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Executive summary

In any future decarbonised energy system 'green molecules' such as biomethane and renewable hydrogen, are expected to play an important role. All green molecules, but especially hydrogen, are facing a chicken-egg problem, i.e. the risk of a mismatch between supply and demand and transport infrastructure. One of the pathways to overcome this are policies and measures towards mandatory physical and/or administrative blending of hydrogen into the gas system. Physical admixing refers to injection of hydrogen into the natural gas grid; administrative blending to a quota-based scheme obliging determined parties to forward certificates to 'green' (a share of) their gas consumption. An overview of the main considerations with regard to both is provided below.

Although from an analytical perspective the distinction between physical and administrative blending can be useful, in actual practice both aspects of blending will mostly occur in conjunction. If a mandatory regime focusses on physical blending, it is likely that an addition certification system will develop to monetise the green premium attached to the admixed hydrogen. In reverse, if a mandatory policy relates to administrative blending, certificates will be issued for use and trade that will ultimately be based on hydrogen that is introduced in any way into the energy system, possibly but not necessarily via physical admixing into the grid.

Physical blending

So far, to our knowledge, no mandatory physical admixing policies with respect to hydrogen do exist. However, a number of laboratory tests, pilots and testing experiments have been carried out in various countries in order to investigate to what extent physical blending poses challenges in terms of gas quality, grid integrity, pressure, safety, etc.

The literature on the various aspects of physical blending of hydrogen into the natural gas grid notes that admixing hydrogen may affect: the gas density, the gas viscosity, the gas pressure, the gas Wobbe-index, and the conditions that may lead to two-phase flows. At relatively low admixing percentages (i.e. below about 20%) these effects do not seem to pose any insurmountable issues.

As far as the risks of embrittlement and induced cracking of the grid due to the admixing of hydrogen is concerned, for conditions reflecting the most common materials and operating characteristics, almost all the studies tend to conclude that no significant changes in the tensile properties of metals (low strength steel e.g. API5L gr B., cast iron, copper, yellow brass) can be observed when exposed to gas mixtures up to a 20 vol% hydrogen blend. In addition they conclude that for non-metallic materials, such as medium density polyethylene (PE80), hydrogen absorption does not affect subsequent squeeze-off or electrofusion joining of pipework [1]. No research was found that looks specifically in the differences between laminar and nodular cast iron and for asbestos cement as material, which are used both in the Dutch regional distribution grids.

The literature, on the other hand mentions some embrittlement risks with respect to compressor and flange components, because of the use of some specific metals, such as titanium and nickel.

The tolerance levels of various appliances and components in the gas value chain for admixing hydrogen vary quite strongly at the current state of equipment. New technological developments may increase tolerance levels significantly, sometimes against relatively low costs. Currently the lowest tolerance levels seem to be concentrated in engines, gas turbines and CNG tanks.

Typical safety issues that apply to many gases and also to hydrogen are: the need for odorization, the risks of leakage, permeation and excavation. On the whole, such risks will need to be taken care of with great caution, but do not seem to pose insurmountable challenges.

In the absence of a common and binding hydrogen limit requirement at EU level, it is up to the Member States the determine which hydrogen blending percentage is considered safe and feasible [2]. This is why the authorized concentrations vary significantly from one country to the other. For instance, in the Netherlands is set at ≤0.02 mol% in the HTL network and ≤0.5 mol% in the RTL and RNB net[1] [3], while in Germany it is 10 mol% [4].

Next, some economic issues related to physical blending should be taken into account. The hydrogen energy density is about one third of that of natural gas and thus blending decreases the energy content of the supplied gas: A 3% hydrogen blend in a natural gas delivery pipeline will reduce the energy transported by about 2%. This point obviously will have metering and billing consequences that will need to be dealt with.

Because on the whole the market value of the carbon neutral hydrogen admixed to the gas flows will surpass the market value of the other gas (typically natural gas and/or syngas), a certificate-based system may be a logical component of mandatory physical admixing schemes in order for the suppliers of the hydrogen to capture their green premium.

Administrative blending

So far mandatory administrative blending or quota schemes have only been implemented with regard to electricity or liquid fuels, not to gases. So, for lessons learned with respect to the optimal design of blending schemes for gases one can only learn indirectly, from experiences elsewhere. Moreover, on the whole there is relatively little literature in the public domain on mandatory administrative blending.

From the existing mandatory administrative blending regimes it can be learned that the most critical design characteristics are:

- if quota sections for various qualities of the admixed substance will be distinguished, and therefore different types of certificates per scheme;
- if the scheme applies generically, or to specific sectors/company types only (e.g. based on competitiveness considerations);
- if the certificates can be traded, are traceable, and if a certificate expires at some date, or can be banked forever;
- if explicit measures are taken to prevent fraud and abuse;
- if certificate prices are maximised or facing minimum levels, or both;
- if the overall quota level varies with the economic conditions and/or the environmental targets;
- if certificate trading on the market will be restricted to specific areas (e.g. the issuing country), or instead is left free to the international market;
- if the acceptance of certificates in an administrative blending scheme is contingent upon the existence of a satisfactory level of physical blending.

The actual design of a mandatory administrative admixing scheme will be based on a mix of targets and the weight attached to each of them, such as: environmental goals; the reliability and credibility of the scheme and its certificates; the scheme’s flexibility in implementation; the recognition of aspects of international competition; the impact of the scheme on investment and innovation in hydrogen production and use; the minimization of the overall societal costs of this mitigation instrument.

[1] *RNB network:* gas transport network that is not managed by the network operator of the national gas transport network.

Insofar as environmental goals are considered a criterion in the administrative blending design, it is often considered important what other gases or energy carriers are displaced by introducing the renewable hydrogen, because the mitigation impact of blending will vary. For instance, the mitigation impact of replacing ‘grey’ hydrogen (i.e. hydrogen produced from natural gas while releasing the CO2 from the production process into the air) is higher than if natural gas is displaced, etc.

One of the clear advantages of introducing mandatory admixing schemes is that they may kickstart a specific and predefined level of market demand that will provide clear market guidance to potential investors in the admixed fuel; a disadvantage of the scheme may be that certificate prices are determined by the supply and demand balance on the market, and therefore are difficult to predict a priori. Also, actual practise has learned that the risks of fraud should not be underrated.

Although it is likely that administrative blending will lead to physical blending as well (see above), it is possible to steer the actual physical blending levels such that any desirable technical or safety issues related to that can be prevented; e.g. an administrative blending scheme could be fulfilled by a combination of small physical admixing options and pure hydrogen flows transported in dedicated systems.

Precisely because a mandatory blending scheme may create an immediate market for specific carbon neutral fuels (e.g. hydrogen), it is considered important in practise to make sure that such sudden demand jump will not crowd out the underlying energy carrier (e.g. green power in case of green hydrogen) from being used for other applications. That is why sometimes an additional condition for the blended hydrogen is propagated, namely that the producer of hydrogen will have to show that it is generated from green power that is produced in addition to what otherwise would have been produced. Sometimes such an additionality condition is even strengthened to the extent that it needs to be proven that the additional production volumes of hydrogen is synchronised with additional volumes of green power.

It is still an open question if and to what extent in the EU subsidized green power is allowed to be used to generate green hydrogen to be used for fulfilling a possible mandatory quota. For a successful launch of a mandatory administrative hydrogen blending scheme, it is imperative that this issue is resolved timely and clearly.

Samenvatting

In een klimaatneutraal Nederlands energiesysteem zullen 'groene moleculen', zoals biomethaan en hernieuwbare waterstof, een belangrijke rol gaan spelen. Met name voor waterstof is er sprake van een kip-ei probleem dat de ontwikkeling van aanbod, vraag en infrastructuur kan belemmeren. Eén van de manieren om dit probleem te doorbreken is door een fysieke en/of administratieve bijmengverplichting in te zetten binnen het gassysteem. Fysieke bijmenging refereert naar het injecteren van waterstof in het aardgasnetwerk; met administratieve bijmenging wordt een quota verplichtingensysteem bedoeld, waarbij bepaalde partijen worden verplicht een deel van hun afzet te vergroenen door het afgeven van verhandelbare 'groene' certificaten. Voor zowel fysieke als administratieve bijmenging is hierna een overzicht gegeven van de afwegingen die hierbij komen kijken.

Hoewel het maken van onderscheid tussen beide vormen van bijmenging wenselijk is vanuit een analytisch oogpunt, zijn beide bijmengmethoden in de praktijk nauw met elkaar verbonden. Wanneer de verplichting gefocust zou zijn op fysieke bijmenging, is een bijpassend certificatensysteem wenselijk om de groene meerwaarde van de bijgemengde waterstof bij de producent te doen neerslaan. Daarentegen zal bij een administratieve bijmengverplichting uiteindelijk ergens in het systeem de waterstof fysiek in het systeem gebracht moeten worden, ofwel fysiek bijgemengd, dan wel door invoeding in een volledig op waterstof gerichte infrastructuur.

Fysieke bijmenging

Voor zover ons bekend wordt momenteel nergens een wettelijk verplicht aandeel waterstof fysiek aan het gasnet bijgemengd. Wel zijn er vele pilots, laboratoriumtesten en experimenten uitgevoerd in verschillende landen om in kaart te brengen welke nieuwe uitdagingen fysieke bijmenging met zich meebrengt met betrekking tot de gaskwaliteit, netintegriteit, druk, veiligheid, enz.

In de gasliteratuur wordt aangegeven dat fysieke bijmenging van waterstof in het aardgasnet effect heeft op: de gasdichtheid, gasviscositeit, de gasdruk, de Wobbe-Index en de condities die leiden tot een tweefasige staat van gas. Voor relatief lage bijmengpercentages (d.w.z. onder de 20%) wordt verwacht dat hierdoor geen problemen ontstaan die niet opgelost zouden kunnen worden.

Uit onderzoek naar de verbrossing van materialen door waterstof gasmengsels (tot 20%) komt naar voren dat de meeste materialen (laagkrachtig staal e.g. API5L gr B, gietijzer, koper, gele messing) geen significante veranderingen in eigenschappen gaan vertonen. Verder wordt geconcludeerd dat voor niet-metaalachtige materialen, zoals polyetheen met gemiddelde dichtheden (PE80), waterstofadsorptie geen invloed heeft op squeeze-off effecten of op door elektrofusie gecreëerde verbindingen tussen pijpleidingen [1]. Onderzoek naar onderscheid van effecten van waterstof op laminair en nodulair gietijzer, of AC (asbest cement) pijpleidingen zijn bij de auteurs niet bekend, hoewel deze wel in het gasdistributienet voorkomen.

Aan de andere kant worden voor bepaalde componenten in compressoren en flenzen wel verbrossingrisico's voorzien, met name door het gebruik van sommige specifieke metalen zoals titanium en nikkel.

Het tolerantieniveau voor waterstofmengsels verschilt sterk voor verschillende toepassingen en componenten in de huidige apparatuur binnen de gaswaardeketen. Met de nieuwe technologische ontwikkelingen kan de tolerantie van bestaande en/of nieuwe apparatuur (aanzienlijk) worden verhoogd, soms tegen relatief lage kosten. Momenteel worden de laagste tolerantieniveaus waargenomen bij motoren, gasturbines en CNG tanks.

Verder spelen typische veiligheidskwesties, net als bij andere gassen, een rol bij waterstof. Denk hierbij aan odorisatie, lekrisico's, permeatierisico's en risico's bij uitgraving. Ondanks dat er met de grootste zorgvuldigheid met deze risico's moet worden omgegaan, hoeven deze niet als onoverkomelijk te worden beschouwd.

Doordat er momenteel geen Europese richtlijn is die minimale of maximale eisen stelt aan de eventuele bijmenging van waterstof, is het aan lidstaten om te bepalen welk percentage voor bijmenging zij als veilig en wenselijk zien [2]. Dit is dan ook de reden dat de toegestane limieten voor bijmenging vrij sterk kunnen verschillen tussen landen. Zo mag er bijvoorbeeld in Nederland momenteel maximaal 0.02 mol% waterstof worden bijgemengd in het HTL netwerk (gepland om dit te verhogen naar 0.5 mol%) en tot 0.05% in het RNB netwerk, waar dit maximale percentage in Duitsland is gelegen op 10 mol% [4].

Ook zullen t.a.v. fysieke bijmenging economische kwesties in acht genomen moeten worden. Zo is de dichtheid van waterstof ongeveer één derde vergeleken met die van aardgas, zodat de energie inhoud van het geleverde gas daalt. Ter illustratie, 3% waterstof bijmengen in aardgas betekent dat 2% minder energie geleverd kan worden. Met dit soort effecten zal rekening moeten worden gehouden bij het meten en afrekenen van het gas.

Daarnaast zit er mogelijk een verschil in de waarde die klanten bereid zijn om te betalen voor pure CO_2 neutrale waterstof en voor het gas waarmee wordt bijgemengd (meestal aardgas en/of syngas). Een certificatensysteem zou een logische component kunnen zijn van een fysieke bijmengverplichting om ervoor te zorgen dat leveranciers deze meerwaarde traceerbaar en verrekenbaar kunnen maken.

Administratieve bijmenging

Tot nu toe zijn administratieve bijmengverplichtingen of quota regelingen alleen geïmplementeerd voor elektriciteit en vervoer, niet in de gassector. Daarom kan van de ervaringen met de bestaande instrumenten alleen indirect geleerd worden, bijvoorbeeld omtrent welke ontwerpkeuzen gemaakt moeten worden voor administratieve bijmengverplichtingen van gassen. Daarenboven is er tot dusver sowieso nog weinig literatuur in het publieke domein beschikbaar over administratieve bijmengverplichtingen.

Uit de literatuur blijkt dat de volgende ontwerpkarakteristieken belangrijk worden geacht bij administratieve bijmengverplichtingen:

- Of onderscheid gemaakt moet worden tussen deelquota voor verschillende substanties en daarvoor verschillende typen certificaten gebruik moeten worden;
- Of een generiek quotum gebruikt zal worden voor al het (gas)gebruik, dan wel het quotum specifiek geldt voor bepaalde sectoren of type bedrijven (bijv. op basis van concurrentievermogen);
- Of certificaten verhandeld kunnen worden, traceerbaar zijn, en of certificaten al dan niet een houdbaarheidsdatum hebben;
- Of expliciete maatregelen genomen worden om fraude en misbruik te voorkomen;
- Of maximum- en/of minimum-prijzen gehanteerd worden voor de certificaten;
- De mate waarin de hoogte van het quotum in de tijd afhangt van bijvoorbeeld de economische of milieu-effecten;
- Of slechts certificaten uit bepaalde gebieden (bijv. Nederland) gebruikt kunnen worden om aan het quotum te voldoen, of dat ook internationaal verhandelde certificaten daarvoor bruikbaar zijn;

- Of een bepaald niveau van fysieke bijmenging benodigd is om administratieve bijmenging acceptabel te doen zijn.

Voor zover milieu-effecten een criterium zijn bij de beoordeling van administratieve bijmengverplichtingen, zal meestal ook sterk worden gekeken naar de gassen of energiedragers die door de bijgemengde waterstof worden vervangen, omdat bijv. het broeikaseffect daar sterk door kan worden bepaald. Ter illustratie, het positieve broeikaseffect van het bijmengen van hernieuwbare waterstof is omvangrijker wanneer grijze waterstof wordt vervangen, d.w.z. waterstof geproduceerd vanuit aardgas waarbij de vrijkomende CO2 in de atmosfeer wordt geloosd, dan wanneer bijvoorbeeld aardgas wordt vervangen.

Wat het wenselijke ontwerp is van een administratieve bijmengverplichting, is afhankelijk van de mix van doelen dat men via het systeem nastreeft en het gewicht dat aan elk van de doelen wordt toegekend. Onderscheiden doelen zijn bijvoorbeeld: de betrouwbaarheid en geloofwaardigheid van het instrument; de mate van flexibiliteit van de regeling tijdens implementatie; de waarde die wordt gehecht aan internationale concurrentieverhoudingen; de impact die de regeling moet hebben op investeringen en innovatie in waterstof productie en gebruik; de mate waarin men kan slagen in de minimalisatie van de totale maatschappelijke kosten voor CO_2 reductie.

Een van de duidelijke voordelen van een bijmengverplichting is de kickstart die wordt gegeven door het garanderen van een vooraf bepaalde marktvraag naar hernieuwbare waterstof, die ervoor zorgt dat potentiële investeerders zeker zijn van afname; een nadeel is dat de prijzen voor certificaten vooraf onbekend zijn aangezien deze worden bepaald door het evenwicht van vraag en aanbod op de markt. Daarnaast leert de ervaring dat de risico's van fraude binnen een administratief instrument niet moeten worden onderschat.

Ondanks dat, zoals hiervoor betoogd, voorzien wordt dat administratieve bijmenging ook deels fysieke bijmenging met zich mee brengt, kan de mate van fysieke bijmenging vaak beperkt worden tot het niveau dat wenselijk is, bijv. met het oog op technische en veiligheidsbegrenzingen. Dit kan doordat immers naast de (op beperkte schaal) fysiek bijgemengde waterstof ook pure waterstof stromen via speciale infrastructuur gebruikt kunnen worden om aan de administratieve verplichtingen te voldoen.

Omdat een bijmengverplichting-regeling onmiddellijk een markt creëert voor de bijgemengde brandstoffen/moleculen (zoals koolstofneutrale waterstof), is het belangrijk dat de gecreëerde vraagstijging niet zorgt voor een ongewenste verdringing van onderliggende energiedragers (zoals groene stroom in geval van groene waterstof en biomassa in geval van biomethaan) die ook gebruikt worden voor andere toepassingen. Daarom wordt vaak gesteld dat een additionaliteitscriterium een wenselijke eis is voor waterstof die gebruikt wordt om te voldoen aan de bijmengverplichting. Hierdoor zou een waterstofproducent moeten aantonen dat de gebruikte groene stroomcapaciteit er anders niet zou zijn geweest. Een nog sterkere eis zou zijn wanneer deze gebruikte groene stroom in zekere mate gelijktijdig moet zijn opgewekt als de voor het quotum gebruikte waterstof.

