be used.

2. Member States shall ensure that industrial products that are labelled or claimed to be produced with renewable energy and renewable fuels of non-biological origin shall indicate the percentage of renewable energy used or renewable fuels of non-biological origin used in the raw material acquisition and pre-processing, manufacturing and distribution stage, calculated on the basis of the methodologies laid down in Recommendation 2013/179/EU 27 or, alternatively, ISO 14067:2018.’.

Delegated act RED2

The criteria stipulating how RFNBOs can be produced from renewable electricity are not yet set out in EU legislation. The EU's existing Renewable Energy Directive (RED2) calls for the Commission to publish these in a delegated act by the end of 2021. This timeline has not been met. This delegated act will set out the rules for what counts in Europe as 'green' (i.e. renewable) hydrogen (of non-biological origin) and its derivative RFNBOs.
Where relevant, we used versions of the delegated act that are publicly available, making clear that the final version might be different.

The delegated act is relevant for this report, because the criteria set rules for the coupling of electrolysers to e.g. offshore wind farms and therefore to the critical timelines for the feasibility of the objective of Art. 22a.

In addition to the delegated act, Eurostat is working to reflect in energy statistics the differentiation between green and fossil hydrogen. This will be essential in order to monitor the consumption of hydrogen and RFNBOs in Europe (Eurostat, 2022).

2.2 50% target in Article 22a

Art. 22a states that the 'contribution of RFNBOs used for final energy and non-energy purposes shall be 50% of the hydrogen used for final energy and non-energy purposes in industry by 2030.'

To calculate this percentage, a denominator and numerator are given. The denominator is calculated on the basis of the energy content of hydrogen for final energy and non-energy purposes, excluding hydrogen used as intermediate products for the production of conventional transport fuels. Hydrogen used in refineries for the production of refinery products other than transport fuels should be counted towards the denominator. On the other hand, hydrogen used for the production of methanol which is used as transport fuel can be excluded from the calculation. The same holds for hydrogen which is used for the production of biofuels. Statistics on the exact size of these different fractions are currently unavailable.

The numerator should be based on the energy content of the RFNBOs consumed in the industry sector for final energy and non-energy purposes, excluding RFNBOs used as intermediate products for the production of conventional transport fuels.

The reason why hydrogen used for the production of conventional transport fuels is excluded under Art. 22a is to avoid double counting. The hydrogen for these fuels is included in the RFNBO objective of 2.6% RNFBOs by 2030 for the transport sector as laid down in the proposal for revision of the RED2 Article 25.1b.

For the calculations the values regarding energy content of fuels set out in Annex III of the proposed directive should be used.

For the denominator only hydrogen is relevant. For the numerator all RFNBOs are eligible. This entails that not only green hydrogen, but also synthetic hydrocarbons and ammonia present opportunities to reach the 50% target. However, the target of at least 70% CO_2 emission reduction compared to the reference must be met for these compounds in order to count as RFNBO. Furthermore, hydrogen from biomass and other sources of biological origin are excluded from the numerator by definition, as this cannot be considered a fuel of non-biological origin.

2.3 Article 22a other provisions

The first section of Art. 22a contains an indicative target for 2030 to increase the share of renewable sources in the amount of energy sources used for final energy and non-energy purposes in the industry sector with 1.1 percentage point annually. Member States shall include the measures planned and taken to achieve this indicative target in their integrated national energy and climate plans and progress reports.

Section 2 of Art. 22a sets the obligation for Member States to make sure that industrial products that are labelled or claimed to be produced with renewable energy and RFNBOs shall indicate the percentage of renewable energy or RFNBOs used in the raw material acquisition and pre-processing, manufacturing and distribution stage. This will be calculated on the basis of the methodologies laid down in Recommendation 2013/179/EU or, alternatively, ISO 14067:2018.

2.4 Enforcement

If adopted by the end of 2022, the RED3 should be transposed into national law by 31 December 2024. The RED proposal does not directly mention penalties for not complying with the Directive. However, enforcement of EU law after adoption is a task of the Commission.

After adoption of a Directive, the European Commission will monitor the performance of Member States in implementing and enforcing the Directive. The Commission prioritises policy areas that have the highest impact on everyday lives of citizens and businesses. Failing to either transpose (in time) or enforce EU law might eventually lead to an infringement case brought before the Court of Justice. The Commission might propose a daily penalty, depending on the gravity and duration of the infringement. The Renewable Energy Directive has been subject of infringement cases in the past. Nonetheless, enforcement of EU law is mainly based on cooperation, guidance and dialogue and a Court case is seen as a last resort.

2.5 Defined terms in Article 22a

Three of the terms in Art. 22a are defined in Art. 2 of the RED, see Table 1.

Table 1 – Definitions of Art. 22a

Term	Definition given (Art. 2)
Industry	Companies and products that fall under Sections B, C, F and J, division (63) of the statistical classification of economic activities (NACE REV.2).
Non-energy purpose	The use of fuels as raw materials in an industrial process, instead of being used to produce energy.
RFNBOs	Liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass.

Following the definition given of industry, the four sectors that fall within the scope of Art. 22a are mining and quarrying, manufacturing (incl. manufacturing of coke and refined petroleum products), construction and information service activities (like data centres). Section D (Electricity, gas, steam and Air Conditioning Supply) is not included.
Hence, hydrogen used as fuel in central power plants is not part of the definition, but hydrogen used as fuel for own use in industry (e.g. CHP) should be taken into account for the denominator.

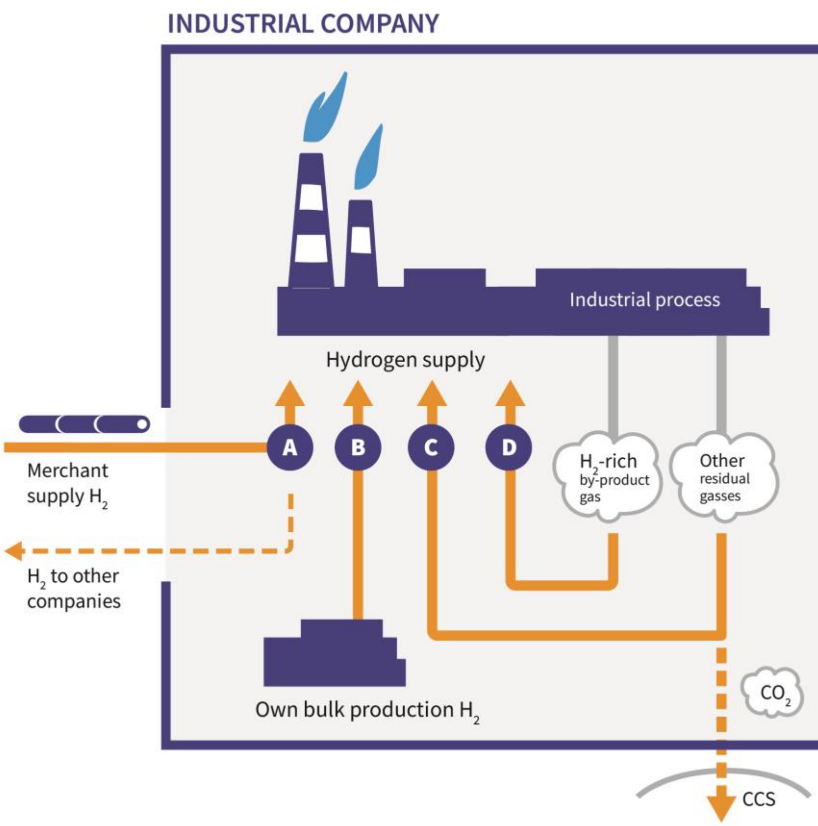
Other than these three definitions, the other terms in Art. 22a are not (yet) explicitly defined.

2.6 Art. 22a and hydrogen use in industry

While Art. 22a represents an obligation on Member State level, a scheme regarding the implications at industrial site level can be schematically drawn as in Figure 5. In the current situation in the Netherlands, most of the hydrogen is self-produced, by own bulk production from natural gas and as by-product within the industrial processes. The total volume of merchant supply by pipelines is relatively small (Weeda and Segers (2020)), see also annex A.

The energy content of the hydrogen in the arrows in Figure 5 shall be counted towards the denominator. For the numerator, the energy content of the RFNBOs flowing through those arrows needs to be counted. Hydrogen used as intermediate product for the production of conventional fuels is exempted from the denominator. However, based on communication with DG ENER, the hydrogen used for the production of biofuels does not need to be included in the denominator. Biofuels are not considered as 'conventional' transport fuels (i.e. fossil fuels).

Figure 5 – Theoretical scheme of hydrogen flows on an industrial site[4]



[4] The 'other residual gasses' (arrow C) in the figure refers to plans to decarbonise methane rich residual gasses via CCS, and use the resulting hydrogen in the industrial processes, instead of these residual gasses.

Hydrogen from bulk production or merchant

Hydrogen consumption in industry differs in degree of purity. Almost pure hydrogen is produced from natural gas (with hydrogen as the only product), self-produced or delivered by merchants. Next to that, hydrogen (in less purer forms) is mainly produced and consumed in the form of syngas, in a mixture with nitrogen (N_2) for the production of ammonia, and in a mixture with carbon monoxide (CO) for the production of methanol.

To calculate the share of hydrogen as demanded in Art. 22a, it needs to be counted apart from other substances that contribute to final energy use. This may represent a significant administrative challenge.

Hydrogen as hydrogen-rich co- or by-product

Some hydrogen is produced as co- or by-product of a certain industrial process and subsequently consumed internally (captive) or traded with another consuming party (merchant). Generally, this hydrogen is inevitably produced within the framework of the existing industrial processes. It concerns hydrogen involved in the processing of oil and oil products into fuels or chemicals, and hydrogen from coke production in the steel industry. Also, a small volume of hydrogen is a by-product of the production of chlorine.

The release or production of co- and by-product hydrogen in the current industrial processes cannot be avoided without changing complete industrial processes or value chains.

In the Impact Assessment of the RED3, it is acknowledged that 'consideration is needed for hydrogen produced on-site as by-product.'[5] However, the reasoning seems to be that the relatively minor amount of this type at EU-level doesn't pose a challenge of achieving an overall, EU-wide target of 50% RFNBOs. Relative proportions of consumption differ considerably among Member States (Hydrogen Europe, 2020).

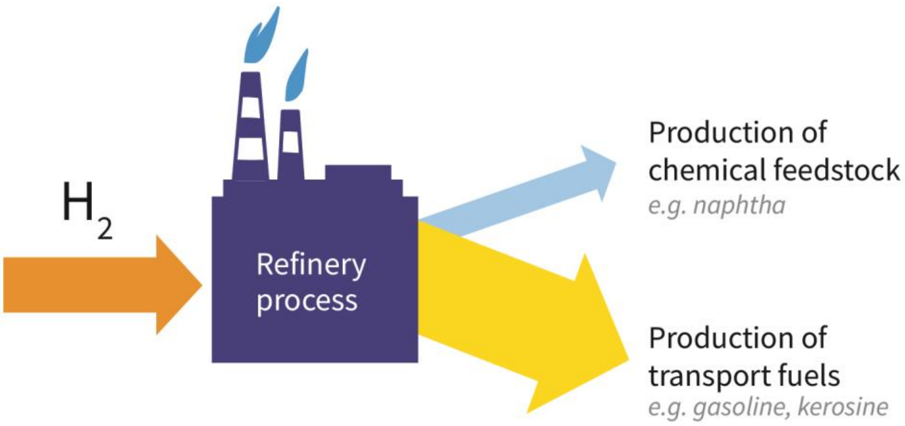
2.7 Hydrogen for production of conventional transport fuels

In refineries hydrogen is used in the process of desulphurization and hydrocracking. Part of this is merchant and part is captive hydrogen, produced from residual gases. Hydrogen used for mineral oil refining is included in the denominator, except when used for the production of conventional transport fuels. This is to stick to sector targets (e.g. transport, industry) and to avoid double counting.

So calculations need to make a distinction between hydrogen used for production of conventional fuels and other oil products like naphtha as feedstock for chemicals (or bitumen, lubricants). A general guideline to calculate the share of hydrogen related to refining for the chemical industry and for the production of conventional transport fuels will be needed. In order to reflect the complex differences among refineries, it might even be needed to develop site-specific guidelines. About 10-15% of the hydrogen use in refineries is for production of chemical feedstock.

[5] RED3 Impact Assessment, p. 131.

Figure 6 – Refineries produce both transport fuels and feedstock for the chemical industry



2.8 Timeline for implementation

The recast RED is currently under first reading in Parliament and Council, for which there is no official deadline. The EP rapporteur has published meanwhile a draft report, in which also amendments to Art. 22a are proposed (Euractiv, 2022). The RED dossier has been earmarked a priority by the French presidency of the Council. Taking into account a reasonable period for the rapporteurs and negotiations in the Council, voting might take place in the second half of 2022. The proposal stipulates that transposition should be due at 31 December 2024 the latest. This is because there should be sufficient time to achieve the targets of 2030.

After transposition into national policy, these national policies subsequently have to be implemented to become operational.

3 National demand for RFNBOs

3.1 Introduction

In this chapter, the national current and future use of hydrogen is elaborated, and the accompanying demand of RFNBOs stemming from the obligation is calculated. In Chapter 5 this will be compared to the availability by 2030 of RFNBOs from domestic production and from import, which are the subject of Chapter 4.

In this chapter we elaborate hydrogen use in Dutch industry and in the transport sector. By 2030, also hydrogen use in the power sector is foreseen in the new coalition agreement. However, the power sector is not part of the industry definition, so hydrogen use for power plants in the electricity sector is outside the scope of Art. 22a. Hydrogen used for power generation in combined heat and power plants in industry is inside the scope of Art. 22a. The current use is elaborated, as are the published plans for hydrogen use towards 2030, together with a short outlook towards the period after 2030. All these use is related to the objective of Art. 22a.

3.2 Current and future hydrogen use Dutch industry

The current and future use of hydrogen by Dutch industry is determined based on Weeda and Segers (2020), the PBL MIDDEN reports[6] and the Dutch Cluster Energiestrategieën (CES). The use of hydrogen as intermediate product for the production of conventional fuels is excluded, following the provisions of Article 22a. While the obligation should be calculated based on hydrogen use, often only hydrogen production capacities are known. Where no specific data was available on hydrogen production and consumption, we assume an average 90% capacity factor to calculate hydrogen production based on production capacity. The estimates have been checked with industry through interviews.

We defined three variants for hydrogen use in industry by 2030, named Low, Middle and High, see Table 2.

The **low variant** is based on current consumption in industry that falls within the definition of Article 22a, as discussed in Chapter 2. An overview of current hydrogen use in the Dutch industry is given in Appendix A. The use of hydrogen for ammonia production is included in its entirety. For methanol, only the hydrogen used for the production of methanol as chemical compound is included. Hydrogen used for the production of methanol that is used as transport fuel is excluded. For refineries, all hydrogen use is included in the low variant except for the hydrogen used as intermediate product in the production of conventional fuels. Lastly, miscellaneous industrial use of merchant hydrogen is included, except the use of hydrogen for the production of biofuels, and the use of by-product hydrogen from various industrial processes such as the production of olefins in naphtha crackers, the production of styrene and the production of chlorine. Concerning hydrogen-rich by-product gas (category D in Figure 5) it is assumed that some internal flows will not be present in national statistics and these are therefore not included in the low variant. Specifically, by-product hydrogen in cokeovengas and in Flexicoker fuel gas are excluded. In total, 16 PJ of current use of by-product hydrogen is included.
The total hydrogen use in the low variant by 2030 amounts to 98 PJ.

6 PBL: MIDDEN: Manufacturing Industry Decarbonisation Data Exchange Network

In the **middle variant,** we include some industrial plans for new hydrogen use, i.e. the Tata Steel plans to install a direct reduced iron plant before 2030 (Roland Berger, 2021), and two industry projects to decarbonise methane-rich fuel gases and use of the resulting low-carbon hydrogen for final energy purposes.
Based on the CESsen, PBL concludes that there are plans for a total of 96 PJ (0.8 Mton) per year for the production of low-carbon hydrogen from fossil fuels (PBL, 2021d). Both projects based on low-carbon hydrogen from methane-rich fuel gases, i.e. the first phase of H-Vision in Rotterdam and a similar project by DOW in Terneuzen, are planned to have about 0.2 Mton production capacity per year (48 PJ)[7]. Assuming a utilisation factor of the hydrogen production facilities of 90%, the middle variant includes 44 PJ of additional low-carbon hydrogen consumption in industry. The expected hydrogen use by Tata is taken from the recently published feasibility study and amounts about 10 PJ taking into account a utilisation factor of 90%. This number relates to the use of pure hydrogen. The number could be somewhat less if the process is first operated with syngas produced from natural gas.
The total hydrogen use in the middle variant by 2030 amounts to 152 PJ.

Use of hydrogen from decarbonised methane-rich fuel gasses in industry contributes towards the denominator of the RFNBO-obligation for industry. This hydrogen, however, does not contribute to meeting the obligation because it is not an RFNBO.

