

A level playing field for the European biogas and biomethane markets



Case of the Netherlands and Germany:
policy environment, key differences and harmonisation issues

JIN Climate and Sustainability, Groningen

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LIST OF ABBREVIATIONS

Throughout this report, the general prevailing abbreviations in German and Dutch are used. This list gives an overview of these abbreviations, along with their meaning as well as English translations. Abbreviations noted **DE** are current in Germany and apply to German laws and regulations, while the notation **NL** refers to the Netherlands.

ACM	NL Authority for Consumers and Market (<i>Autoriteit Consument en Markt</i>)
AGP	NL Excise warehouse (<i>accijnsgoederenplaats</i>)
AIB	Association of Issuing Bodies
ATvGR	NL Connection and Transport Conditions Gas Regional Network Operators (<i>Aansluit- en transportvoorwaarden Gas RNB</i>)
BImSchG	DE Federal Immission Control Act (<i>Bundes-Immissionsschutzgesetz</i>)
Biokraft-NachV	DE Biofuel Sustainability Regulation (<i>Biokraftstoff-Nachhaltigkeitsverordnung</i>)
BiomasseV	DE Biomass Regulation (<i>Biomasseverordnung</i>)
BioSt-NachV	DE Biomass Electricity Sustainability Regulation (<i>Biomassestrom-Nachhaltigkeitsverordnung</i>)
BLE	DE Federal Office for Agriculture and Food (<i>Bundesanstalt für Landwirtschaft und Ernährung</i>)
BNetzA	DE Federal Network Agency (<i>Bundesnetzagentur</i>)
DENA	DE German Energy Agency (<i>Deutsche Energie-Agentur</i>)
DSO	Distribution System Operator
DVGW	DE German Association for Gas and Water (<i>Deutsche Vereinigung des Gas- und Wasserfaches</i>)
EC	European Commission
EECS	European Energy Certificate System
EEG	DE Renewable Energy Law (<i>Gesetz für den Vorrang Erneuerbarer Energien (Erneuerbare-Energien-Gesetz)</i>)
EnergieStg	DE Energy Tax Act (<i>Energiesteuergesetz</i>)
EEWärmeG	DE Renewable Energy Heat Law (<i>Erneuerbare-Energien-Wärmegesetz</i>)
EnWG	DE Energy Law (<i>Gesetz über die Elektrizitäts- und Gasversorgung (Energiewirtschaftsgesetz)</i>)

EVK	DE Feedstock Compensation Class (<i>Einsatzstoffvergütungsklassen</i>)
FQD	Fuel Quality Directive
G-gas	Groningen gas (see also: L-gas)
GasNEV	DE Gas Network Fees Regulation (<i>Gasnetzentgeltverordnung</i>)
GasNZV	DE Gas Network Access Regulation (<i>Gasnetzzugangsverordnung</i>)
GoO	Guarantee of Origin
HBE	NL Renewable Fuel Unit (<i>Hernieuwbare Brandstofeenheid</i>)
H-gas	High-calorific gas
IB	Issuing Body (of guarantees of origin)
ILUC	Indirect Land Use Change
ISCC	International Sustainability & Carbon Certification
L-gas	Low-calorific gas (see also: G-gas)
MBS	DE Mass Balancing System (<i>Massenbilanzsystem</i>)
MEP	NL Environmental Quality of Electricity Production subsidy scheme (<i>Milieukwaliteit Elektriciteitsproductie</i>)
Nabisy	DE Sustainable Biomass System (<i>Nachhaltige Biomasse System</i>)
Nawaro	DE Renewable resource (<i>Nachwachsender Rohstoff</i>)
NEa	NL Dutch Emissions Authority (<i>Nederlandse Emissieautoriteit</i>)
NTA	NL Dutch Technical Agreement, standard (<i>Nederlandse Technische Afspraak</i>)
ODE	NL Sustainable Energy Surcharge (<i>Opslag Duurzame Energie</i>)
OVMEP	NL Transitional Scheme MEP (<i>Overgangsregeling MEP</i>)
REB	NL Regulatory Energy Tax (<i>Regulerende Energiebelasting</i>)
REC	Renewable Energy Certificate
RED	Renewable Energy Directive
SDE	NL Encouragement of Sustainable Energy subsidy scheme (<i>Stimulering Duurzame Energie</i>)
StrEG	DE Electricity Feed-in Law (<i>Stromeinspeisegesetz</i>)
TSO	Transmission System Operator
Version 14	NL Additional Terms Regional Network Operators Green Gas Injectors (<i>Aanvullende Voorwaarden RNB Groen Gas Invoeders, 'Versie 14'</i>)

1. INTRODUCTION

This project, called ‘A level playing field for the European biogas and biomethane markets’, has focused on policy and economic aspects related to biomethane. The main aim of this project has been to explore the key institutional differences between two countries, the Netherlands and Germany, in the area of biogas and biomethane, and to see if and to what extent such differences could result in market distortions in the internal EU market.

The research project has been co-funded by INTERREG IVa Netherlands-Germany, as part of ‘*Groen Gas-Grünes Gas*’ programme, that consisted of 18 projects.¹ These projects have focused on different aspects of biogas and biomethane, such as new pre-treatment technologies for biogas feedstocks, biogas and biomethane production optimisation, as well as on the economics of biogas and biomethane and spatial planning and policy aspects.

This specific project has performed in-depth studies of the existing institutional regimes for biomethane in the Netherlands and Germany by analysing the key features of the different policy instruments related to biomethane activities (including biomass supply, biomethane production, distribution and end-use).

The findings of this project can be embedded in further research and policy efforts on the effectiveness and efficiency of harmonisation of renewable energy policies in the internal energy market. Convergence and/or harmonisation of national renewable energy policies is thought to be an important element in increasing the cost-effectiveness of renewable energy policies. This project shows that policy harmonisation in the field of biomethane is multifaceted and does not only require the implementation of exactly the same support instrument in each member state. We have shown that for policy convergence to be effective, the possible side-effects of the remaining differences in flanking or auxiliary policy instruments need to be taken into account. If not properly addressed, the costs (or inefficiencies) resulting from such differences could partially or completely offset the benefits from the harmonisation effort.

In addition to the institutional convergence analysis, we have explored if and to what extent there are credible alternatives for feed-in subsidies as a primary support scheme for biomethane. We explored to what extent some of the existing so-called ‘quota obligation and green certificate trade’ schemes could serve as a credible alternative support scheme, and have compared the functioning of such a support scheme in the internal market relative to the more traditional feed-in support schemes.

Chapters 2-4 will give an overview of the institutional frameworks in the Netherlands and Germany, and their differences. Conventional instruments, including the injection of biomethane into the natural gas network, the feed-in of renewable electricity into the electricity grid and feed-in support policies for renewable energy production are covered in chapter 2. In chapter 3, certificate schemes are discussed, including those for biofuel trading in the transport sector, guarantees of origin (GoOs) for renewable energy, and sustainability certificates. Chapter 4 provides a summary and highlights the key differences between the two countries.

¹ For an overview of these 18 projects, please refer to www.groengasproject.eu (website is available in Dutch and German only).

In chapter 5, a theoretical framework for the analysis on costs and benefits of possible convergence scenarios is presented, followed by the analysis of two convergence scenarios (the Netherlands adopts the German framework, or Germany adopts the Dutch framework). The final chapter 7 provides a summary, concluding remarks and a future-oriented reflection on institutional convergence, quota-based cap and trade schemes and cross-border trade.

The authors hope the reader will find the facts, analysis and findings of this report an interesting addition to their knowledge-base on policy harmonisation and institutional convergence in the area of renewable energy in the EU.

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2. CONVENTIONAL INSTRUMENTS

This chapter describes key features of a series of conventional policy instruments relevant for biogas and biomethane activities. These activities include the injection of biomethane into the natural gas network (Section 2.1), and the feed-in of renewable electricity into the electricity grid (Section 2.2). Section 2.3 focuses on feed-in support policies for renewable energy production. The chapter foremost centres around the 'current' policies (with 2012 as a reference year) in Germany and the Netherlands. Where applicable some issues regarding announced policies are taken into account.

2.1 Biomethane injection into the natural gas network

Upgraded biogas (known as green gas or biomethane) can be fed into the public natural gas network. Several factors define biomethane injection costs, both for the injector and for the gas network operator (DSO² or TSO³). These factors include the technical options as well as the institutional, legal and regulatory settings.

2.1.1 Gas network specifications

Natural gas networks can be broadly differentiated between H-gas networks for high-calorific gas, and L-gas networks for low-calorific gas.⁴ In the Netherlands, most of the injection of biomethane takes place in the L-gas networks, while both L-gas and H-gas networks are used for this in Germany. To date biomethane is mostly injected in the distribution networks with a pressure below 16 bar in Germany or 8 bar in the Netherlands. As feed in of biomethane in Germany predominantly takes place in an H-gas network, gas quality requirements for the Wobbe Index⁵ and calorific value are different from the Netherlands. In the Netherlands, the allowed Wobbe Index range is much narrower than in Germany. According to Hylkema (2012), a raise of the upper Wobbe limit is considered in the Netherlands for after 2021. This would lead to cost savings with regard to gas quality conversions, assuming the equipment of all connected gas users is able to cope with this wider range.