Daarnaast staan er nog vragen open hoe de Europese regelgeving zich gaat ontwikkelen, bijvoorbeeld ten aanzien van de vraag of waterstof geproduceerd met gesubsidieerde groene stroom gebruikt mag worden om te voldoen aan een dergelijke bijmengverplichting. Voor een succesvolle implementatie is het vanzelfsprekend van belang dat er tijdig duidelijkheid komt over dit soort vraagstukken.

Table of contents

Definitions and abbreviations

CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
DSO	Distribution System Operator
EC	European Commission
EU	European Union
DEI+	Demonstration Energy and Climate Innovation subsidy
FCGR	Fracture Crack Growth Rate
GO	Guarantee of Origin
HBE	Renewable Fuel Entity (G=Advanced, C=Conventional, O=Other)
HER+	Renewable Energy Transition subsidy
HHV	High Heating Value
H_2	Hydrogen
HE	Hydrogen Embrittlement
HIC	Hydrogen Induced Cracking
LHV	Low Heating Value
NG	Natural Gas
RED	Renewable Energy Directive
RFNBO	Renewable Fuel of Non-Biological Origin
Rli	(Dutch) Council for Living Environment
SDE++	Stimulation Renewable Energy production subsidy
TSO	Transmission System Operator

Introduction

Hydrogen is considered to be one of the main energy carriers in a future, decarbonised energy system. In the Dutch Climate Agreement, for instance, [5], that aims for a 49% CO_2 reduction in 2030 compared to 1990, hydrogen is mentioned as an important option to reduce carbon emissions in industry, built environment and mobility. Moreover, hydrogen is seen as a system integrator to deal with intermittency of solar and wind energy. Although the main energy sources in a decarbonised future are expected to be solar and wind, the Dutch TSOs for electricity and gas, Gasunie and TenneT, foresee that an about equally shared mix of electrons and molecules (e.g. hydrogen and biomethane and various 'liquids') will be needed to keep energy infrastructural costs and e-grid congestion risks under control and satisfy demand for molecules where electrons cannot provide this economically or technically [6].

Currently, hydrogen is already used as energy source and feedstock for decades in heavy industry, such as refineries, fertilizer producers and chemical industries. In the Netherlands, yearly 800 kilotons of 'grey' hydrogen are produced mainly by Steam Methane Reforming (SMR) [7], being responsible for 10% of the Dutch natural gas consumption and 8% of the Dutch CO_2 emissions [8]. It is foreseen that in the future hydrogen will be produced via 'green' methods, mostly referring to electrolysis with the help of renewable electricity. 'Blue' or 'low-carbon' pathways are also considered, often using the same conversion technologies as for grey hydrogen, but then the CO_2 emissions are captured and stored in depleted offshore gas fields or utilized and recycled in other industries. Nowadays the production of grey hydrogen is typically directly linked to the industrial processes that use it, so there is no common infrastructure for it, nor a transparent open market to physically (and/or virtually via certificates) exchange hydrogen. It is, however, expected that in the future, when carbon neutral hydrogen is used as a common feedstock and energy carrier, an open-access common infrastructure and (certificate) market will evolve [9].

The Dutch Government has the objective to increase domestic electrolyser capacity towards 500 MW in 2025 and 3-4 GW in 2030 [5]. In order for companies to invest in such capacities, there should be sufficient demand for green hydrogen. Such demand has been lacking so far, because production costs and therefore prices of carbon neutral hydrogen are higher than those of grey hydrogen even if the current (May 2021) EU ETS CO2 penalties (some 50 euro per allowance) are taken into account, but also because technologies and infrastructure for a broader introduction of carbon neutral hydrogen is still lacking. One of the pathways to overcome the lack of demand for carbon neutral hydrogen are policies and measures towards mandatory physical and/or virtual blending of hydrogen into the gas system. Physical blending means for instance injecting (blue or) green hydrogen into the existing natural gas grid, which has the advantage that no new dedicated infrastructure needs to be installed. Physical blending is, however, equally possible in dedicated customized structures; what matters is that the blending is real. Another way to blend is virtually, i.e. via an exchange of certified certificates based on production and grid injection (or any other transport mode) elsewhere. Provided the certificate is transferred properly, the new owner can use it to claim to use a green gas and therefore satisfy its mandatory quota. When a certain physical and/or admixing percentage for hydrogen is determined and obliged, a specific volume of demand for green hydrogen is guaranteed to prospective producers that will incorporate this information into their investment decisions. In addition it will set the rest of the value chain into motion because mandatory blending also creates clarity towards the transport and storage needs and overall availability of green hydrogen for various applications.

The aim of this report is to provide an overview of existing literature that is relevant for the development of a hydrogen admixing schemes. In doing so, other energy blending schemes as well as other ways of integrating green gases into the energy system will be considered as well. Part I and

Part II will subsequently discuss issues related to physical and virtual admixing. In the Summary a state-of-the-art outlook of the current knowledge will be provided and future research needs inventoried.

Part I: Physical admixing

1. Introduction

The European natural gas grid, in its most fundamental role, has a dual function in the energy system: (1) to transport vast quantities of energy over long distances, and (2) to store energy as it is delivered from A to B. Contrary to the electricity grid for which it is necessary to constantly manage input and output in a balancing effort, the gas system can to a certain degree act as a buffer. This capacity is known as 'linepack'[2]. This is helpful, also for admixing hydrogen with natural gas, e.g. to green the gas [10]. Such admixing, or blending, can take place either physically, or administratively with the help of certificates, or both. Section 2 will focus on physical blending, and in particular how it may interfere with the grid infrastructure that is traditionally used for transporting natural gas. Section 3 will discuss the various characteristics of administrative blending.

A small hydrogen content in natural gas can exist naturally. In addition, hydrogen can be added through blending, resulting in a mix stream serving various purposes. Such blending has often been a way of increasing the combustion properties of the blend. Nowadays, more novel reasons arise, such as the need of cutting down environmentally harmful emissions derived from the combustion of natural gas, in order to meet the EU Climate Goals [10] [11], or even as a means of eventually delivering (almost) pure carbon neutral hydrogen - by at any point separating the hydrogen again from the blend.

1.1 Hydrogen sources

There are several methods to produce hydrogen and a myriad more ways to use it. Generally, a distinction between 'grey',' blue' and 'green' hydrogen is used in many countries worldwide to distinguish between its source of production and mitigation impact. In 2019, the International Energy Agency estimated that 76% of the world's hydrogen production was derived from natural gas and 22% from coal. This suggests that nearly all hydrogen produced in the world is produced from fossil fuels (mostly by steam reforming or partial oxidation, or a mixture of both) [12]. The large volumes of product obtained this way are commonly known as 'grey' hydrogen, and its production contributes to large amounts of greenhouse gas emissions [13]. By comparison, only about 2% of hydrogen is currently extracted through electrolysis from renewable sources [12]. The latter hydrogen is referred to as 'green' hydrogen. Another technique is to generate hydrogen from fossil fuels, but to sequestrate or capture and permanently store, or utilize the resulting CO_2 [14]. This hydrogen is called 'blue' hydrogen.

1.2 The European pathway to hydrogen

In its recently established EU strategy on energy system integration, the EU characterised hydrogen as one of the major enablers to *'accelerate, over the next two decades, a profound transformation of our energy system and its structure'* [15]. This special attention for hydrogen is echoed by the many other views of EU institutions signalling it as a key carrier to achieve the EU climate goals, e.g. in the EU Hydrogen Strategy [16], which is part of the 'European Green Deal' [17].

According to the Commission, and in line with the 2050 climate neutrality goal set out in the European Green Deal, the new Hydrogen Strategy will explore the potential of clean hydrogen to help the process of decarbonising the EU economy in a cost-effective way. It also points out that the recovery from the economic effects of COVID-19 should be aided by this strategy [15, p. 21]. Worth of noticing is the

[2] The 2009 Gas Directive (n 18), art 1(15), defines 'linepack' as: 'the storage of gas by compression in gas transmission and distribution systems, but not including facilities reserved for transmission system operators carrying out their functions'.

choice of wording when referring to hydrogen as 'clean'. The Commission in its Hydrogen Strategy defines 'clean' hydrogen as renewable hydrogen produced by means of the electrolysis of water or through the reforming of biogas and as biochemical conversion of biomass. Nonetheless, in other documents 'clean' hydrogen can be found as a reference for both 'green' and 'blue' hydrogen, and 'not clean' for the rest, a.o. to speed up and scale up the introduction of a broader range of carbon neutral-emissions sources [2].

2. Physical blending

Under the 2009 Gas Directive Article 41 [18, p. 18] a '*non-discriminatory access to the gas system'* is granted to any type of gas, provided '*that those gases can technically and safely be injected into, and transported through the natural gas system and (should also) address their chemical characteristics*.' [2].

The following sections show how altering hydrogen percentages in natural gas has significant impacts on the thermo-physical properties of the blend, and therefore the feasibility of blending.

2.1 Natural gas composition

The chemical composition of natural gas streams varies according to: its production source, the time of production, treatments (such as purification), and the way of transportation. Basically, what one calls natural gas is a gas mixture composed largely by high amounts of methane, and amounts of ethane, propane, n&i-butane, and n&i-pentane. Among these chemical compounds, some traces of non-hydrocarbons components such as hydrogen, carbon-dioxide, hydrogen-sulfide, arsenic, nitrogen, water and helium can also be found. Varying ratios of these combinations can result in significant alterations in the natural gas properties, like viscosity, density, phase envelope, critical properties, and the caloric value [19].

2.2 Density and viscosity of a blend mix

Density of gas mixtures is an important notion with regard to hydrogen blending, a.o. because in some European countries natural gas is offered on the market based on density metering on top of the traditional mass flow metering, whereby gas density is commonly understood as the mass of the gas divided by the volume at a specific temperature and pressure [20]. Research on the impact of blending hydrogen into the 'typical natural gas mixture' shows that an increase in the hydrogen content decreases the density of the typical natural gas mixture. The lowest mixture density records at 10% H_2 a value of 51.8146 kg/m^3 corresponding with a -11.7766% deviation from the typical natural gas density. To better understand the consequences of this behavior, we refer to sections **Error! Reference source not found.** and **Error! Reference source not found.** below.

Several studies confirm the commonly accepted notion that adding hydrogen to natural gas lowers the relative density of the final mixture [20] [21] [22] [23]. By analyzing the impact on several different gas fields, [21] concluded that the relative density decreases almost linearly with the injection of hydrogen, with the exception of fields with higher concentrations of hydrogen sulfide in the natural gas.

2.3 Pressure losses

Another important factor related to the density and viscosity of a gas mixture is pressure loss, which is an inherent aspect of any transport of gases via a pipeline system. Due to the friction between the inner surface of pipelines and the gas molecules transported, the stream is bound to lose momentum. At the transmission level, boosting stations are set in place in order to compensate for these losses and sustain the desirable operating pressure to meet the end point specifications. This process comes, however, at a hefty energy consumption, i.e. around 3%-5% of natural gas is used as fuel in the compressors [20]. Because lighter elements increase pressure losses more than denser components

[20], an increase in the hydrogen content in the natural gas will generally elevate the pressure drop over the pipeline. The authors of [14] obtained a 5.38 % deviation from a typical natural gas mixture attributed to a 10% added hydrogen concentration, while the deviation amounted 0.69% when the hydrogen content was 0.2% only.

Ali et al. [20] pointed out that their most remarkable finding was that the viscosity of the gas mixture increases with a temperature rise at low and medium pressures, whereas at temperature rise under high pressures the viscosity of the gas decreases to approach the liquid viscosity behavior. The presence of hydrogen at concentrations below 2% in the natural gas mixture may increase viscosity of the blend, whereas at concentrations above 2% it lowers its viscosity. Because high viscosity results in higher pressure losses, lower hydrogen concentrations than 2% therefore have this backdrop.

2.4 Two-phase flow

Two-phase pipe flow is the simultaneous flow of a gas (or vapor) and a liquid, exhibiting different physical properties, through the same pipe. Being able to predict the fluid physical properties and pressure drop in a two-phase pipe flow is of vast importance during the design and operational stages in all applications to ensure that the fluid does not deviate from its operational envelope and thus causes damages to persons or installations.

The physical properties of two-phase fluids are not constant or uniform throughout the piping system, and flow-induced pressure drops can cause considerable changes in the magnitude of one phase compared to the other. For instance, some of the liquid can evaporate (flash) due to pressure drop across pipelines or an orifice, resulting in an increase in gas/vapor. There are also a number of disadvantages to two-phase flows. Compared to single-phase pipe flows they typically have a higher pressure drop, and may develop flow instabilities that result in pressure surges and vibrations. Incorrectly designed two-phase systems can also trap the vapor phase against surfaces resulting in inadequate cooling or energy transfer, and many flow components such as pumps and flow meters may also not function properly in two-phase flows [24].

To avoid a two-phase flow, the natural gas mixture flowing in the transmission pipeline should be above its critical temperature and pressure. The results from Ali et al. [20] show that the presence of hydrogen in the natural gas mixture elevates its critical pressure while decreasing its critical temperature. Moreover, the findings reveal that the presence of hydrogen even in low concentration can change the phase envelope of the natural gas mixture to a significant extent. This phase envelope projects the pressure and the temperature of the phase diagram determining whether the gas can be one phase or two phases at a specified temperature and pressure.

2.5 Heating Value

The high-heating value (HHV) of hydrogen amounts to 13 MJ/Nm3, while that of natural gas is almost 40 MJ/Nm3 [25]. This means that the amount of hydrogen to be delivered needs to be about three times that of natural gas to meet the same energy demand. Thus, injecting hydrogen in natural gas decreases the energy delivered – when compared at constant volumetric flow rate. On the other hand, hydrogen’s lower-heating value (LHV) is also lower than that of natural gas, so increasing the hydrogen concentration also decreases the mixture's lower-heating value [21].

The lowering of the heating value due to the injection of hydrogen in natural gas generally leads to a Wobbe index decrease as well. The Wobbe index is defined as a measure of the interchangeability of fuel gases and their relative ability to deliver energy. So, on the basis of previous research [22] [23], it is clear that the injection of hydrogen lowers the Wobbe index, but only up to a certain proportion. From that limit onwards the Wobbe index instead increases with increased hydrogen content. In other words, there is a minimum value of the Wobbe index, which usually occurs at hydrogen addition higher than 60%-70 vol%. Results from [22] [21] show that amounts of hydrogen in the order of 10 vol%, reduce the mixture's low-Wobbe and high-Wobbe index by 2.4% and 2.2 %, respectively.

The current limits of the Wobbe index for the Dutch gas distribution network of 43.46 and 44.41 MJ/m_n^3 restrain the addition of hydrogen. From the maximum value of the Wobbe index, it is possible to add up to about 10 vol% hydrogen at most to remain within the Wobbe band. This means that hydrogen admixture to somewhat higher admixture contents - of 8 vol% or higher - is only possible in the current situation with an extension of the Wobble bands within the Ministerial Regulation on Gas Quality. Above all, suppliers and manufacturers of gas appliances will have to declare the suitability of their products for the use of a specified percentage of hydrogen. In addition to the Ministerial Regulation on Gas Quality [3], other regulations, such as the gas codes and various NEN-standards[3], must be adjusted to allow more than 0.5 vol% hydrogen distribution [26].

A gas chromatograph (GC), which is used to measure the composition of the gas for the monitoring of the gas quality and for the allocation of the calorific value to the connected parties and their settlement, must be equipped with a column and detector that can detect hydrogen measured. Many of the current GCs now used for gas quality measurement do, however, not have a column for measuring hydrogen [26].

3. Impact on the materials of the transmission and distribution networks

3.1 Existing Dutch infrastructure

NOGAT[4] currently operates one of the major offshore gas transport lines. It consists of approximately 264 kilometers of pipe and transports approximately 6 billion Nm^3 of gas per year. Through a gas treatment plant in Den Helder, it connects many offshore platforms to the Dutch mainland grid. Its pipes are almost entirely made of iron, with a steel grade of STE 415.7TM. There are three different sizes used: 36, 24, and 16 inch. The main trunk line has a 36 inch outer diameter and a wall thickness of 17.8 mm [27].

	STE 415.7TM [%]	(T)STE 355 [%]	L415 [%]
Mn	1.63	1.55	1.30
C	0.007	0.18	0.28
P	0.01	0.03	0.03
S	0.005	0.03	0.03
Nb + Ti + V	0.134	0.12	0.15
Si	0.22	0.50	-
Cr	0.11	0.30	-
Cu	0.013	0.20	-
Al	0.008	0.02	-
Mo	0.228	-	-
Ni	0.011	-	-
N	0.008	-	-

Table 1 - STE 415.7TM, L415 and (T)Ste 355 grade steel chemical composition in mass percentage [27].

Gasunie operates the Dutch onshore gas transport network. It consists of 12,000 kilometers of transport pipelines, as well as the required connection points, compressors, and mixing stations. The

[3] NEN, the Royal Netherlands Standardization Institute Foundation https://www.nen.nl/
[4] NOGAT B.V. is the owner and operator of the pipeline system NOGAT. It transports gas produced on the Danish, German and Dutch part of the continental shelf to the Dutch market. https://www.nogat.nl/

transportation network is split into two sections: the main transport system (HTL) and the regional transport system (RTL). The HTL is linked to gas producers, import points, significant domestic end users (such as power plants and industries), international transmission operators, storage facilities, and, of course, the RTL, into which it feeds. The piping is made of steel grade L415, and the flange connections are made of steel grade (T)Ste 355 [27]. The material's composition is shown in Table 1.

The RTL is linked to the grid of regional distribution system operators (DSOs), smaller power plants, and industrial facilities. The distribution grid is divided into two sections: the high pressure distribution grid (HDD) and the low pressure distribution grid (LDD). It consists of approximately 130,000 km of pipes, 60% of which are made of PVC [24, p. 10].