In the framework of the H-vision initiative, hydrogen will be produced from 90% residual gasses from three refineries and 10% natural gas. The initiative is part of the plans adopted by Dutch industry to comply with the ambitions of the Dutch Climate Agreement. H-vision envisages a capacity of 750 MW from 2026 and 1,500 MW to be realised by 2030. The produced CO_2 will be captured and stored (CCS). The hydrogen will subsequently be supplied as fuel to industrial consumers for high temperature heat demand and to the energy system in general. It will mainly replace methane-rich fuel gas and some natural gas. The project will therefore reduce CO_2 emissions but also add to the denominator of the objective of Article 22a (See Section 6.2.2). The project will not count towards the numerator of the objective.

In the **high variant** we included the second half of the 0.8 Mton of new low-carbon hydrogen production from PBL's analysis of the CESses. If realised before or by 2030, the additional hydrogen consumption will lead to an increase in the RFNBO obligation for 2030. The projects included are the second phase of the H-vision project (Werkgroep CES Rotterdam-Moerdijk, 2021), and two projects that envision new hydrogen production from natural gas (H2Gateway, 2020, Vattenfall et al., 2018). For the latter two projects, it is not clear yet whether the hydrogen will be used for industrial or other applications. This adds to the uncertainty of whether they will result in a larger RFNBO obligation. Realisation of these projects before or by 2030 is considered less certain than the two included in the middle variant. But if realised before or by 2030, the additional hydrogen consumption will lead to an increase in the RFNBO obligation for 2030.

The projects included in the high variant are those of which most information is available, but it is possible that other new hydrogen use in industry can materialise by 2030.

[7] For H-vision we assume all hydrogen is used as fuel gas instead of the methane-rich fuel gas. DG ENER has indicated that hydrogen used for energy purposes in refineries does not count has intermediary for conventional fuel production and therefore has to be included in the denominator of the industry RFNBO obligation from Article 22a. If the hydrogen is used for conventional fuel production or in sectors other than industry, the contribution to the RFNBO obligation will be smaller. In such cases, another source of heat must be found instead of the fuel gas.

Some uncertainty therefore remains for the resulting height of the RFNBO obligation of the high variant.
The total hydrogen use in the high variant by 2030 amounts to 195 PJ.
In Table 2, the three variants for the estimated hydrogen use of the industry in the Netherlands by 2030 are presented, as well as the RFNBO/green hydrogen demand resulting from the Article 22a obligation to use 50% RFNBOs in industry by 2030.

Table 2 - Industrial hydrogen use in the Netherlands by 2030 in the three variants, together with the resulting 50% RFNBO target

Industrial hydrogen use	Low variant (PJ/y)	Middle variant (PJ/y)	High variant (PJ/y)
Current hydrogen use, consisting of: — Current use in production of ammonia and methanol — Use in refinery for production of chemical feedstock — Miscellaneous use of merchant hydrogen — By-product hydrogen-rich gasses	98	98	98
Tata Steel plans 2030	-	10	10
Additional H_2 from the decarbonization of fuel gasses by 2030	-	44	65
(Additional) projects for production/use of low-carbon H_2 from natural gas with CCS	-	-	22
Total hydrogen use in denominator Article 22a	98	152	195
50% RFNBO obligation based on Article 22a	49	76	98

3.3 RFNBO demand Dutch transport

Next to the RFNBO obligation for industry, the RED proposal has a RFNBO sub-target for fuel suppliers of at least 2.6% of energy supplied to the transport sector by 2030.
The denominator being the amount of energy consumed in the transport sector (including electricity) and the numerator the energy content of RFNBOs supplied to all transport modes in the territory of the EU.

The target can be fulfilled with RFNBOs that are used as intermediate for the production of conventional fuels and by RFNBOs directly used in transport. The first option had been planned by the Dutch government under the RED2 transposition for a two-year period (the years 2023 and 2024). In the RED3 proposal, the use of hydrogen as an intermediate for the production of the fuels is counted towards the 2.6% RFNBO transport target.

Scope of transport modes

While the RED2 transport targets are specifically aimed at road and rail transport, the legislative proposal of the RED3 is aimed at all transport modes in the territory of the EU, including maritime bunkering and aviation fuels. Aviation and maritime transport have also separate targets in new legislative proposals within the Fit for 55 package (ReFuelEU Aviation and FuelEU Maritime).

Since the Netherlands plays an important role in the bunkering market (with Rotterdam as the second bunkering port in the world and Amsterdam as the fourth airport in Europe), the transport target will have a substantial impact on the supply and hence on the use of RFNBOs in the Netherlands. In the Netherlands, in the years before Covid (up till 2019), aviation represented approximately 25% of total bunkering fuels and shipping the remaining 75%.

Current and 2030 use of RFNBOs in the Netherlands

Table 3 shows the energy consumed by the transport sector and the consequences of the 2.6% target. For comparison, also the current situation is displayed, for the year 2019 (because 2020 gives a distorted image due to the global corona pandemic). It becomes clear that based on projections the target for 2030 will be slightly lower than when based on current data and also that bunkering is the main reason for the height of the target.

Higher expected rates of mobility by 2030 are offset by higher efficiency (e.g. electric vehicles) and this results in a lower energy consumption in transport. The KEV expects that with established and planned policy, the energy content of bunkering fuels decreases slightly, continuing the trend since 2007. The KEV also gives a projection of 0.42 PJ direct use of hydrogen in transport, a practically negligible quantity compared to the target.

Overall, 2.6% of energy supplied to the transport sector leads to a calculated[8] transport target for RFNBO in 2030 in the Netherlands of 29 PJ. This obligation is to be met with direct use of RFNBOs in transport, in bunkering fuels or by using RFNBOs as an intermediate product for the production of conventional fuels. RFNBOs supplied to the aviation and maritime modes shall be considered 1,2 times their energy content. With the insights from the KEV (i.e. very small H_2 use in transport in 2030, see Table 3), the use of RFNBOs as an intermediate product in the production of the fuels will be crucial to meet the transport target.

Table 3 – Projections for energy consumption in transport in the Netherlands for 2019 and 2030 in PJ (KEV)

	2019 (PJ/y)	2.6% (PJ/y)	2030 (PJ/y)	2.6% (PJ/y)
Energy consumption in transport	515	13.4	461	12
- Of which final use of hydrogen	0		0.42	
Bunkering (international shipping and aviation)	667	17.3	644	16.7
Total	**1,183**	**31**	**1,101**	**29**

Hydrogen demand from transport sector after 2030

The downward trend of energy consumption in transport is likely to continue after 2030, but nothing is known yet about RED targets for transport after 2030. However, legislative EU documents for the aviation and maritime sector have set goals towards 2050. The target for sustainable aviation fuels (SAF) by 2030 will be 5%, but in 2035 it will be 20%. Of this, synthetic fuels need to be 0.7% by 2030 and 5% in 2035. Also for maritime shipping, CO_2 emission reduction goals will be 6% by 2030, 13% in 2035 and 26% in 2040.

It can therefore be expected that, under the influence of the Fit for 55 package, demand for RFNBOs from 2030 will increase significantly for aviation and the maritime sector.

Moreover, most of the conventional fuels produced in the Netherlands are exported (around 75%). The interplay between an obligation in importing EU Member States (without the possibility of applying RFNBOs as intermediate) and use of RFNBOs in Dutch refineries may result in a complex situation, where export flows might become subject to conditions flowing from the 2.6% target in the respective member state. These situations are therefore

8 The calculated value might change in case changes in the markets occur, for example when geographic shifts occur in worldwide bunkering. To investigate these possibilities lies outside the scope of this study.

not taken into account in the calculated value of 29 PJ for RFNBO use in the Netherlands in 2030, stemming from the obligation.

3.4 Total Dutch RFNBO use by 2030

In Table 4, the sum of the national RFNBO use is given for 2030, stemming from the 50% objective in Article 22a for the industry, and the 2.6% RFNBO obligation for the transport sector including the bunkers for maritime and aviation.

Table 4 - Variants of total RFNBO use in the Netherlands by 2030, resulting from the obligations

Variants 2030	Low + transport sector (PJ/y)	Middle + transport sector (PJ/y)	High + transport sector (PJ/y)
Industry sector 50% RFNBO from Art. 22a	49	76	98
Transport sector 2.6% RFNBO	29	29	29
Total	**78**	**105**	**127**

4 Domestic production and import of RFNBOs

In this chapter, the total RFNBO supply in the Netherlands is elaborated, from domestic green hydrogen production and from RFNBO import. This gives insight in the possible gap between the projected national use of RFNBOs in 2030 following from the obligations, and the availability.

Renewable electricity, electrolysers and production of 'green hydrogen'
In our calculations in this report we assume that RFNBO production is based on renewable electricity produced by offshore wind. The expectation is that offshore wind will be the main source of renewable electricity for green hydrogen production in the Netherlands. However, in practice, also renewable electricity from onshore wind and solar-pv may be used, which may be combined with offshore wind, e.g. using Power Purchase Agreements (PPAs).
We have also assumed a 1:1 ratio between the capacity of electrolysers and offshore wind capacity, using 4,300 full load hours per year for both offshore wind and the electrolyser, unless stated otherwise. In practice, the capacity of the electrolyser may be chosen smaller, resulting in more full load hours of the electrolyser, but also to a larger required renewable electricity capacity to be able to produce the same volume of green hydrogen per year.

More full load hours of the electrolyser scales linearly with the calculated capacities. As an example: using 6,000 full load hours instead of 4,300 reduces the required electrolyser capacity to a factor of (4,300/6,000) = 72%.

The calculations are performed using a 57.65% conversion efficiency of the electrolyser (i.e. 57.8 kWh/kg H_2), which is a plant efficiency (i.e. not only the stack or power module), based on the Lower Heating Value (LHV) of hydrogen (i.e. 119.96 MJ/kg H_2), and in which a degradation factor of 1%/yr was taken into account. These values are also used in the SDE++, and are based on market consultations.
In the future, towards 2050, the expectation is that higher conversion efficiencies will be achieved (see e.g. IRENA 2020 Green hydrogen cost reduction : Scaling up electrolysers to meet the 1.5ºC Climate)

4.1 Required capacity for industry + transport target

In Chapter 3 the demand for RFNBOs in the Netherlands is calculated. In this chapter we first calculate the required offshore wind and electrolyser capacity to produce sufficient hydrogen to fulfil the different demand scenarios with national production. With these results the current plans for RFNBO production can be compared to what is needed to meet the RFNBO target.

Table 5 shows that 38 to 61 TWh of renewable electricity is needed to realize the demand scenarios. Resulting in calculated electrolyser and offshore wind capacities of 9 to 14 GW, in case the target will be met using offshore wind only. Our general assumptions are an electrolyser conversion factor of 57.8 kWh/kg H_2 and 4,300 full-load hours for offshore wind[9]. We have assumed a 1:1 ratio between electrolysers and offshore wind power[10].

Table 5 – Required volumes and capacities to fulfil national RFNBO demand by 2030 with domestic production, in case the electricity will be produced with offshore wind

	RFNBO-obligation (PJ/y)	Required volume renewable electricity (TWh/y) and (PJ/y)	Required offshore wind capacity (GW)	Required electrolyser capacity (GW), assuming 1:1 ratio
Low + transport sector	78	38 TWh/y (137 PJ/y)	9	9
Middle + transport sector	105	51 TWh/y (184 PJ/y)	12	12
High + transport sector	127	61 TWh/y (220 PJ/y)	14	14

4.2 Domestic green hydrogen production

In this paragraph we determine the potential green hydrogen production in the Netherlands based on current plans for renewable electricity production and electrolyser capacity. Secondly, we discuss the timeline and important dependencies.

4.2.1 Renewable electricity and electrolysers

For green hydrogen production, both renewable electricity and electrolyser capacity is required. Therefore we will analyse both to determine the potential domestic production.

Availability of renewable electricity

For the production of green hydrogen, renewable electricity is required. The RED2 delegated act on additionality will set out the specific rules for what counts in Europe as 'green' (i.e. renewable) hydrogen and its derivative RFNBOs. In our analyses we assume for the sake of simplicity that RFNBO production is based on offshore wind[11].

The 'Stuurgroep extra opgave' advised that by 2030 an additional capacity of 10 GW (additional to the capacities that were assumed in the Climate agreement) offshore wind is required to meet the renewable electricity demand by 2030, producing 45 TWh per year. The 'Stuurgroep' assumed an allocation of 15.4 TWh of renewable electricity to green hydrogen production[12]. This allocation is consistent with the ambition in the Climate

[9] Onshore wind and solar-pv might contribute also, however the expectation is that offshore wind will be the main source of renewable electricity for green hydrogen production in the Netherlands.

[10] The volume of renewable electricity is the dominant factor. Assuming a different ratio will lead to more full-load hours of the electrolyser, but also to a larger required offshore wind capacity to produce the same volume of green hydrogen.

[11] Renewable electricity from onshore wind and solar-pv may enhance the production of green hydrogen, but to a lesser extent than the large volumes that are expected from offshore wind.

[12] The 'Stuurgroep' assumed also an allocation of 26.6 TWh/y for direct electrification in the industry, and 15 TWh/y additional demand from datacenters.

agreement of 3 to 4 GW of electrolyser capacity.[13] The allocation is however an assumption and in practice will be based on contracts between market parties. Note that the proposed 50% RFNBO target for industry was not known in these plans and hence not taken into account, nor was the RFNBO target for the transport sector.

Based on the current insights from VAWOZ[14], 6 GW of this 10 GW could be connected to the electricity network by 2030 and the remaining 4 GW by 2031 (Ministerie van EZK, 2021b). The realisation of more offshore wind capacity is limited by the onshore electricity grid capacity. If by 2030 60% of 10 GW offshore wind can be connected, also 60% of the 15.4 TWh electricity could be allocated to green hydrogen, based on the 'Stuurgroep extra opgave'. In Table 6 we show the resulting hydrogen production based on the 'Stuurgroep extra opgave'.

Table 6 - Potential green hydrogen production based on offshore wind

	Additional off-shore wind VAWOZ (GW)	Allocated electricity for hydrogen production based on 'Stuurgroep extra opgave' (TWh/y)	Total potential of hydrogen production with 57.8 kWh/kg H_2 electrolyser efficiency (PJ/y)
VAWOZ 2030	6	9.2	19
VAWOZ 2031	10	15.4	32

In case the assumed allocation of renewable electricity for green hydrogen production is shifted to 2030, the total volume of green hydrogen that could be produced by 2030 will be 32 PJ. This leads to a range of 19 to 32 PJ. We assumed that these capacities will be fully operational on 1-1-2030, as 2030 is the target year for the RFNBO obligation.

There are diverse options to enhance the domestic production of green hydrogen by 2030:
- using more renewable electricity from offshore wind, onshore wind and solar-pv for green hydrogen production, within the existing national plans;
- further expanding offshore wind, onshore wind and solar-pv capacity for increased green hydrogen production.
- this may be accompanied by allowing electrolysers to make more full load hours, e.g. with combination of Power Purchase Agreements (PPAs) from more than one renewable electricity source.
- Swift development of a stimulation policy instrument for scaling up beyond the 50 MW limit for the electrolyser capacity in the current 'Opschalingsinstrument'

Possible issues with the required expansion of the high-voltage network may be resolved by building electrolysers directly at the landing location of offshore wind electricity without the need to expand the onshore electricity grid. Hydrogen may also be produced offshore by means of an electrolysis unit integrated in the turbine or with a unit located nearby the turbines, for example on an offshore oil platform. The offshore produced hydrogen can be transported to the shore by (existing) pipeline(s).
However, using more electricity for hydrogen production, within the existing national plans, will compete with demand for electricity for other uses like electrification of heat demand in industry and in the built environment, electricity demand of datacentres, and electrification of mobility.

[13] 15.4 TWh offshore wind and an electrolyser with 57.8 kWh/kg H_2 conversion factor produces 32 PJ of green H_2, consistent with 3.6 GW offshore wind with 4,300 full load hours, connected to 3.6 GW of electrolyser capacity.

[14] 'Verkenning aanlanding wind op zee - Dutch research into grid connection offshore wind'.

In case the full production of all 13 GW offshore wind (i.e. 7 GW already confirmed plans within the Climate agreement to be realised between 2023 and 2030), plus 6 GW planned in VAWOZ2030) that will be realised between 2023 and 2030 will be fully used for green hydrogen production, there is a theoretical upper limit for domestic green hydrogen production by 2030 of 116 PJ. Renewable electricity production capacity that will be realised already by 2023 is out of scope due the time constraint that is set by the (draft) delegated act RED2 between additional renewable electricity capacity and the electrolysers. The first large scale electrolysers are scheduled to become operational in 2025.

Plans and ambitions for electrolyser capacities

In the Dutch climate agreement, an ambition has been set of 3 to 4 GW electrolyser capacity by 2030. The current portfolio of potential electrolyser projects has a larger total capacity than the climate agreement ambition for 2030. For many of these projects a final investment decision has not yet been made, decisions depend e.g. on certainty of demand and certainty about incentive policies. To give an impression, some of the relevant larger projects that are made public, among others part of the CESses, are:

- In the NorthH_2 project there are plans for a total of 4 GW electrolyser capacity in the Eemshaven by 2030.
- In the harbour of Rotterdam there are plans for a 2 GW conversion park. In the conversion park, among others, the Hydrogen Holland I (200 MW) and H_2-Fifty (250 MW) projects are expected in the coming years and Uniper intends build a 500 MW installation on their own terrain.
- The Hydrogen Delta is a plan in the Smart Delta Region. It is a combination of projects with among others the SeaH_2land project (1 GW electrolyser capacity) and multiple smaller projects of 100-200 MW.
- In the NZKG region there is among others the H_2ermes projects with an expected capacity of 200-500 MW.