The maximum operating pressure of the networks is limited at the upper end. As a result, the amount of injected gas, which is usually very constant over time, is restricted by the minimal outtake for gas consumption of that network.

When a larger number of biomethane producers wants to inject biomethane into the natural gas network, the complexity of network operation grows as the capacity of the grid may be insufficient. However, there are several options for increasing that capacity: (1) compression and overflow to higher pressure networks; (2) connection of several regional networks; and (3) building a gas buffer. Considering the high costs and safety issues, on-site biomethane buffering is in practice only feasible in a few situations.

² DSO = Distribution System Operator (German: *Verteilernetzbetreiber*, Dutch: *regionale netbeheerder*).

³ TSO = Transmission System Operator (German: *Fernleitungsnetzbetreiber*, Dutch: *landelijk netbeheerder*).

⁴ L-gas is in the Netherlands also called G-gas, after the giant Groningen low-calorific gas field.

⁵ The Wobbe Index is the main indicator of the interchangeability of fuel gases. The Wobbe Index is used to compare the combustion energy output with different composition of fuel gases.

2.1.2 Legal framework

The German legal framework with respect to biomethane injection is formed by the Gas Network Access Regulation (*GasNZV*⁶) and the Gas Network Fees Regulation (*GasNEV*⁷). Since the *GasNZV* and *GasNEV* are delegated legislations under the German Energy Law (*EnWG*⁸), they are fixed by law. This regulatory framework therefore seems to provide legal certainty. However, German DSOs may put additional requirements on the biomethane producers if deemed necessary from a network operations perspective. In the case of disagreement, the producer can file a complaint at the Federal Network Agency (*Bundesnetzagentur, BNetzA*). The necessity of additional requirements is therefore surveyed in great detail.

The regulatory situation in the Netherlands is more multifaceted. Regulations relevant for feed-in of biomethane are codified in the Connection and Transport Conditions Gas Regional Network Operators (*ATvGR*⁹) by the Authority for Consumers and Market (ACM). Additional conditions are set in the Additional Terms [by] Regional Network Operators [for] Green Gas Injectors¹⁰ (generally known as ‘Version 14’). These additional conditions do not have a formal legal status, but are commonly imposed on injectors by the DSOs. It is generally considered to be very difficult for injectors to not accept these additional conditions and therefore they are regarded as a common practice.

Meanwhile, the DSOs set additional conditions, which may or may not be the conditions as described in ‘Version 14’. In 2013 there has been a mediation process between biomethane producers and DSOs, aiming to come to an agreement on a new version of the *ATvGR*. These new conditions should include all regulations and conditions and not provide the possibility for DSOs to set additional terms (i.e. the aspects currently regulated through ‘Version 14’ have to be integrated in the regulation codified by ACM). In addition, the aspects related to gas quality and composition will be removed from the *ATvGR* as well as the related additional conditions. Instead, these are regulated through a ministerial regulation starting in October 2014 (i.e. through delegated legislation, similar to the German situation).¹¹

2.1.3 Responsibilities sharing

In the Netherlands, the primary responsibility for gas quality and safety lies with the producers, based on ‘Version 14’ and case law. The DSOs are fully indemnified from all liabilities, i.e. the injector is and will remain responsible for the gas quality, also after injection into the grid. Since the liberalisation of the gas market there is a split between gas suppliers and DSOs. The gas in the network originates from several producers, while the DSO is the physical supplier of the gas towards the consumer. According to Tempelman (2012), it is believed that both the DSO and the gas supplier will lay the liability with the gas producer – i.e. the injector of biomethane. However, in real practice it may not always be clear which gas producer can be held responsible, because the gas will blend with gas from other producers connected to the network.

⁶ German: *Gasnetzzugangsverordnung – GasNZV*. Released in 2010, last updated in 2012.

⁷ German: *Gasnetzentgeltverordnung – GasNEV*. Released in 2005, last updated in 2010.

⁸ German: *Energiewirtschaftsgesetz – EnWG*. Released in 2005, last updated in 2013.

⁹ Dutch: *Aansluit- en transportvoorwaarden Gas RNB – ATvGR*. Last updated in 2012. This code is an elaboration on the Gas Act (*Gaswet 2000*).

¹⁰ Dutch: *Aanvullende Voorwaarden RNB Groen Gas Invoeders – ‘Versie 14’*. Released in 2009.

¹¹ The ministerial regulation on gas quality (Dutch: *Regeling gaskwaliteit*) has been published in July 2014, and takes effect by 1 October 2014.

According to GasNZV (§36), the producer is legally responsible for the gas composition in Germany. The DSO is responsible for the gas composition measurement prior to the injection into the network (Von Bredow & Valentin, 2010). The DSO then also has to ensure that the transported gas will reach the exit-point with the prescribed quality. DSOs have the right to refuse bio-methane feed-in if this does not comply with the gas quality requirements of the DVGW work sheet G260 (GasNZV, §34). No further responsibilities and liabilities are specified in case of network damage stemming from the poor quality of injected gas.

2.1.4 Gas quality requirements

The gas quality requirements of the regional networks for G-gas in the Netherlands are determined in the ATvGR. 'Version 14' states additional quality requirements for the injected gas. These regulations are to be replaced by the new ministerial regulation on gas quality by 1 October 2014. In Germany, according to §36 of the GasNZV, the injector has to comply with the requirements of the DVGW works sheets G260 and G262 as formulated in 2007. Injection requirements in the Netherlands (in the new ministerial regulation) and Germany are hence as indicated in Table 1.

Table 1. Gas quality requirements for gas distribution networks in the Netherlands (G-gas) and Germany

Requirement	Unit	Netherlands	Germany
Oxygen level (dry gas networks)	mol%	≤ 0.5	≤ 3.0
Sulphur	mg/m ³ (n)	≤ 5.5 (before odourisation)* ≤ 16.5 (after odourisation)*	≤ 30*
Inorganically bound sulphur	mg/m ³ (n)	≤ 5	
Sulphur bound in mercaptans	mg/m ³ (n)	≤ 6	≤ 6*
Hydrogen sulphide	mg/m ³ (n)		≤ 5*
Water dew point	°C	≤ -10	≤ ground temperature
Condensate dew point	°C		≤ ground temperature
Temperature of gas	°C	5 – 20	2 – 20
Odourant level	mg/m ³ (n)	THT: 10 – 30	'yes'
Ammoniac	mg/m ³ (n)	≤ 3**	technically none
Dust, particles	mg/m ³ (n)	≤ 100	technically none
Chlorinated compounds	mg/m ³ (n)	≤ 5	
Fluorinated compounds	mg/m ³ (n)	≤ 5	
Hydrogen chloride	ppm	≤ 1**	
Hydrogen cyanide	ppm	≤ 10**	
Carbon monoxide	mg/m ³ (n)	≤ 2,900	
Carbon dioxide	mol%	≤ 10.3	≤ 6
BTX (benzene, toluene, xylene)	ppm	≤ 500**	
Hydrocarbons	mol%	≤ 5	
Hydrogen	mol%	≤ 0.1	≤ 5
Nitrogen	mol%		≤ 5
Methane level	mol%		> 95

Siloxanes	mg/m ³ (n)	≤ 0.4	–
'Smellability'	-	Sufficient	
<p>* For some requirements, values may be temporarily higher than the indicated maximum annual average. In the Netherlands this is called peak value (piekwaarde), in Germany short-term value (Kurzzeitwert).</p> <p>** These requirements are not included in the new ministerial regulation, but assumed to be still relevant based on 'Version 14'.</p>			

There are certain differences in the specific values of trace components in the gas. However, these differences do not give rise to a significant unlevel playing field for biomethane producers in Germany and the Netherlands. There is a serious difference in the CO₂ specification: ≤ 10.3 mol% in the Netherlands vs ≤ 6 mol% in Germany. Without adding other inert gases it is not possible to meet the Wobbe Index criterion for L-gas in the Netherlands with maximally 6 mol% CO₂ in the upgraded biogas. This requirement in Germany blocks physical export of upgraded biogas to the Netherlands because of the Wobbe criterion in the Dutch L-grid. Also physical export from the Netherlands to Germany would encounter problems with the CO₂ criterion. Of course, blending of the upgraded gas in a large stream of fossil gas could alleviate these problems.