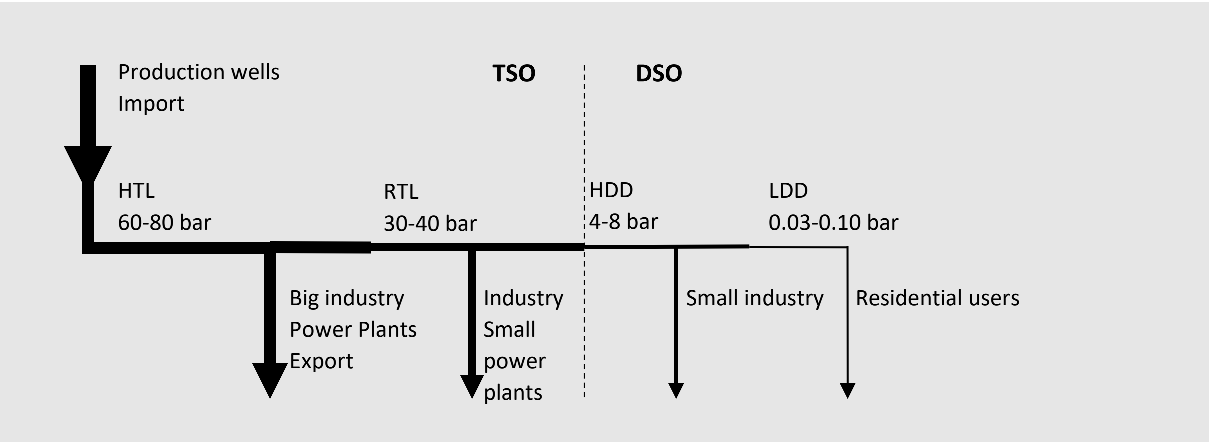

Figure 1 - Overview Dutch onshore gas grid [27]

A recent study [1] conducted by the HSE's Research and Science Centre[5] under contract to Cadent and Northern Gas Networks in the UK, tested a series of materials present in a typical distribution grid to investigate their possible reactions in the presence of natural gas and hydrogen mixtures. Its conclusion was that all the materials were acceptable for use within a blended natural gas/hydrogen gas stream within the range of 0-20 vol% hydrogen and 0-2 barg operating pressure.

Furthermore, their experimental work concluded that "metallic materials showed no significant deterioration in mechanical (tensile) properties" while "polymeric materials showed no deterioration to efficiency of squeeze-off collar electrofusion"[6].

3.2 Metallic materials

Hydrogen Embrittlement (HE) and Hydrogen Induced Cracking (HIC)

Hydrogen Embrittlement (HE) is a process resulting in a decrease of the toughness or ductility of a metal due to the presence of atomic hydrogen. With a tensile stress or stress-intensity factor exceeding a specific threshold, the atomic hydrogen interacts with the metal to induce subcritical crack growth leading to fracture.

HE occurs when metals become brittle as a result of the introduction and diffusion of hydrogen into the material. The degree of HE is influenced both by the amount of hydrogen absorbed and the microstructure of the material. Microstructures bestowing high strength, often monitored by hardness level, or having specific distributions of grain boundary particles or inclusions, can show increased susceptibility to embrittlement. This phenomenon usually becomes significant when it leads to cracking that will happen when sufficient stress is applied to a hydrogen-embrittled object. Such stress

[5] Laboratory for biological monitoring of occupational exposure in the UK (https://www.hse.gov.uk/research/)
[6] Under pressure conditions representative of the network (up to 2 barg), in 100% hydrogen, 20% hydrogen in methane, and 100% methane.

states can be caused both by the presence of residual stresses associated with fabrication operations such as forming and welding, or by applied service stresses. The severity of hydrogen embrittlement is also a function of temperature: most metals are relatively immune to hydrogen embrittlement above approximately 150°C [28].

When higher concentrations of hydrogen atoms continue to be absorbed after some earlier HE, the probability may increase of recombination reactions of some of the atoms. This may lead to the formation of molecular hydrogen causing localized areas of increased gas pressure. This in turn can result in a mechanical failure, a process usually referred to as Hydrogen Induced Cracking (HIC)) [1].

According to Birkitt et al. [1] the main effects of HE and HIC are:
1) loss of ductility and reduction in yield strength and ultimately tensile strength;
2) cracking within the body of a material; and
3) blistering on the surface of materials (caused by rapid recombination of hydrogen atoms close to the surface boundary of the metal and increasing pressure beyond the material yield strength).

Given the potential consequences of a crack or deformation in a pipeline system due to either HE or HIC, many researchers have focused on better understanding this potential impact of hydrogen blending and the plausibility of such effects under a myriad of testing conditions [29] [1] [30]. For conditions reflecting the most common materials and operating characteristics, almost all the studies tend to conclude that no significant changes in the tensile properties of metals (low strength steel e.g. API5L gr B., cast iron, copper, yellow brass) can be observed when exposed to gas mixtures up to a 20 vol% hydrogen blend. In addition they conclude that for non-metallic materials, such as medium density polyethylene (PE80), hydrogen absorption does not affect subsequent squeeze-off or electrofusion joining of pipework [1]. No research was found that looks specifically in the differences between laminar and nodular cast iron, which are used both in the Dutch regional distribution grids. Similarly, the effects on asbestos cement distribution pipelines are not seen in research.

The study [31] performed on low-carbon steel and natural gas/hydrogen mixtures of 10 vol%, 20 vol% and 30 vol% hydrogen content respectively at 4 bar and room temperature, shows a significant acceleration of the Fatigue Crack Growth Rate (FCGR) for natural gas/hydrogen mixtures, compared to what happens in pure nitrogen, natural gas, and even hydrogen gas conditions. They argue that the coupling effect of carbon dioxide and hydrogen on the material can explain why mixtures of natural gas and hydrogen enhance HE for low carbon steel.

A TNO report in collaboration with the University of Amsterdam [27], expresses concerns with steels, nickel-based alloys, metastable stainless steels and titanium alloys, given that they are most prone to hydrogen embrittlement. The report shows that both the pipe and flange used in a compressor station in the HTL contained titanium (< 0.15% and < 0.12%, respectively), with fittings such as flanges also containing a fair bit of nickel (0.30%). On the other hand, the report indicates that aluminium and aluminium alloys showed to be one of the most resistant metals to embrittlement.

For steel, stainless steel and cast iron, which is typically used in the gas distribution grid, [1] [32] [33] conclude that in practice HE does not occur. They found the deterioration of some mechanical properties to be minor and therefore insignificant. Copper, brass and aluminium also do not appear to be affected by hydrogen, so they are suitable for transporting hydrogen.

3.3 Polymeric and elastomeric materials

Distribution networks vary in their utilisation of plastic materials throughout their systems. Nonetheless, the vast majority can be narrowed down to: the three generations of Polyethylene (PE), rigid and impact resistant Polyvinyl chloride (PVC), Nitrile and Styrene-butadiene (NBR and SBR) rubbers, and Polyoxymethylene (POM) used in precision parts requiring high stiffness and low friction.

Even though data generally suggests that there is no equivalent to HE in polymeric materials [34] [35] [32], the different tests performed in the 2020 study [1] of a representative UK distribution network did show that gas permeation rates were generally higher than for metallic materials. According to [33], hydrogen permeates five times faster through plastic than methane. In addition, plastics can be attacked by reacting chemically with hydrogen or by changing their physical properties through, for example, absorption or swelling. Nonetheless, the study found that both effects are negligible under the conditions that apply in the Dutch distribution networks and do not lead to a significant degradation or increase of the safety risk.

Moreover, none of the reviewed literature expressed any concern about long-term exposure of the polymeric and elastomeric materials currently found in gas networks.

3.4 Existing equipment

DNV GL in their 2017 report [36] identified the following tolerances regarding hydrogen volumetric shares, that different equipment can withstand:

- For steel tanks in natural gas cars, UNECE Regulation No. 110[7] states that the maximum allowable amount of hydrogen is 2 vol%.
- For gas turbines, the majority of the currently installed gas turbines are designed for hydrogen fractions of 1 vol% or less. This can probably be increased to 5 vol% with minor adjustments to the turbines. For new turbines, this fraction could go up to 15 vol%.
- For gas engines it is generally recommended to limit the hydrogen concentration to 2 vol%. Engines with advanced engine management systems could handle higher concentrations of up to 10 vol% if the methane number of the natural gas/hydrogen mixture remains above the specified minimum.

Furthermore, the following measures for adapting equipment and components of the gas distribution network to cope with different shares of hydrogen are outlined in Table 2 below, which was adapted from the 2020 Kiwa's report commissioned by Netbeheer Nederland "De impact van het bijmengen van waterstof op het gasdistributienet en de gebruiksapparatuur" [34].

Table 2 - Measures for the transition from 1to 100 vol% hydrogen admixture for the gas (adapted from [26])

Max. vol% H_2 →	**1**	**2**	**3**	**8**	**10**	**20**	**100**
Measure ↓							
Adjustment of MR Gas Quality	!	!	!	!	!	!	!
Adjusting standards and work instructions	!	!	!	!	!	!	!
Agreements with hydrogen injector	!	!	!	!	!	!	!
Checking the suitability of appliances for small consumers	!	!	!	!	!	!	!
Checking the suitability of CNG tanks		!	!	!	!	!	!
Checking gas turbines for suitability			!	!	!	!	

[7] Regulation No 110 of the Economic Commission for Europe of the United Nations (UN / ECE) - Uniform provisions concerning the approval of: I. Specific parts of motor vehicles using compressed natural gas (CNG) and/or liquefied natural gas (LNG) as fuel, II. Vehicles with regard to the installation of specific components of an approved type for the use of compressed natural gas (CNG) and/or liquefied natural gas (LNG) as fuel [2015/999].

Eventual separation installation			!	!	!	!	
Set up a settlement system			!	!	!	!	
Check methane number				!	!	!	
Check suitability of PPE and tools				!	!	!	
Check and replace unsuitable equipment from before 1-1-2017				!	!	!	
Check suitability of valves and gas pressure regulation system					!	!	
Check suitability of leak detection					!	!	
Adjusting unsuitable industrial burners					!	!	
Suitable gas meters						!	
Gas engine adaptation							!
Adapt networks (additional costs; see report Toekomstbestendige Gasdistributienetten **[33]**)							!
Purchase of hydrogen appliances							!
Finding out what distribution quality hydrogen is needed							!
Suitable gas meters							!
New odorant (if so decided) or H_2 detection							!

The exclamation mark (!) means that some measures should be taken into account when a certain level of hydrogen is blended into natural gas streams

4. Safety and points of attention

The 2018 study of Kiwa [33] presented the main safety concerns when dealing with hydrogen in the distribution grid. These are discussed below:

Odorization

Hydrogen, like natural gas, is an almost odorless substance. In order to be able to use a comparable marker, an odorant must also be added to hydrogen. The current odorant for natural gas is THT that contains sulfur and – if used as an odorant in hydrogen distribution – therefore may hinder the normal operation of fuel cells. The presence of sulfur in concentrations higher than 0.1 ppm limits the life of the catalytic converters in fuel cells. However, sulfur-free odorants are also available and not an expensive switch to adapt.

Excavation damage

In the distribution of hydrogen, the risks of excavation damages are a point of attention: due to the lower ignition energy of hydrogen (0.019 mJ) than of natural gas (0.2 mJ), hydrogen can ignite in the presence of a smaller ignition source (spark).

In addition, a hydrogen/air mixture has a wider explosion limit. This means that the chance, for example in the event of excavation damage, that a gas cloud will ignite or explode is larger than in case of a natural gas leak.

On the other hand, under comparable conditions, hydrogen dissipates much faster than natural gas (due to the large difference in density) making the ignitable gas cloud much smaller.

Permeation risk

Hydrogen permeates through plastic five times faster than methane. In practice this only causes a problem with longer casing pipes (indication: length more than 5 meters), not with normal wall ducts. Crawl spaces, where a comparable permeation / ventilation situation prevails, are in principle sufficiently ventilated.

Leakage from connections

Leakage from connections (both outside and inside) poses a risk to all piping systems that distribute combustible gas. In small gap leaks, the flow is laminar at distribution pressures. This means that the volume flow, at a given pressure, is inversely proportional to the dynamic viscosity of the gas. The viscosity of hydrogen is 0.88 x 10^{-5} Pa-s (at 20 °C). That of methane is about 25% higher: 1.10 x 10^{-5} Pa-s (at 20 °C).

The consequence is that a leaking connection in a hydrogen network generates an about 25% higher volume flow than the same leaking connection in a natural gas network. Such a difference is, however, hardly significant from a safety point of view, the more so since the energy content of the hydrogen leak is more than half smaller than that of a natural gas leak. A remaining point of safety attention is the lower ignition energy and the larger concentration range of the combustible mixture than of natural gas only. The expert opinion on this so far is, however, that the impact of these aspects on safety risks is negligible.

5. Policy & Legal Framework

In the absence of a common and binding hydrogen limit requirement at EU level, it is up to the Member States the determine what limit is considered safe and feasible [2]. This is why the authorized concentrations vary significantly from one country to the other. For instance, the current maximum accepted level of hydrogen in the natural gas stream[8] in the Netherlands is set at ≤0.02 mol% in the HTL network and ≤0.5 mol% in the RTL and RNB net[9] [3], while in Germany it is 10 mol% [4]. With regard to the conditions of access to the gas grid of 'green' or 'renewable' hydrogen, the 2018 successor to the 2009 Renewable Energy Directive (RED), known as REDII, provides, pursuant to Article 20(2), that Member States must require both TSOs and DSOs to publish technical rules for network connections, including requirements for gas quality, odorization and pressure. Nonetheless, since TSOs and DSOs are largely regulated by the Member States themselves, the issue of regulating the maximum hydrogen content in the natural gas streams remains at the discretion of individual Member States.

The Gas for Climate Consortium[10] has recently released a policy paper [37] that offers an analysis-based argument as to why an 11% renewable gas blending goal is required to achieve the EU's climate ambition to reduce GHG emissions with 55% by 2030. The same paper follows last year's Gas for Climate's Gas Decarbonization Pathways 2020-2050 study [10], which illustrates what additional policy steps are required to scale up the production of biomethane and green and blue hydrogen to reach the EU climate goals.

The consortium calls on the European Commission to adopt a renewable gas blending target of 11% of consumed gas with sub-targets of 3% for renewable hydrogen and of 8% for biomethane in RED II as

[8] G-gas when fed into a connection.
[9] *RNB network:* gas transport network that is not managed by the network operator of the national gas transport network.
[10] 'Gas for Climate: a path to 2050' is a group of ten leading European gas transport companies (Enagás, Energinet, Fluxys, Gasunie, GRTgaz, ONTRAS, Open Grid Europe, Snam, Swedegas, and Teréga) and two renewable gas industry associations (Consorzio Italiano Biogas and European Biogas Association).

soon as possible. The paper defines all gas consumption as: final gas consumption, gas for power generation, and gas for feedstock.

Netherlands

In the National Policy Paper for the Netherlands [38], issued under the scope of the HyLAW project it is emphasized that technical challenges and changes in regulations, codes and standards for the gas value chain need to be addressed in order to allow (the injection of) hydrogen for use through the gas grid.

The reviewed literature showed that with certain adjustments the gas grid is technically equipped for the transportation and distribution of hydrogen. Nevertheless, in the Netherlands it is legally still not allowed to inject, transport or distribute any significant amount of hydrogen through the Dutch gas grid.

The HyLAW national paper for the Netherlands [38], identifies the following policy recommendations to allow for a faster adoption of hydrogen into the natural gas:

1. It is suggested to build opportunities for network operators to enhance the non-exclusive position in the field of hydrogen by improving and/or clarifying possibilities of current instruments, such as making it possible to have exemptions for specific hydrogen AMvB experiments despite the current non indelibility of the legal duties.
2. Renewing and combining the existing (old) electricity and gas laws into a new Energy Law. They advocate for a new Energy law 1.0 in which TSOs, DSOs, e-TSOs and e-DSOs are granted with more legal possibilities to produce, store, trade and distribute hydrogen and electricity, foreseeing in this way a more efficient manner to serve the energy markets. It acknowledges the fact that this implies a restructuring of not only Dutch but also European legislation/regulation, Network Codes, etc. The recommendation also bears words of warning about the possibility of far-reaching implications that should first be carefully weighed, before allowing TSOs to produce and trade hydrogen and electricity.
3. Amendment of the MD Gas Quality; incorporate increasing percentages of hydrogen injection taking into consideration delivery specifications
4. Suggest that the gas infrastructure should be viewed as more than a public liability, but also as a potentially enabler for public-private ownership, by limiting the potential negative effects of competition-risk and making the infrastructure such that it contributes to the public interest – by assuring security of supply and sustainability.

Furthermore, the Dutch government through the Regulation of the Minister of Economic Affairs and Climate of 12 September 2018 amending the Regulation on gas quality [39], stated that more hydrogen may be used in the energy supply in the future to make it more sustainable and to reduce natural gas consumption. As a result, it is preferable to already provide some space for this. The network operator of the national gas transport network's restriction on the system of regional transport pipelines to 0.02 mol% hydrogen is an impediment to this. Furthermore, gas flows from the RNB to the RTL as a result of the construction of a so-called green gas booster, may contain a slightly higher percentage of hydrogen. This is a limitation of the green gas input when the RNB and RTL have mutually different rules for accepted percentages of hydrogen. So, it seems that the accepted percentage for the RTL must be adjusted.

6. Economics of blending hydrogen into the transmission and distribution networks

6.1 Costs of grid adaptions

The International Energy Agency, in its 2019 report "The Future of Hydrogen" [12] draws attention to the advantages and disadvantages of the main transmission and distribution options when considering blending hydrogen into the natural gas grid. It emphasizes that the most economical approach will vary significantly according to geography, distance, scale and the required end use of the hydrogen.