The total electrolyser capacity as published in the CESses is estimated at 9.5 GW (PBL, 2021). The Hydrogen Monitor 2020 identifies a planned electrolyser capacity of about 11 GW by 2030 in the Netherlands (Hydrogen Europe, 2020). Table 7 shows the planned electrolyser capacity, together with a calculation of the green hydrogen production capacity in case enough renewable electricity would be available, in line with the provisions of the RED2 Delegated act. The plans are more than enough to cover the ambition of 3-4 GW of electrolyser capacity within the Climate Agreement. However, it should also be noted that most projects are at feasibility stage. Realisation of these plans depends e.g. on the certainty of the demand, policy development and on clarity about the stimulation regime by the government. The overview indicates that the limiting factor for domestic green hydrogen production to meet the national RFNBO target as proposed in the RED3 lies more with the availability of renewable electricity by 2030 than with the ambitions for electrolyser capacity.

Table 7 - Planned electrolyser capacities by 2030, published plans and ambitions

	Electrolyser capacity (GW)	Potential green hydrogen production (PJ/y) - efficiency 57.8 kWh/kg H_2
		In case of 4,300 full-load hours
Climate agreement	3-4	27-36
	3.6	32[15]
CESses	9.5	85
Hydrogen Monitor 2020	11	98

Note: Only if the produced hydrogen has a credible connection with renewable electricity in line with the provisions in the RED2 Delegated act, the hydrogen will be eligible to meet the proposed targets.

4.2.2 Dependencies for domestic production

The most important dependencies for the production of (sufficient) green hydrogen in the Netherlands are:
- Certainty of demand, following from final adoption of the RED3, and certainty of market conditions, following from transposition of the RED3 to national policy and subsequent implementation.
- Sufficient availability of green electricity to be used for hydrogen production. Large quantities of green hydrogen production require a fast increase in renewable electricity production. In the upcoming decade, green electricity will remain scarce. Renewable electricity is required in several sectors and for reaching CO_2 reduction goals in general. Therefore, there is also an interrelation with developments in other sectors.
- Sufficient availability of electrolysers in the period before 2030 for the Netherlands. Worldwide the demand for electrolyser is expected to increase significantly, in Europe especially influenced by the RED3 industry target and the RFNBO targets for transport. Electrolyser manufacturing capacity may remain limited.
- The certification of RFNBOs in line with the expected RED2 delegated act on additionality. This Delegated act will set requirements related to the timeline of the realisation of the electrolysers in relation to the capacity of the renewable electricity production. Also it will set requirements on the moment of production of hydrogen related to the moment of electricity production. It should be noted that industry will require a continuous supply of hydrogen and hydrogen demand is not coupled with the renewable electricity production, thus requiring storage facilities and also markets to balance supply and demand.
- The on-time realisation of the required electricity and hydrogen infrastructure. Electricity infrastructure for offshore wind, hydrogen infrastructure on land, hydrogen storage and possible electricity infrastructure on land are required for hydrogen transport and production. At this moment there is especially a shortage of onshore electricity grid and therefore additional integration of offshore wind in the onshore infrastructure is not feasible. To which extend offshore hydrogen production can contribute on large scale by 2030 depends highly on facilitating and stimulating policies.
- Permitting processes may result in delay of projects.

4.2.3 Timelines for domestic production

The timelines are visualized and further interpreted in Paragraph 5.4. For domestic production we discuss the timelines for electrolysers, the electricity infrastructure and hydrogen infrastructure.

15 Consistent with the 15.4 TWh allocated to green hydrogen production in the advice of the 'Stuurgroep Extra opgave'.

Timeline electrolysers for green hydrogen production

The total timeline for the realisation of new green hydrogen production is about 8 years, however the timeline can be shortened to 5 years (CE Delft, 2021). For the timeline to be shortened, efficient planning, early reservation of electrolyser production capacity and an early investment decision are required. There is an important dependency on renewable electricity production and the electricity network for this timeline to be met, which is discussed in more detail below.

Critical in the timeline are the permits, the clarity of subsidy and/or demand to realise the business case, the electricity network capacity, the detail engineering phase and the delivery time of the electrolysers. These elements can go partly in parallel. Permits can have a long processing time, especially at greenfield locations. Subsidy is required in the current situation for a positive business case.

At this moment time slots for production of electrolysers have to be reserved approximately two years before scheduled delivery[16]. If the slots are reserved in an early stage of the project development, the timeline of the project as a whole can be shortened.

Note that not all electrolysers can be built at the same latest possible time following the analysis above. Building the required capacities has to be spread in time, to be able to have enough skilled personnel and enough manufacturing time of the equipment.

Timeline electricity infrastructure

A connection to the high voltage network has a lead time of 1 to 1.5 years. However, in case network reinforcements are required, the time span is lengthened to 7 to 10 years, with a risk of a 5 year delay. The entire project timeline could therefore be significantly lengthened if a network reinforcement is required. Realisation of the electricity network at sea to connect offshore wind has also a lead time of approximately 7 to 10 years. If network reinforcements are required, it can already be impossible for TenneT to realize network reinforcements on time for realisation before 2030. This is both due to the timeline but also due to a maximum realisation capacity of TenneT. TenneT already has to prioritize which network reinforcements are made in time, resulting in delays in other areas (TenneT, 2021).

From our analysis of the potential green hydrogen production in the Netherlands, the limiting factor for a further scale up is expected to be the realisation and connection of offshore wind. The total timeline for realisation of offshore wind capacity is approximately 8–10 years. In our analysis we assume the potential of offshore wind as determined by VAWOZ.

Timeline hydrogen infrastructure, including storage

In the Netherlands, hydrogen infrastructure is developed within and between the large industrial clusters, the latter named the national hydrogen backbone. Gasunie and partners have set the goal to develop this network towards 2027[17], including regional backbones

[16] This situation may change, e.g. due to the RFNBO targets in the RED3 proposal, Implementation by the EU Member States may cause shortages towards 2030.

[17] There is a link with demand and supply volumes and their timelines. Low-carbon hydrogen might be needed to put the backbone system into operation. These goals have been set before the RED3 target.

(RIBs) within the industrial clusters. Gasunie states that the timeline of adding an additional pipeline route requires approximately four years if it lays within reserved geographical areas (PwC, 2021). After a financial investment decision, the lead time is three years, mostly for permits and delivery time of components. If the new pipeline is outside of a reserved area, the lead time may be significantly longer. The longer timeline is due to the acquisition of land and additional lead time for permits.

Hydrogen storage is an essential part of the hydrogen infrastructure. The production of green hydrogen will be variable, since it is based on wind profiles or arrival of import. The industry requires a stable and secure supply and hence storage is needed. Storage is planned in salt caverns in Zuidwending, including a connection to the national backbone. The first cavern is planned for 2026. Gasunie has the goal to realize four caverns before 2030. Note that the supply may also come from low-carbon or grey hydrogen.

4.3 Import of RFNBOs

The European Union has set an ambition of 40 GW of green hydrogen production in the EU and 40 GW of hydrogen c.q. RFNBO import by 2030. The former Dutch state secretary set out her vision on the development of the hydrogen market in a recent letter (Ministerie van EZK, 2021a). The Netherlands expects several European countries will produce and export renewable hydrogen such as Spain, Portugal, Norway, Iceland and Russia. Intercontinental export is expected from Africa, Australia, the Middle-East and South-America. In the National Hydrogen Programme an ambition is formulated for 48 PJ (0.4 Mton) of imported hydrogen by 2030. It is expected that the Netherlands will also have a transit function in which hydrogen is transported to for example Germany and Belgium.

Hydrogen can be imported via pipelines from countries within or close to the EU. Intercontinental import will most likely take place via ships. Hydrogen can be imported as liquid hydrogen, bound to another chemical component such as ammonia or to a liquid organic hydrogen carrier (LOHC). Multiple large harbours have extensive experience with the import of liquids. Hydrogen which arrives in the main ports will be transported via the to-be-realised hydrogen backbone to Dutch industry clusters and can be coupled to the German and Belgian hydrogen infrastructure.

4.3.1 Current import plans and capacity

The Port of Rotterdam expects up to 18 Mton (2,160 PJ) of hydrogen import via Rotterdam by 2050 (Port of Rotterdam, lopend), for the Dutch market but to a large extent also for export to e.g. Germany. The Port of Amsterdam set an ambition of 1 Mton (120 PJ) RFNBO import by 2030 (Port odf Amsterdam, 2021). Also SDR/NSP and Groningen Seaport have ambitions for import of hydrogen(carriers). Import may be viable from 2025 with an expected volume of minimal 0.2 Mton and will grow towards 0.4 Mton (48 PJ) by 2030 (Port of Rotterdam, 2021). In the context of the ‘Nationaal Waterstof Programma’ comparable volumes are used of 0.2 Mton in 2025 and 0.4 Mton (48 PJ) by 2030 (Nationaal Waterstofprogramma, 2021).

Recently new large scale projects have been announced or researched in among others Namibia (FuelCellWorks, 2021), Australia (South Australia and Port of Rotterdam, 2021), Mauritania (Atchison, 2021), South Africa (Sasol, 2021) and Egypt (OCI, 2021). The most concrete project is Helios/NEOM, the realisation of a large scale renewable hydrogen based green ammonia plant in Saudi-Arabia by Air Products (Nationaal Waterstofprogramma, 2021). The expected export from Helios/NEOM to North-West Europe is 0.09 Mton RFNBOs in the form of green ammonia, possibly from 2026. To be able to count towards the RED3 target, certification is needed, which depends on the publication of the delegated act RED2 and on the final adoption of the RED3. The latter sets e.g. a requirement for a minimal 70% CO_2 abatement.

At this moment the total potential of RFNBO import by 2030 is highly uncertain. Important dependencies are the worldwide availability of RFNBOs, following upstream investments in exporting countries in renewable electricity production, electrolyser capacity, ammonia plants or other conversion facilities needed for export of the green hydrogen, harbour facilities, creation of international trade routes and international trade relations. In case ammonia is used as carrier, also ammonia crackers are needed for reconversion[18].
A main dependency however is the chicken-and-egg relation with the demand in the Netherlands. The objective of Art. 22a may change this situation and lead to a large demand for RFNBOs in the Netherlands by 2030.

In discussions with Port of Rotterdam, Port of Amsterdam and SDR it was stated that an import volume of 1 Mton per year (120 PJ) could be feasible already by 2030, in line with the provisions of the RED, and at a price that is competitive with domestic production of RFNBOs. This would require swift policy decisions to substantiate the demand, and a task force of Government, the Dutch sea harbours, companies active within the harbours, hydrogen consuming industry and hydrogen importers to realise the task. The realisation of import chains of RFNBOs is also relevant for the period after 2030, when demand will grow further.

We stress that the time frame to 2030 to organise and realise these RFNBO import supply chains is short. On the other hand, imports will be needed also to meet the growing demand for RFNBOs after 2030. Hence, efforts to establish these supply chains can be seen as no-regret.

In this study we assume two import scenarios. The low scenario assumes a potential of 0.4 Mton or 48 PJ hydrogen by 2030 as set as ambition in the Nationaal Waterstof Programma. As high scenario assumes a potential of 1 Mton (120 PJ) by 2030, as described above.

4.3.2 Dependencies for import of RFBNOs

Firstly, the import of RFNBOs is dependent on the availability of RFNBOs on the world market. The production capacity in other countries needs to be scaled up and the Netherlands has to ensure a reliable and stable import. It is vital that the security of supply and security of demand is created. To realize significant amounts of import some preconditions have to be met before the development of terminals can take place.
These preconditions are:

- Clarity from the European Commission on the certification of imported RFNBOs, to be counted towards achieving the target. This will require a registration and control system.
- Sufficient availability of RFNBOs worldwide by 2030 for export to the Netherlands. The availability of sufficient RFNBOs is dependent on:
  - upstream investments in the exporting countries;
  - competition with other importing countries;
  - compliance to the RED requirements, such as a 70% CO_2 abatement.
- Certainty of demand and certainty about the market rules from implementation of the RED3 after final adoption and transposition.

[18] With an exception for imported green ammonia that can be used directly as ammonia in the fertilizer industry.

- A financial investment decision for the hydrogen backbone (incl. storage) to connect also to the import terminal(s).
- Permits for additional ammonia shipping and handling.
- Allowance for the emission of nitrogen due to the reconversion of ammonia to hydrogen[19].

Additionally, sufficient capacity is required in the Dutch ports and infrastructure to receive, reconvert, and transport and store the hydrogen. The import of hydrogen (in the form of ammonia, LOHC, or liquid hydrogen) is technically feasible, but requires additional installations to reconvert the hydrogen carriers to gaseous hydrogen. The ports will require docks/jetties, storage and transhipment for hydrogen or hydrogen carriers. However, the required space for hydrogen import is small compared to the available space in for example the port of Rotterdam (Lanphen, 2019). The backbone needs to be developed to transport the hydrogen to the Netherlands and Germany. Transport capacity to e.g. Germany can help scale up the import of hydrogen and could thereby increase the feasibility of developing import routes.

4.3.3 Timeline for import terminals

The timeline for import terminals is determined. The Port of Rotterdam expects to be able to import hydrogen from 2025 onwards. The Ports of Amsterdam and Rotterdam indicate concrete plans for a further growth towards 2030 in their harbours. The entire timeline requires a total of 4–5 years of which 2 years for building the terminal itself. Before the start of the timeline the preconditions have to be realized, especially the certainty of demand.

An important requirement for import is of course the upstream supply of RFNBOs in the exporting countries. International hydrogen production is outside of the scope of this timeline.

4.4 Hydrogen export from the Netherlands

Exports limit the availability of RFNBOs in the Netherlands to meet the targets. Therefore, we analysed the possible export volumes by 2030.

4.4.1 Hydrogen demand Germany for export by the Netherlands

Hydrogen demand in Germany is expected to increase up to 2030. The demand can be met in part through imports from the Netherlands. In particular the region of North Rhine-Westphalia (NRW) is looking at imports from the Netherlands as a means to source RFNBOs. The hydrogen can be produced domestically in the Netherlands or imported and re-exported to Germany.

Table 8 and Table 9 present an overview of current hydrogen demand and expected hydrogen use by 2030, respectively, for Germany as a whole, and for North Rhine-Westphalia in particular. The data are a summary of various German studies and an EU data base. As such they may not provide a fully consistent data set. An indication for this is that the low estimate for hydrogen use in German industry by 2030 based on one source is considerably lower than the demand in 2020 based on another source. Nevertheless, the industry part in the high estimate may still be larger than the 2020 demand, which may reflect the uncertainty of developments in refineries and other industries.

[19] NB: part of the imported ammonia can be used as such, to replace domestic production of ammonia.

Table 8 - Hydrogen demand in 2020 in Germany and North Rhine-Westphalia (NRW) per application

<table>
<tr><th>Sector</th><th>Germany (PJ/y)</th><th>NRW (PJ/y)</th><th>Sources</th></tr>
<tr><td>Industry</td><td>198</td><td>61</td><td rowspan="5">North Wasserstoff Roadmap (IN4climate.NRW, ongoing)
Wissenschaftliche Begleitstudie der Wasserstoff Roadmap Nordrhein-Westfalen (Cerniauskas et al., 2021).
Fuel Cells and Hydrogen Observatory (2021)</td></tr>
<tr><td>Transport</td><td>-</td><td>-</td></tr>
<tr><td>Electricity</td><td>-</td><td>-</td></tr>
<tr><td>Others</td><td>-</td><td>-</td></tr>
<tr><td>Total</td><td>198</td><td>61</td></tr>
</table>

Table 9 - Projected hydrogen use by 2030 in Germany and North Rhine-Westphalia (NRW) per application

<table>
<tr><th rowspan="2">Sector</th><th colspan="2">Germany (PJ)</th><th colspan="2">NRW (PJ)</th><th rowspan="2">Sources</th></tr>
<tr><th>Low</th><th>High</th><th>Low</th><th>High</th></tr>
<tr><td>Industry</td><td>126</td><td></td><td>65.5</td><td>65.5</td><td rowspan="4">North Wasserstoff Roadmap (2020), Wissenschaftliche Begleitstudie der Wasserstoff Roadmap Nordrhein-Westfalen (2021)</td></tr>
<tr><td>Transport</td><td>72</td><td></td><td>15.8</td><td>15.8</td></tr>
<tr><td>Electricity</td><td rowspan="2">90</td><td></td><td>0</td><td>10.8</td></tr>
<tr><td>Others</td><td></td><td>1.4</td><td>1.4</td></tr>
<tr><td>Total</td><td>288</td><td>396</td><td>83</td><td>94</td><td>Wissenschaftliche Begleitstudie der Wasserstoff Roadmap Nordrhein-Westfalen (2021), The National Hydrogen Strategy (2020)</td></tr>
</table>

Table 10 presents a summary of German expectations for the need of hydrogen import. Estimates for import via the Netherlands vary from 11 to 36 PJ of hydrogen annually. This is equivalent to 90 to 300 kton/y. These estimates are based on studies from before the adoption of the Fit for 55 package and therefore do not yet include an indication of the effect of the RED revision on the hydrogen import demand from Germany.