2.1.5 Network and contract capacity balancing

In Germany, biomethane producers are obliged to provide the DSO with a forecast about the planned feed-in quantities. This document is, however, not binding for the biomethane producer, i.e. production can be adjusted during the twelve-month balancing period (for fossil gas the balancing period is 24 hours only). §35 of the GasNZV obliges the DSOs (more specifically the one in charge of a market area) to provide an extended balancing service for the balance accounts utilising biomethane. This extended balancing regime consists of higher flexibility equal to 25% of the account's volume (for fossil gas 5% with additional requirements). Furthermore, within this limit, biomethane surpluses can be transferred into the next balancing period. Deviations from the flexibility frame are sanctioned with a reduced balancing fee of € 0.001 per kWh. This clause is, however, subject to regular BNetzA monitoring and may be modified later if found inefficient.

In the Netherlands, the biomethane producer is constrained by the capacity stated in the contract with the DSO. The balancing period in the Netherlands is one hour.

If the hourly feed-in is higher than the contracted quantity, the producer has to enter into a new contract with the DSO. These contracts may be short-term, e.g. for one week or one month. Producers are never allowed to feed in more than the instantaneous demand for gas in the same network, even if their contracted capacity is higher, in order to avoid unacceptable pressure in the grid.

If the biomethane producer injects into the network of the TSO, he is bound by the rules for that grid and the balancing period is one hour. However, any hourly imbalances that are accumulated during the day are settled at very low costs by the TSO.

2.1.6 Obligation to connect

§33 and §34 of the GasNZV guarantee biogas producers priority network connection and gas transportation. Based on these paragraphs, network services can be refused only if the measures associated with these tasks are technically or economically not feasible. In such a case, the DSO is obliged to suggest an alternative solution to the injector. Hereby, insufficient network capacity cannot

be used as reason for refusal of network service. Nevertheless, the available literature for Germany keeps reporting low or inadequate cooperation levels of DSOs (Ritter, Horn, Köttner, & Kastenholz, 2012). This is claimed to be caused primarily by the high associated costs of the support scheme that the DSOs would have to bear, related to for example network reinforcement (Von Bredow & Valentin, 2010).

According to the Dutch Gas Act of 2000, DSOs do not have a legal obligation to come up with solutions for insufficient capacity of the network. The DSO can refuse a grid connection for biomethane injection on the basis of inadequate capacity. If additional network capacity is necessary, realised for example through an overflow facility, it is not fully clear which party can or should carry the costs. However, since the DSO is not obligated to connect, it is expected that the producer will have to carry the overflow investment and operational costs (Holstein, et al., 2011).

The GasNZV requires DSOs to prioritise biomethane transport over fossil gas. In the Netherlands there is no such regulation. However, since biomethane producers feed in with a pressure of 8.1 bar on an 8 bar distribution network, the biomethane is prioritised automatically.

2.1.7 Costs

In Germany, investment and operation costs of the gas grid connection are shared between the injector and the DSO. The DSO is responsible for the measurement of gas composition and the odour facility, and thus carries all the investment and maintenance costs for these. All the other components are considered to represent the network connection components (GasNZV, §32, section 2) for which the investment costs are shared. Once constructed, the network connection becomes the property of the DSO.

In the Netherlands, investment and operational costs for biomethane injection are borne by the injector only (De Bruin, 2011). This is called the ‘deep charging method’: producers are expected to pay both for the grid connection and possible grid reinforcement (Knight, et al., 2005). See Table 2 for a comparison of the costs distribution between producers and DSOs in the Netherlands and Germany. Notwithstanding the rules below, if the connecting pipeline is shorter than 1 kilometre, the producer pays a maximum of € 250,000 for the entire grid connection.

Table 2. Gas grid connection costs distribution in the Netherlands and Germany

Costs for...	Netherlands	Germany
Biogas upgrading facility	Producer	Producer
Compressor, volume and calorific value measurement	Producer	Producer 25%; DSO 75%
Odouriser, gas composition measurement, connection maintenance	Producer	DSO
Connecting pipeline	Producer	<10 km: Producer 25%; DSO 75% >10 km: Producer 100%. Partial refund if other plants connect to the same pipeline

Grid reinforcement	DSO (if reinforcement is requested by the producer, it is usually to be compensated by this producer)	DSO
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The table below shows investment cost estimates for a standard 550 m³/h connection facility in the Netherlands (De Bruin, 2011) and a comparable 500 m³/h facility in Germany (FNR, 2006). Since operation and maintenance costs are to be borne by the owner of the grid connection facilities, this is in Germany for the DSO, and in the Netherlands for the producer.

Table 3. Example of gas grid connection costs in the Netherlands and Germany

Facility 500 – 550 m ³ /h	Netherlands	(producer)	Germany	(producer)
Measur. equipment	80 000	80 000	125 000	6 250
Odourisation	15 000	15 000	14 000	0
Compression	170 000	170 000	50 000	12 500
Connect. pipeline (1 km)	100 000	100 000	160 000	40 000
Other costs	85 000	85 000	21 000	5 250
Total	€ 450 000	€ 450 000	€ 370 000	€ 64 000

There is some difference in the compression costs, which results from the lower pressure grid assumed in the German case. However, the main difference stems from the cost sharing mechanism. The grid injection facility in Germany costs the producer 64,000 euro (89,000 – 99,000 euro with the more expensive Dutch compressor estimate), as compared to 450,000 euro (330,000 euro with German compressor estimate) in the Netherlands, where costs are not shared.

In Germany, the GasNZV obliges the DSO to absorb the bio-methane as long as it is physically possible (§34). Overflow facilities are explicitly stated within the regulation as one of the possible options for network capacity increase (§34). As opposed to this, costs of capacity expansion measures are most likely to be carried by the biomethane producers in the Netherlands. The costs for an overflow facility from the regional network to the transport network consists of several components, most notably the compressor (Holstein, et al., 2011). These are estimated to range between 400,000 and 700,000 euros, depending on its capacity.

Alternatively, a gas buffer could be built. According to De Bruin (2011), the investment costs for a gas buffer with a capacity of 6,600 m³ are 225,000 to 275,000 euros. Jonkman (2011) states that the costs for a 1,000 m³ buffer are estimated to be 80,000 euros.

2.2 Feed-in of renewable energy into the electricity grid

Once biogas has been converted into electricity, it can be fed into the public electricity network in order to transport it to the final consumers. The feed-in of electricity has several aspects that define its costs: for the producer, for the energy supply company, and for the DSO. These aspects include the technical options as well as the institutional, legal and regulatory settings.

2.2.1 Institutional and regulatory setting

Since 2005, Germany applies a regulated grid access system, which had been common in all other EU countries (including the Netherlands) since 1996 (Grashof, 2007). In Germany, the Federal Network Agency is responsible for the supervision of the grid access regulation. The main legislative acts that are concerned with electricity grid connections are the German Energy Law (*EnWG*) and §§ 5 – 15 of the Renewable Energy Law from 2012 (*EEG*¹²) that guarantees a priority feed-in for renewable electricity, amongst others. Both laws were established to comply with the European directives on the liberalisation of energy markets (96/92/EC and 98/30/EC) and on the promotion of renewable electricity (2001/77/EC). Due to the required unbundling of market activities, the transportation of electricity has become the core task of independent DSOs (Part 2, *EnWG* 2005). While being supervised by the Federal Network Agency and bound by the *EnWG* and *EEG*, these entities are responsible for the proper functioning of the grid, its access and its capacities.

In the Netherlands, according to the Dutch Electricity Act¹³, the DSO is responsible for registering, constructing, maintaining and operating grid connections. In addition, it is the role of the DSO to transport the electrical energy, both the electricity that is to be delivered and the electricity that is fed back into the grid.

2.2.2 Grid connection and capacity

The situation with regard to the capacity of the grid connections is more or less the same in the Netherlands and Germany. In the Netherlands, the DSO is responsible for checking if the grid connection has sufficient capacity for the requested feed-in. If the connections' capacity is insufficient, the producer is responsible for a new connection, although this is usually facilitated by the DSO (Enexis, 2013). In Germany, also the producer has to bear the costs for the grid connection itself, while the DSO should provide a cost prediction for the connection within eight weeks and establish the connection 'without delays' (§5 *EEG* 2012). If the capacities are insufficient to connect the renewable electricity facility, the DSO is obliged to increase the capacities if this is technologically and economically feasible (§9 *EEG* 2012). The costs for grid enforcements due to insufficient capacities have to be borne by the DSO (§14 *EEG* 2012).

Both article 24 of the Dutch Electricity Act and part 3, section 2 of the German *EnWG* define the obligation of the DSO to connect every entity to the grid in a non-discriminatory manner. The obligation to connect is only invalid if the connection would be economically or technically infeasible. In such a case, the grid operator must give a justification for denying the grid connection.