Blending hydrogen into the natural gas grid would prevent the lofty capital investment of building and installing new dedicated infrastructure. While the latter option may increase the price end users would pay for their natural gas, it would also contribute to CO_2 emissions reductions. The hurdle that this option faces is heavily linked with the existing national regulations on hydrogen in natural gas and the harmonization of cross-border regulations [12].

Following the same report, a series of challenges are to be confronted when exploring the potential of blending hydrogen into the natural gas grid, including but not limited to the following aspects:

- The hydrogen energy density is about one third of that of natural gas and thus the blend decreases the energy content of the supplied gas: A 3% hydrogen blend in a natural gas delivery pipeline will minimize the energy transported by the pipeline by about 2%. This characteristic may have economic impacts that can complicate market adoption, given that end consumers may want to use higher concentrations of gas to satisfy their energy needs. For instance, industrial processes that depend on the carbon content of natural gas (e.g. for metal treatment) will have to use higher quantities of gas if blended with hydrogen.
- The upper cap for hydrogen blending in the grid relies on the equipment connected to it, and this will have to be assessed on a case-by-case basis. In principle, the device with the lowest tolerance factor will determine the overall network tolerance.

Several existing components along the natural gas value chain would be able to cope with high concentrations of hydrogen blended into the natural has streams. Among these, polyethylene distribution pipelines can handle up to 100% hydrogen, and in the same way, salt caverns can store pure hydrogen instead of natural gas without the need for improvements. Furthermore, various gas heating and cooking appliances in Europe are approved for up to 23% hydrogen, but the implications of this standard over many years of usage remain uncertain [40].

Conversely, there are other components of the current supply chain of natural gas that cannot withstand large amounts of blended hydrogen. The biggest constraints are expected to show up in the industrial sector, where some industrial processes rely on strict and narrow gas characteristics, as well as in CNG stations, where the tolerance for CNG tanks may be as low as 0.1% depending on the humidity of the natural gas (United Nations, 2014). Other critical examples can be found in the control systems and seals of gas turbines, which are not designed for handling hydrogen and can typically tolerate less than 5% blended hydrogen [12]. Similarly, installed gas engines present a maximum tolerance of 2%. The solution to cope with these issues could range from minor adaptations to completely replacing the equipment for new ones, depending on the level of hydrogen concentrations.

All in all, the 2019 IEA report [12] foresees that hydrogen blending would likely increase transport costs marginally by around € 0.25/kgH_2 to € 0.34/kgH_2 [11]. This increase is due to the need for injection stations on transmission and distribution systems, as well as to higher operating costs.

In the United Kingdom, it is estimated that the cost implications to retrofit the gas network to supply pure hydrogen to buildings would be around € 0.5/kgH_2 [41]. The cost of converting pipework and other (non-boiler) gas appliances is included in these forecasts. Such conversions may not be required if pipework in consumer premises can safely carry hydrogen without needing to be upgraded, and if

[11] Considering USD/EUR conversion of €0.8412 on March 8th, 2021.

gas appliances in the homes, such as cookers or fires, can be converted to electric equivalents or made 'hydrogen-ready' in anticipation of a hydrogen conversion.

Moreover, the need for seasonal hydrogen storage is discussed. According to system modeling, substantial investment in salt cavern storage may be needed in both the Full Hydrogen and Hybrid Hydrogen scenario. Due to hydrogen's lower energy density, additional storage capacity would be required to meet heat demand, costing an additional € 0.42/kgH2 [12].

The IEA finally suggests that improved understanding of the need for, and operating characteristics of, geological hydrogen storage could result in substantial cost savings.

6.2 Cost difference in gases

FCH JU in its 2020 report ; 'Opportunities for Hydrogen Energy Technologies considering the National Energy & Climate Plans' [42] indicates that the average green hydrogen delivery costs at EU28 level by 2030 for all sectors range from 4.6 to 4.9 EUR/kg_{H2}. For the Netherlands, the expected renewable hydrogen delivery costs excluding end-user related costs are found to be in the range of 4.55 – 5.2 EUR/kg_{H2}. These costs are calculated as total annual costs excluding end user costs divided by the overall consumption of renewable hydrogen. Hence, they correspond to green hydrogen costs without any margins or taxes that are paid by end-users, such as FCEV refueling station charges, or industrial consumer charges upon delivery at sites [42].

The same study shows that the total expenditure (1.4–3.9 billion EUR) and annual costs (0.3–1.1 billion EUR) by 2030 for blue hydrogen production in the Netherlands are lower than for green hydrogen. This difference is primarily due to the low assumed natural gas prices of 25 EUR/MWh and the low assumed CCS costs of around 18 EUR/t_{CO2}. As a result, the average low-carbon delivery cost (excluding end user equipment) ranges between 2.4 and 2.2 EUR/kg_{H2}.

Furthermore, the authors of a 2019 policy paper from the University of Groningen's Centre of Economics Research (CEER) [43] point out, among their conclusions, that grey hydrogen is far more attractive than green hydrogen at market price levels of natural gas and electricity seen over the last decade. To make green more attractive than grey at the current gas price of about 20 euro/MWh, the electricity price should be less than half of the current electricity price (which is around 45 euro/MWh). They extend the same statement for blue hydrogen, signifying that blue hydrogen is much more cost-effective than green hydrogen at the moment. When the price of CO_2 exceeds 30 EUR/t_{CO2}, blue hydrogen tends to be much more attractive than SMR-produced hydrogen without CCS (the so-called grey hydrogen). With respect to physically blending they argue that economically it will not be viable to blend more expensive gases into the cheaper natural gas if the (green or low carbon) hydrogen producer will receive the average price paid for gas, which is obviously lower than the hydrogen production costs.

In their economic modelling analysis of Great-Britain, Quarton & Samsatli [44] found that hydrogen blends of 10-17% can be reached by providing a Feed-in-Tariff of £30-50/MWh. However, mainly blue hydrogen would be injected due to its lower production costs. Similarly, investigations of the Dutch government state that the difference in value could be a hurdle to inject hydrogen physically into the natural gas grid [45], and therefore that physical blending would not happen without any support and/or virtual certification scheme. Finally, compared to the fossil alternatives, green and low carbon hydrogen have to compete with very low natural gas prices in the grid (~€1.68/kg) compared to higher revenues (respectively ~€2/kg and ~€5.4/kg) in the industry and mobility sector [46]. In other words, in the first phase and in the absence of additional support producers of renewable and/or low carbon hydrogen can probably receive more revenues in other sectors than by just injecting the hydrogen into the natural gas grid.

7. Pilots and experiences

As was argued already, the permitted amounts of hydrogen blended into the natural gas grid differ dramatically between EU member states, also due to the fact that previously the likelihood of gas grids conveying hydrogen mixtures was considered small (for an overview, see Table 3) [4].

Table 3 - Maximum H2 concentration allowed in the gas grid

Belgium [47]	Italy [40]	Germany [48]	France [49]	Spain [50]	Netherlands [3]	UK [51]
<0.1% mol (injection up to 2% vol could be considered)	<2-3% vol (0.5% vol for bio-methane)	<10% mol (<2% mol-for CNG tanks)	6% mol	5% mol	0.02% mol (There are plans to raise to 0.5% mol)	0.1% mol

More recently, attention for hydrogen in the gas blend has increased rapidly, which explains the growing number of hydrogen blending testing and demonstration pilots; see also below.

Ameland

The 2012 project 'Hydrogen in natural gas on Ameland' [52] demonstrated blending of up to 20% green hydrogen in the Dutch natural gas distribution network.

The project showed that even blending hydrogen up to 20% with natural gas had no impact on infrastructure materials or indoor installations. Worth noticing, is that this conclusion assumes not current but new devices including domestic boilers and stoves.

The project was carried out during a test period of 4 years while the lifespan of the system components covers on average some 50 years. The conclusion therefore was that the test just suggested that degradation of the materials in the presence of 20% hydrogen blend with natural gas is unlikely.

Hørsholm, Denmark

The 2010 report [32] titled 'Field test of hydrogen in the natural gas grid' summarizes the results obtained by the Danish Gas Technology Centre on a small-scale pilot grid. The test aim was to better understand the compatibility between long-term natural gas grid exposure and transportation of hydrogen. The test program covered steel pipes from the Danish gas transmission grid and polymer pipes from the Danish and Swedish gas distribution grid.

The results of the polymer pipe tests showed no degradations of any kind related to the continuous hydrogen exposure for more than 4 years.

Similarly, the steel pipes tests showed that even with pipes sections containing field girth welds made in the early 1980s and exposed to pressure variations twice the maximum daily swing in the Danish transmission grid (during 80 years of operation), hydrogen is compatible with the usual pressure swing in the transmission grid.

GRHYD [53]

In 2014, with the support of the French government, a project was launched conducted by ENGIE by a consortium of industrial partners[12]. It aimed to convert surplus energy generated from renewable sources into hydrogen, which was then blended with natural gas for a broad range of applications including space and water heating and as a fuel.

A 5-year trial was kicked off in 2016 devoted to testing the injection of hydrogen into the natural gas distribution network of a new neighbourhood and a refuelling station for buses. The quantity of hydrogen mixed with the natural gas varied depending on the availability of green electricity while remaining below 20% in volume in order to respect safety regulations. The project is up-and-running.

HyDeploy [54]

In a live demonstration of hydrogen to be used in homes, this project aims to test the safety and greening properties of blending up to 20% vol of hydrogen with natural gas. Among its goals is to demonstrate that inhabitants do not need to modify their cooking and heating appliances when taking the blend, and in fact do not even notice the difference.

In November 2019, the UK Health & Safety Executive gave permission to run a live test of blended hydrogen and natural gas on a part of the private gas network in Staffordshire. In next phases, the project will move towards larger demonstrations on public networks.

DVGW [55]

Below there is a brief description of DVGW's most relevant projects related to hydrogen transportation and its grid impact:

H2 gas grid compendium

Project completion: Dec.-2020 (no public results have been found)

Objective: Evaluation of the hydrogen compatibility (to withstand 20% vol H_2 admix) with components and products of gas transmission and distribution grids with respect to materials and functioning, and integration of the results into the DVGW Set of Rules.

Approach and Results

- Within the project, a book of facts is compiled reflecting the current level of knowledge on how up to 100 per cent hydrogen may impact the gas transmission and distribution grids.
- Gas infrastructure components and products will be described in the form of a one- or two-page briefing including an evaluation of the hydrogen tolerance of each component or product.

H2 in the gas grid · Conversion of natural gas pipelines

Project completion: May-2021

Objective: Clarification of technical issues related to gas quality requirements, and elaboration of recommendations for action regarding the conversion of natural gas grids to include hydrogen.

HIGGS · Hydrogen in gas grids

Project completion: Dec.-2022

[12] Twelve industrial partners are taking part in the GRHYD demonstration project alongside ENGIE. Companies include: GrDF, GNVERT, AREVA Hydrogen and Energy Storage, CEA, McPhy Energy, INERIS, CETIAT and CETH2.

<u>Objective</u>: Determining the hydrogen compatibility of the high-pressure gas transmission grid and compilation of data on pan-European rules, standards and certificates for hydrogen blends with natural gas at volumes up to 100 per cent.

H2-20 · Field test injecting 20% by volume of hydrogen into the distribution grid

<u>Project completion</u>: July-2023

<u>Objective</u>: Injection of up to 20 per cent by volume of hydrogen into an existing distribution grid supplying about 400 domestic and commercial customers, and deriving recommendations for action.

H2Net&Engines · Hydrogen in the gas grid and in gas engines

<u>Project completion</u>: Dec.-2021

<u>Objective</u>: This project studies the impact on current technologies of an altered gas mixture in the gas grid, with a special focus on internal combustion engines.

THyGA · Hydrogen/natural gas blends for gas applications

<u>Project completion</u>: Dec.-2022

<u>Objective</u>: To enable the European-wide adoption of hydrogen and natural gas blends by closing knowledge gaps regarding technical impacts on residential and commercial gas appliances.

Part II: Administrative admixing

1. Introduction

According to the European Commission [56], virtual admixing, or virtual blending, of hydrogen into the gas system refers to introducing ‘’*a share of hydrogen in the overall volume of gaseous energy carriers (i.e. methane) regardless as to whether these gases are blended physically in the same infrastructure or in separate, dedicated infrastructures*.’’ So, a decisive characteristic of any hydrogen virtual blending scheme is to have a system in place to reliably track the origin of the hydrogen entering the scheme, and subsequently exchange those entities of hydrogen that are part of the scheme on the basis of certificates guaranteeing the hydrogen origin. With respect to the latter component, the exchange of the certificates, one usually distinguishes between schemes where e.g. producers only have to prove that they introduced a specific volume of hydrogen into the gas system, or where it is instead assumed that the certificates will be freely traded on a separate open market. In the first case a so-called mass-balance tracking system is usually implemented, whereas in the second case a simpler so-called book-and-claim system typically can be applied (see also Mol and Oosterveer [44] for a more detailed description of the various tracking systems).

In this report in discussing the literature the tracking system suggested by the European Commission [56], namely a book-and-claim approach will be followed, because it enables certificate trading independently from the infrastructure system such as the natural gas pipeline infrastructure used for hydrogen transport. Obviously, a virtual admixing system implies some physical admixing regime, but precisely when physical blending and certificate trading are decoupled, it will be easier to overcome most of the technical, economic and legislative challenges described in Part I of this report, because, when feasible, the most suitable transport- and storage modes and gas specifications can be used.

1.1 Voluntary and mandatory blending

When defining virtual blending schemes, a distinction between voluntary and mandatory schemes can be made. In most of the European electricity and natural gas grids, the sustainable energy carrier is injected in the same grid as the traditional (unsustainable) energy carrier. So, renewable electricity is transported via the general electricity grids, or biomethane or carbon neutral hydrogen via the natural gas grids. End-consumers can voluntarily buy certificates to proof (to whoever they like) that (a share of) their consumed energy is to be considered ‘green’, even if (they are aware that) the physical energy consumed comes from a potentially non-green source. Only when their willingness-to-pay to pay the extra certificates costs for green energy is high enough, administrative blending of green and traditional energy will take off. Mandatory blending, instead, means that (specific) energy users (e.g. energy suppliers to end-users and/or large end-users) are obliged by law to purchase ‘green’ certificates for a specific share of their energy (commodity) uptake. Often, mandatory blending schemes are referred to as ‘quota systems’, ‘obligatory target systems’ or ‘administrative blending obligation systems’.

1.2 Existing mandatory admixing quota systems

Currently various mandatory quota systems exist in various countries to stimulate the production and use of renewable energy. Firstly, since the start of this millennium several renewable electricity quota systems were implemented by countries and/or regions in Europe, USA and Australia. An overview of some, mainly European examples is given in Table 4.

Table 4: Overview of renewable electricity quota systems

Name scheme	Region	Starting year	Main target	Obligated parties	Tradable entities (certificates)
Renewable Energy Target	Australia	2001	33 TWh renewable electricity in 2020	High energy users	LGC and STC
Quota-obligation	Vlanders	2001	21.5% for renewable energy and 11.2% for CHP after 2018	Electricity suppliers, producers and large customers	GSC and CHP certificates
Renewable Obligation	United Kingdom	2002	Set yearly	Electricity suppliers	ROC
Property Rights Market*	Poland	2005	34 TWh renewable electricity in 2020	Energy users	Certificates in different 'colours'
Renewable Energy Sources Quota	Romania	2008	Depends based on maximum accepted consumer costs	Electricity suppliers and large customers	Green Electricity certificates
Norwegian-Swedish Electricity Certificate Market	Sweden and Norway	2012	28.4 TWh renewable electricity in 2020	Electricity suppliers and certain customers	Electricity certificates

Secondly, especially in the EU mandatory blending of green liquids in mobility has been introduced for over a decade now. The EU biofuels Directive (2003/30/EC) and Renewable Energy Directive (2018/2001/EU) mandated fuel suppliers that 14% of energy in fuels should be renewable by 2030. Further, a minimum of 3.5% should be filled in with 'advanced' biofuels and biogases and a maximum of 6% should be filled in with 'first generation biofuels', those categories are based on the feedstocks used to produce the biofuels[13]. These binding targets have led many EU member states to implement mandatory quota for biofuels. Those quota's differ in their detailed implementation, and have been specified on the basis of: energy content or volume; an overall biofuel target; targets for biofuel in petrol and/or diesel; and making a distinction between advanced and traditional biofuels or not [57]. Moreover, in some schemes other fuels than liquids such as electricity and hydrogen are also included to meet the fuel blending targets, or distinctions are made in the multipliers per fuel type to meet the target. As far as the Netherlands' case is concerned, a blending obligation for biofuels was introduced in 2007. The quota based on this was defined at 14% in 2020, and could be reached by cancelling three subcategories of certificates, called Renewable Fuel Entities (HBE's), namely for: advanced biofuels (HBE-G); conventional biofuels (HBE-C); and other fuels (HBE-O), including renewable electricity and Renewable Fuels of Non-Biological Origin (RFNBO, such as renewable hydrogen, all having quantified sub targets.

[13] See Annex IV in RED II 2018/2001/EU

1.3 Mandatory gas admixing quota

Although mandatory quotas have been regularly implemented to support the introduction of renewable electricity and fuels, to our knowledge no comparable schemes for renewable and/or low-carbon gases do exist nowadays. Only by 2020, such a mandatory blending scheme for gases (involving carbon-neutral or 'clean' hydrogen) has been proposed at the EU [16] [58] [59] and also the Netherlands' level [60] by various organisations. The main purpose of Part II of this report is to discuss the most relevant literature on this. This will be done on the basis of what we considered to be the main design aspects that collectively shape a mandatory blending system for gases. Table 5 provides an overview of these aspects and the various issues addressed in the literature on each of these aspects.