Table 10 - Projected hydrogen import need by 2030 in Germany and North Rhine-Westphalia (NRW)

<table>
<tr><th rowspan="2">Sector</th><th colspan="2">Germany (PJ/y)</th><th colspan="2">NRW (PJ/y)</th><th rowspan="2">Sources</th></tr>
<tr><th>Low</th><th>High</th><th>Low</th><th>High</th></tr>
<tr><td>Via NL</td><td>21.6</td><td></td><td>10.8</td><td>36</td><td>Wissenschaftliche Begleitstudie der Wasserstoff Roadmap Nordrhein-Westfalen (2021), TNO, Jülich and Dena (forthcoming 2022)</td></tr>
<tr><td>Total</td><td>43.2</td><td>50.4</td><td>n.a.</td><td>n.a.</td><td>Wissenschaftliche Begleitstudie der Wasserstoff Roadmap Nordrhein-Westfalen (2021)</td></tr>
</table>

4.4.2 Hydrogen demand other countries for export by the Netherlands

Like in Germany, the industry in Gent and Antwerp in Belgium will develop a demand for RFNBOs in the near future, with a pace depending on government policy and stimulation. The North Sea Ports Vlissingen and Terneuzen are sea harbours where hydrogen (carriers) can be imported, partly used by the industries in the area, and partly transported to the hinterland like e.g. Gent and Antwerp. The involved hydrogen volumes may be substantial (Buck Consultants and CE Delft, 2021) reaching tens of PJ’s already by 2030 as potential. However, there are no published plans with targets yet.

Therefore, and because of the uncertainties already mentioned in the demand from Germany for export from the Netherlands and the uncertainties mentioned in the import volumes in the Netherlands, we assume that the additional export potential to Belgium is already covered within the already mentioned uncertainties in import and export.

4.5 Total of domestic production and import/export

Table 11 provides an overview of the RFNBO availability by means of domestic production and RFNBO import in and export from the Netherlands. In this overview, data from the previous sections are put together. The expected domestic green hydrogen production by 2030 ranges from 19 to 32 PJ by 2030.
We calculated a (theoretical) upper limit for domestic green hydrogen production by 2030 at 116 PJ, assuming that all 13 GW offshore wind that will be realised between 2023 and 2030 will be used for green hydrogen production (see page 24 for the analysis).

The estimated amount of (green) hydrogen that could be imported by 2030 varies widely from 48 to 120 PJ per year, with high levels of uncertainty.

Exports to the hinterland (e.g. Germany) have to be considered also, since they lead to a lower availability of RFNBOs to meet the domestic demand. Export projections range from 11 to 36 PJ by 2030, also with high levels of uncertainty.

Table 11 – Overview of expected hydrogen availability in the Netherlands by 2030

	RFNBOs availability (PJ/y)	
	Lower value	**Higher value**
RFNBOs production in the Netherlands	19	32 (theoretical upper limit of 116 PJ)
RFNBOs import	0-48	0-120
Total RFNBOs availability	**19-67**	**32-152**
Potential exports from the Netherlands to e.g. Germany	11	36

5 Physical feasibility

5.1 Introduction

The analysis of the physical feasibility consists of three parts. Firstly, the demand and supply scenarios for 2030 of the previous chapters are compared to determine whether there will be enough RFNBOs to fulfil the objectives of the RED3 on the national level for the industry and the transport sector together. Secondly, the question is addressed whether the combined possibilities of intake of RFNBOs by 2030 by industry and refineries adds up to the objectives as laid down in the RED3. Thirdly, we examine the critical paths towards 2030 for the buildings blocks that are needed to meet the objectives by 2030.

See also the text box in the introduction of 4 with the assumptions and reasoning behind.

5.2 Physical feasibility by 2030: will there be enough RFNBOs?

As set out in Chapter 3, the Dutch RFNBO obligation may range from 78 to 127 PJ/y by 2030, of which 29 PJ/y is for the RFNBO target of the transport sector. The variants for the RFNBO obligation in industry alone, following the objective of 50% RFNBO of Article 22a, ranges from 49 to 98 PJ.

Current provisions from the advice of the 'Stuurgroep extra opgave' for domestic green hydrogen production range from 19 to 32 PJ by 2030 (see Paragraph 4.2). Clearly, the envisaged domestic green hydrogen production is too low to meet the RFNBO demand by 2030, stemming from the obligations in the RED3.

In order to achieve the target by domestic production, and in case the target will be met by electricity from offshore wind and with a 1:1 capacity ratio to the electrolysers, an *additional* capacity of offshore wind and electrolysers would be needed ranging from 5 to 11 GW, for the low and the high variant respectively, which should be operational by 2030.

There are diverse options to enhance the domestic production of green hydrogen by 2030. We calculated a theoretical upper limit for domestic green hydrogen production by 2030 at 116 PJ (i.e. +84 PJ above the mentioned upper range of 32 PJ), assuming that all 13 GW offshore wind that will be realised between 2023 and 2030 will be used for green hydrogen production. However, current domestic production is less than 1 PJ and there are many other potential users for that green electricity.

Table 12 – RFNBO demand and required production capacities for the Netherlands by 2030, following from the obligations

RFNBO demand variants		Low	Middle	High
National RFNBO demand by 2030 (PJ/y)	**Total industry + transport sector**	**78**	**105**	**127**
Required *total* offshore wind and electrolyser capacity to meet demand (GW)	4,300 full load hours[20]	9	12	14
Additional electrolyser capacity, on top of the 3-4 GW in the Climate Agreement (GW)	Assuming 4,300 full load hours	+5	+8	+11

Hence, to be able to meet the target, already for the low variant, it is likely that import is needed. The 32 PJ/y domestic production, together with the import volume of 48 PJ/y by 2030 that is the ambition within the 'Nationaal Waterstof Programma', would be just enough to meet the combined targets for industry and transport in the low variant, under the assumption that no RFNBOs will be exported from the Netherlands to e.g. Germany.

More import by 2030 might be possible, up to a total volume of about 120 PJ/y (i.e. +72 PJ above the mentioned 48 PJ). It will be challenging, however, to have these supply chains operational by 2030, even for the ambition in the national hydrogen programme.

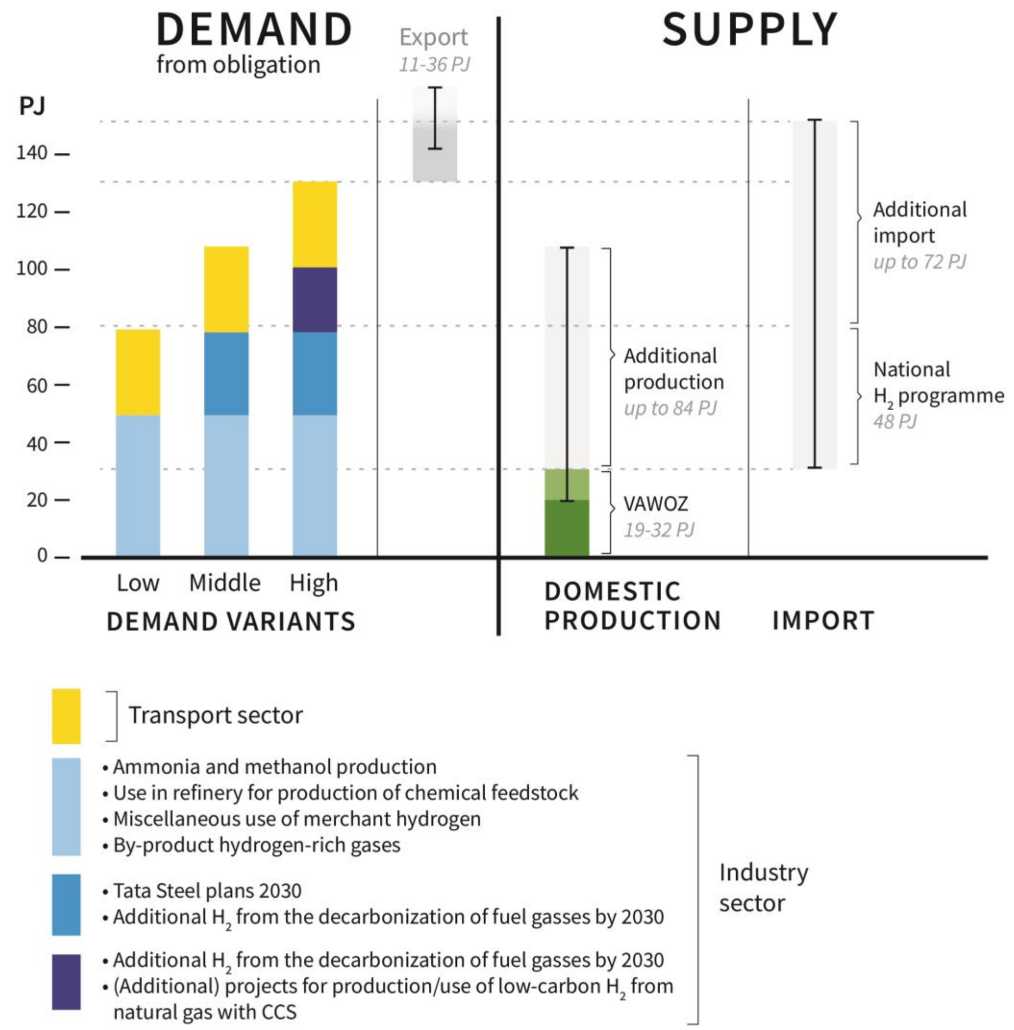
Regarding physical availability of RFNBO's, the low variant might be feasible by 2030, but the bar is set high, additional domestic production and/or import (additional to current 2030 national plans and ambitions) is needed, and all required interrelated building blocks have to be operational by 2030.

In Figure 7, the combined results are shown on demand (following the RED3 obligations) and supply.

[20] Assumptions: 4,300 full-load hours (i.e. 1:1 to capacity of offshore wind), and an electrolyser efficiency of 57.8 kWh/kg H_2.

Figure 7 – Comparison of estimated national RFNBO supply and demand by 2030, for different industry target variants

Combined results of the analyses of demand and supply of RFNBO in the Netherlands by 2030. Horizontal lines are drawn to guide the eye. To compare the availability of RFNBOs in the Netherlands with the demand variants, also exports have to be taken into account. Supply can come from domestic production and from import, which are separately shown in the figure.



In the analyses, we compared RFNBO demand (following the objectives of the RED3) to RFNBO supply. Looking in detail at the text of Article 22a, in combination with the nature of the hydrogen demand in the Netherlands (of which a substantial part is for production of ammonia), there appears to be a specific possibility. This route is the import of green ammonia and using it directly to replace current fossil based ammonia production in the fertilizer industry. This will lower the denominator of the 50% target since ammonia does not count as hydrogen consumption (whereas the current production processes do, as they make ammonia from natural gas with hydrogen as intermediate product), but it will count towards the numerator of the 50% target because green ammonia counts as RFNBO (assuming it meets the RED criteria). As the route seems unintended, the Commission may change Article 22a to ensure that imported RFNBOs are counted in both the denominator and the numerator. Note that import and subsequent use of 'grey' ammonia by the fertilizer industry, instead of self-production of grey ammonia from natural gas with hydrogen as intermediate product, also lowers the denominator (but does not count towards the numerator).

5.3 Physical feasibility: possible intake of RFNBOs by 2030

The objective of Art. 22a implies that an intake of 50% RFNBOs by the industry is feasible by 2030, calculated at the national level. But is it, in the Dutch situation? The question is relevant when one looks at the scheme of industrial hydrogen consumption in Figure 5. Relatively large parts of the current hydrogen production and use are part of integrated industrial activities and cannot easily be replaced on the short term.

To answer this question, we investigated in more detail both the current hydrogen use in industry and the refineries, and the published plans for hydrogen production and use towards 2030.

The results of these analyses cannot be published in detail because of competition guidelines. **On an aggregated level, the combined possibilities of both industry and refineries add up to about 50 PJ/y of RFNBOs that is feasible for relatively easy physical intake**. It is not a strict limit, more is possible, but will require significant adaptation of industrial installations with associated investments. This will also take time to realise, and may cause accelerated depreciation of existing assets.

The total of 50 PJ/y comes from four different contributions:
- partial replacement of the hydrogen production for production of ammonia (fertilizer industry);
- replacement of hydrogen produced from natural gas with Steam Methane Reformers in refineries;
- partial replacement of hydrogen delivered by producers of industrial gasses for several applications;
- partial replacement of the hydrogen used for the production of methanol.

The amount of 50 PJ/y intake by industry plus refineries has to be compared by the targets as shown in Table 12, ranging from 78 to 127 PJ/y by 2030 for the low and high variant, respectively.

This analysis is in line with the subconclusion that it will be difficult to fulfil the combined national RFNBO targets by 2030 as proposed in the RED3, already for the low variant[21].

5.3.1 Timeline industrial intake

The timeline for the implementation of RFNBO use by industry depends on the type of specific industrial process and the percentage of RFNBO intake. A small percentage of

[21] Also adding the Tata Steel hydrogen plans for 2030 to the minimum variant instead of the middle variant does not solve this situation. The Tata Steel plans are for 100% green hydrogen consumption, 10 PJ to be realised in 2030, see Table 2.

RFNBOs can often be implemented without significant adaptations to the overall plant. The implementation of higher percentages of RFNBOs may require additional purification and pressurization, adaptations to the heat management, potentially new resources and specific adaptations to the production process. A 50% RFNBO intake will in most cases result in substantial production facility adaptations.

Based on information from market parties we estimate a total timeline of six years between start of the project and end of realisation. Five years before realisation, all preconditions have to be clear. These include making arrangements for a secure hydrogen supply (physically and in contracts), preparations for the development of hydrogen pipeline infrastructure between hydrogen production sites and the industry (i.e. regional and national backbone), and obtaining financial certainty for the increased total production cost. Three years before realisation a financial investment decision (FID) has to be made. Important dependencies for the FID are permits, subsidy programmes and the business case. Production stops on the industrial sites of hydrogen consumers occur every three to four years. Timing is therefore essential. A potential delay of one to two years may occur due to a delayed permitting process and because the industrial consumer has to align the timeline with a planned production stop.

Note that the timeline for industrial intake varies per industry sector and per specific industrial site, and is also dependent on the percentage of RFNBO that needs to be taken in. Small percentages can be taken in relatively easy without significant adaptations, larger percentages require adaptations, the turning point depends on sector and specific site.

5.4 Overview timelines (backcasting)

In this study we have worked out timelines for policy and legislation (Paragraph 2.4), offshore wind, electricity network reinforcements, RFNBO production (Paragraph 4.2.3), RFNBO import (Paragraph 4.3.3) and industrial intake (Paragraph 5.3.1). The timelines for offshore wind and for electricity network reinforcements are for the national plans as laid down in VAWOZ. Figure 8 shows a combined overview of the timelines.

The important dependencies for achieving the required timelines are:

- For all required investments, a Final Investment Decision (FID) has to be made. The target date of 1-1-2030 thus creates a critical point of time for the last FIDs. For the FIDs, the market conditions (including the stimulation regime) have to be clear. This creates a dependency with the implementation process of the national policies for the RED3. The FIDs itself need preparation time, and some will have to start earlier than others since not all assets can be built at the same time. To start the preparation process for the supply side projects, there has to be enough certainty of demand. This creates a dependency with the final adoption of the RED3, in which the RFNBO targets for the Member States will be established.
- The timeline for the development of renewable electricity production capacity is the critical timeline for domestic green hydrogen production. The onshore electricity network is an important constraint for additional offshore wind and thereby for additional hydrogen production on land, but direct coupling of wind turbines to electrolysers (onshore or offshore) could be developed as a technical solution before 2030.
- Import terminals may be realised relatively quickly, however all upstream investments in the exporting countries have to be made also to be able to realise these supply lines.
- On the short term, the development of hydrogen infrastructure (national backbone, regional backbones, and storage facilities) is an important precondition for the

realisation of the RFNBO target. Connection to the national hydrogen backbone is important to gain access to national hydrogen storage facilities and to facilitate the development of a national hydrogen market. Other investments decisions are all dependent on these timelines.
- Following certainty about the targets and financial conditions, the hydrogen consuming industries have to engineer and plan the required process adaptations.

Most timelines in Figure 8 end in the period 2028-2029. However, there might be also scarcity of technical personnel and of construction capacity, for example in the supply line of electrolysers. Therefore, not all projects can be realised in the last years. A development path spread over a larger time period is required for a feasible realisation. The sooner a national programme starts to work towards the RED3 RFNBO targets, the smaller the risk of shortages in supply lines and technical personnel.