2.2.3 Value of fed-in energy

In Germany, the price paid by the DSOs to the producers of renewable electricity is determined directly by the feed-in tariff of the *EEG* (§16 *EEG* 2012). In the Netherlands, the price paid to small-scale consumers for renewable energy is determined as a 'reasonable compensation' by the Authority for Consumers and Market. The 'reasonable compensation' is at least 70% of the basic price of supply excluding VAT. Large-scale suppliers of renewables should agree on an energy price with the energy

¹² German: *Erneuerbare-Energien-Gesetz – EEG*. Originally released in 2000, last updated in 2012.

¹³ Dutch: *Elektriciteitswet 1998*.

company on an individual basis. Agentschap NL (2012) estimates that the common price for large-scale suppliers is similar to the established reasonable compensation.

2.2.4 Costs

Both in the Netherlands and Germany, the connection costs are not fixed and may vary between several thousand euros to approximately € 250,000.¹⁴ The actual costs depend on the individual circumstances at the respective production sites (e.g. distance to grid, voltage). Since the connection can be used for both energy consumption and feed-in, and renewable energy producers usually already own a connection for energy consumption, the additional costs for enabling renewable energy feed-in are often insignificant.

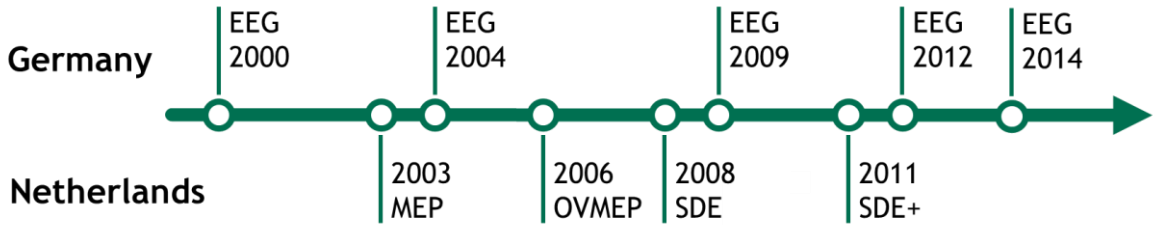
In both countries, grid expansion and reinforcement have to be paid by the DSOs. This is known as the shallow charging method (Knight, et al., 2005): electricity producers have to pay for their connection, but not for the grid reinforcement.

2.3 Feed-in subsidy and tariff schemes for biomethane

One of the aspects of the institutional and economic ‘playing field’ is the system of promotion policies for renewable energies. These individual national policies were initially realised to comply with EU directive 2001/77/EC on the promotion of renewable electricity. Since the beginning of the millennium, different incentive structures evolved in Germany and the Netherlands. The institutional, legal and regulatory settings of these subsidy and tariff schemes influence the playing field of biogas/biomethane producers in both countries.

2.3.1 Historical development

Figure 1. Timeline of the renewable energy promotion policies in Germany and the Netherlands



In Germany, the promotion of renewable electricity has been established quite early in comparison to other European countries. Already in 1990, the Electricity Feed-in Law (StrEG¹⁵) has been passed, which guaranteed between 65 and 90% of the final consumer price for producers of renewable electricity. Due to falling electricity prices, and because of the regional divergence in the production of renewable energy, the StrEG became ineffective and an issue of the political debate on the distribution of the cost burden (Zitzer, 2009).

These developments made it necessary to renew the renewable promotion policy in Germany and led to the establishment of the EEG in the year 2000. The law was designed to challenge the major drawbacks of the StrEG and therefore became a feed-in tariff scheme with fixed technology-specific

¹⁴ See for Dutch examples Enexis [\[link\]](#), Cogas [\[link\]](#) and Rendo [\[pdf\]](#).

¹⁵ German: Gesetz über die Einspeisung von Strom aus erneuerbaren Energien in das öffentliche Netz (Stromeinspeisegesetz). Originally released in 1990, replaced by EEG in 2000.

electricity prices (to battle the price uncertainties) and a federal cost clearing mechanism (to counter the regional imbalances) (Wüstenhagen & Bilharz, 2006). The EEG only promotes the production of renewable electricity including that produced from biomass, and constitutes the foundation for the rapid development of renewable energy production in Germany, where the production of renewable electricity rose from 39,181 GWh in 2000 to 136,075 GWh in 2012 (AGEE, 2013).

In the Netherlands, the first subsidy scheme for sustainable energy production was introduced on 1 July 2003.¹⁶ Under the MEP¹⁷ subsidy scheme, energy producers could receive a fixed compensation per unit of sustainably generated electricity on top of the market price. This included energy generation through biomass combustion, solar energy, wind power and hydro power. The Minister of Economic Affairs set the subsidy for all new requests for all categories to zero in August 2006, because it was expected to reach the targets for 2010 without new subsidies (Algemene Rekenkamer, 2010).

From 19 December 2006 until 31 May 2007 there was a transitional scheme called OVMEP. This scheme was only applicable for biomass co-digesters that already applied for environmental and building permits before August 2006 (Agentschap NL, 2011).

Starting in April 2008, a new subsidy scheme for encouraging sustainable energy called SDE¹⁸ was created. This scheme not only subsidises sustainable electricity, but also renewable gas. While the goal of the MEP scheme was to reach 9% sustainable electricity in 2010, the goal of SDE is to reach 14% renewable energy in 2020 (Algemene Rekenkamer, 2010). The Rutte II government's coalition agreement of October 2010 increased the target for 2020 to 16% (Agentschap NL, 2013a), but in the 'Energy Agreement' (*Energieakkoord*) signed by a wide range of stakeholders in September 2013, the target was reversed to 14% by 2020, and 16% by 2023 (SER, 2013).

The budget of the SDE scheme was fixed annually, and the scheme opened for a few months per year before the budget claims exceeded the available budget. In the SDE scheme there were several separated budget amounts available for different technology categories. The SDE+ scheme was introduced in 2011 as the successor of SDE. There are some differences between SDE+ and SDE, notably that there is now one budget for all technologies combined, so that technologies compete with each other for subsidies. Another important difference is the introduction of competitive bidding, where application for subsidies takes place in categories from low to high subsidy rates, in order to make the allocation of subsidies as cost-effective as possible (Agentschap NL, 2013a).

Even though no new MEP, OVMEP and SDE subsidies are granted anymore, many of the projects that received these subsidies are still active. The MEP subsidies will gradually expire and the scheme fully terminates in 2015 (Agentschap NL, 2013a).

2.3.2 Eligible feedstock

In the Netherlands, the SDE(+) scheme uses two 'positive lists' that stipulate which biomass can be used for (co-)digestion. (Co-)digestion of manure is defined as the digestion of "the mainly pumpable

¹⁶ Before Introduction of the MEP, renewable energy was from 1996 to 2004 promoted through the regulatory energy tax (*regulerende energiebelasting, REB*). Renewable electricity was exempted from this tax. Since this was an incentive for consumption instead of production of renewable electricity, also foreign energy producers could benefit and taxpayers' money leaked to other countries. In 2003 the REB exemption measure was replaced by the MEP.

¹⁷ Dutch: *Milieukwaliteit Elektriciteitsproductie*. Originally released in 2003.

¹⁸ Dutch: *Stimulerend Duurzame Energieproductie*. Originally released in 2007.

solid and liquid excrements of animals, whether or not accompanied by one or more products listed in the Implementation Regulation on the Fertilisers Act.”¹⁹ In appendix Aa, part IV, of this regulation, a positive list is included. At least 50% of the feedstock should be manure; otherwise the project is classified as ‘all-purpose digestion’ instead of ‘manure co-digestion’.

With regard to all-purpose digestion (*allesvergistig*), the SDE+ scheme states that it encompasses “the biological degradative reactions of biomass as meant in the NTA 8003: 2008, with the exception of the number 410, 420, 500, 550 until 559.” This positive list is thus based on the biomass classification for sustainable energy NTA8003 as composed by NEN (Netherlands Standardisation Institute).

In Germany, the overall allowed biomass inputs used in biogas production are covered in the *BiomasseV*. The eligible renewable raw materials, in relation to first the *Nawaro-Bonus* and currently the *EVK* categories (introduced in Section 2.3.5 below), are defined in the annex of the *BiomasseV* (FNR, 2010). It has been adapted along with the different versions of the law itself (FNR, 2010).

Market conditions, national circumstances and differences in eligible feedstock regulations and conditions between the two countries have led to significant differences in the types of feedstock that are used. Figure 2 shows that more than half of the mass share of feedstock in Germany consists of maize and other primary feedstock, while in the Netherlands more manure and residues is used.

Figure 2. Mass input share in Germany and the Netherlands

	Maize	Other primary	Manure	Other
DE	39%	15%	41%	5%
NL	8%	5%	59%	28%

2.3.3 Financing source and budget

In the Netherlands, the subsidy schemes are all financed directly from the national government budget, which in turn is generated through the sustainable energy surcharge (*ODE²⁰*) on the gas and electricity bill of energy consumers. In Germany, end-users connected to the electricity grid pay a surcharge (*EEG-Umlage*) that compensates the DSOs for paying a fixed price to the renewable electricity producers.