This part of the report, part II, will be structured as follows. In chapter 2 the reasons why mandatory blending schemes for gases are considered will be discussed, with a specific focus on the case of the Netherlands. Next in Chapter 3 the design choices of a gas blending quota system will be discussed for both producers and consumers as well as what would be required for a proper certificate trading system. Chapter 4 discusses literature on how a mandatory quota system can be integrated in the regulatory framework and how its certification scheme can be connected with other certification schemes. Chapter 5 addresses the issue how to implement a mandatory quota system, and Chapter 6 summarizes the main risks and uncertainties to be taken into account.

Table 5: Overview main questions addressed to develop a virtual blending obligation

	Main questions to develop a virtual blending obligation for hydrogen and/or green gas
General	What are the generic aspects of a blending obligation? • How to define a blending obligation? • What are generic aspects of existing blending obligations? • How does the trading system of a blending obligation work? • What critical success factors can describe success and failure of a blending obligation?
Production	What hydrogen and/or green gasses should be obligated? • How can low-carbon and green gasses be categorized and defined? • What gasses should be obligated? • Can gases or their resources be sourced internationally?
Consumption	How to determine the obligation targets? • What parties or sectors should be obligated? • Should targets be national or international? • How to set the targets over time, for different gasses and/or different parties?
Trading system	What is required for an effective trading system of a blending obligation? • What are requirements to ensure tradability, traceability, reliability, validity, and verifiability of the certificate trading system? • How should the design of: a trading system, certificate(s) and its issuing body look like?
External integration	What relations with other policies and certification initiatives should be considered? • What international policies and certification initiatives should be considered? • What national policies and certification initiatives should be considered? • What relations with other certification initiatives should be considered?

Implementation	How should a blending obligation for hydrogen and/or green gasses being implemented? • How to determine the right timing of implementation? • Are other supporting policies desirable when implementing the blending obligation? • Should the blending obligation be implemented via a top-down or bottom-up approach?
Risks	What are risks and uncertainties of a blending obligation? • What unexpected and undesirable developments can occur?

2. Discussion on a mandatory quota for green gases in the Dutch context

Various sources in the literature reflect on the role of green gases (e.g. renewable/low-carbon hydrogen and biomethane) in a future decarbonised energy and feedstock system. Most of them seem to agree that, whatever the scenario is that will unfold, in all cases green gases will play a decisive role both as an energy carrier and as a feedstock (replacing the large volumes of 'grey' hydrogen currently typically used for that purpose). To illustrate, the report 'Gas for Climate' [61] states that in a decarbonised European energy system renewable gases will still have an important role to provide:

- Storable and dispatchable renewable energy;
- Applications to decarbonise several sectors, such as build environment, heavy industry, heavy fuels for road, water and air transport;
- Cross-sectoral advantages in waste management;
- Future-proof jobs.

Also according to the formally adopted Dutch Climate Agreement [5] green hydrogen and biomethane will have an important role to play in a future decarbonised Dutch energy and feedstock system. In order to substantiate this, the government formulated the targets to establish in the Netherlands 500 MW electrolyser capacity by 2025 and 3-4 GW by 2030 [5]. At the same time the government is well aware of the business challenges of speeding up the introduction of carbon neutral hydrogen. Because the current production costs of renewable hydrogen are estimated to be around €70-€130/MWh, those of low carbon hydrogen some €37-€41/MWh and of biomethane about €50-€100/MWh (compare current natural gas costs of some €15/MWh) [62], one is well aware that large efforts need to be made to close the gaps.

This explains why the Netherlands government is currently investigating three directions for speeding up the introduction of green hydrogen [45]:

- Broadening the DEI+ and HER+ for pilots and demonstration projects of green hydrogen, and including electrolysis in the SDE++;
- Introduce integrated tenders for electrolysis and offshore wind deployment;
- Introducing mandatory administrative admixing schemes for hydrogen, and broadening the physical admixing limits at least in some parts of the gas distribution grid.

In some cases policies considered/discussed in the Netherlands towards hydrogen are combined with policies towards other green gases such as biomethane Unlike hydrogen, biomethane is already included in the SDE++ subsidy scheme, but at the current production costs this subsidy option does not generate incentives that are strong enough to roll out biomethane and/or other CO_2-neutral gases in the quantities that are targeted in the Climate Agreement [63]. That is why the government also considers to introduce three additional instruments [63]:

- A subsidy for technologies enabling to scale up the production of biomethane;
- A blending obligation for biomethane (Currently an administrative blending obligation exists for the mobility sector, but similar blending obligations could be developed for the built environment and/or industry.);

- Differentiation in taxes for gases, making the use of green gases more attractive compared to grey alternatives.

So, all in all, for both biomethane and green hydrogen (and potentially other CO_2 neutral gases) a mandatory administrative blending policy or quota is currently actively assessed and studied as an instrument to stimulate production and consumption of low-carbon or carbon neutral gases.

The main advantage of a mandatory quota for green gases is that demand for it is ensured, and the traditional chicken-and-egg problem between supply and demand resolved. Moreover, the quota guarantees that a specific decarbonisation target will be achieved, instead of, such as with subsidy schemes, being dependent on the subsidy budget and unknown market responses as is, for instance, the case for the SDE+ instrument [64]. Besides, a quota gives a clear market perspective to the stakeholders also on the longer term potentially enhancing investment, competition and innovation of and between producers of green gases [64]. The certificate market emerging from mandatory blending quota of green hydrogen could in maturing trigger the emergence of a more mature and transparent hydrogen market, something still missing nowadays [65].

Given the current state in which the blending concept now is, namely generic assessment of the concept and feasibility studies on how it could be designed in order to be introduced successfully, it seems that the main challenge is first of all to find answers on how to specify the design characteristics of such an instrument: how can it be designed such that potential risks and undesired (side)effects are avoided that may cause unforeseen societal costs and/or prevent the instrument reaching its goal [64]? Therefore, detailed design characteristics will be discussed next.

3. Design choices of mandatory gas quota schemes

3.1 General

Figure 2 provides a conceptual representation of a mandatory quota scheme for green gases including the involved parties [64]. The main element of a blending obligation is the percentage blending target, which may be based on: political motives towards greening; technical restrictions e.g. related to grid integrity; and the amount of green gasses that is expected to be available. The European fuel target as specified in RED II of 14% renewable fuels in 2030 as well as the proposed renewable gas target of 11% in 2030 suggested by Gas for Climate [59] both seem to be based on a mix of the three arguments mentioned.

Given the blending percentage determined for a specific blending scheme, such schemes are operated in various ways. It typical way functioning is to translate the blending percentage in the total number of certificates that will need to be introduced to be cancelled upon use. The number of certificates therefore depends on the amount of liquids or gases used per annum; annually the required percentage of certificates may be set to increase. For a typical green gas based blending scheme, in the first instance the certificates can be obtained by gas producers to the extent that they produce gases that have been verified as being green. Production facilities satisfying specific criteria can be accepted for the scheme by certification bodies, and when they deliver the gas with the required production data (1), the certification body issues certificates per entity of gas that is produced according to the criteria that are set to obtain the certificate (2). Subsequently, those certificates can usually be traded and sold to energy suppliers, gas consumers or traders (3) separate from the gas. By selling the certificates the gas producer will get additional revenues. The mandatory quota is set for specific parties, such as energy suppliers and/or large (industrial) gas consumers. They are obligated to cancel a certain amount of certificates per gas amount offered/consumed during a specified period in order to comply with the obligation (4). Hence, they have the choice to purchase certificates on the market, or generate their own certificates. The blending quota thus creates a guaranteed demand for green gas that is known to the market players, and is therefore expected to support investment in green gas capacities.. This stimulates innovation and the production costs of the accepted technologies [64]. To ensure serious perspective for investment, most blending schemes are designed for a long period, typically lasting (at least) 15 to 20 years [64].

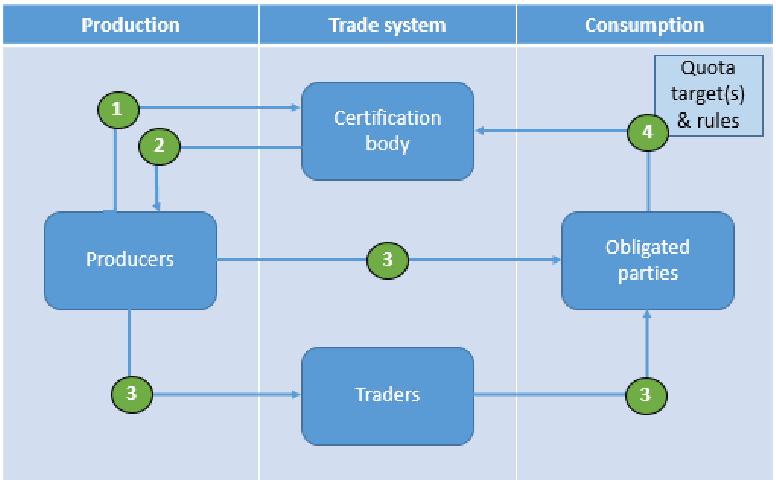

Figure 2: General overview of a mandatory quota, based on [64]

1. Producer shares required production data with certification body
2. Certification body issues the fitting amount of certificates on the account of the producer
3. Certificates can be traded between producers, traders and obligated market parties, separate from the physical energy trade
4. Based on the quota, a specific amount of certificates should be cancelled every period by the obligated market parties

Critical success factors

Several factors collectively define if a blending scheme can work successfully:

- <u>Societal costs of the system</u>
  Ideally blending generates a greening target against lower societal costs than any other set of instruments to achieve the same target [64]. In practice, however, it is impossible to compare the effectiveness and efficiency of different instruments in a straightforward manner. Moraga González et al. [66], for instance, summarize seven principles for optimal economic regulation of renewable gases and hydrogen, including allocative efficiency, dynamic efficiency, no market power, no information asymmetry, no hold-up, fair distribution and cost-effectiveness, in an effort to structure a comparison between instruments.
  In practice therefore all kind of criteria are used to assess instruments such as blending quota. The Dutch government for instance, also took windfall profits and the energy bill for consumers into account in their assessment [64]. Other criteria used in practise are that the industry is able to meet the requirements [67] or that national industries will not move abroad due to the introduction of the schemes [68].
- <u>Security of incentives for investors in green gas capacities</u>
  Investment in green gas capacity will obviously depend on incentives that are derived from policy instruments. Unlike in subsidy schemes, in quota systems such incentives are based on the prices of certificates, that are unknown beforehand. This uncertainty may lower investment due to the higher risk attached to the business case for specific green gas production technologies [64].
- <u>Credibility of the system</u>
  Credibility is an important aspect of certificate based quota schemes: Both the system of validation and certification of the certificates needs to be watertight and generally accepted

based on their contribution to greening, and the same applies to the trading system where it needs to be controlled that only officially approved certificates enter the market. If different certificate schemes are developed in parallel, it obviously is a difficult matter which of them are considered 'acceptable' for which purposes.
Besides the credibility that the system is operated 'fair' and without fraud, the system should be designed in such a way that the difference between the 'real' (what happens in reality with the product) effects and the 'claimed' (what is told to the consumer that happens as a result of the trading of the certificate) effects is limited.

3.2 Production

In the production stage of 'green gases', it is important that a sufficient level of 'being green' is respected in order for the derived certificate (or guarantee of origin) to be acceptable for use in the quota system. This section discusses the most relevant literature on this topic.

Criteria for technologies and gases

In the STORE&GO project a green gas was defined as: '*a gaseous energy carrier offered to the market without a serious GHG footprint*' [69]. However, at the same time it was recognized that issues with regard to setting system boundaries and accepting greening criteria for sources of gases, should be taken into account as well when certifying green gas [69]. Gas for Climate assumes that in a carbon neutral 2050 the main gaseous energy carriers in Europe will be biomethane and hydrogen [70]. There are, however, plenty of pathways to produce such gases, and those molecules can moreover be transported and utilized in different phases, pressures and purities. In designing certificate schemes it is important to find an optimum in on the one hand being as precise as possible in specifying green gas criteria and indicators, while on the other hand introducing an manageable certificate system with a limited number of certificates. For biomethane, that has been used, unlike low carbon hydrogen, as a source of green gases for quite a while already, various different standards and certification schemes already exist throughout Europe [71] [72]. This makes it difficult to get to a common European certificate for green gas based on biomethane. This explains why for hydrogen certification, a European standard has been proposed by CertifHy, although outside Europe other standards may develop and within Europe it is not known in which degree these standards will be accepted. Since the Vertogas green gas certificates and (pilot) CertifHy schemes for green and low-carbon hydrogen are already applied in the Netherlands, their definitions and criteria will be discussed in more detail below.

<u>Green gas certification by Vertogas</u>

To be able to obtain 'green gas' (i.e. biomethane) certificates based on Vertogas, several requirements should be met for the production installation, input and performance measurement and resources that are used. For production, digesters or gasification installations can be registered at Vertogas. Also, a certified person for validation and verification should be appointed. Certificates (or actually guarantees of origin) are typically obtained for injecting biomethane in the gas grid; only certificates of biomethane that are injected to the grid can be traded. Three types of biomass are categorized as being accepted as a source of green gas production, conform the NTA8003:2017 norm by NEN:

- 'Pure biomass': the NTA 8003 biomass groups 100: wood/forestry, 200: biomass from agri- and horticulture, 300: manure, 400: sludge, 500: residues industry, 600: organic waste from households and companies, 710: paper waste, 721: textile without synthetics.
- 'Biomass that is not pure by nature': NTA8003:2017 groups 701, 709, 729, 800 until 809, 900 until 909. For those fuels pyrolysis, torrefaction and/or carbonisation is applied and a sample has shown that it is polluted for less or equal than 3 percent.
- 'Not pure biomass': the other categories, a sample should be taken to determine the part of the biomass that has a biological nature.

The certificates/guarantees of origin can only be obtained for the part of energy that is produced by renewable sources, which includes biomass from biological or short-cycle organic nature [73]. Also additional information needs to be provided, such as on the country where the biomass is coming from or on the used production standard, such as GlobalGAP, LEAF, SAN/RA, ACCS, IFOAM, SA8000 and/or ATFS [74].

Green and low carbon hydrogen certification by CertifHy

In the spirit of CertifHy it has been proposed a dual GO/certificate system for 'premium' hydrogen in complying with the RED, FQD and ETS [75]. The argument was that by distinguishing between 'green' and 'low-carbon' certificates the full potential of environmental performance can be exploited and the total market value of hydrogen demand can be increased [75].

In order to obtain 'green' or 'low-carbon' hydrogen certificates, the following requirements should be met [76]:

1. Only facilities producing hydrogen with GHG emissions lower than the benchmark value (which can be adjusted, but initially is 91 gCO_{2eq}/MJ[14] based on the state-of-the art steam reforming of natural gas in large installations [77]) can access the CertifHy scheme.
2. The emissions associated with CertifHy 'green' and 'low-carbon' hydrogen should be lower than the Low Emissions Threshold, which is the benchmark value minus 60% (i.e. 36.4 gCO_{2eq}/MJ)[15].
3. CertifHy Green Hydrogen certificates can be obtained for hydrogen produced from renewable sources as defined in the REDII. In multi-fuel plants using both renewable and non-renewable sources, only the renewable part of the hydrogen is taken into account to calculate the quantity of certificates [77].
4. CertifHy Low-carbon hydrogen can be obtained from a batch or sub-batch of produced hydrogen having a greenhouse gas footprint equal or lower than a specified limit (initially 60% of the of the benchmark process, 36.4 gCO_{2eq}/MJ). A sub-batch is a part of the production batch, which is the produced hydrogen between any two points of time. Specific calculation procedures are defined by the CertifHy scheme [77].

The greenhouse gas footprint from the raw materials used as an input until hydrogen is produced of at least $99.9_{vol}\%$ and a pressure of 3MPa can be defined by the ISO 14044 and 14067 as specified in REDII. The renewable origin of the consumed energy (e.g. electricity, gas or heat) should be established by cancelling the GO/certificate of that specific energy carrier [77].

What gases should be included?

There is few literature on quota schemes for 'green' and 'low carbon' gases. Nowadays, information on quotas for green gas can typically be found in position papers or policy reports and proposals. What gases to include in quota schemes differs from one source to another, just as the arguments why to exclude or include certain gases. Biomethane is mostly included in the various studies on mandatory gas quota [16, 59]. However, sometimes the scope of the quota is limited to hydrogen [58, 68]. The Dutch government in some recent policy reports assessed how (administrative) blending obligations for both biomethane [78] and green and/or low carbon hydrogen [79] could be introduced. Hydrogen Europe [58] calls for both 'green' and 'low carbon' hydrogen quotas on the demand side. However, it states that RED targets should be for renewable hydrogen only, while other instruments can be considered for support of low-carbon hydrogen in addition, and not replacing, renewable hydrogen targets [80]. Gas for Climate [61] instead argues that 'low carbon' hydrogen will be incentivized enough by an assumed higher ETS carbon price until €55/tCO_2 in 2030, and therefore that only an additional binding target for 'green' hydrogen and biomethane should be introduced [59]. In CERRE [81] it is stated that no specific target for renewable electricity sourced hydrogen should be set, as it depends

[14] MJ of hydrogen using the lower calorific value.

[15] Altough, CertifHy mentions that this threshold will be adjusted when European legislative standards evolve (for example in the RED II revision or the EU taxonomy for sustainable activities).

on the availability of such electricity in the future, which is expected to remain problematic in the future. FSR [68] argues that no distinction between colours of hydrogen should be made, since the market (including the ETS system) could determine best which form of hydrogen could be used most effectively. The Dutch Council for Living Environment and Infrastructure (Rli) [60] states that climate neutral hydrogen competitiveness differs between sectors, which is why they propose separate quota systems and targets for different sectors. In short, there is a whole variety of opinions popping up in the literature on what gases to include in any future green gas blending schemes.

Geographical criteria for production

The geographical location of the production site of the green gas and of the resources that act as an input are important aspects to consider in any certification scheme. Whether or not imported green gases and/or imported resources are accepted will obviously have a large impact on the cost price, available volumes and integrity demands of the derived certificates.