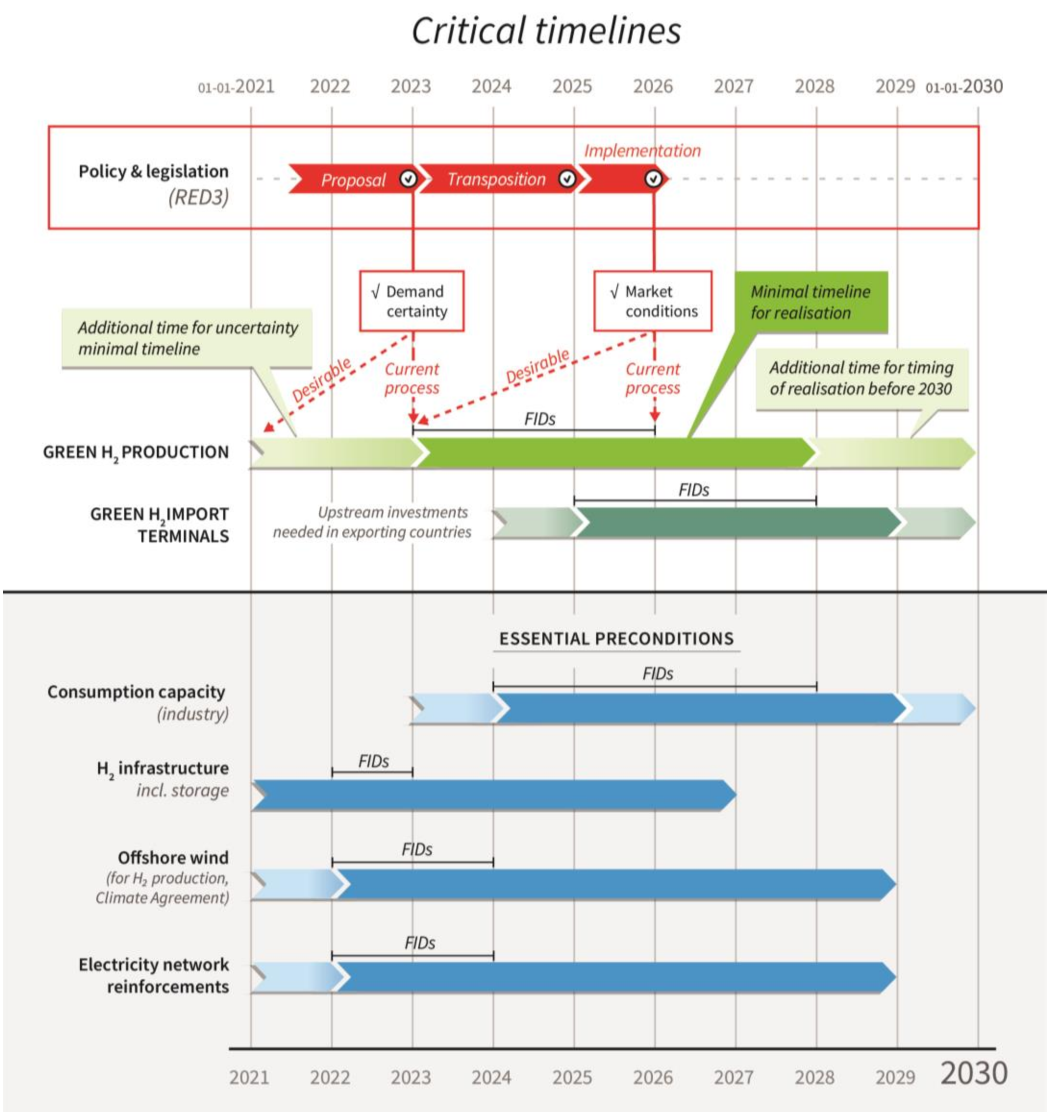
The height of the target might be influenced by projects such as taken into account in the middle and high variants, for production of decarbonized or low-carbon hydrogen. In case investment decisions for such projects are taken towards 2030, but soon enough to realise these project by 2030, this will result in a higher national RFNBO target.

All timelines are interrelated, as all elements are required to build the system. Figure 8 indicates that the final adoption of the RED3 by the end of 2022 – that sets the national targets (certainty of demand) - is on the critical path and there is no room for delay. The same applies to the transposition and implementation of the RED3 in the Netherlands, that provides certainty of the market conditions including the stimulation regime, necessary for the FIDs on both supply and demand side.
The bar for offshore wind indicates the timeline to realise the offshore wind capacity *as currently planned*.

Figure 8 – Timelines for realisation of the target

The figure shows three blocks:

1. Above, in red, the policy process of the RED3. With final adoption by the end of 2022, setting the targets for the Member States and creating demand certainty. Followed by transposition and implementation in national policy and regulations, creating certainty on market conditions including stimulation regime. The lines labelled 'desirable' indicate that these clarities are rather late, since investment decisions have to be taken earlier.
2. In green the supply side investments in electrolyser plants and import terminals. In dark colours the minimal lead times between start project and start operations, in light colours the additional time for uncertainty in minimal lead times, and for timing or realisation before 2030 since not all projects can be build at the same time. For import, not only the import terminal has to be realised but also all upstream investments have to be realised in the exporting countries. Those are not shown as timeline in the figure.
3. Below, in blue, the timelines of essential preconditions are provided. Consumption capacity in the industry indicates the investments needed for the intake of green hydrogen. H_2 infrastructure (incl. storage), offshore wind (as major, but not the only, source of the required renewable electricity) and electricity network reinforcements have to be realised in time. The bar for offshore wind indicates the timeline to realise the offshore wind capacity *as currently planned (VAWOZ)*.



6 Effects on hydrogen using industry

6.1 Introduction

The RFNBO target influences the total production cost of hydrogen using industries and potentially their international competitiveness.

In this chapter the effects on the Dutch industry are first described qualitatively in Paragraph 6.2. The effects are quantified in three industrial cases in Paragraph 6.3. In Paragraph 6.4 the effects of two relevant revisions to the EU ETS are discussed. In our analysis we have determined two price scenarios for green and grey hydrogen which are described in Appendix C.

6.2 Effects on Dutch hydrogen using industry

6.2.1 Effects on costs: qualitative description

The implementation of the RFNBO target has three cost effects:
- An increase in hydrogen cost due to the higher price of RFNBOs as compared to 'grey' hydrogen.
- Additional cost for the production process that apply this hydrogen, due to investments and higher operational expenses.
- A decrease in cost for ETS-rights due to lower CO_2 emissions. The ETS-costs are included in the grey hydrogen price.

In this chapter we will discuss qualitatively the effects of the RFNBO target on the hydrogen cost and ETS-rights. The additional cost for the production process are dependent on the process itself.

Effect of RFNBO target on Dutch industry

The RFNBO target is only imposed on Member States of the European Union. In the current proposed regulation, there are no requirements stated on imported goods. Therefore, the enforcement of this regulation will result in a price increase for the European industry due to a higher hydrogen price. Industry outside of the European Union will not fall under this target and at this moment there are no plans for a (border) correction mechanism related to the RFNBO target. This will result in a relative cost price increase for production within the EU and deterioration of the competitiveness. The EU or individual nations can realize support mechanisms to correct for the price increase, for example by subsidies on use or on production of RFNBOs.

Effect of RFNBO industry target on EU ETS allowances and CBAM

The RFNBOs target has potentially also an effect on the CO_2 cost for industrial companies. Most large hydrogen producers have free ETS rights under the free allocation regulation. If a current legislative proposal is implemented, free allocation will be replaced by the Carbon Border Adjustment Mechanism (CBAM). CBAM has the goal *"…to address carbon leakage as a result of the increase Union climate ambition"* (EC, 2021d)

If the proposal is accepted, the CBAM will come into effect in 2023. After a transition period, all provisions will be enforced in 2026. With the CBAM a CO_2 price has to be paid over the carbon content of imported goods. The CO_2 price for imported goods is coupled with the EU ETS price. Thereby a level playing field is created between producers within and outside of the EU for products sold within the EU. At this moment sectors with the risk of carbon leakage receive free ETS allowances to prevent carbon leakage. This free allocation will be replaced by the CBAM, ensuring all production within and outside of the EU will require CO_2 rights for their emissions.

Large industrial hydrogen users, such as fertiliser production, will fall under the CBAM[22] (EC, 2021d). Therefore, CO_2 rights will have to be paid of the carbon content of imported fertilizer. Related to CO_2 emissions a level playing field is created between European and non-European producers. For sectors that fall under the CBAM, the usage of RFNBOs reduces the costs related to CO_2 allowances for a company. In our analysis the ETS costs are included in the grey hydrogen price.

The CBAM is a border mechanism. All goods sold in the EU will therefore pay a CO_2 price. However, products that are exported to outside of the EU will have to compete with products which might not pay (an equal) CO_2 price. The competitiveness of these exported goods is thus still influenced by the EU ETS, also with the implementation of a CBAM.

6.2.2 Effects of RFNBO industry target on CO_2 goals in Climate Agreement

CO_2 emission reduction due to RFNBO industry target

The deployment of RFNBOs in industry also leads to CO_2 emission reduction. Performing a simple calculation, using 9 kg direct CO_2 emission per kg of produced hydrogen from fossil fuel compared to no direct CO_2 emission per kg of produced green hydrogen, the CO_2 emission reduction is 3.6 to 7.4 Mton CO_2 for the low and the high variant under Art. 22a, respectively. Note that system effects[23] are not taken into account in this calculation.

Green hydrogen (RFNBO) and low-carbon c.q. decarbonized hydrogen are both routes to reduce the CO_2 emission of Dutch industries. An important difference between these approaches lies in the cost difference between CCS-projects and green hydrogen projects. The ministry of Economic Affairs and Climate estimates the costs of CO_2 reduction with green hydrogen are 250 €/ton CO_2 reduced higher than CCS, on average up to 2030.[24]

[22] For a list of products, see Annex 1 of the EU regulation.

[23] Like e.g. changes in national electricity demand and supply as possible effect of the RFNBO obligations for industry and transport

[24] Assuming CCS cost of 100 €/ton CO_2 and a CO_2 price of 50 €/ton CO_2. See page 20 of 'Kamerbrief over ordening en ontwikkeling waterstofmarkt.' https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof/21294248.pdf

Green hydrogen is thus a possible decarbonization route, however with significantly higher costs then low-carbon of decarbonized hydrogen for at least the period up to 2030.

Interaction RFNBO industry target and plans for low-carbon hydrogen

Within the Dutch Climate Agreement, the industry adopted plans to realise 14.3 Mton of CO_2 emission reduction by 2030. These plans are further substantiated in the CESses (Cluster Energy Strategies) for each industrial cluster. In total, PBL concludes that 96 PJ/y (0.8 Mton) additional hydrogen production capacity from fossil fuels with CCS (low-carbon and decarbonized hydrogen) is included in the CESses (PBL, 2021c), to be realised towards 2030. This amounts to approximately 5.6 Mton CO_2 emission reduction. Amongst these plans are two planned projects for the production of decarbonized hydrogen from methane-rich fuel gasses: the H-vision project in Rotterdam (Werkgroep CES Rotterdam-Moerdijk, 2021) (Werkgroep CES Rotterdam-Moerdijk, 2021) and DOW's plans for a hydrogen plant that utilizes by-products from their core processes[25]. There are other plans to produce low-carbon hydrogen from natural gas with CCS with a volume of about 20 PJ/y, to meet the expected need for hydrogen with low climate impact, e.g. to replace current use of natural gas. These projects are taken into account in this study in the middle and high variant, respectively.

The decarbonisation of these methane-rich residual gasses and also the production (and subsequent use) of low-carbon hydrogen from natural gas with CCS leads to an increase in the Art. 22a target for RFNBOs, while those flows themselves cannot be made green. This interference therefore results in investment uncertainty and possible postponement of those plans. Achieving the RFNBO objective by 2030 is even more difficult in case CO_2 emission reduction plans will be realised from the Dutch industry regarding low-carbon hydrogen with CCS, that are taken into account in the middle and high variants in this study.

6.3 Effect of RFNBO industry target on total costs and for three industrial cases

We analyse the effect of the RED3 industry target on three industries based on two hydrogen price scenarios, see Annex C for details. The two price scenarios (A and B) are based on a low and high price for both grey and green hydrogen. The parameters that are varied for green hydrogen are the electricity price and electrolyser investment cost. For grey hydrogen the parameters are the natural gas price and CO_2 emission costs. Since the factors for green and grey hydrogen are not related the prices can be seen as largely independent. To show the maximum bandwidth of future price development, we have coupled the low green hydrogen price with the high grey hydrogen price and vice versa. The assumptions are:

A **Low grey hydrogen price and high green hydrogen price**. For grey hydrogen we assume a natural gas price of 5,1 €/GJ and CO_2 price of 53 €/ton CO_2. For green hydrogen we assume an electricity price of 40 €/MWh and electrolyser investment cost of 1,500 €/kW.

B **High grey hydrogen price and low green hydrogen price**. For grey hydrogen we assume a natural gas price of 10,1 €/GJ and CO_2 price of 85 €/ton CO_2. For green hydrogen we assume an electricity price of 30 €/MWh and electrolyser investment cost of 600 €/kW.

[25] Dow Benelux outlines roadmap to support Dutch Climate Agreement, achieve CO2 emissions neutrality

The hydrogen price scenarios are displayed in Table 13. We assume market prices which are determined based on cost calculations and an assumed mark-up of 10%. All assumptions and calculations are described in Annex C.

Table 13- Hydrogen price scenarios

Price scenario	Variant	Grey hydrogen		Green hydrogen		Average hydrogen price (€/kg)	Change average hydrogen price (%)
		Percentage grey	Price grey (€/kg)	Percentage green	Price green (€/kg)		
A	A1. 100% grey	100%	€ 1.8	0%	€ 7.2	€ 1.8	
	A2. 50% grey, 50% green	50%	€ 1.8	50%	€ 7.2	€ 4.5	+150%
B	B1. 100% grey	100%	€ 2.2	0%	€ 4.3	€ 2.2	
	B2. 50% grey, 50% green	50%	€ 2.2	50%	€ 4.3	€ 3.3	+50%

We have estimated the total additional costs due to the RFNBO industry target and the price effect in three industries: fertilizer industry, methanol production and refinery products for the industry. We have used public figures on market prices in the sector. We estimate the additional costs consisting of additional hydrogen costs, investment in installations and additional OPEX. A scenario with 100% green hydrogen is not included since it is not feasible for many existing industrial processes.

We emphasize that all displayed case results are aggregated and are based on public information and own assumptions and calculations by the authors.

6.3.1 Total additional costs RFNBO industry target

Using the prices as displayed in Table 13, the additional costs of 50%/50% green/grey hydrogen as compared to 100% grey hydrogen can be calculated. These additional costs range from € 0.9 to 2.2 billion per year by 2030 for the low variant of the RFNBO target for industry, and from € 1.7 to 4.4 billion per year by 2030 for the high variant. Note that investments in the industry that are needed for the intake of green hydrogen are not included in these figures.

6.3.2 Case: Fertilizer industry

The fertilizer industry will be heavily influenced by the RFNBO industry target since hydrogen costs are a large share of the total production cost.

The main fertilizer type produced in the Netherlands is nitrogen-based fertilizer. As example we analyse the effect on calcium ammonium nitrate (CAN), which is a mix of ammonium nitrate and calcium carbonate. The production process of fertilizers is described in detail in the Midden report on the Dutch fertilizer industry (PBL and TNO, 2019).

Table 14 shows the required input of different chemical substances for the production of the end product, based on the underlying chemical reactions. For the production of 1 tonne of CAN a total of 0.32 tonnes of ammonia is required, which in turn requires 0.057 tonnes of hydrogen. For the production of grey hydrogen, the average CO_2 emissions are 9 tons per ton of H_2 (Argonne, 2019). Of these 9 tons are 5.5 tons non-energy usage of natural gas. In total we conclude that 0.31 ton of non-energy CO_2 is produced per ton CAN.

Table 14 - Overview mass balance for fertilizer production

Mass balance	CAN	Ammonium nitrate
CAN	100%	
Ammonium nitrate	75%	100%
Ammonia	32%	43%
Hydrogen	5.7%	7.6%

To analyse the effect of the RFNBO target on the competitiveness of the fertilizer industry, we analyse the effect on the total price of CAN, using own models and assumptions combined with the Midden report (PBL and TNO, 2019) and public data on fertilizer markets. The chosen expected natural gas price for 2030 in the calculations is 26 €/MWh. In our scenario the CO_2 price by 2030 does not significantly increase compared to the prices in Q2 2021. We assumed the other cost factors also to remain equal.

We have also included investment cost in the ammonia plant and additional electricity usage for syntheses of hydrogen and N_2 production. Cost that are not included are cost for the production stop to make alteration to the production site, back-up storage of hydrogen and the purification of hydrogen since the purity is still unknown. There are uncertainties in this estimate, but it is accurate enough for a cost comparison in case of increasing hydrogen cost and hence we can estimate the cost price development due to the RFNBO target.

Cost impact on fertilizer industry

Table 15 shows the impact of different hydrogen price scenarios on the price of CAN. As reference price we have assumed an estimated 2030 market price. We have added the additional cost related to the RFNBO industry target as described above. Only hydrogen scenarios with 50% green hydrogen are presumed, related to the proposed target in the RED3. In our analysis we have included the additional hydrogen cost, additional electricity consumption for hydrogen syntheses and N_2 production and investment cost.

Table 15 - Effect of RED3 industry target on price of calcium ammonium nitrate (CAN)

	Average hydrogen price (€/kg H_2)	Hydrogen cost CAN (€/ton CAN)	Increase in production cost CAN (€/ton CAN)
A1. 100% grey	€ 1.8	€ 105	
A2. 50% grey, 50% green	€ 4.5	€ 255	+70%
B1. 100% grey	€ 2.2	€ 125	
B2. 50% grey, 50% green	€ 3.3	€ 185	+30%

For the assumed price scenarios, a price increase for calcium ammonium nitrate (CAN) fertilizer of 30 to 70% is expected in case of a 50% green hydrogen target. Per ton CAN the CO_2 emissions are 0.31 ton non-energetic and 0.2 ton energetic CO_2 emissions. A 50% hydrogen target reduces these emissions with 50% compared to grey hydrogen, thus the cost price of the emissions reduction is equal to a price of approximately 250–500 €/ton CO_2.