By its nature, the German EEG provides an unlimited budget. The *EEG-Umlage* can in theory be increased as much as necessary to finance the renewable energy production. The approach in the Netherlands makes that the budget is limited; it is deliberately set by the government. An effect of this system is that subsidy money is claimed by potential producers, but it is not necessarily used: due to the limited budget, project developers submit a claim on subsidy money to ensure being in time. As a result, also projects that in the end turn out to be unfeasible claim subsidy money. The German system provides more certainty to project developers, since there a subsidy is – in principle – always available.

2.3.4 Duration of payments

In the Netherlands, the duration of the subsidy depends on the scheme vintage and the project characteristics. In the MEP, the subsidy duration was in principle 10 years, without differentiation per

¹⁹ Dutch: *Uitvoeringsregeling Meststoffenwet*. Originally released in 2005.
²⁰ Dutch: *Opslag Duurzame Energie*.

technology. In the SDE(+), the minister can decide on a subsidy duration per technology. The choice of the duration of the subsidy per category is as much as possible in line with the expected technical lifespan of the facility (Van Tilburg, et al., 2008). In general, the duration of subsidy for biomass categories is 12 years, while for other facilities a time span of 15 years is applied. The duration of bank loans for biogas plant investments and the depreciation period of the facilities are anticipated to be the same as the duration of the subsidy (Lensink, et al., 2011). For the expansion of plants where biomass is converted into heat a subsidy duration of 5 years is stated.

In Germany, §21 of EEG 2012 defines the duration of support at 20 years for every technology, including biomass technologies. This means that German projects gain more certainty on long-term revenue than Dutch ones.

2.3.5 Subsidy and tariff rate setting in Germany

The German system provides certainty regarding the tariff rate. However, the annually determined tariffs in the Netherlands provide more flexibility to set the rates at competitive levels that reflect the market circumstances.

In the EEG scheme, fixed tariffs are determined for every kilowatt hour that is fed into the public grid. There is a differentiation in the level of the tariff per kWh with regard to the rated power²¹ of the facility and to the feedstock that is used. A degression to the tariff is applied annually, in order to anticipate technological development, learning curves and economies of scale, and to encourage project developers to operationalise their plants as soon as possible.

§20 of the EEG defines technology-specific degression rates. For example since 2012, the degression rate for new facilities using biomass is 2% per year. This means that a newly built facility in 2013 gets a 2 % lower tariff than a facility built in 2012 (BMU, 2012a). See Annex 1 for an overview of tariffs and degression rates.

To foster market integration of renewable electricity, a new direct marketing approach has been established in §33 of the EEG 2012. Up till then, the only possibility was to produce the renewable electricity while the DSO was obliged to feed in and sell the electricity on the market. The producer receives the fixed tariff on a monthly basis from the respective DSO.

The new approach of direct marketing allows the producer to market the energy on his own. At the same time, a market premium has been established. It is designed to guarantee an economic incentive to invest in renewable electricity. Similar to the tariff, this premium is paid by the DSOs on a monthly basis and socialised through the *EEG-Umlage* (§33g EEG 2012).

Following §33d of EEG 2012, renewable electricity producers are allowed to switch between the fixed tariff and the different forms of direct marketing on a monthly basis. In addition, if renewable electricity is produced by using biogas or biomethane, the producer is able to gain the flexibility premium (§33i EEG 2012). This premium is an incentive to invest in additional production capacities that allow for a more independent production of gas and electricity, in compliance with time-wise fluctuating demand patterns.

²¹ The definition of rated power in this context is given by §3 of the EEG: “[the] rated power of a facility [is] the quotient of the sum of the produced kilo watt hours in one calendar year and the sum of the total number full hours within that respective calendar year [...]”

While since 2000 the EEG was designed to promote the use of solid biomass (e.g. wood residues), the introduction of a bonus on renewable raw materials ('Nawaro-Bonus') in the EEG adaptation of 2004 boosted the production of biogas, especially as it focused on the use of, amongst others, maize (DBFZ, 2010). To receive payments, the producers of electricity made from biogas have to keep daily records (*Einsatzstoff-Tagebücher*) on their input materials and have to provide them to external auditors on demand (FNR, 2010).

The impressive growth effect by the Nawaro-Bonus was further enhanced by the introduction of a bonus on the use of excrement in the EEG of 2009. It was allowed to be used in conjunction with the other five bonuses (see Annex 2) and therefore again increased the general level of payments (DBFZ, 2010). One of the other bonuses is the technology bonus which since 2009 was applicable on the upgrading of biogas to biomethane. In Germany, the upgrading technology itself has been first installed in 2006, but a real uptake did not happen until its implementation in the technology bonus in 2009. Since 2006 however, an increasing amount of 'raw' biogas has been upgraded to biomethane and fed into the German gas grid. Until 2012 an hourly production capacity of 116,175 m³ of biomethane has been installed which represents about 8% of the total installed biogas production capacity (Biogas Fachverband, 2014).

Because the EEG of 2009 could be seen as a mere extension and adaptation of the prior versions since 2000, only the tariff structure of the EEG 2009 is presented here in detail. The version of 2009 is still of crucial importance, because following §66 paragraph 1 of the EEG, older biogas facilities remain under the 2009 legislature even after the adaptation of 2012.

Overall, the EEG has been responsible for the increase in the number of biogas production facilities from 1,050 in 2000 to 7,515 in 2012, and an overall electricity production from biogas of 22,840 GWh in 2012 (Biogas Fachverband, 2014).

The differences between the biomass subsidy structures of the EEG 2009 and EEG 2012 are substantial. The bonus system has been abolished and replaced by a new system. In doing so, the Biomass Regulation (*BiomasseV*²²) has also been changed so that for example corn and other renewable raw materials have been put in a lower category for payments and other ecologically preferred biomass inputs are granted higher compensation.

The bonus system has been replaced by a system of three different input categories which consist of the base category getting the base tariff, and two feedstock compensation classes (EVK) getting larger amounts. It is important to notice that the additional subsidy for the use of EVK I & II inputs is not subject to any depression, and is therefore the same for all new facilities disregarding the year they are built (see Annex 3).

In addition to the inputs given in the EVK within the *BiomasseV*, the biomass which is allowed to be used is also generally defined in §2 of the *BiomasseV*. It includes all phyto and zoo mass and their residues and by-products such as plants, biogenic waste and biogenic gases. To further specify this broader definition, §3 of the *BiomasseV* defines a negative list of inputs that are under no circumstances considered biomass, e.g. fossil fuels and their by-products, paper and textiles.

²² German: *Biomasseverordnung*. Originally released in 2001.

To receive a tariff payment, the biogas and biomethane producers have to follow certain technological conditions and obligations.²³ These obligations are defined under §27 paragraph 4-6 of the EEG and include a minimum heat use and requirements for documentation. In §6 of the EEG there are two technical provisions for the biogas production. These demand fermentation residue depots with covers and installations that enable ecologically efficient congestion management (e.g. gas flares).

The upgrading of biomethane itself is subject to further obligations which are laid out in Annex 1 of the EEG and consist of a maximum slip of methane to the atmosphere, a maximum use of process electricity, and a restriction on the use of fossil fuels for process energy.

Following §27c paragraph 1 of the EEG, the producers of biomethane are also obligated to use a mass balancing system (MBS) to prove the origin of the input gases. Since 1st January 2013 it is necessary to use MBS for the approval of EEG subsidies on biogas upgrading and the approval of biomethane under the Renewable Energy Heat Law (*EEWärmeG*²⁴)(BMU, 2012).

Also in §27c paragraph 1 of the EEG, it is stated that only those gases could be recognised that are fed into the grid within the area of application of the law itself. It is therefore not possible for domestic electricity producers to receive payments when the renewable gas is fed into the grid from outside Germany by foreign biomethane producers.

On 4 March 2014 an official draft of the new version of the EEG has been published by the Federal Ministry of Economics and Energy (Bundesregierung, 2014). This draft includes major changes for the promotion of biomass and a radical change in the tariff structure (§42 of the Draft EEG 2014, see Annex 4).

The implementation of the law in that way would include the following:

1. Direct marketing would become the first option for the producers of renewable electricity. Therefore, the capacity levels for the mandatory participation in the direct marketing scheme would be successively lowered to 100kW in 2017 (§35 of the Draft EEG 2014).
2. There would be no further promotion for the use of renewable raw materials. The input compensation categories (EVK) would be abolished and there would only remain a base tariff.
3. There would be no additional payments for the production of biomethane anymore.
4. The abolishment of the demanding technological requirements as the minimal heat use criterion, amongst others.

The only facilities that would still gain additional compensation are biogas facilities that are using bio-waste and residuals, and small facilities that are using excrement as an input. In addition, for every new facility with an installed capacity above 100kW it would become obligatory to be able to produce electricity in a flexible manner. The supply of the excess production capacity would be compensated by a flexibility premium (§51 of the Draft EEG 2014).