First, it is clear that accepting certificates based on green gases produced abroad will on the whole reduce their costs. For instance, when an administrative blending obligation of renewable electricity was researched in the Netherlands, it was found that connecting the system with the Swedish system could save a lot of costs for society and consumers because in other countries cheaper production technologies or conditions may be available [82]. Especially for renewable hydrogen, it is known that locations abroad may show similar advantages due to their cheap availability of renewable electricity. This also explains why some research is currently performed on the feasibility international value chains involving hydrogen production in e.g. North Africa and the Middle-East and shipping it towards Europe. However, national green hydrogen production targets are still quite commonly used, such as the 3-4 GW electrolysis capacity target for the Netherlands in 2030. both for reasons of energy security of supply or for stimulating national conversion activity to enhance the domestic economic activity.

A next issue is if resources for producing green gases should comply to a specific area or not. For example, in the CertifHy schemes the origin of the electricity can be proven by cancelling renewable electricity certificates for the electricity used to produce the hydrogen [83], irrespective whether or not the resources of such electricity are domestic. The proposed CertifHy certificates show the geographical location of the produced hydrogen and which fuel has been used for its production, but not the geographical location of the fuel itself (e.g. renewable electricity) [84]. Therefore, in the current CertifHy proposal green hydrogen certificates can be obtained by importing and cancelling green electricity certificates produced in other countries. The Dutch Consumers Association [85], however, typifies electricity suppliers that ‘green’ their supplied electricity with the help of the imported electricity GO’s as ‘greenwashing’. In the case of renewable electricity GO’s, this could be the case since electricity of Norwegian wind parks physically replacing hydroelectric power leads to a real effect of zero carbon reductions, while consumers using those certificates in the Netherlands claims ‘green’ electricity that physically is produced by natural gas. Summarizing, specifying geographical boundaries for the resources (e.g. electricity and biomass) used to produce renewable gases can increase the perceived sustainability of the instrument, but is highly likely to involve higher societal costs.

Temporal correlation

Typically for renewable hydrogen produced by electrolysis, temporal correlation criteria could be considered, as in the physical system renewable hydrogen can only be produced when physically renewable electricity is produced at that time. This can be done by shortening the expiry date of the certificates (which is usually one year for GO’s, see ‘Expiry date of certificates’) or by requiring that the production date on the electricity GO should match the moment that hydrogen is produced, in order to obtain a certificate for the produced hydrogen.

Additionality of installations

Another decision that impacts the quota is if only new installations are approved to obtain certificates or all produced gas complying to the criteria can be used to fulfil the target. In the Dutch fuel blending scheme, there are no restrictions on the age of installation. In the Norwegian and Swedish renewable electricity quota, only new installations or volumes produced by increases of production capacity are able to obtain certificates for a period of 15 years [86]. An important difference between both systems is that for biofuels in many cases mainly OPEX rise due to increased costs for resources, while renewable electricity involves mainly CAPEX for the investment in new installations. Therefore, when the CAPEX of these new installations are depreciated and installations are still viable to use, windfall profits can be generated in the following years when only OPEX are in place compared to new market players that still have high costs to pay back their investments. The impact of CAPEX and OPEX in the business cases for the accepted gas production technologies on the quota scheme should be investigated to assess the impact of this consideration.

Secondly, additionality of renewable hydrogen produced by electrolysis in the revised RED II potentially requires that the ages of renewable electricity production installations and the electrolyser are similar. This would imply that renewable hydrogen producers should contract electricity capacity that has not been built, while typical lead times for realisation of offshore wind assets are up to 7 years compared to only 2 years for electrolysers [80].

3.3 Consumption

On the consumption side of the quota, decisions should be made about how much of the certified gases should be consumed and what parties are part of this obligation. Further, rules will be discussed that are involved in the compliance of the quota.

Setting the targets

A first note that should be taken into account to set the target(s) of an administrative admixing policy, is the main purpose of the policy. As stated in the introduction, the main purpose of this paper is if and how and virtual/physical admixing regime can stimulate the development of production capacity and an open market for green and/or low carbon hydrogen. The reviewed renewable gas/hydrogen quota proposals could have other main purposes (e.g. decarbonising the gas sector or heavy industry), therefore an overview of the similarities and differences in the different papers is shown in Table 6.

Table 6: Overview proposals for mandatory gas targets

Quota proposal	Main aim	Gases included	Targets	Obligated sectors	Area
[59]	Scale-up renewable gases	Biomethane Renewable H_2	8% 2030 3% 2030	Gas consumption Gas for power Gas for feedstock	EU
[16]	Production, market uptake renewable gases	Renewable gases*	11% 2030	Total gas consumption (incl. liquid and H_2)	EU
[58]	Hydrogen market stimulation	Renewable H_2 Low carbon H_2	N/S 2030, 2050	Industrial quota Transport quota** Heating quota	EU

[60]	Hydrogen market stimulation	Carbon neutral gas/fuels	N/S	Industrial quota Transport quotas Build environment quota	Netherlands
[81]	Decarbonisation gas use	Biomethane Low carbon H_2	10% 2030 100% 2050	Total gas consumption	EU

*All gases contributing to EU renewable target
** Including carbon free kerosene, shipping bunkering fuels, hydrogen powered trains and hydrogen in transport fuels

The target and eventually sub-targets can be determined based on different arguments. In the first place, it can be based on certain targets for CO_2 reduction, renewable energy deployment, etc. For example the Australian RET was based on the goal to produce 33,000 GWh of renewable electricity in 2020.

Secondly, it should be considered what is achievable with regard to demand and/or supply characteristics. An example of (sub-)targets based on the supply limits can be found as the proposed sub-targets for biomethane. Those are set based on the assumed availability of biomass [81, 59] and the amount of biogas plants with enough scale to be upgraded towards biomethane plants easily [59]. Morga González et al. [81] mention that the target for biomethane should be adapted when the total gas consumption decreases. For renewable hydrogen, Gas for Climate [59] based its target on the major compatibility of physical admixing of hydrogen into natural gas transport infrastructure and end-use applications. Also, the supply of renewable hydrogen could be constrained by the expected availability of (low cost or surpluses) of renewable electricity [81].

Finally, when setting the target, implications of those supply limits and their effect on the costs for consumers on the demand side should be taken into account. As seen in Figure 3, the height of the targets will determine the technologies that are required to reach the target, which will be paid by the final consumers. The more expensive production technologies are needed to meet the quota, the higher the costs paid by the consumers. This increases the societal costs of the instrument and the energy bill of consumers.

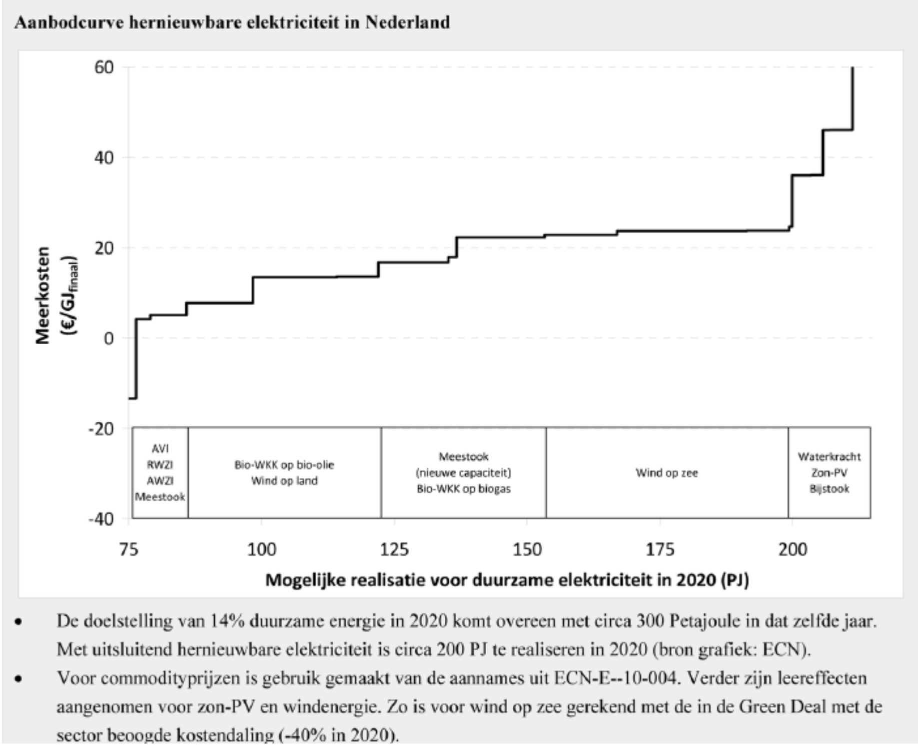

Figure 3: Supply curve of renewable electricity in the Netherlands [64]

Sub-targets

In some cases multiple technologies are desired to be stimulated, and it is not perceived desirable to let the market fully determine the portfolio of technologies. In these cases specific sub-targets can be set. Examples of these can be found in the Dutch Fuel blending scheme, where a limit counts for conventional biofuels and a minimum target exist for advanced biofuels. Or in the Australian RET, to ensure that both large and small scale renewable electricity capacity are deployed. Gas for Climate [59] also propose mandatory sub-targets for 3% green hydrogen and 8% green methane in 2030 on EU level, since they state that to meet the EU climate targets in 2050, both type of gasses are needed. While production costs of biomethane are currently lower than green hydrogen, the (sustainable) supply volumes of this technology are limited and therefore green hydrogen should be stimulated to develop these technologies as well with regard to the future energy outlook in 2050 [61].

Intermediate targets

Beside the sub-targets for specific certificates, intermediate (sub-)targets are used to determine the obligated amount of certificates that should be bought during every time step (mostly periods of one year). The intermediate (sub-)targets rise every period towards the final goal in the target year of the mandatory scheme, such that production capacity and the market can develop over time.

Market participants with a quota obligation

Another discussion is who is mandated by the quota. The proposal of Gas for Climate [59] sets a binding target over ‘all gas consumed in the EU’, regardless if it is used as gas, to produce electricity or as industrial feedstock. No distinction in the height of the target for different sectors is discussed. However, consumers, appliances and alternatives for green gases (or molecules in liquid form) might differ per sector. This means that in some sectors hydrogen could be closer to cost competitiveness than other sectors and also the emission reductions per MWh of substituted green hydrogen can differ along appliances (especially when 1 MWh of hydrogen can be interchanged with 1 MWh of biomethane, the effects accounted in the administrative system will differ from the effects in the ‘real’, physical system). These could be reasons to differentiate targets between sectors, or at least ensure that conversions should be made and tracked by the administrative system. Hydrogen Europe [58] proposes to set different quotas/targets for industrial feedstock (incl. carbon free steel, ammonia, methanol, etc.), transport (incl. carbon free kerosene, shipping bunkering fuels, hydrogen powered trains and hydrogen in transport fuels) and heating (eventually differentiate between high and low temperature heating). The Rli [60] proposes even more differentiation in admixing regimes on the Dutch national level, including separate admixing regimes for maritime, aviation, build environment, road traffic and industry sectors, which differ in being physical and/or virtual. Besides the competition and alternatives in each sector, they differ in the infrastructure that is available, possibilities for physical blending and existing regulations, which all might influence the blending scheme. However, differentiation of targets for consumers in different sectors could lead to unequal distribution of decarbonisation costs, which should be taken into account. The main implications per obligated party are discussed below:

- Gas suppliers: gas suppliers can be obligated to purchase biomethane and/or hydrogen certificates for a part of the gaseous energy they sold, in order to 'green' the build environment. When gas has to be admixed physically, biomethane has no limitations since it has the same structure as natural gas. For physical admixing of hydrogen, the volumes in the short term are limited due to technical restrictions of the grid. The advantage of administrative blending is that it has no limitations. For both options the extra costs of biomethane and (renewable and/or low carbon) hydrogen production are paid by the gas consumers. Higher costs for gas may stimulate insulation and all-electric options.
- Industrial consumers: industrial users can be obligated for their gas used for low and/or high temperature heating and/or feedstock. Also, the obligation can be limited to specific gases, such as grey hydrogen. They can meet the requirement by investing in own green gas production capacity or the purchase of certificates. The volumes of these customers are that large that investing in dedicated infrastructure for physical delivery could be an option. Moreover, it is the only sector where hydrogen is currently used in large volumes. Replacing one kilogram of grey hydrogen by one kilogram of renewable hydrogen can save 8.5-10 kg of emitted CO_2, which is way more than replacing one kilogram of natural gas by an carbon neutral alternative. The biggest challenge of this sector is the international competition, which increase the risk of carbon leakage when industry moves to other regions due to increasing energy and/or feedstock costs.
- Gas power plants: gas power plants are large consumers of natural gas in the Netherlands. Including them in the obligation will improve the competitive position of renewable electricity production technologies, but also technologies that have larger emissions than gas powered plants, such as coal powered plants.
- Fuel suppliers for road transport: for fuel suppliers, currently an blending obligation for renewable alternatives exists already, including bio-CNG and bio-LNG. Also renewable hydrogen used in pure form in fuel cells or as component in renewable energy carriers with non-biological nature can be used to meet the renewable fuel blending obligation. Therefore, green gases are already included in a blending obligation. The question that remains is how the system boundaries should be set: could the same certificate(s) be used in multiple sectors and how can differences in technical requirements of the hydrogen and/or biomethane (e.g. pressure, purity and state) among different sectors be tracked and accounted well in the administrative system, taking into account the required conversions.
- Aviation & shipping: for both shipping and aviation renewable/carbon neutral fuel blending obligations are under discussion on Dutch national and EU wide level. Also here the challenge is how the system boundaries are set and the certificates used interact with each other. More elaboration on the interaction between different certificates is discussed in section 4.3.

Compliance to the target

Buy-out and minimum prices

As mentioned before, every period (which is mostly yearly) intermediate targets determine the amount of certificates that should be cancelled by the obligated market parties. When obligated market parties do not comply to the target, a penalty is paid for each missing certificate. The price paid per missed certificate is called the buy-out price. Obviously, the obligated parties can decide not to buy certificates when they prefer to use the buy-out, therefore the price of certificates will never pass the buy-out price and this price determines the maximum price of certificates, the maximum (extra) costs for consumers and the allowable range of technologies that can potentially produce cost effective by implementing the blending obligation [64]. As seen in figure 2, the certificate price is theoretically determined by the most expensive technology that is required to meet the target volume of the quota. When this price is higher than the buy-out price, the obligated parties will prefer to pay the buy-out penalty and the targeted goal will not be reached. Therefore, the buy-out price should be set carefully and hand in hand with the mandatory target: low enough to protect consumer/society against undesired high costs on the one hand, and high enough to ensure that the target of the obligation can be completed.

The previous discussed buy-out price is determined ex ante. Buy-out prices can also be determined ex post, for example 150% of the average certificate price of the previous year. This increases the uncertainty of not buying enough certificates and therefore there will be no determined maximum certificate prices, which are beneficial for investors but involves a risk for consumer and societal costs [64]. Secondly, an buy-out fund (as in the UK Renewables Obligation) excludes maximum prices for certificates, since payments for buy-outs are distributed by the share of certificates that every obligated supplier had purchased [64].

Besides buy-outs, minimum prices can be considered to ensure investors of extra income comparable with a deployment subsidy. However, these costs are paid by consumers and the scheme will lose some of its market driven character [64]. By implementing a minimum price and ex ante buy-out price, the certificate prices can be regulated within a determined range.

Banking and borrowing

It might be hard to meet the mandatory quota exactly at every time frame. Since the obligation is a minimum, no problems occur without a banking and/or borrowing system. However, when more certificates are purchased than required during a period, and those can be used to comply to the quota in a period in the future, there is spoken of banking. An advantage of banking it is expected to increase the stability of certificate prices [64]. In the same way, borrowing is allowed when certificates can be used to meet debts of previous periods.

3.4 Trading system

Certification systems

In order to get a good understanding of the various ways of issuing, transferring and trading of energy certificates two types of energy certificates need to be distinguished: quota certificates and tracking certificates [87]. Quota certificates are certificates the main purpose of which is for obligated market parties buying them to show that they did their share to support the targeted (new) renewable or low carbon energy production. Tracking certificates have as their main purpose to proof the source of energy used to the end-consumer, for example to express the environmental value of production. The prices of both types of certificates are determined by supply and demand. However, for quota certificates the demand is determined by a legal obligation, whereas for tracking certificates it is typically determined by the willingness-to-pay and marketing value for green energy. In case of a mandatory quota, there are three ways in which the two types of certificates can be used:

- Hybrid system: this is a system where a single certificate is usable for both quota and tracking. For example in the USA a Renewable Energy Certificate (REC) can be used both to comply to the quota and to claim the origin of the used electricity [87].
- Multi-certificate system: in the Swedish and Norwegian REC system two certificates are issued per MWh of electricity produced: one ‘elcertificate’ that can be used to meet the quota, and

one Guarantee of Origin (GO) to proof the location and method used to produce the electricity [87].

- Connected system: in this case tracking certificates can be used in order to proof that the energy that is used in the specific sector complies with the quota of accepted renewable sources. The Dutch fuel blending obligation uses the tracking certificates of Vertogas to establish the origin of gas that is extracted from the grid by the fuelling stations in order to be able to determine how many quota certificates have been received [88]. By subsequent cancelling of Vertogas certificates in the Vertogas register, HBE's are received in the NEa register. The origin stated on the tracking certificate determines the type of HBE (advanced, conventional or other) that is received [89].

With regard to the various proposed gas quota schemes, it has not yet been specified what certificate system should be used (e.g. hybrid, multi-certificate or connected systems). Research on hydrogen GOs typically states that those certificates should be designed to be capable of both tracking as well as being usable for quota systems [83], [90]. It is, however, unclear whether generic European hydrogen GOs are compatible with the requirements that national governments will introduce when setting up gas quota schemes. There are no guidelines for governments as to what the advantages and disadvantages are of the various systems. Hybrid systems could be more constrained in possibilities, to the extent that GOs have to comply with the international standards of REDII. The same international standards could be beneficial for international trade in certificates and compliance to international legislation and targets [91]. A multiple-certificate system may be more flexible for national governments, but also confusing, especially when support certificates are used to claim sustainability. Connected systems still depend on the design and information provided on the GO, which may be a backdrop.