6.3.3 Case: Refinery sector non-transport products

For the refinery sector we use data from the MIDDEN report (PBL and TNO, 2020) and CBS data (CBS, 2021). The total costs of the sector in 2018 were € 36.8 billion and average profit between 2016–2018 was € 400 million (PBL and TNO, 2020). From the total production in the Dutch refineries in 2018, about 25% of the final products fall under the RFNBO industry target, which percentage is based on the weight of the final products produced (CBS, 2021).These are all the non-transport products. With an equal distribution based on final product weight, the total cost counted towards industry products is € 9.2 billion/year and the profit € 100 million/year.

From several studies the hydrogen consumption in Dutch refineries falling under the RFNBO industry target is estimated between 10 and 16%. We will assume that 15% of the hydrogen consumption in refineries count towards the target. The different hydrogen production sources and the hydrogen production counting towards the RFNBO industry target is displayed in Table 16.

Only hydrogen produced by SMR (Steam Methane Reforming) can logically be replaced by green hydrogen. The other hydrogen sources are by-products, produced during the refining process.

Table 16 - Hydrogen consumption of Dutch refineries

Hydrogen consumption refineries	Total hydrogen consumption refineries 2018 (kton/y)	Hydrogen consumption under RFNBO industry target - 15% of total consumption (kton/y)
SMR	167	
Hydrogen as by-product from catalytic reforming	278	
Hydrogen from gasification	104	
Total hydrogen consumption	549	82
RED3 50% industry target		41

Source: (PBL and TNO, 2020).

It is uncertain how the RFNBO target for industry will result in hydrogen target for the refineries. The current legislation leaves room for interpretation. It could be argued that only 25 kton hydrogen can be replaced since this is 15% of the total current SMR production. However, with a larger allocation of SMR production to the industrial products it is also possible to replace 50% of the hydrogen consumption for industrial products. We assume the second interpretation resulting in 41 kton green hydrogen replacement, see Table 16.

An SMR does not only provide hydrogen within the refineries, but also provides heat as a by-product. Scaling down hydrogen production can be achieved by lowering the production in SMR, but this can only be done to a certain minimum within the SMR. Below that minimum, an SMR installation might have to shut down and be disintegrated from the industrial site. This will influence the heat balance within the industrial site and will require alterations and investments in heat production and distribution.

Cost impact on refinery sector

Table 13 shows the assumed hydrogen price scenarios. The price difference between grey and green is 5.4 €/kg in scenario A and 2.1 €/kg in scenario B. We calculated the effect of the higher hydrogen price on the total cost of the refinery sector related to the industry products. The total cost in 2018 were € 36.8 billion. In total 25% of the products count towards the RFNBO industry target, based on the weight of products produced (CBS, 2021). Therefore, as approximation we also assume that 25% of the total cost of the sector can be counted towards production for industry, equal to 9.2 billion €/year.

Table 17 shows the cost effect of the RFNBO industry target. We estimate a cost increase of € 90 to 220 million per year due to a 50% RFNBO industry target. This is equal to a percentual cost increase of 0.9 to 2.4% of the refinery products for the industry.
The average profit in the year 2016–2018 was approximately € 100 million/year for products sold to the industry. The additional hydrogen costs in the two scenarios are approximately equal or higher than the average profit on industry products in those years.

Table 17 - Effect of RED3 industry target on refinery sector, total cost

Hydrogen price scenario	Total cost refinery related to industry product (mln €)	Average hydrogen price (€/kg)	Additional cost for 50% green hydrogen (mln €)	Increase of production cost in refinery sector (%)
A1. 100% grey	€ 9,200	€ 1.8		
A2. 50% grey, 50% green	€ 9,200	€ 4.5	€ 220	2.4%
B1. 100% grey	€ 9,200	€ 2.2		
B2. 50% grey, 50% green	€ 9,200	€ 3.3	€ 90	0.9%

6.3.4 Case: Methanol production (for chemical industry)

Methanol is produced from mainly CO_2 and hydrogen, which are both produced using Steam Methane Reforming of natural gas.[26] A total of 1.4 ton CO_2 and 0.2 ton H_2 is required per ton methanol. Implementing green hydrogen in the production process of methanol will thus also require a source of (renewable) CO_2. Implementation of 50% green hydrogen production in the production process is feasible. However, it will require significant investments and alterations on the factory site.

An estimate has been made on the increase in production cost due to the RED3 industry target. The high level analyses include investment cost in the process, feedstock cost for hydrogen, steam, electricity and CO_2 and additional operational cost. Table 18 shows the results for the two price scenarios. At least a cost increase is expected of 45-65%. This is a minimum due to potential higher investment costs which are at this moment still uncertain.

Table 18 - Effect of RED3 industry target on methanol production cost

Price scenario	Average hydrogen price (€/kg)	Increase in methanol production cost (%)
A1. 100% grey	€ 1.8	
A2. 50% grey, 50% green	€ 4.5	> 65%
B1. 100% grey	€ 2.2	
B2. 50% grey, 50% green	€ 3.3	> 45%

26 For more information see the MIDDEN-report on the Dutch biofuels industry

6.4 Revisions to ETS regulation relevant to target of Art. 22a

In this paragraph we discuss two proposed revisions to the existing EU ETS regulation (EC, 2021b).

Free allocation for electrolysis hydrogen

At this moment free EU ETS allowances are received for the production of grey hydrogen due to the risk of carbon leakage. In a new EU proposal for revisions to the ETS, the interaction between these free allowances and green and grey hydrogen is described in paragraph 30, page 500 (EC, 2021b). The average CO_2 emissions during production of grey hydrogen are 9 ton CO_2 per ton of H_2 (Argonne, 2019). With the current regulation, grey hydrogen production receives 6.48 EUA per ton of hydrogen from 2021 to 2025 and 6.018 EUA from 2026 to 2030. Since approximately 2/3 of the average required ETS-rights are received for free, there is a reduced financial incentive to transfer to green hydrogen.

One of EU proposals for revisions to the ETS is to supply free allowances for products rather than processes (EC, 2021b). This means that in principle free allowances could be given for all hydrogen production, also if it is produced with electrolysis. The number of free allowances given will be set each five years based on a benchmark, based on the best performing producers. With more and more hydrogen being produced from green electricity, the benchmark CO_2 emission will decrease rapidly. Also, free allocations of allowances to hydrogen production will be proportional to "E_dir / (E_ind + E_dir)" (with E_dir = direct emissions; E_ind = indirect emissions) which represents the ratio of direct emissions to the total emissions of an installation. This ratio for an electrolyser will be close to zero since direct emissions will be close to zero, hence the electrolyser will not be eligible to any free allocation.

Note that the free allocation mechanism will be phased out when the CBAM is introduced in 2026, for the sectors that fall under the CBAM.

Carbon Contracts for Differences

Carbon Contracts for Differences (CCfD) is also a new policy proposal of the European Commission for de-risking the effect of the uncertain ETS-price for sustainable investments (EC, 2021b). It is a funding mechanism that allows Member States to guarantee a fixed CO_2 price above the ETS-price. CCfDs are long term contracts between a company and a public counterpart. The public party pays per ton CO_2 emission reduction, the difference between the fixed strike price and the actual ETS-price.

As example, a government can guarantee a CO_2 price of 100 €/ton CO_2 for 15 years. If the CO_2 price is 60 €/ton CO_2 a subsidy is provided of 40 €/ton CO_2. If the CO_2 price increases to above 100 €/ton CO_2, no additional funding is supplied. CCfDs can thus also be used to de-risk investments in green hydrogen production. If a higher strike price is agreed, the profitability of the project for the company will also significantly increase.

7 Policy options for implementation of Art. 22a

7.1 Introduction

The RED sets out the obligations for Member States, but the way targets will be reached is subject of the national transposition and subsequent implementation process, in which - in the case of a directive - a Member State has some room to manoeuvre.

This chapter mainly focusses on the options for implementation of RED3 Article 22a, for which the main national policy decisions will be made during the transposition phase. However, since the target is challenging to very challenging and timelines are tight, we will first focus (Section 7.2) on options to make the target less challenging, during the current adoption phase of the RED3.

In the other sections of this chapter we will consider the different policy combinations for implementation of the RFNBO industry target. A policy combination consists of two main elements, see Figure 9:
- Which party has the obligation?
- Which party pays for the costs?

These two questions are interrelated. There is also a relation with the physical feasibility of the target. **For all analyses on implementation options, we assume that the target will be set to a physically feasible level within the Member State.**

It is unlikely that the final implementation will coincide exclusively with one policy combination. It is more likely, and probably more desirable, that a final policy combination contains several elements.

Next to the policy combinations, certain general market conditions for implementation are needed for any implementation option. These will be discussed in Section 7.3.

Figure 9 - Schematic structure of the policy options for implementation

<table>
<tr><td>Who has the obligation?
- Government
- Hydrogen using industry</td><td>Who pays for the additional costs?
- Government (*)
- Hydrogen using industry
* Costs for the government can be passed to: all industrial energy users, all energy users (ODE), all citizens (taxes), all companies (corporation tax)</td></tr>
<tr><td colspan="2">General market conditions:
- Certification system
- Trading system
- Monitoring, reporting, verification</td></tr>
</table>

7.2 Adoption phase RED3 – options to make the obligation more feasible

As discussed in the previous chapters, the target is challenging to very challenging, timelines for realisation are tight, and costs are high. In this section, we therefore provide some options to make the obligation more feasible. We also provide some options for early investment security that allow for early build-up of green hydrogen production capacity, i.e. electrolysers and additional renewable electricity production. Those may be taken on the national level already during the adoption phase of the RED3, to avoid losing time, since investment decisions across the hydrogen value chain need already to be taken before final adoption of the RED and subsequent formal transposition time.

To make the obligation more feasible while still in line with the objective of the RED to mainstream RFNBOs in industry (green hydrogen), we find the following options. The list is not exhaustive and options may be combined.
- Set the target in absolute terms (i.e. obligated demand in PJ) rather than relative terms (% of green hydrogen use in industry). This would provide more certainty for policy makers, industry, grid operators and renewable electricity developers. It would also avoid creating a possible barrier for growth in hydrogen demand due to new hydrogen applications.
- Reduce the scope of the target setting, e.g. by excluding hydrogen rich by-product gasses and/or by excluding decarbonized fuel gasses from the denominator (i.e. set the target towards the low end variant in this study).
- Allow for a lower percentage than 50% in 2030
- Allow for a longer timeframe to meet the 50% target, i.e. target later than 2030, to obtain more time for realisation
- Allow for a flexibility mechanism which enables green hydrogen use in other EU Member States to be counted towards the national target (statistical transfers).
- Allow for more full load hours for electrolysers, while connecting to different renewable electricity sources using e.g. PPAs. This option might affect provisions in the RED but also requires changes to the national stimulation regime.

To provide for early investment security on the national level to build up supply and demand, and to make the target less challenging to realise on the national level, we find the following options. Also this list is not exhaustive:
- To provide for the required certainty of demand, a national target might be set in 2022 or 2023 already, together with appropriate market conditions and financial resources.
- Implement a national programme for swift and concerted action to realise all interrelated elements, including certification, trade platform, and import supply chains.
- Stimulate import of ‘green ammonia’ (provided it is compliant with the RED criteria) together with subsequent direct use in the fertilizer industry, replacing ammonia production based on natural gas
- Stimulate alternative industrial production processes, not using hydrogen.
- Allow the ‘refinery route’ for RFNBOs also after 2024. This route allows refineries to value the use of green hydrogen in the production process in the products. In the Dutch national regulations, this route is now open for 2023 and 2024.
- Swift development of a stimulation policy instrument for scaling up beyond the 50 MW limit for the electrolyser capacity in the current ‘Opschalingsinstrument’
- Further expansion of offshore wind, onshore wind and solar-pv capacity for increased green hydrogen production.
- Allow for combined tenders of renewable electricity production and green hydrogen production.

7.3 General market conditions

The obligation of Art. 22a lies on Member States, but the private sector consumes the hydrogen. Therefore it is unavoidable that Member States will need a policy instrument to ensure that the obligation is translated successfully to companies. We assume that in all policy options a system for certification, a trading system and a system for monitoring, reporting and verification will be needed. It is also assumed (but cannot be taken for granted) that the government guarantees that the **required infrastructures** are in place (electricity infrastructure, and hydrogen backbone with connection to producers, consumers and to storage).

In December 2021, the Commission presented a proposal for a directive and regulation that should enable a working hydrogen market. It includes harmonized rules on the quality of hydrogen and rules for transport, supply and storage of hydrogen. It aims to establish a Union-wide interconnected hydrogen system (EC, 2021c). Part of the Regulation is also the establishment of a European Network of Network Operators for Hydrogen (ENNOH) (EC, 2021c).

To enable that RFNBOs can be used to comply with the obligation, a **certification system** is needed that proves compliance with the requirements set by the RED. Certification is important for domestic supply, but also for imported RFNBOs. The development of an EU-wide system of certification for hydrogen is also addressed in the proposal of December 2021, but the exact methodology will be developed in a delegated act (EC, 2021c).

Certification is also needed to establish a **trading system** (like HyXchange) that connects supply and demand.

To be able to prove compliance with the obligation, a system for **monitoring, reporting and verification** (MRV) is required. Eurostat has already published plans how it will differentiate the data on hydrogen use (Eurostat, 2022). MRV may be challenging because accurate measurement of hydrogen contained in by-product and residual gasses is complex.

7.4 Policy options for implementation

Policy options to realize the target are complex since they would apply to an immature market. During policy sessions within the framework of this report, we concluded with the steering group that the following policy focal points form the basics in constructing a policy package to implement Art. 22a:
- Obligation for the government:
  - subsidies;
  - subsidies and covenant;
  - tender mechanism.
- Obligation for the industry:
  - costs for the industry;
  - costs for government.
- Supply side obligation.

A complementary option is a green products policy, with the RFNBO obligation for industrial hydrogen consumers, but with policy measures by the government to create value for green products. In that case the consumer would pay a premium for green products.

7.4.1 Obligation for government

The judicial obligation will in any case lie with the Member State. Not meeting the target might ultimately result in a fine from the Court of Justice. Here we discuss three options: a subsidy scheme as main instrument, a subsidy scheme + a covenant, and a tender system. For all three policy options, the government will pay for the costs to comply with the target. The government can choose from various sources to fund the costs: all energy users (ODE), industrial energy users, all citizens (taxes), or all companies (corporation tax).

Subsidies to cover the costs

Subsidies are a familiar - though not the only possible - instrument to comply with obligations on Member State level. The Netherlands has for example experience with the SDE, to try to reach the target of 14% renewable energy by 2020. The SDE also includes a subsidy for realisation of green hydrogen production. The mere fact of providing subsidies (direct or fiscal) does not make sure that consumption of RFNBOs reaches 50% by 2030. In case the subsidy is attractive enough, this might be the case (provided the target is feasible and the essential preconditions are met). However, the intake by industry of green hydrogen in large volumes requires changes in existing processes, which may be already relevant for the low end variant in this study. Subsidies alone might not provide enough leverage needed to reach the target.

Subsidies and covenant with industry

As compared to option 1, a covenant will make the industry more committed to reach the target. Therefore, it has a higher degree of certainty in achieving the target because through a covenant between government and industry a plan with a common strategy can be developed. A covenant would also provide a platform for a frequent exchange of progress reports and could sustain a channel for the industry to discuss on permanent basis the required infrastructural conditions to realize the RFNBO consumption. This policy angle therefore provides a good platform for public-private cooperation and coordination of subsidies for RFNBO consumption together with CO_2 targets.

Subsidies with tender mechanism

Tenders provide a way to reduce the costs for subsidies. The Dutch approach used for offshore wind may provide an example. In this approach, the government provides the connection to the electricity network (through TenneT) and the permits, whereas market parties compete for the tenders. The approach resulted in considerable reduction of costs. Another example might be the German mechanism for import of hydrogen. Germany introduced tenders for large scale H_2 import, where the government has the obligation and pays for the additional costs. In Germany, a trade platform (HINT.CO) has been put in place to link demand in Germany (and the EU) with supply from import. Through the platform long term contracts for import will be connected to short term contracts on the demand side. The German government has made € 900 mln available to bridge the gap between supply and demand price. A key aspect of this mechanism is that the German government will conclude trade deals with potential import countries, to where in exchange, German technology will be exported. Shipping is aimed to go through the port of Hamburg.
The instrument in Germany was set up already before the RED3 RFNBO proposal was published.

The approach might also be applied to combinations of domestic production of green hydrogen, with subsequent use by hydrogen using industry. Government spending will be needed both for price compensation and for establishing the tender system. The option could be connected with the main financial support mechanism in the Netherlands, the SDE++.

7.4.2 Obligation for the industry

While the legal obligation will always remain with the Member State, the Member State might choose to extend the obligation to the industry. Attention points in that case are the question how to set the target, with the subquestion how to set the target path in time, towards the target for the year 2030. The target and the path in time should be clear and stable to provide for the certainty of demand that is needed for all upstream investment decisions in the supply line of RFNBOs, both from domestic production and from import. Obligations for market parties work well for mature markets, which is not yet the case for RFNBO use in industry. Essential preconditions that are outside the span of control of industry should be fulfilled by government as result of flanking policies.

The financial and technical threshold to use a higher percentage of RFNBOs in processes, varies among companies and installations. Hence, an obligation for the industry will require a **trading system** that accommodates companies to exchange certificates against a certain price without physically reaching the 50%.