The overall impression of a substantial cutback in the promotion of biomass is supported by the newly defined 'development corridor'. In §1 of the Draft EEG 2014, this biomass corridor is defined at only

²³This seems to be a major difference to the Netherlands where no such regulatory dimensions exist.

²⁴ German: *Erneuerbare-Energien-Wärmegesetz*. Originally released in 2008.

100 MW installed capacity for every year starting 2014. In perspective, the average newly built capacity per year between 2004 and 2014 was as much as 315 MW (Biogas Fachverband, 2014). If the proposed corridor is exceeded, the tariffs and premiums for future facilities will be lower (see Annex 4).

2.3.6 SDE(+) subsidies in the Netherlands

The Dutch SDE(+) scheme has a fixed tariff system per technology.²⁵ Because the tariff is fixed, a flexible subsidy is provided to compensate for the fluctuations in the energy price. The tariff is determined annually and can vary, as there is no degression system as in Germany. The MEP scheme was considerably different, as it had a fixed subsidy which was determined per technology annually. In combination with the flexible energy price, the total tariff for renewable energy was also flexible.

Subsidy under the SDE scheme is provided per unit of energy (i.e. kWh, Nm³ or GJ) supplied to the grid, while for project categories (and per bidding round) different base rates have been set. A base rate is determined based on production costs, which are identified through expert consultation. According to Lensink et al. (2011), the base rate is based on a reference facility consisting of a certain technology or combination of technologies, combined with a common number of full load hours. For the biomass categories a reference fuel is used. “For the financial framework (...) it is asked by the Ministry to count on a financial total profit of 7.8%” (Lensink, et al., 2011, p. 12). The base rate is applicable during the entire subsidy duration (Van Tilburg, et al., 2008).

The size of the subsidy is the difference between the category-specific base rate and an average ‘base energy price’. The base energy price is corrected ex-post corresponding to the real energy price, so that when the energy price is higher, the subsidy is lower and vice versa (Algemene Rekenkamer, 2010). The base energy price is determined by ministerial regulation. The base price prevents the maximum subsidy tariff to be identical to the abovementioned base rate. Every year on 1 April a correction on the base rate is applied. Corrections are based on the average energy price, and in the case of renewable electricity also based on the value of guarantees of origin.

The subsidy tariff is determined by changing the base rate in line with the corrections. If the subsidy tariff is negative, the subsidy for that calendar year is set to be zero. The subsidy is equal to the product of the subsidy tariff and the quantity of energy units. For every category a maximum number of energy units is determined, and based on that a maximum number of full load hours for the facility. Remaining eligible hours from a certain year can be carried over to the next year (RVO, 2014). In the MEP and SDE systems this was not yet possible (Van Tilburg, et al., 2008).

A main difference between the SDE scheme and the MEP scheme is that the subsidy tariff for SDE is based on the realised financial gap, while the tariff for the MEP subsidy was based on the financial gap that was anticipated in advance. The reason for this change is to ensure that no redundant subsidy is given in case of higher electricity prices (Van Tilburg, et al., 2008).

Since 2011 the successor of SDE, called SDE+, is operational. All eligible project categories, as set out in the previous section, can participate in several subsequent bidding rounds with gradually increasing base rate subsidy levels. In 2011 there were four bidding rounds, in 2012 five and in 2013 and 2014 six. This structure is intended to increase the cost-effectiveness of the overall scheme (most renewable energy produced for the lowest possible costs). Both in SDE and in SDE+ subsidies are distributed on a

²⁵ In order to be eligible for SDE+ subsidy, a building permit as well as environmental permit need to have been granted in advance.

'first come, first serve' basis, although in SDE there was a specific minimum amount of subsidy available per technology category.

Instead of a subsidy limit for each category, there is one overall subsidy limit in SDE+. All technologies compete with each other for subsidy. The phased opening of the scheme (via the several rounds) covers cheaper technologies first. In addition, there is a 'free category'. In this category, producers that have a production plant that is on average too expensive for a certain round can still request subsidy for the maximum base rate of that round. Some technologies are identified as being only eligible for applying for subsidy in the 'free category'. In 2013 this includes the technologies of osmosis and run-of-the-river hydropower.

2.3.7 Comparison of payments for biomethane production

To summarise and to get an impression on the different dimension of payments between the two countries, a calculation based on an assumed installation has been conducted (see Table 4).

Please note one important assumption: while in the Netherlands the payment is directly going to the biomethane producer, in Germany it is paid to the CHP-producer by the DSO. This is due to the fact that under the EEG, only the production of electricity is subject to payments. To make the payments comparable, it is therefore necessary to estimate a certain maximum price that is attainable for the producer of biomethane in Germany. This would include the overall revenue from tariff payments minus an estimated share that is left for the CHP-producer. This includes his costs and expected profit. The actual price that a biomethane producer is able to attain is the result of individual negotiations between him and the CHP-producer.

This comparison shows that while assuming an equivalent energy content in Germany and the Netherlands (L-Gas), the payments per cubic meter would be about seven cents higher for the German facility. When assuming a higher energy content (H-Gas), the payments per cubic meter for the German facility would be a lot higher at 78.9 cents, or 19.7 cents more than the Dutch facility (L-gas). This is due to the fact that the EEG payments are calculated per kWh of electricity produced.²⁶

In conclusion, the absolute payments over the total eligible time span are substantially higher in Germany than in the Netherlands. This is mostly due to the significantly higher duration of payments of 20 years in Germany. The German facility in the example below (see Table 4) is expected to gain € 22 million more than the comparable Dutch facility.

²⁶ As a matter of fact, the Dutch facility would also be able to trade GoOs. While this adds to the total revenue, it does not constitute a tariff or subsidy payment and is therefore not subject to this calculation example. For sake of completeness: there is no public market place or transparent pricing, but based on estimates the average price for a single GoO is set at 7 cents per cubic metre. To include this in the overall revenue of the Dutch facility would balance the payments between the two countries at around 66 cents per cubic metre. However, this amount would represent the total revenue for the Dutch facility, while the German facility would still be able to attain a significantly higher price from the CHP producer by relying on expected additional heat revenue. This revenue aspect is not part of the calculation. To summarise, even if the price for GoOs would be recognised, looking at overall revenue, it is expected that the German facility would earn more than the Dutch one.

Table 4. Calculation example and a comparison of tariff payments (Germany and Netherlands)

	Germany	Netherlands
Year	2012	2012
Heat value (H_s) of biomethane (kW/Nm³)		
L-Gas	8.8	8.8
H-Gas	11.3	
Energy produced per year (kWh)	31,250,000	31,250,000
Upgrade		
Installed capacity (Nm ³ /h)	650	444
Full load hours	-	8000
CHP		
Installed Capacity (kW _{el})	1500	-
Full load hours	8000	-
Rated power (kW _{el})	1366	-
Category	95% EVK I 5% EVK II	'Allesvergisting (groen gas)'
Biomethane per year (Nm³)		
L-Gas	3,551,136	3,551,136
H-Gas	2,765,487	
Tariff (ct/Nm³)		
L-Gas	EEG ¹	SDE+
H-Gas	66.6	59.2
L-Gas	78.9	
H-Gas		
Time span of payments (years)	20	12
Total payments over time span in € (L-Gas)	47,301,132	25,227,270

1) Numbers given here are estimates of the share of the EEG tariff a biomethane producer could receive if he is able to attain the highest price possible from the CHP-producer. The CHP-producer receives the EEG payments.

3. CERTIFICATES

In this chapter, key features of a series of biomethane-related certificates are described. These certificates are used for administrative trading of certain qualities or attributes of the biomethane. Section 3.1 focuses on administrative biofuel trading in the transport sector, for example through biotickets. The second section of this chapter handles the regulatory setting and trading of guarantees of origin (GoOs) for renewable energy. In Section 3.3 issuing and trading of sustainability certificates are described. The chapter foremost centres around the current policies in Germany and the Netherlands, whereby on some issues announced policies are taken into account.

3.1 Administrative biofuel trade in the transport sector

The EU Renewable Energy Directive (RED²⁷) obliges all EU Member States to bring renewable energy into the transport sector. Both Germany and the Netherlands allow to count gas produced from biomass towards this EU goal. This chapter describes the regulatory setting implemented in the two countries.

3.1.1 Legal framework

Article 3, section 4 of the RED obliges the Member States to ensure at least a 10% share of renewable energy on final energy consumption in all forms of transport.

In the Netherlands, the EU requirement is implemented through the Environmental Management Act,²⁸ which sets the blending obligation and the target group for which the obligation applies. The act is substantiated by the Decree on Renewable Energy and Transport²⁹ and by the Regulation on Renewable Energy for Transport³⁰. These two documents specify in a greater detail the implementation of the blending obligations in the country.