Roles and responsibilities

Certificate systems are characterised by multiple roles and responsibilities. The overall responsibility for a certificate system in a geographical location is legally allocated to a competent body. The recast Directive 2018/2001/EU states that competent bodies of GOs should not have overlapping geographical responsibilities and should be fully independent from supply, trade and production. Other roles and responsibilities in energy certification systems are [84]:

- Certification role. This is the responsibility of the verification of production installations and production batches to comply with the criteria set by the certificates in the certification system.
- Issuing role, A register tracks the certificates that are issued, traded and cancelled for every participant. The issuing body is the party that is responsible for supervision and operation of the registry. Also the registration of new participants is done by this body. The issuing role can be exercised by the competent body, but sometimes also multiple registries exist that can trade or interact with each other, such as in the Norwegian-Swedish electricity certificate [86] or the Dutch fuel blending obligation case [88].
- Registrant or Account Holder. Accounts can be opened by: producers who want to obtain and sell certificates; traders on the certificate market; and those who just want to buy certificates. Obligated market parties commonly have to open an account [86]. At the end of every period, enough certificates should be owned by such parties to cancel against the obligated amount of certificates.

Trade of certificates

Generally speaking there are two types of contracts that can be used by account holders to trade energy certificates: forward contracts and spot contracts [86]. The price of the certificates in both contracts is set at the date of agreement; contracts differ with respect to when certificates are transferred and the payment is done. For spot contracts the transfer of certificates and payments are done within a couple of days, while forward contracts set the price and volumes of certificates for a longer period of time, which ensures volumes and prices between two parties to be predetermined. Both types of contracts can be closed bilaterally or via brokers.

The market price is the actual certificate spot price based on supply and demand at a given time, while the register price is the average price paid for certificates transferred during a specific period [86]. Hulshof et al. [72], [92] researched the market performance of several renewable electricity and gas certificates and noticed, especially with regard to certificate prices, a lack of certificate market transparency. Also in the Dutch fuel blending scheme prices of HBEs are not equally transparent for different market parties, which may explain the wide range of HBE prices seen during the last years. Generally it holds that the more transparent market prices are, the more efficiently the market operates. As a compromise participants may be protected against having to reveal market-sensitive information, by just sharing historical spot price data.

Expiry date of certificates

Usually to create some sort of simultaneity, certificates have an expiry date. GOs can only be traded until one year after their production date. When they are not cancelled within a year, the certificate expires and cannot be used anymore. Especially for intermittent renewable energy sources, such as solar and wind (and potentially production of electrolysers fed by these sources in the future), discussions are to what extent production and consumption of these sources should be matched with certificates in shorter time frames (e.g. hourly), in order to introduce the need for flexibility into the certification schemes [93].

4. Integration with other policies and schemes

4.1 EU legislation

In December 2019 the European Green Deal was presented, in which document the EU emission reduction target for 2030 was sharpened from 40 to 55% (compared to emission levels in 1990) in order to keep on track for climate neutrality in 2050 [94]. This was the start of a process to revise a lot of European climate regulations. The most important regulations with relevance for the concept of mandatory gas quota schemes are discussed below: REDII, the European Gas Directive, and the EU ETS. Besides climate regulations, also general EU anti-cumulation principles are important to consider.

REDII

The REDII (2018/2001/EU) provides the European targets, definitions and policy measures to stimulate renewable energy. Institutes that argue for a binding renewable gas target, propose that this target should be recorded in the revised REDII [16], [59]. Moreover, some specific articles in this Directive should be discussed when considering a national gas blending quota scheme:

- Article 2: This article specifies the definitions of ‘renewable energy’ and ‘Guarantees of Origin’. The definition of renewable energy describes what criteria for hydrogen are to be used in considering it ‘renewable’. REDII only specifies renewable energy sources and therefore ‘low carbon’ hydrogen or gases are not included in the scope of this Directive.
- Article 19 Specifies standards and regulations for GOs used in Europe. It therefore applies if GOs do play a role in mandatory quota schemes.

REDII specifies regulations especially for renewable electricity and biofuels. A revision of REDII also including a more extensively specified regulatory framework for renewable hydrogen is expected to be released in 2021, including: in what way renewable hydrogen is defined; a European objective for renewable gases towards 2030;legislation for renewable hydrogen support schemes; and a quota for RFNBOs. Gas for Climate [59] and CertifHy [83] both have stated that the additionality criterion will be important to consider in this revision. These criteria will determine the geographical, temporal and installation age requirements for renewable hydrogen and biomethane, that are discussed in section 3.2. Moreover, the revised RED II could specify if a general target for renewable gas consumption will be introduced, and/or (sub)targets in specific hard to abate sectors will be introduced, such as steel production, aviation and maritime sectors.

European gas directive

The purpose of the European gas Directive (2009/73/EC) is a.o. to ensure that specific rules governing the European gas system are applied in the transmission lines connecting member states and third countries. Currently, the European gas Directive is designed for natural gas. In 2021 this Directive will be revised in order to provide a regulatory framework for infrastructure and markets for a broader range of gases, such as 'low carbon' and 'renewable' hydrogen. The following aspects that relate to the design of a mandatory gas quota scheme and its certification are currently proposed to be addressed in the revised gas Directive:

- The EU wide definitions and benchmarks for 'low carbon' hydrogen and gases (Hydrogen Europe proposes to use the CertifHy standard for low carbon hydrogen as a starting point [95]).
- A framework for EU harmonised standards and guidelines for hydrogen quality, safety, purity, pressures and flow speeds in hydrogen grids.
- Guidance for natural gas and hydrogen infrastructure and markets providing clarity on the degree to which hydrogen can be physically admixed into the existing natural gas infrastructure.
- Guidance as to what use of green power should be prioritized given mitigation criteria in cases of competing use options, e.g. between electrification and electrolyser deployment (see also VFSR [96]).

The EU ETS

The EU ETS is a compulsory instrument for a large number of industrial market players on the basis of which emission certificates can be traded to stimulate the reduction of carbon emissions of large polluters, mostly companies in the heavy industry and fossil power sector. Also for the EU ETS Directive, a revision is planned before the end of 2022 as a result of the sharpened carbon reduction target set by the Green Deal. Although the ETS does not relate directly to the gas sector, its impact does relate to the competitiveness of low carbon gas production technologies. As discussed in the Gas for Climate proposal [59], if the ETS will be sharpened towards a CO_2 price of around €50/tCO_2 , low carbon hydrogen may become cost competitive compared with the grey alternative, without the need for an additional mandatory gas quota. Although, it should be considered that low carbon hydrogen competes with other carriers than grey hydrogen in several sectors, such as for high temperature heat and aviation. Therefore, the CO_2 price required making a low carbon hydrogen alternative competitive differs per sector. Hence, three aspects of the EU ETS revision would need to be taken into account in designing a mandatory quota scheme for gases:

- What is the impact of the sharpened reduction targets on the expected emission prices and therefore the competitiveness of gas production technologies?
- What is the impact of the Directive revision on different sectors, especially if road transport, maritime shipping and intercontinental aviation are to be included into the scheme [97] [98]?
- What is the impact of the revision of the 'State Aid Guidelines for 'indirect ETS Costs' for sectors that are exposed to international competition, as these Guidelines set the boundaries for member states to compensate the extra costs specific industries are expected to face due to the ETS system [99]?

Anti-cumulation

Generally, in the EU investments cannot be provided with subsidies or support schemes twice. Therefore, to just give an example, in the existing Dutch biofuel quota and SDE++ subsidy scheme for green gases, producers have to make the choice between receiving the subsidy or selling HBEs to comply with the relevant biofuel quota, since otherwise multiple support is received for the same product. For a mandatory gas quota including green hydrogen, this could be a problem for two reasons:

- The cost difference between green hydrogen and natural gas is that large, that no subsidy-free hydrogen can be achieved on the short term, with (or without) a mandatory quota. Learning effects will therefore be unduly postponed.
- A discussion can emerge as to whether it is allowed to use subsidized renewable electricity for the production of green hydrogen used to comply with the quota, since in that case multiple support is given to the same product. Moreover, it should be tracked if the subsidy is received for the input resources of a specific amount of hydrogen, which will be way more complex than what, for instance, has been arranged in the proposed CertifHy system.

Under specific circumstances, the European Guidelines on State aid for environmental protection and energy (2014/C 200/01, chapter 3.3 number 114) do accept the combination of state aid for biofuels that are used to comply to a blending obligation [100], as is, for instance, implemented in Italy. It therefore needs to be clarified to what extent comparable exceptions will be accepted with regard to other mandatory quota schemes for renewable gases. Moreover, the EU Guidelines on State aid for environmental protection and energy provide the boundaries that member states have in order to support decarbonisation technologies in general. Therefore, the revision of these guidelines planned to be implemented at the 1st of January 2022, could have major consequences for national hydrogen and/or biomethane quota schemes if member states are limited in the degree in which support may favour production capacities located in their own country.

4.2 Dutch national legislation

Dutch legislations Energy for Transport

As discussed before in this report, there is an operational quota scheme to support renewable fuels in the Netherlands. In this scheme, besides advanced and traditional biofuels, also other perceived sustainable fuels can be used to obtain usable certificates or HBEs, such as green electricity. Until now hydrogen is not (yet) specifically incorporated in this scheme. This, however, is expected to change after 2022 when the scheme will be adapted based on the revised REDII [101]. In the view of the so-called H2Platform [102], a collaboration between multiple private and public organisations supporting the use of hydrogen in the transport sector, the suggested adaptations should cover the following points:

- In article 9a, paragraph 3 of the proposed version is states that gaseous renewable fuels cannot obtain HBEs if an exploitation subsidy is received for such fuels, while in the explanatory text to the article is stated that if the unprofitable margin is not compensated fully by the subsidy, the remaining share can be used to obtain HBEs. It is unclear how this is projected to be calculated, given that both the subsidy- and HBE-instrument will be essential to make a profitable business case for renewable hydrogen.
- For reasons of traceability and control, a chain for renewable biofuels is limited to two tiers (a producer and supplier), which limits opportunities for transport and conversion.
- In the proposed adaptions, renewable hydrogen used by refineries to produce petrol or gasoline cannot be used to obtain HBEs, while at the same time REDII allows member states to do so when the renewable hydrogen replaces fossil hydrogen. This seems to be inconsistent.

- Imported renewable hydrogen and renewable fuels with non-biological origin are not included in the current proposal for not completely clear reasons.
- It is mentioned in the proposed version that in any case initially an earlier proposed BKE-system (a certificate related to the emissions) will not be introduced, even if it is seen as an instrument to stimulate the introduction of 'low carbon' hydrogen in the transport sector.

Other crucial aspects for the adapted fuel quota scheme are: the weight factor, the mass balance system, regulations about direct connections for (renewable) electricity and hydrogen, how it is dealt with (pure) liquid hydrogen, and the perspective on the instrument for the period after 2030 [102].

In short, it is expected that renewable hydrogen will be included in the Dutch fuel blending quotas scheme, but the degree to which this will support renewable hydrogen production remains unclear.

An upcoming new issue is how legislation will interact in case of multiple quota schemes towards renewable (and potentially low carbon) molecules. With respect to this case, the Rli [60] , for instance, argues that it is then conceivable that multiple systems affect each other, e.g. when the same product (biomethane and/or hydrogen) including its certificate can be used to comply to different quota schemes. It should then be addressed how these schemes are allowed to interact, compete and depend on/with each other.

SDE++

The SDE++ is the Dutch national instrument to provide exploitation subsidy to renewable energy production and carbon emission reduction technologies [103]. In 2020, the SDE++ was opened for hydrogen produced via electrolysis with less than 2000 load hours and CCS [104]. For the production of renewable gas (i.e. biomethane), the SDE++ exists already for a longer period [105]. Main issues for subsidizing hydrogen produced by electrolysis is that 2000 load hours are too less to make a profitable business case, and opening the SDE++ for more load hours will lead to relatively less CO_2 reductions, since more fossil based electricity is used for production [79]. Thereby, the SDE++ for biomethane is not leading to investments in promising gasification technologies, since digestion technologies are more competitive now, however mainly utilized on limited scale [63].

The main question related to the SDE++ and potential blending quota('s) is if electricity and/or gas produced with the SDE++ subsidy can be used to comply with the quota. On the one hand there is the argument that cumulation of support schemes should be avoided (anti-cumulation). On the other hand the SDE++ is a competitive support scheme where a bidding process is applied to ensure that only the most cost-effective carbon reduction technologies will get support, and moreover a cap is set on the maximum support that can be provided. Some experts argue that the revenues from the blending obligation should be allowed to be taken into account when the correction sum of the SDE++ is determined such that it overcomes overstimulation [102], comparable to how advantages of the ETS prices are taken into account in the SDE++ [103]. In the discussion how this is to be resolved, the option to use subsidized electricity to produce renewable hydrogen as well as the increased complexity of tracking such information, should obviously be taken into account.

4.3 Other certification schemes

Biomethane, 'green' hydrogen and 'low carbon', can all be produced via different techniques, mostly using other primary energy sources (e.g. electricity converted to green hydrogen via electrolysis, or biomass used to produce biomethane). Certificates and GOs should be aligned to each other in order to trace and proof the resources and conversion technologies used to produce the final product. The CertifHy initiative addressed this issue by stating that technically no connection between systems is required, since existing GOs/certificates can be cancelled in one system whereas new GOs/certificates can be issued in another system, based on the energy carriers used and produced during the physical conversion [83]. Therefore, the FaStGO project suggested clear separation and alignment between GO's for different energy carriers, including rules and data protocols for conversions between them [106]. Currently, a Revision of Standard EN 16325 is taking place aiming to standardise aspects of the GO system within Europe and across multiple energy carriers.

Building upon the three types of certification systems as discussed in section 3.4, both hybrid and connected certification systems are dependent of the information that is carried by the GO's, since all the required information should be provided from the GO certificate in order to be able to issue a support certificate in the register of the quota scheme (in a connected system), or to use the GO as hybrid certificate for both tracking and support purposes, . Moreover, the more a national support scheme allows to use resources from other countries (in Europe, or even outside Europe), the more complex the alignment of different certification schemes is expected to be due to:

- Fragmentation of certification schemes: for example when connecting the system to international biomass and biomethane certification systems, there is the issue of a lot of fragmentation between systems in different geographical areas. It will therefore create challenges if some certification systems do not provide the required information that is needed to verify the criteria set by the national blending quota.
- Standardisation of certification schemes: for example when a European hydrogen certification scheme will be developed and this scheme will not provide the required information to verify compliance to the national blending quota criteria, similar challenges as the just mentioned ones due to fragmentation of certification schemes will arise.

So, both alignment challenges will force the designers of national blending quota to be combined with other schemes to consider whether the criteria of the quota certificates should be adjusted, or that less alignment to other certificates would be acceptable.

5. Implementation

On the general issue what support mechanisms should be used at what stage of decarbonization of the gas sector, literature is divided. FSR [68] discusses the timing of implementing deployment subsidies or quota for low and zero-carbon hydrogen, by arguing that since decreasing the costs of deployment by learning takes time, activating such deployment should not be started too late to make full decarbonisation practically achievable. Aalto [91] argues in this respect that the optimal support for renewable energy technologies depends on the maturity of the technology, as shown in Figure 4. It is argued that price-based mechanisms such as feed-in tariffs and premiums have preference for promoting emerging technologies since the risk of actors is taken away by guaranteed revenues that enhance chances on competitiveness with existing technologies [91]. When the volumes and maturity grows, price-based mechanisms loose this advantage over volume-based mechanisms, due to increased certificate market liquidity and reduced investment risks [91]. Aalto [91] argues that, when available, existing GO certificates should be used to implement the quota, since such certificates already have a market value.

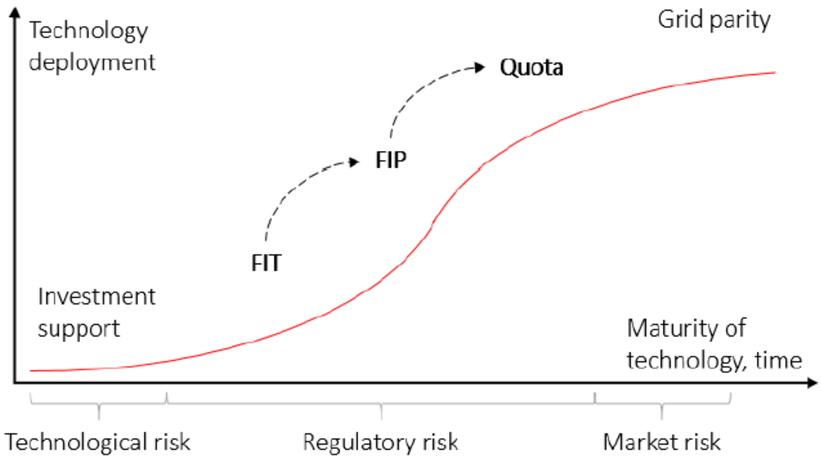

Figure 4: The fitting support schemes at various stages of development [91]

Leguit et al. [107] evaluated several instruments to provide a roadmap to achieve the goal of 2 bcm green gases as stated in the Dutch Climate Agreement and taking into account the longer-term goals of 2050. He argues that instruments are required that let the market pay for CO_2 -reduction and the introduction of 'green', and distinguishes between three criteria to determine in which sector to start market demand stimulation in order to support new production technologies: the adaptability of infrastructure and appliances; existing instruments that increase the price for green gas; and the future-proof effort of the gas [107]. These criteria make the application of biomethane in the build environment most suitable to start. Figure 5 shows the pathway during the first 5 years with a subsidy for production technologies to create enough volumes to prepare the market for the blending quota; innovation of several technologies can then be stimulated during the next phase. The subsidy is proposed to have a duration of 12 years, so the last subsidy ends 12 years after the last one is issued. After the first 5 years the blending quota is started and only additional volumes can be used to obtain certificates, of which the criteria should be similar as apply to the subsidy. The costs of the remaining additional volumes are borne by the market.