Costs for the industry

An obligation on individual industrial consumers may be met by handing over enough certificates, acquired on the market. Not meeting the target could involve a fine.
We assume the fine is high enough for industry to avoid it by complying to the target. That makes this option theoretically most certain in achieving the target, again provided the national target is physically feasible and that all essential preconditions are met.

In case the costs have to be paid by industry, it would have negative impacts on the competitiveness, since industries outside the EU will not be confronted with these costs.
It is also uncertain how other EU Member States will deal with the target and therefore even within the EU a competitive disadvantage might be the result. Meanwhile, industry will not be able to pass on these additional costs to the customers without posing a risk to its competitive position.

Costs for government

The industry may have the obligation but the government may pay for the costs involved via direct or fiscal subsidies or via tenders, again provided the national target is physically feasible and that all essential preconditions are met. This combination might result in relatively high certainty of realisation of the target, without posing a risk for the competitive position for the industry. However, state aid rules might cause issues for this combination, which might also result in long timelines before certainty of demand can be provided to upstream investments in domestic RFNBO production and import. Depending on how the government chooses to fund the subsidy, the costs will ultimately be passed on to tax payers.

7.4.3 Supply side obligation

The Impact Assessment of the RED3 does not contain an elaborated analysis of policy options. It merely states on page 135 that "Defining a target for RFNBO consumption in industry could either be accomplished through a demand-side obligation on the respective industries, or a supply-side obligation on energy suppliers to these respective industries. However, industry is much more diversified in terms of sectors, applications, fuels, and suppliers. Furthermore, there is only a very limited market for hydrogen with the majority of production and consumption of fossil-based hydrogen locked in through existing supply contracts. Nevertheless, a supply-side obligation would require significantly less administrative resources from the economic operators affected (EC, 2021f)."

With 'supply-side obligation', an obligation is meant to parties (suppliers) that sell hydrogen to industrial consumers, to deliver 50% RFNBOs by 2030. This would resemble the existing obligation on renewable energy for fuel suppliers in the Netherlands. Notwithstanding the possible administrative advantages, during policy sessions for the purpose of this report it became clear that an obligation on hydrogen suppliers will have serious complications, the most important being the effectiveness with regard to the target, since the volume of hydrogen that is currently delivered by merchants in the Netherlands to industry and refineries is about 15% of the total volume of hydrogen that is used (based on Weeda and Segers (2020)). Another complication will be the investments and process adaptations that are needed in the industry to accommodate large volumes of RFNBOs in their existing processes.

A theoretical variant would be an obligation on hydrogen producers, to produce 50% of green hydrogen by 2030. Such an obligation would not be effective because not all producers are located within the EU. It would therefore put EU producers at a competitive disadvantage. Hydrogen consumers might shift to cheaper extra-EU parties, that most likely produce grey H_2. Exports to other countries also present a similar problem. Also for this option, there exists the already mentioned complication due to the investments and process adaptations that are needed in the industry to accommodate large volumes of RFNBOs in their existing processes.

7.4.4 Costs paid by the consumer (green products policy)

A more comprehensive and complementary option is a Green products policy, where policies create a situation for creation of green value and consumers would pay a premium for green products. For this option, the first step would be to elucidate the climate footprint of the whole supply chain of an end product.

As described in Paragraph 2.3, the RED3 proposes that Member States should make sure that industrial products that are labelled or claimed to be produced with renewable energy and RFNBOs shall indicate the percentage of renewable energy or RFNBOs used in the raw material acquisition and pre-processing, manufacturing and distribution stage.

The Impact Assessment also stressed the importance that customers are willing to pay the price premium for renewable or low carbon fuels compared to fossil-based technologies. For the moment, this seems not a likely perspective. Moreover, a green products policy would need an overarching policy strategy, also in connection to the carbon border adjustment mechanism (CBAM).

However attractive this option is from multiple perspectives, it is rather something for the long term because of the systems approach that requires an extensive policy framework. It is not considered an apt instrument to achieve the target of Art. 22a by 2030.

7.5 State aid rules

Green hydrogen is currently not competitive and it is expected that this will neither be the case by 2030. Subsidies may be an essential aspect of any policy option. Accordingly, state aid rules need to be taken into account. The urgency for kickstarting the hydrogen economy is however acknowledged in Brussels. In January 2022, the European Commission adopted new guidelines that would create a enabling framework to provide support in reaching the Green Deal objectives.

In the Impact Assessment a carbon contracts for difference (CCfD) was suggested as an important element that could help in steering investments into renewable technologies (EC, 2021f). A possible European CCfD-instrument was also mentioned in the update of the Industrial Strategy (EC, 2021a).

In December 2021, Germany received green light for its support scheme of € 900 million for imports. The Commission recognized that public support is necessary because the carbon price and other regulatory requirements do not fully internalize the costs of pollution, and consequently the project would not take place (EC, 2021e).

Individual projects can also apply for a less stringent state aid judging by being accepted on the IPCEI-hydrogen list (Important Project of Common European Interest). Projects on the list can cover the whole supply chain of renewable hydrogen (production, storage, transmission, distribution and consumption (EC, 2020b)).

8 Conclusions

Demand from proposal RFNBO target

The Fit for 55 proposal for 50% renewable fuels of non-biological origin (RFNBOs, 'green hydrogen') for the industry by 2030 leads to a target of approximately 50 to 100 PJ/y of RFNBO use. We developed three variants for industrial hydrogen use that could count towards the target: low, middle and high. For the low variant, we included the current use of hydrogen. In the middle and high variant, we included several industry plans based on climate targets that will enhance the use of hydrogen by 2030. Tata Steel plans to use a total volume of 10 PJ hydrogen by 2030, there are industry plans to decarbonise fuel gasses leading to a volume of hydrogen use of about 65 PJ by 2030 that will then fall within the target, and there are plans to produce low-carbon hydrogen from natural gas with CCS with a volume of about 20 PJ. The proposal demands that 50% of these volumes should be RFNBO, on a national level. Note that hydrogen use stemming from decarbonised fuel gases and low-carbon hydrogen production increases the target: both routes contribute to CO_2 emission reduction but increase hydrogen use from fossil fuels which do not count as green hydrogen. Hence, these climate strategies do not fit well with the proposed RFNBO target.

The proposal also includes an RFNBO obligation for the transport sector, that is estimated at 30 PJ/y by 2030, resulting in a total national target for RFNBO use of between 80 and 130 PJ by 2030.

Supply: domestic production and import

In case the RFNBO target will be met with domestic production only, and based on renewable electricity from offshore wind, 5 to 11 GW of additional offshore wind is needed, for the low and the high variant, respectively. The production of the hydrogen also requires additional electrolyser capacity of up to 5 to 11 GW. The electrolyser capacity depends on target variant and on the dimensioning of the capacity and hence the full load hours of the electrolysers.

The ambition for domestic production of green hydrogen by 2030 within the Dutch climate agreement (including the 'Extra opgave') is 3-4 GW of electrolyser capacity and allocation of 15 TWh (about 55 PJ) of renewable electricity, resulting in hydrogen production of approximately 30 PJ. This is based on allocation of renewable electricity to the different sectors. The challenge of the 50% RFNBO target for industry and the RFNBO target for the transport sector was not yet taken into account in these numbers.

All variants require a massive and rapid scale-up of electrolyser and renewable electricity capacity in the Netherlands. There are diverse options to enhance the domestic production of green hydrogen by 2030:
- using more renewable electricity from offshore wind, onshore wind and solar-pv for green hydrogen production, within the existing national plans;
- further expanding offshore wind capacity for increased (onshore and offshore) green hydrogen production.
- further expanding onshore wind and solar capacity for increased green hydrogen production.

Using more electricity for hydrogen production, *within* the existing nationals plans, will compete with demand for electricity for other uses.
We calculated a theoretical upper limit for domestic green hydrogen production by 2030 at about 120 PJ, assuming that all 13 GW offshore wind that will be realised between 2023 and 2030 will be used for green hydrogen production.

The other option to comply with the target is import of RFNBOs. Within the Dutch national hydrogen programme, it is assumed that about 50 PJ is a feasible import volume of green by 2030 via the Dutch seaports. Also for this ambition, the challenge of the 50% RFNBO target for industry and the RFNBO target for the transport sector was not yet taken into account. More might be possible, up to a total volume of about 120 PJ. It will be challenging, however, to have these supply chains operational by 2030, even for the ambition assumed in the national hydrogen programme. Exports to e.g. Germany, estimated to range from 10 to about 40 PJ, may reduce the availability of RFNBOs in the Netherlands. Coordination between Germany and the Netherlands might help to reduce uncertainty on future green hydrogen exports from the Netherlands to Germany. The same holds for Belgium.

Demand versus supply by 2030

The planned domestic production of green hydrogen is insufficient to meet the target in all variants. Additional domestic production is needed to meet the targets even in the low variant, to be combined with imports. As indicated, both are possible, but their potential is uncertain, hence realisation by 2030 will be challenging. The larger the required volumes of green hydrogen, e.g. in the middle and high variants, the more uncertain the realisation of sufficient supply.

Note that there is a limit to the physical intake volume of green hydrogen by 2030 without substantial changes to processing facilities in industry and refineries. This is due to the integrated nature of the existing processes, where most of the current hydrogen use is self-produced. We estimate this limit to be 50 PJ for the current situation, for industry and refineries together. It is not a strict limit, more is possible, but will require significant adaptation of industrial installations with associated investments. This will also take time to realise, and may cause accelerated depreciation of existing assets.

This finding is in line with the conclusion that it will be challenging to fulfil the combined national RFNBO targets by 2030, already for the low variant.

Timelines

All timelines are interrelated, as all elements are required to build the system.
Investment decisions across the hydrogen value chain need already to be taken before final adoption of the RED by the end of 2022 and subsequent formal national transposition and implementation time.

For the final investment decisions, both on the supply and on the demand side, the market conditions (including the stimulation regime) have to be clear. To start the preparation process, there has to be enough certainty of demand. This creates a dependency with the adoption of the RED3 that sets the targets for the Member States.

Also, the essential preconditions (i.e. hydrogen infrastructure, renewable electricity production, electricity network, modifications to industrial processes) have critical pathways.

Costs

The additional costs of 50% RFNBOs for the industry as compared to 100% fossil based hydrogen range from € 0.9 to 2.2 billion per year by 2030 for the low variant, and from € 1.7 to 4.4 billion per year by 2030 for the high variant. The ranges arise from the price scenarios for green and grey hydrogen. Note that investments for adaptations to current processes in industry that may be necessary to enable the integration of RFNBOs are not included in these figures.

Policy options for implementation

After adoption, the target has to be transposed to Dutch policies and regulations. If the government passes on the Member State obligation to the hydrogen-using industry, this provides the greatest certainty of achieving the target, provided it is physically feasible by 2030, and provided the essential preconditions are met. Competitors outside the EU, however, will not be confronted with these costs. For competitors in other EU Member States this depends on the policy choices taken by the specific Member State to implement the target. Therefore, the industry cannot pass on these additional costs to the customers without posing a risk to its competitive position. If the government pays for the additional costs, this will have the least impact on the competitive position of the industry.
The government may use a tender system to try to keep the total additional costs for society as low as possible.

Is it feasible?

The low variant could be feasible by 2030, but the bar is set high and timelines are tight. To achieve the low variant of the target, the hydrogen consuming industry will need to invest in the necessary changes to processes, other industries will need to invest in production and import of green hydrogen including upstream investments, the national government will need to provide full certainty about the market rules no later than by the end of 2025 and preferably (much) earlier, and the EU will need to adopt the RED3 no later than by the end of 2022. This is necessary to provide enough certainty of demand that is required to start all necessary investment planning, including for additional domestic hydrogen production and import. Investment decisions need already to be taken before final adoption of the RED and subsequent formal national transposition and implementation time. Swift and concerted action is needed in a national programme to realise all interrelated elements.

As clarity on the 2030 target as well as the instruments envisaged to achieve this target are needed as soon as possible, a national target might be set in 2022 or 2023 already by the national government, together with appropriate market conditions. This involves bringing into place policy instruments and financial resources that provide investment security for the supply chain and for industrial use of green hydrogen, in line with the objective of the RED to mainstream green hydrogen. These policy instruments need to allow for early build-up of green hydrogen production capacity, i.e. electrolysers and additional renewable electricity production.

Achieving the target by 2030 will become even more challenging if Dutch industry plans are realized for CO_2 emission reduction through decarbonization of fuel gases and fossil fuels with CCS (low-carbon hydrogen), and the resulting hydrogen must be included in the target setting for green hydrogen. These plans are included in the middle and high variants in this study. The middle and high variants are not feasible without large to very large volumes of both additional domestic hydrogen production and import. These variants lead to high to very high extra costs due to the investments needed to enable use of these large volumes of green hydrogen in industry.

Possible policy options that are relevant in the current adoption phase of the RED3 to make the ambitious green hydrogen obligation more feasible are:
- Set the target in absolute terms (i.e. obligated demand in PJ) rather than relative terms (% of green hydrogen use in industry). This would provide more certainty for policy makers, industry, grid operators and renewable electricity developers. It would also avoid creating a possible barrier for growth in hydrogen demand due to new hydrogen applications.
- Reduce the scope of the target setting, e.g. by excluding hydrogen rich by-product gasses and/or by excluding decarbonized fuel gasses from the denominator (i.e. set the target towards the low end variant in this study).
- Allow for a lower percentage than 50% in 2030.
- Allow for a longer timeframe to meet the 50% target, i.e. target later than 2030, to obtain more time for realisation.
- Allow for a flexibility mechanism which enables green hydrogen use in other EU Member States to be counted towards the national target (statistical transfers).
- Allow for more full load hours for electrolysers, while connecting to different renewable electricity sources using e.g. PPAs. This option might affect provisions in the RED but also requires changes to the national stimulation regime.

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A Overview national hydrogen use

This section provides a more detailed breakdown of current hydrogen use in the Netherlands, used to determine the industry RFNBO-obligation resulting from the Article 22a proposal in the proposal for revision of the RED2 under the EU 'Fit for 55' package. Current hydrogen use has been estimated by Weeda and Segers (2020). Hydrogen is used for the production of ammonia, methanol and for the production of various products in refineries. In addition, there is miscellaneous use of merchant hydrogen, e.g. for the production of hydrogen-peroxide; hydrogenation of unsaturated fats and oils in the food industry; for glass purification (glass industry) and various metallurgical applications (welding, annealing and heat treating metals). Lastly, there is miscellaneous use of by-product hydrogen from chlorine production, naphtha steam cracking and various chemical processes such as dehydrogenation of ethylbenzene to styrene. An overview is given in Table 19, based on the analysis from Weeda and Segers (2020). Various public data sources have been used to determine nameplate capacities of processes and production plants that deliver hydrogen for final energy and non-energy purposes in industry. Based on these capacities, an estimate has been made for the actual generation and use of hydrogen by applying a capacity factor of 90%. Capacities and application of the capacity factor have been checked in industry interviews and assessed to be sufficiently accurate for the current analysis.

Table 19 - Breakdown of the estimated current hydrogen use in industry in the Netherlands

Sector	Hydrogen use (PJ/y)
Ammonia	58
Methanol	12
Other miscellaneous industrial use	17
Miscellaneous use of by-product hydrogen	28
Refineries	65
Total	**180**

Source: (Weeda and Segers, 2020).

It should be noted that the data in the table have been the starting point for interviews held with industry in the context of this study. some figures have been slightly adjusted as a result of the interviews. Furthermore, there has been a shift between 'Other miscellaneous industrial use' and 'Refineries'. Part of the use for other industrial purposes has been shifted to refineries. The adjusted figures were ultimately used as a basis for calculating the RFNBO obligation in the low variant in Table 2 in Paragraph 3.2 of Chapter 3

B Used abbreviations

ATR	Autothermal Reformer
CAN	Calcium Ammonium Nitrate
CBAM	Carbon Border Adjustment Mechanism
CCfD	Carbon Contract for Difference
CCS	Carbon Capture and Storage
CES	Cluster Energy Strategy
CHP	Combined Heat and Power
EC	European Commission
ETS	European Trading System
EU	European Union
FID	Final Investment Decision
HHV	Higher Heating Value
IA	Impact Assessment
KEV	Klimaat- en Energie Verkenning (Climate and Energy Outlook)
LHV	Lower Heating Value
MRV	Monitoring, Reporting and Verification
NRW	North Rhine-Westphalia
ODE	Opslag Duurzame Energie
PJ	PetaJoule (10 to the power 15)
RCF	Recycled Carbon Fuel
RED	Renewable Energy Directive
RFNBO	Renewable fuels of non-biological origin
RIB	Regional Integrated Backbone (hydrogen infrastructure)
SAF	Sustainable aviation fuels
SMR	Steam Methane Reformer
VAWOZ	Verkenning Aanlanding Wind op Zee
WoZ	Wind op Zee (offshore wind)

C Hydrogen cost prices

In this Annex, cost prices are provided for green hydrogen, and for grey and low-carbon hydrogen.

C.1 Green hydrogen price

Table 20 contains an overview of recent cost price predictions for green hydrogen. It shows a wide range of estimates of the hydrogen price. The studies show an dependency of the hydrogen cost price on the assumed electricity price, the investment cost of the electrolyser, the assumed network tariff cost and project size.