In Germany, the EU requirement is implemented through the Federal Immission Control Act (*BImSchG*³¹), where the blending obligations and target group for the obligation as well as the possibility of obligation trading are specified. The act is accompanied by the Energy Tax Act³² and by the Regulation on Biofuels Quota³³, which introduce the sustainability requirement.

²⁷ RED = Renewable Energy Directive (Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC).

²⁸ Dutch: *Wet van 13 juni 1979, houdende regels met betrekking tot een aantal algemene onderwerpen op het gebied van de milieuhygiëne (Wet milieubeheer)*.

²⁹ Dutch: *Besluit van 18 april 2011, houdende regels omtrent de inzet van energie uit hernieuwbare bronnen ten behoeve van bepaalde vormen van vervoer (Besluit hernieuwbare energie vervoer)*.

³⁰ Dutch: *Regeling van de Staatssecretaris van Infrastructuur en Milieu van 2 mei 2011, nr. BJZ2011044006, houdende nadere regels met betrekking tot energie uit hernieuwbare bronnen voor vervoer (Regeling hernieuwbare energie vervoer)*.

³¹ German: *Gesetz zu Schutz vor schädlichen Umweltwirkungen durch Luftverunreinigungen, Geräusche, Erschütterungen und ähnliche Vorgänge (Bundes-Immissionsschutzgesetz – BImSchG)*. Status: 17.05.2013.

³² German: *Energiesteuergesetz (EnergieStg)*. Status: 05.12.2012.

³³ German: *Sechsendreißigste Verordnung zur Durchführung des Bundes-Immissionsschutzgesetzes (Verordnung zur Durchführung der Regelungen der Biokraftstoffquote) (36. BImSchV)*. Status: 24.02.2012.

3.1.2 Requirements for the transport sector

In both countries, actors bringing fuels into the transport sector are obliged to blend in a certain share of biofuels. This share is then defined as a percentage of the total energetic value sold.

In the Netherlands, these shares are set at a minimum of 3,5 % for both petrol and diesel fuels. Furthermore, suppliers are obliged to achieve a 5,5% biofuel share on the overall fuel portfolio sold. Targets beyond 2014 will be determined in 2014 with a target of 10% or higher expected for 2020.

Similarly, in Germany the minimum biofuel shares for petrol and diesel are set at 2,8% and 4,4% respectively. A minimum 6,25% share is to be achieved on the total amount of petrol and diesel sold. Targets beyond 2014 are in Germany defined in terms of emission reduction targets, i.e. blended biofuels need to reduce the overall emissions of the sold fuels by a certain percentage instead of achieving a certain energetic share in a mix. The emission reduction targets put requirements beyond the 10% target of the RED.

Table 5. Biofuel share targets in the Netherlands and Germany.

Blending obligation	Netherlands	Germany
2011	4,25%	6,25%
2012	4,50%	6,25%
2013	5,00%	6,25%
2014	5,50%	6,25%
2015	6,25 %	3% emission reduction
2016	Not specified	3% emission reduction
2017-2019	Not specified	4,5% emission reduction
2020	Not specified (at least 10%)	7% emission reduction (corresponds to ca. 13% energy share ³⁴)

3.1.3 Administrative trade

In both countries, the biofuel obligation can be fulfilled either by direct blending of the biofuel or by administrative trade.

In the Netherlands, suppliers that market more biofuels than their obligation are allowed to sell their surplus to other fuel suppliers. Proof of the surplus is called a 'bioticket'. Fuel suppliers have to report every year before April 1st the amounts of fuels and biofuels marketed in the previous year (Te Buck, 2010). This is done by submitting a biofuels balance sheet to the Dutch Emissions Authority (*NEa*).

In Germany, biofuel blending obligations themselves are traded, rather than blending performances. Transfer of an obligation is performed through a written contract. This has to specify the parties involved, the amount of the transferred obligation, the time-frame for which the contract is valid (trade over several years is possible) and the type of the fuel. One copy of the contract with the report on the

³⁴ Based on a forecast by the German Federal Ministry of Food and Agriculture (BMELV, 2013).

quota obligation has to be submitted to the controlling authority (main customs office) by April 15th of the following year.

In both countries sustainability of the blended biofuels needs to be proven. Biofuels need to fulfil the requirements prescribed by the EU regulation. Any sustainability certificate accepted by the EU can be used as a proof. See Section 3.3 for more information on sustainability certification.

Based on the EU legislation, biofuels produced from wastes, residual materials, cellulose-rich non-food and lignocellulose-rich materials can be double-counted towards the blending quota in both countries. Double counting is furthermore conditioned by the requirements that it does not apply to materials that can be used for more sustainable purposes. A double-counting certificate is required (see Section 3.3.4 below for double-counting rules in the Netherlands and Germany).

Carryover of biofuel quota surpluses to the following year is allowed in both countries. In the Netherlands, biofuel suppliers can carry 25% of their commitment into the next year since 2013. As opposed to this, no upper carryover limit exists in Germany. Alternatively, German biofuel suppliers might decide to claim tax refund on the biofuel surpluses instead; i.e. tax refunds then replace the unused quotas.

3.1.4 Opt-in

Even though green gas suppliers fall within the blending obligations in neither of the two countries, they can decide to participate in the system.

In the Netherlands, sustainable gas suppliers, similar to electricity suppliers, supplying to the transport sector may decide to participate in the blending obligations systems as an 'opt-in party'. All the surpluses after fulfilling the quota can be then be sold to the obliged parties. As a result, green gas producers could sell 94,5% of their production as biotickets in 2014. Importantly however, sustainable fuels receiving SDE(+) subsidy can no longer be used for generating biotickets (Groen Gas, 2012) as per 2011.

In Germany, the obligation scheme recognises only petrol and diesel suppliers and hence does not include obligations for e.g. methane suppliers. Nevertheless, the German BImSchG recognises biomethane as a bio-fuel since 2009 and allows counting it towards the quota. This means that German green gas producers are allowed to sell 100% of their production to the obliged parties. Similar to Netherlands however, only biomethane that did not receive any form of subsidy at home or abroad can be counted towards the obligations.

3.1.5 Non-compliance

In the Netherlands, The Netherlands Emissions Authority may impose administrative penalties (*bestuurlijke boete*) and penalty payments (*dwangsom*) on the non-compliant parties. Even if sanctions have been applied, the target obligations need to be compensated in the following year (Van der Weijden, Reintjes, & Feld, 2011). The enforcement framework has been included into the Act on economic crimes (*Wet op de economische delicten*) and therefore non-compliance with the obligation may constitute a criminal offence (Feld, 2012).

Similar to the Netherlands, Germany also sanctions non-compliance with penalty payments. These are set at € 19 per GJ for the diesel quota, € 43 per GJ for the petrol quota and € 19 per GJ for the non-

compliance with the overall biofuel quota. As opposed to Netherlands however, the sanction does replace the missed obligation.

3.1.6 Certificate prices

In the Netherlands, bioticket trade started in 2007. In Germany, biomethane suppliers are allowed to participate in administrative trade since the recognition of green gas as a biofuel in 2009.

In both the Netherlands and Germany, the value of the bioticket or obligation is defined by the cost of the diverse biofuels (substitutes) as well as by the level of biofuel targets prescribed in the country³⁵. In Germany, the price is then capped by the sanctions replacing the quota. In case of biomethane, this corresponds to ca. 6.84 ct./kWh. On a similar note, the energy tax refund defines a biomethane obligation floor price in Germany, which is set at 1.39 ct./kWh.

Independent of these limits, revenues from selling biofuel obligations in Germany was reported for biomethane producers to lie somewhere between 3 and 4.5 ct./kWh without double-counting (Elek, 2012; Grope & Holzhammer, 2012). Converting the units, this implies prices of roughly € 0.26 to 0.40 per cubic metre of biomethane. Here, the price of obligations stemming from the biomethane sales seems to be limited by the wholesale price of biodiesel at ca. 3.6 ct./kWh (Erdgas Mobil, 2013). However, it needs to be remembered that the income from obligations is earned in addition to the earnings from the physical delivery of CNG. Prices for CNG are then estimated to lie between 2 and 4 ct./kWh. A cubic metre of biomethane had a value of € 0.44 to 0.75 in 2012 (value of the gas plus value of the obligation). Nevertheless, it might be expected that the biomethane producer will receive only part of these earnings depending on the amount of actors (traders, fuel station operators) between the producer and the end consumers.

In the Netherlands, broker STX Services publishes a weekly overview of bioticket prices for biodiesel and ethanol. The bioticket price was found to decrease steadily from around € 11.00³⁶ in March 2012 to € 6.50 at the end of the year. In May 2013, the price of biotickets for diesel was approximately € 8.75 to € 8.90, while the bioticket price for petrol fluctuates around € 8.50. Taking the bioticket price of € 8.50, the value of green gas used for biotickets can be estimated.