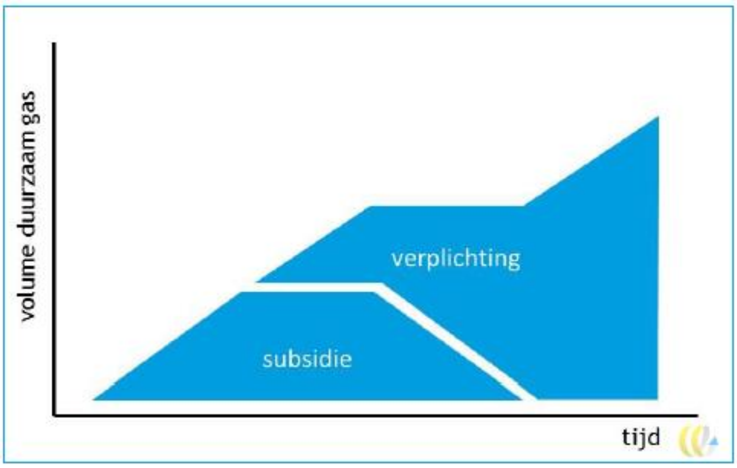

Figure 5: Schematically representation of the subsidy in the first period and the blending quota in the second period [107]

Leguit et al. [107] presume that in the initial phase until 2030 mainly biomethane will be used to green the gas uptake. Thereafter, a national infrastructure for hydrogen transport is expected to be ready and also locally some specific parts of the distribution grid.

Another point of view on the implementation of a blending quota scheme for hydrogen is taken by Berenschot & Kalavasta [9] and Den Ouden [65]. They argue that the lack of infrastructure is the main hurdle to create a renewable and low carbon hydrogen system. A virtual blending connection is therefore considered as one of the feasible options to connect several hydrogen clusters and markets into a national system [9], [65]. In virtual blending schemes the certificates offer end-users that are not physically connected to green or blue hydrogen production locations the opportunity to yet virtually use these types of hydrogen. This could support overall consumption and production of low-carbon hydrogen to reach the volumes required to invest in dedicated hydrogen infrastructure. Therefore, so they argue, implementation of a blending quota in the initial phase of technology deployment could potentially solve the chicken-egg problem between hydrogen demand and infrastructure development.

Although arguments on the timing of the implementation of mandatory quota schemes differ, they are not mutually exclusive. The Hydrogen Act is an example of how multiple mechanisms on supply and demand side can be combined to ramp-up the market of hydrogen in particular [108]. On this note, the following compromise guidelines are mentioned in the literature:

- Before the introduction of a mandatory quota scheme, deployment subsidies can be used to lower investment risks of the relatively unmatured conversion technologies, and (existing) early voluntary certification schemes can be used or set up in order to ensure market liquidity at the moment when the quota starts [91].
- To initiate demand stimulation for several green gas production technologies, one can start most effectively in markets where: infrastructure and appliances can be made ready easily; instruments increasing the price of green gases already exist; and the appliances of the gas are future-proof [107].
- The mandatory quota should be announced well in advance to give investors enough time to prepare themselves [107].
- For gases without an existing common infrastructure, such as hydrogen, the implementation of a virtual exchange system (i.e. certification scheme) and/or mandatory quota should take into account the simultaneous development of demand and infrastructure [9].

However, apart from the various discussions on the optimal design of a gas quota system as discussed above, also still a host of practical questions about the implementation of such system are hardly discussed yet in the literature. It is unclear, for example, if the quota for hydrogen and biomethane should start simultaneously or at different moments. Another question is if a distinction should be made between different end-use appliances, and if so, in which sector one should start. Furthermore, as the relation with infrastructure developments is clearly important, it must be defined how the implementation of a quota scheme can be aligned with hydrogen infrastructure developments and eventually physical blending in (parts of) the natural gas grid. Should one initiate small-scale experiments bottom-up to assess how the scheme works out, or instead start with developing large-scale, top-down implementation for all gas users? These remaining questions should be addressed in order to determine how a mandatory gas blending scheme should be implemented in order to function effectively in actual practice.

6. Risks and uncertainties

6.1 Undesired market developments

Since a quota scheme is an instrument that involves the functioning of the market, some risks of undesired market outcomes should be considered.

Uncertainty in certificate prices

As the mandatory quota can be filled in by certificates the prices of which are determined by the market interplay of supply and demand, the actual revenues of investors from their certificates are unknown beforehand. This uncertainty is taken into account in the business case assessment by investors of new production technologies. There is therefore a chance that the uncertainty is perceived as being too high to invest in such renewable production capacity. If such investment yet is made, there is a chance that the volumes produced with the help of the new production capacity do not match with the artificial demand created by the mandatory quota:

- When there is relatively little production capacity compared to the quota, the prices of certificates will rise. This will be beneficial for investors, but the end users will face high costs.
- When production capacity is high compared to the quota, the prices of the certificates will be low. This can be the case if too many companies determine to invest or when the quota target will not be achieved, e.g. when alternatives gain market share. This could for example be the case in the build environment, where electrification can be seen as an alternative.
- A disadvantage of a hydrogen quota as compared to the existing quota for fuels is that currently hydrogen cannot (yet) be exported that easily to reduce local oversupply.

Especially in the first year(s) of the implementation of a quota, there may be uncertainty about how much capacity will be deployed to fulfil the target. Later on as the scheme matures the potential new investors will make up their investment decisions on the basis of certificate prices, and therefore the balance between market supply and the target are theoretically expected to balance over time. To increase the willingness to invest in the early stages, some practical actions can be taken:

- Predetermining the duration and (headroom of) target percentages of the quota for a longer period;
- Creating transparency on the certificate market;
- Increase the amount of market players;
- Using ‘banking’, ‘buy-out prices’ and potentially even a ‘minimum certificate prices’ and/or subsidy combinations;
- Preventing the inclusion of technologies with mutually large difference in costs;
- Excluding imported green hydrogen from the quota.

Beyond these design options and practical actions, investors and obligated market parties themselves can create more certainty in the price paid/received for certificates by closing forward contracts for (a large share of) their certificates traded. In the same way, investors and consumers of renewable electricity use Power Purchase Agreements (PPA’s) to reduce the uncertainty of future (renewable) electricity prices.

Windfall profits

In theory the market price of the certificate will be determined by the most expensive marginal production technology cost to fulfil the quota at a given time [64]. The lower-cost technology producers will receive a producer surplus as a margin on their investments. If, however, such margins surpass normal business margins one can speak of ‘windfall profits’. According to Verhagen [64], this can happen in cases of mandatory quota schemes for two reasons:

1. There are large differences in marginal costs between the technologies used to comply to the quota. As discussed before, this is currently the case when comparing production costs for ‘green hydrogen’, ‘low carbon hydrogen’ and biomethane. When the quota is based on multiple low carbon gases and all three production technologies are accepted and needed to fulfil the quota scheme, low-carbon production technologies will receive large margins due to

their relatively low cost levels compared to the marginal technology being green hydrogen production.

2. There is shortage on the certificate market. When the level of the quota is relatively high compared to the amount of production capacity that can be deployed, the price of certificates will rise and it will become more attractive for more expensive technologies to enter the market. Since the realisation of energy projects could take some years, high certificate price levels may last for a significant period. When relatively little production capacity is deployed, electrolysers will be able to produce hydrogen also during hours when the electricity prices are high, so that margins on the cheaper production technologies may explode.

Windfall profits can be mitigated when a) the quota scheme is limited to relative mature technologies that are comparable in terms of costs, and b) a low buy-out price is set to limit the certificate prices [64]. In the Dutch fuel quota scheme, different types of certificates (i.e. HBEs) are used to comply with corresponding sub targets. In fact this design creates multiple quota systems for different types of technologies.

When a broad quota scheme supporting all technologies is preferred, additional measures can be used to mitigate the cost differentials between production technologies. These additional measures will favour some more expensive technologies and therefore reduce the market driven character of the quota scheme. Verhagen [64] describes two of these measures:

- Banding: regulation determines how many certificates are given per technology. The system could be relatively simple, assigning technologies to a set of 'bands', but bands can also be determined per technology or sub-technology.
- Bonus/malus: this measure determines that some cheaper technologies pay an extra fee (malus) for every certificate and the relative more expensive technologies receive a bonus for every certificate they sell on the market.

Unequal market powers

It is undesirable that one or few parties are responsible for a large share of the supply of certificates, since they would have a lot of market power on the certificate market. Since the overall volume of demand for certificates is determined by law, this could be very harmful, because consumers have no option to decline the purchase of certificates when the price rises too high (the low price elasticity principle) [64]. The risk of unacceptable market power increases: when investment costs are high, permissions are hard to obtain, or there are only a few large players involved in production and/or uptake of certificates. The market liquidity will increase when more participants are able to enter the market. International connections between quota/certification schemes can increase the market liquidity, but, as discussed before, can also scare off some investors to enter the market.

6.2 Carbon leakage

Especially for exposed industrial companies, additional costs for energy can harm their international competitive position. When a quota scheme will result in industries moving abroad, then the scheme will not contribute to effectively reducing global carbon emission levels [109]. Verhagen [64] mentions that this could be a reason to differentiate the costs or level of the target between sectors. Another option could be to differentiate in hydrogen support instruments between sectors at all [110], even if this could be perceived as unfair when one sector should comply to higher quota targets, or less preferable support mechanisms (e.g. receiving subsidy instead of paying taxes) than another.

Before, some factors were mentioned to limit the quota costs for end-users, such as determining the level of the target, limiting the maximum costs by a buy-out price, or using additional supporting mechanisms to decrease the production costs before the quota is implemented. In short, when proposing a national, or even a European mandatory gas quota scheme, it is important that the competitive position of industry should be taken into account and research should be done if and what additional measures are needed to preserve an attractive business climate.

As other sectors, such as heating the build environment, are not exposed to international competition, still the effect of the quota on the end-users energy costs should be assessed and concerned. For example, in households energy poverty might be become a problem for a share of society when the gas bill would rise towards unacceptable levels.

6.3 Fraud

Reliability, accuracy and fraud-resistance are crucial for mandatory quota schemes to serve their purpose [111]. Since a mandatory quota scheme is ultimately based on an administrative system that often relies on the administration of participants, other (international) certification systems and sometimes multiple certification bodies, history has shown that fraud can never be excluded completely [112], [113].

6.4 Credibility of the system

Confuse of the 'real' and 'claimed' effects

For consumers, it should be very clear who is able to 'claim' the use of green products and the carbon emission reductions involved with them. For example, when a company produces and uses their green gas, but sells all the certificates to another company, it should not claim that they are green themselves. Verification should be in place to avoid such wrong claims.

Difference in the 'real' and 'claimed' effects due to cross sectorial trade

Other differences between the 'real' and 'claimed' effects can occur when multiple energy carriers and sectors are included into the system. Imagine for example a quota scheme for the industry and gas suppliers, there could be a situation when hydrogen is physically blended into the natural gas grid (physically substituting 1 MWh of natural gas by 1 MWh of green hydrogen) and those certificates are bought by a pure hydrogen consuming industrial company (1 certificate 'greening' 1 MWh of grey hydrogen). In this case there will be a large difference between the 'real' and 'claimed' effect, since to produce grey hydrogen actually 1.4 MWh of natural gas is used to produce this gas. Therefore, conversions and system boundaries should be taken into account very carefully when multiple energy carriers and states of those carriers (e.g. gaseous vs liquid) are included in the system and certificates are exchanged through market players with different applications.

Summary of insights and research gaps

With respect to the notion of mandatory blending of hydrogen into the natural gas flows, one usually distinguishes between physical and administrative blending. Although from an analytical perspective this distinction can be useful, an actual practice both aspects of blending will almost always occur in conjunction. If a mandatory regime focusses on physical blending, it is likely that an addition certification system will develop to monetise the green premium attached to the admixed hydrogen. In reverse, if a mandatory policy relates to administrative blending, certificates will be issued for use and trade that will ultimately be based on hydrogen that is introduced in any way into the energy system, possibly but not necessarily via physical admixing into the grid.

Physical blending

So far, to our knowledge, no mandatory physical admixing policies with respect to hydrogen do exist. However, a number of laboratory tests, pilots and testing experiments have been carried out in various countries in order to investigate to what extent physical blending poses new challenges in terms of gas quality, grid integrity, pressure, safety, etc.

The literature on the various aspects of physical blending of hydrogen into the natural gas grid notes that admixing hydrogen may affect the gas density, the gas viscosity, the gas pressure, the gas Wobbe-index, and the conditions that may lead to two-phase flows. At relatively low admixing percentages (i.e. below about 20%) these effects do not seem to pose any insurmountable issues.

As far as the risks of embrittlement and induced cracking of the grid due to the admixing of hydrogen is concerned, for conditions reflecting the most common materials and operating characteristics, almost all the studies tend to conclude that no significant changes in the tensile properties of metals (low strength steel e.g. API5L gr B., cast iron, copper, yellow brass) can be observed when exposed to gas mixtures up to a 20 vol% hydrogen blend. In addition they conclude that for non-metallic materials, such as medium density polyethylene (PE80), hydrogen absorption does not affect subsequent squeeze-off or electrofusion joining of pipework [1].

The literature, on the other hand mentions some embrittlement risks with respect to compressor and flange components, because of the use of some specific metals, such as titanium and nickel.

The tolerance levels of various appliances and components in the gas value chain for admixing hydrogen vary quite strongly at the current state of equipment. New technological developments may increase tolerance levels, sometimes against relatively low costs. Currently the lowest tolerance levels seem to be concentrated in engines, gas turbines and CNG tanks.

Typical safety issues that apply to many gases and also to hydrogen are: the need for odorization, the risks of leakage, permeation and excavation. On the whole, such risks will need to be take care of with great caution, but do not seem to pose insurmountable challenges.

In the absence of a common and binding hydrogen limit requirement at EU level, it is up to the Member States the determine which hydrogen blending percentage is considered safe and feasible [2]. This is why the authorized concentrations vary significantly from one country to the other. For instance, the maximum accepted level of hydrogen in the natural gas stream in the Netherlands is set at ≤0.02 mol% in the HTL network and ≤0.5 mol% in the RTL and RNB net [3], while in Germany it is 10 mol% .

The hydrogen energy density is about one third of that of natural gas and thus the blend decreases the energy content of the supplied gas: A 3% hydrogen blend in a natural gas delivery pipeline will minimize the energy transported by the pipeline by about 2%. This point obviously will have metering and billing consequences that will need to be dealt with.

Because on the whole the market value of the carbon neutral hydrogen admixed to the gas grid will surpass the market value of the other gas (typically natural gas or syngas), a certificate based system may be a logical component of mandatory physical admixing schemes in order for the suppliers of the hydrogen to grasp their green premium.

Administrative blending

So far only mandatory administrative blending or quota schemes have been implemented with regard to electricity or liquid fuels, not related to gases. So, for lessons learned with respect to the optimal design of blending schemes for gases one can only learn indirectly from experiences elsewhere. On the whole, there is relatively little literature in the public domain covering the topic of mandatory administrative blending.

From the existing mandatory administrative blending regimes it can be learned that the most critical design characteristics are:

- if quota sections for various qualities of the admixed substance will be distinguished and therefore different types of certificates per scheme;
- if the scheme applies generically, or to specific sectors/company types only (e.g. based on competitiveness considerations);
- if the certificates can be traded freely, and are traceable;
- if a certificate expires at some date, or can be banked forever;
- if explicit measures are taken to prevent fraud and abuse;
- if certificate prices are maximised or facing minimum levels, or both;
- if the overall quota level varies with the economic conditions and/or the environmental targets;
- if certificate trading will be restricted to specific areas (e.g. the issuing country), or instead is left free to the international market;
- if the acceptance of certificates in an administrative blending scheme is contingent upon the existence of a satisfactory level of physical blending.

The actual design of a mandatory administrative admixing scheme will be based on a mix of targets and the weight attached to each of them, such as: environmental goals; the reliability and credibility of the scheme and its certificates; the scheme's flexibility in implementation; the recognition of aspects of international competition; the impact of the scheme on investment and innovation in hydrogen production and use; the minimization of the overall societal costs of this mitigation instrument.

One of the clear advantages of introducing mandatory admixing schemes is that they may kickstart a specific and predefined level of market demand that will provide clear market guidance to potential investors in the admixed fuel; a disadvantage of the scheme may be that certificate prices are determined by the supply and demand balance on the market, and therefore are difficult to predict a priori. Actual practise has learned that the risks of fraud should not be underrated.

Although it is likely that administrative blending will lead to physical blending as well (see above), it is possible to steer the actual physical blending levels such that any desirable technical or safety issues related to that can be prevented; e.g. an administrative blending scheme could be fulfilled by a combination of small physical admixing options and pure hydrogen flows transported in dedicated systems.

Precisely because a mandatory blending scheme may create an immediate market for specific carbon neutral fuels (e.g. hydrogen), it is considered important in practise to make sure that such sudden demand jump will not crowd out the underlying energy carrier (e.g. green power in case of green hydrogen) from being used for other applications. That is why sometimes an additional condition for the blended hydrogen is propagated, namely that the producer of hydrogen will have to show that it is generated from green power that is produced in addition to what otherwise would have been produced. Sometimes such an additionality condition is even strengthened to the extent that it needs to be proven that the additional production volumes of hydrogen is synchronised with additional volumes of green power.

It is still an open question if and to what extent in the EU subsidized green power is allowed to be used to generate green hydrogen to be used for fulfilling a possible mandatory quota. For a successful launch of a mandatory administrative hydrogen blending scheme, it is imperative that this issue is resolved timely and clearly.

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