Table 20 - Overview of recent cost price predictions for green hydrogen by 2030

Source	Cost price hydrogen (€/kg)			Electricity price			Description
	Low	Middle	High	Low	Middle	High	
CE Delft (2018)	2.33	3.43	3.81	0.032	0.048	0.053	NL, wind
CE Delft (2018)	2.05	2.55	3.05	0.018	0.023	0.030	Morocco including transport
CE Delft (2018) & bewerking	2.55	3.88	5.17	0.036	0.057	0.080	NL, KEV prices
TNO and DNV GL (2018)		2.94			0.032		NL, 2025 values for electricity mix
BloombergNEF (2019)	1.27		2.64	0.022			World
TKI Nieuw Gas (Gigler and Weeda, 2018)	3.00		3.50				NL, MW-scale
TKI Nieuw Gas (Gigler and Weeda, 2018)	2.00		3.00				NL, 10-100 MW scale
IEA (2019)	1.73		3.64				Europe
METI Japan (2017)		2.82					Japan
Glenk & Reichelstein (2019)	2.00		2.50	0.019		0.028	Germany
IRENA (2019)		1.73					World, wind
IRENA (2019)		1.45					World, solar
Weeda (2019)	2.60		4.20	0.035		0.057	NL, KEV prices

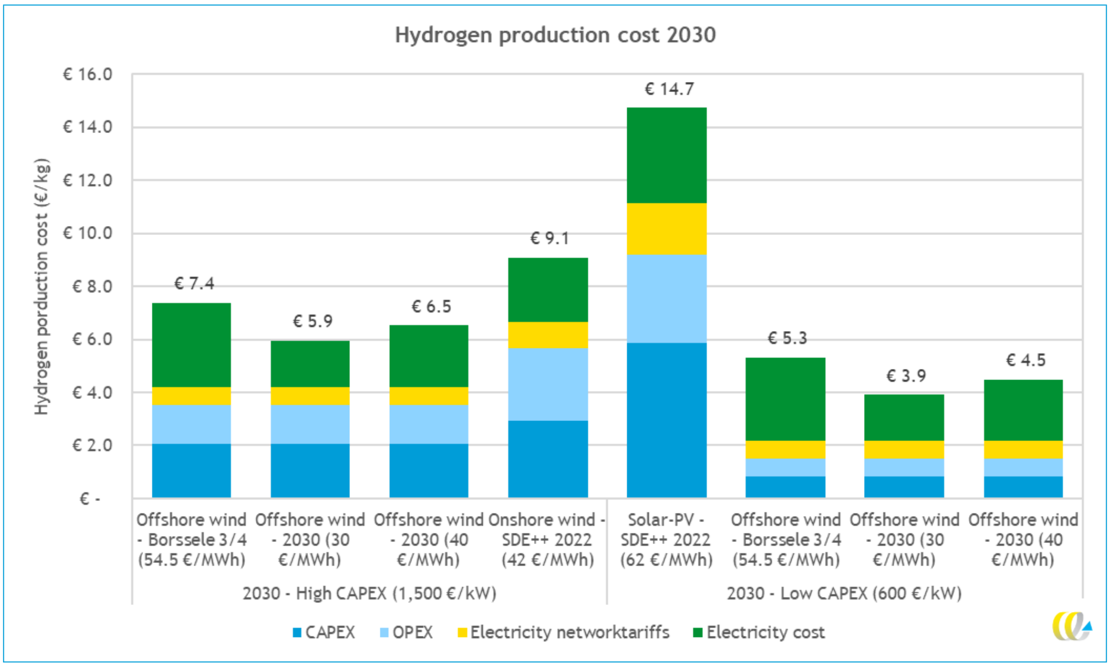
Source: (CE Delft, 2019).

Calculation of expected green hydrogen price

A high-over analysis of expected hydrogen prices in the Netherlands has been made in this study. We have assumed investment cost for electrolysers of 1,500 €/kW and additional scenario with cost of 600 €/kW by 2030 (TNO, 2022). We assume an electricity demand of 57,8 kWh/kg hydrogen. For operational expenses we assume replacement of the stack after 40,000 hours at 50% of the investment cost of the electrolysers and 2% other operational expenses. The electrolysers have am assumed lifetime of 15 years and a weighted average cost of capital (WACC) of 5.8% (PBL, 2021b). The average network tariffs are based on the SDE++ advice for which an average value of 50.4 €/kW$_e$ is calculated (PBL, 2021a). Different electricity prices for wind offshore (Ecofys, 2018) and SDE++ prices for solar and

onshore wind (PBL, 2021b) are used. The costs do not include the transport of hydrogen. For offshore wind 4,300 full-load hours are assumed, for onshore wind 3,000 and for solar 1,500.
The resulting prices for hydrogen production are displayed in Figure 10. These are cost prices and thus do not include a profit margin. The cost prices based on offshore wind are within range with the prices found in the literature. The prices based on onshore wind and especially solar are higher. The prices found in the literature are however world prices and not specifically for the Netherlands.

Figure 10 - Green hydrogen production cost estimates for 2030



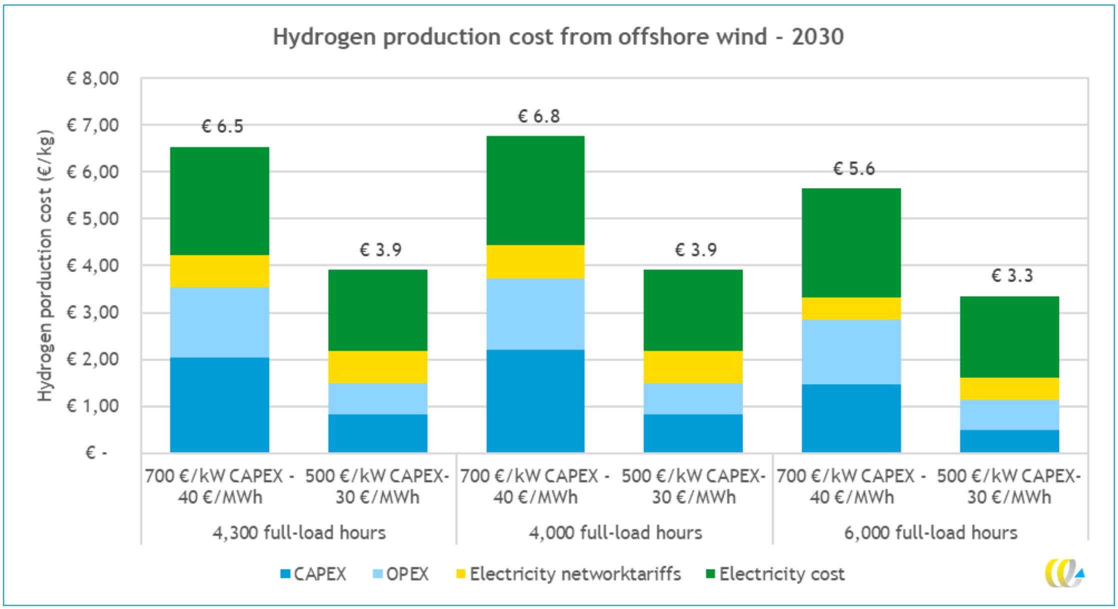
In this study we will assume a low and high price for green hydrogen, both based on offshore wind. The assumed prices are displayed in Table 21. At this moment we estimate a profit margin on grey hydrogen of 10-14%. We assume that this profit margin has to be in the same order of magnitude for green hydrogen. Therefore, we assume a profit margin of 10% on the production cost, resulting in the final hydrogen price. The market price for green hydrogen by 2030 is thus assumed at 4.3 to 7.2 €/kg.

Table 21 - Green hydrogen cost and market price estimations for 2030

Green hydrogen price scenario	Electricity price	Electrolyser investment cost	Hydrogen production cost	Hydrogen commercial market price
High price scenario	40 €/MWh	1,500 €/kW	6.5 €/kg	7.2 €/kg
Low price scenario	30 €/MWh	600 €/kW	3.9 €/kg	4.3 €/kg

A short sensitivity analysis is performed for different full-load hours. Figure 11 shows the hydrogen prices for 4,300, 4,000 and 6,000 full-load hours. For 4.300 full-load hours we calculate a production price between 3.9 and 6.5 €/kg. The commercial price is calculated at 4.3 to 7.2 €/kg. For 4.000 full-load hours the market price increases to 4.3–7.4 €/kg. For 6.000 full-load hours (i.e. smaller electrolyser compared to the offshore wind capacity and/or operating on other electricity sources also, like e.g. solar-pv) the market price decreases to 3.6-6.2 €/kg. In this analysis an equal electricity price for all the full-load hours scenario's is assumed.

Figure 11 - Hydrogen production cost from offshore wind for different full-load hours



The cost for hydrogen transport are yet unknown. By 2030, the hydrogen backbone in the Netherlands should be realized. The tariffs for transport via this backbone are however unknown. Potentially these will also differ based on the location of entry and exit of the gas. These transport cost will result in a price increase for the industry, except for when the hydrogen is produced on-site. It is uncertain and situation dependant if the cost will increase if green hydrogen is used instead of grey hydrogen. Due to these uncertainties transport cost are not included in this study.

Hydrogen can be produced for different prices in different countries. The most important parameters which effect the hydrogen price are:
- The electricity price and amount of full-load hours that green electricity is available.
- Regulation regarding green hydrogen production in Europe and countries from which green hydrogen could be imported.
- The investment price of electrolysers. It is however uncertain if there will be regional price differences in electrolysers. There is also a dependency between the investment price and the size of the project.
- The electricity network tariffs. In the Netherlands these are 10 to 15% of the total hydrogen production cost.
- Transport cost differences for the transport of hydrogen.

Costs of imported green hydrogen

Production cost for imported hydrogen are estimated by CE Delft at 3.4 to 5.7 €/kg by 2030.[27] This is analysis based on three development scenarios, seven hydrogen carriers and eight potential exporting countries. The production cost for hydrogen in these countries excluding conversion, storage and transport is between 2.1 and 3.4 €/kg by 2030. Dibenzyltoluene (DBT, which is a LOHC) and ammonia are expected to be the hydrogen carriers with the lowest cost by 2030. The Hydrogen Council expects the cost for international hydrogen transport to be between 0.5 to 3.1 €/kg (Council, 2021).
The Hydrogen Council predicts in this study that hydrogen production in Saudi Arabia with transport to Rotterdam by ship will cost between 2.8 to 4.3 €/kg by 2030.

Green hydrogen production cost in the Netherlands from offshore wind, as calculated in Paragraph 4.2, are expected to be 3.9 to 6.5 €/kg by 2030. The price including profit margin is expected to be 4.3 to 7.2 €/kg. Domestic green hydrogen production is thus expected to be more expensive than most import routes. The exact competitiveness is however still uncertain and dependant on the development of electricity prices, transport cost and governmental policy in the different countries. In general market parties assume green hydrogen import can compete with domestic production.

C.2 Grey and low-carbon hydrogen cost price

As an indication of the cost price of grey and low-carbon hydrogen in the Netherlands between 2020 and 2030, we make use of the estimations made in a recently finished study for Smart Delta Resources, which contained a hydrogen cost price analysis (Buck Consultants and CE Delft, 2021). In this analysis, grey and low-carbon hydrogen are assumed to be produced with an autothermal reformer (ATR), using investment cost figures from NTNU (2016). For low-carbon hydrogen import, it was assumed that LNG is imported by ship from Norway, and is converted to hydrogen in the Netherlands. Furthermore, the cost price analysis made use of three different scenarios, in which the natural gas price, CO_2 price and the energy efficiency of the autothermal reformer are varied (but not for the year 2020). The used values are shown in Table 23.

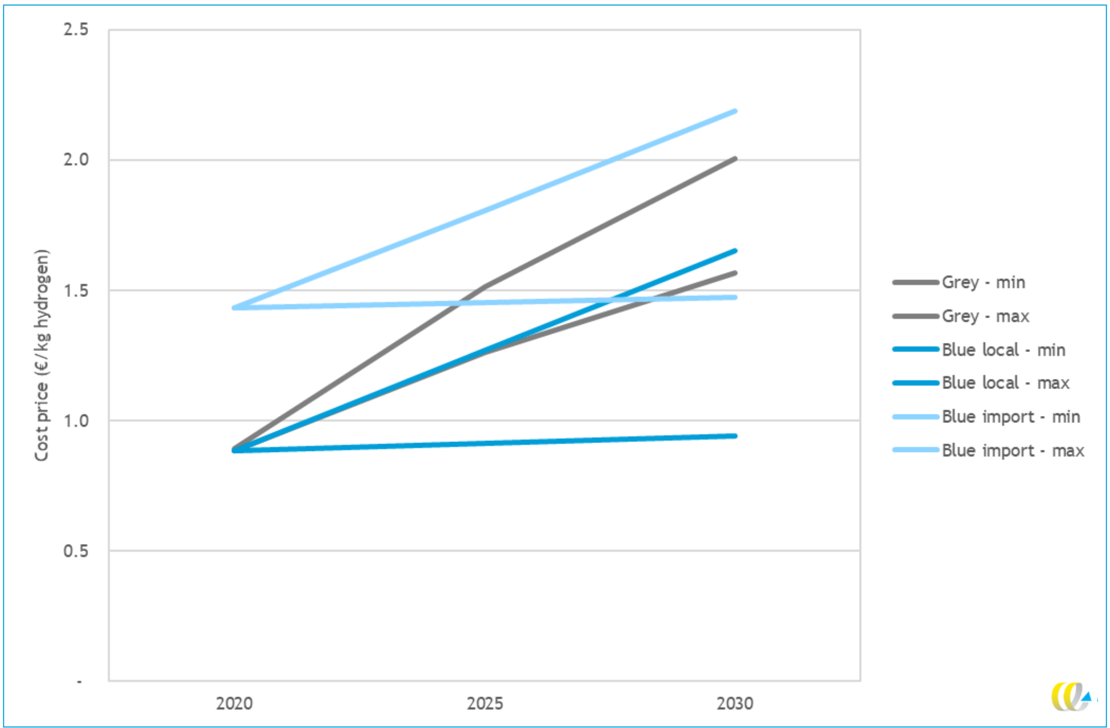
Table 22 - Input values in hydrogen cost price analysis of Buck Consultants and CE Delft (2021)

Variable	2020	2025	2030	Remarks
Natural gas price (€/GJ)	4.7	4.9-7.4	5.1-10.1	The 2030 values are based on projections from (PBL, 2021c).
CO_2 price (€/ton)	50	52-68	53-85	The 2030 values are based on projections (EC. 2021f)
Efficiency of autothermal reformer (ATR) (%)	82.0%	82.4-82.6%	82.8-83.2%	

[27] Report is not yet published.

Currently, (grey) hydrogen producers do not have to acquire CO_2 emission allowances from the EU Emissions Trading System (ETS). They receive free CO_2 rights within the ETS, in order to prevent carbon leakage. If a current EU legislative proposal is implemented, this free allocation of CO_2 rights will be replaced by the Carbon Border Adjustment Mechanism (CBAM) in 2023. After a transition period between 2023 and 2026, the free emission rights will be phased out. Considering this, we have assumed that hydrogen producers must pay for 0% of its CO_2 emissions in 2020, 70% in 2025, and 100% by 2030, and have adapted the estimations from the cost price analysis of Buck Consultants and CE Delft accordingly. Considering this, we have assumed that hydrogen producers must pay for 0% of its CO_2 emissions in 2020, 70% in 2025, and 100% by 2030, and have adapted the estimations from the cost price analysis of Buck Consultants and CE Delft (2021) accordingly. The resulting cost prices of grey and low-carbon hydrogen are shown in Table 23.

Figure 12 - Bandwidth of grey and low-carbon hydrogen cost prices, based on different natural gas price and CO_2 price scenario from Buck Consultants and CE Delft (2021)



Note: Assumed share of CO_2 emissions for which the CO_2 price must be paid: 0% in 2020; 70% in 2025; 100% by 2030. Low-carbon hydrogen import = imported in the form of LNG. Low-carbon hydrogen local = produced from natural gas from regular gas network.

Due to the cost of CO_2 allowances, the estimated cost price of grey hydrogen becomes higher than that of local hydrogen well before 2025. The estimated cost price of imported low-carbon hydrogen (i.e., the import of LNG plus conversion to hydrogen in the Netherlands) is on overall higher than that of grey hydrogen, but the uncertainty ranges overlap by 2030, which means that imported low-carbon hydrogen might become cheaper than grey hydrogen by 2030.

It should be noted that the hydrogen cost price level in 2020 does not reflect the natural gas prices observed in the Fall of 2021, which are a lot higher than is reflected in the projections from PBL. With the observed natural gas prices in the EU day ahead market, the grey hydrogen cost price was in the order of 5 €/kg. However, it is expected that the current price peaks are temporary. Therefore, we have adopted the natural gas price projections from PBL.

Assuming that hydrogen producers apply a profit margin of 10%, we obtain estimated market prices for grey and low-carbon hydrogen. The cost price and market price estimations for the year 2030 are presented in Table 23.

Table 23 - Grey and low-carbon hydrogen cost price and market price estimations for the year 2030

Hydrogen type	Price scenario	Cost price (€/kg)	Market price (€/kg)
Grey	High	2.01	2.21
	Low	1.57	1.72
Low-carbon local	High	1.65	1.82
	Low	0.94	1.03
Low-carbon import	High	2.19	2.41
	Low	1.47	1.62