The energy content for petrol is approximately 32.7 MJ/Nm³ (Staffell, 2011). For natural gas from the Groningen gas field, the energy content (lower heating value) is 31.65 MJ/Nm³. Based on the blending requirement for 2013 (5%), out of every cubic metre of petrol, 1635 MJ should consist of biofuel. Considering the energy content of natural gas (and green gas of Groningen gas quality), 1635 MJ corresponds to 52.07 cubic metre of gas. Therefore, every cubic metre of green gas has an green value of € 0,163. Similar to Germany, this income is then earned in addition to the earnings from the physical delivery of CNG.

3.1.7 Outlook

Thus far, only the targets until 2014 were discussed. The target setting after 2014 appears to be more difficult to judge. Starting in 2015, Germany intends to convert its obligation system towards emission

³⁵ The value of biotickets or obligations based on biomethane from double-counting biomass is twofold. See Section 3.3.4 below for double-counting rules in the Netherlands and Germany.

³⁶ The price of €11 for a bioticket represents the value transport fuel suppliers pay to get one cubic meter of fossil fuel (e.g. diesel or gasoline) up to blending specifications (i.e. a 5% renewable fuel blending obligation, would represent 1635 MJ of renewable fuel in case of gasoline, which is roughly equivalent to 52 m³ of biomethane).

reduction targets, which is expected in its requirements to go beyond the 10% renewable fuels minimum target. Separate quotas for diesel and fuel will be dropped within this system. Instead, only the overall greenhouse gas emission reduction target is defined. This means that the blended biofuels do not need to achieve a certain energetic share in a mix as before. They need to reduce the overall emissions of the sold fuels by a certain percentage. Any fuels fulfilling sustainability criteria can be used for this purpose. This then implies that the fuels with the highest emission reduction potential are the most efficient means to reduce the emissions, i.e. smaller overall quantity of these fuels needs to be purchased in order to fulfil the quota.

Furthermore, biofuels will need to fulfil stricter sustainability criteria. Increase in the CO₂ criterion³⁷ from the 35% reduction for existing installations to 50% and 60% in 2017 and 2018 respectively, for new installations. These stricter targets will in practice exclude some biofuels, such as first generation biodiesel, from the biofuel blending obligations trade. As biomethane does comply with the strict CO₂ criterion and is characterised by high emission reduction potential, demand within the mobility sector for biomethane is expected to rise in the future (Erdgas Mobil, 2013).

For the Netherlands, it is clear that the overall biofuel obligation target will increase up to at least 10% by 2020, as prescribed by the EU. Whether the targets will go beyond the EU prescription remains uncertain at the time of writing. The blending obligation target for 2015 is set at 6.25%, and targets until 2020 are expected to be defined by the end of 2014. Until 2020, a new system of Renewable Fuel Units (*Hernieuwbare Brandstofeenheden, HBE*) will be employed. HBEs are expected to simplify the administrative system of biotickets, but are still based on fuel blending obligations, rather than emission reduction targets as in the German system.

3.2 Guarantees of origin for renewable energy

Tracking and tracing of renewable energy with the help of guarantees of origin (GoOs) is a cost-effective manner to provide the end-user with sufficient proof that a certain unit of renewable energy used has actually been produced and the property right of the green value has been obtained by the energy seller, despite the fact that the production and consumption location are geographically dispersed. As a result, GoOs provide an important facilitating mechanism for market actors to prove and claim certain 'green' performances (e.g. emissions avoided and fossil energy use avoided).

3.2.1 Regulatory setting

EU level

The basis for GoOs is laid in the RED. The RED focuses on electricity, heating, cooling and transport fuels. However, it hardly contains any explicit reference to biogas, green gas or biomethane. The RED defines a GoO as follows: "a 'guarantee of origin' means an electronic document which has the sole function of providing proof to a final customer that a given share or quantity of energy was produced from renewable sources as required by Article 3(6) of Directive 2003/54/EC."

The RED stipulates that "a guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another." In case such a transfer takes place the EU Member States must ensure that so-called double-counting or double-disclosure is avoided.

³⁷ The CO₂ criterion defines by how much the biofuel has to be reducing emissions compared to the fossil fuel.

The RED also states the general terms and conditions for GoOs (with regard to for example issuance and quality assurance). It also mentions the minimum required information carried by the GoO, including the identity and location of the production plant and its age, the feedstock used and the date of production of the energy.

The RED obliges the EU Member States to implement the GoO certification into national legislation. This leads to officially recognised certification systems with a legislative basis at the national level. In most countries these compulsory systems are based on the European Energy Certificate System (EECS) rules defined by the Association of Issuing Bodies (AIB), which predominantly focus on renewable electricity.

National level

On GoOs the RED mainly refers to electricity. Therefore, there are no EU rules for GoOs for biomethane. Nevertheless, the market in the Netherlands felt a need for a GoO system to promote biomethane production and trade. When the system of issuance of GoOs for biogas or bio-methane was developed in 2008 it was therefore done on a voluntary basis. In Germany, and some other EU countries, a similar route was taken. Logically, the principles of the GoO scheme for electricity were taken as an example and applied to biomethane, but the systems in the various countries are not harmonised because of the lack of EU steering.

In the Netherlands the Regulation on Guarantees of Origin for Sustainable Electricity³⁸ is the relevant national GoO legislation, and it relates to electricity. The Dutch Gas Act does not refer to GoOs and therefore there is no legal basis for GoOs for biomethane (yet) in the Netherlands. However, in June 2014 a new concept of this regulation was published for market consultation and it contains explicit references to GoOs for biogas used for electricity generation³⁹.

In Germany, there is legislation for electricity as well as for biomethane. The EEG (electricity) and EEWärmeG (heat) require a mass balance system for the biomethane value chain. The mass balancing is mandatory for obtaining the EEG renewable energy tariff⁴⁰ (see Section 2.3). The requirements aim at reliable and complete traceability of biomethane to ensure the payment of the adequate tariff, which differs for different feedstock categories.

3.2.2 GoO certification

The administrative trading of the green value of energy requires a trustworthy and reliable system of issuance, trading and subsequent cancellation of GoOs. This system is operated by the so-called issuing body (IB). It is of paramount importance that the IB is a reliable body that is trusted by all involved parties.

The IB should clearly define which are the requirements for the gas, its production plant, the accuracy of the measuring equipment, the feedstock and the process to obtain a GoO. It must assure all parties that these requirements are fulfilled when issuing the GoOs. It must cancel the GoOs when the gas leaves the gas distribution system. The GoOs are digital documents (see Annex 5 for an example). The IB must operate a reliable GoO registry, similar to a bank accounting system.

³⁸ Dutch: *Regeling Garanties van Oorsprong voor Duurzame Elektriciteit*. Released in 2003.

³⁹ Dutch: *Concept Regeling Garantie van Oorsprong voor Duurzame Elektriciteit en HR-WKK-elektriciteit*. Published 25-06-2014 for consultation.

⁴⁰ §27 c Abs.1 Nr. 2 EEG and §55 EEG; §5 Abs. 2 EEWärmeG in combination with Annex Nr.II.1.c.bb EEWärmeG.

Issuing bodies

As stipulated in the Dutch Electricity Act, CertiQ is the legally appointed IB of GoOs for electricity, heating and cooling. To date, no IB for biomethane GoOs has been appointed by law in the Dutch Gas Act. TSO Gasunie took the initiative to set up an IB for GoOs for biomethane injected into the public gas grid. The name of this IB is Vertogas. Its system is not yet legally recognised and hence it is a voluntary system. Usually well-informed informal contacts have mentioned that it is likely that Vertogas will receive a legal status in the Dutch Gas Act in the near future, similar to that of CertiQ⁴¹ in the Dutch Electricity Act. The ways of operation of CertiQ and Vertogas are similar.

In Germany no entity is appointed by law to look after the reliable and complete traceability of biomethane to ensure the payment of the adequate tariff, which differs for different input categories. The development of verification systems was entrusted to the market participants. The system mostly used now is the Biogasregister, owned and operated by the German Energy Agency DENA.

Types of GoOs issued

In the Netherlands, Vertogas issues GoOs for biomethane based on basic requirements on renewability of the feedstock and the production route. On the GoOs it is indicated if the feedstock used to produce the biomethane is certified for sustainability using NTA 8080. Also whether or not SDE+ subsidy has been awarded is indicated on the GoO.

All biomethane GoOs issued refer to one single type of feedstock. When a mixed feedstock is used for biomethane production, the produced gas (and the number of GoOs) is divided over the feedstock types in relation to their energy input in the feed. For electricity, CertiQ issues GoOs based on the basic renewability requirements. It issues separate GoOs for electricity from hydro, wind, solar and biomass. In this case, CertiQ considers biomass as one group, and no further divisions are made between feedstock types, as happens for biomethane.

In Germany, Biogasregister obtains proof from an accredited auditor that provides evidence on the kind and quantity of the biomass used as feedstock for the biomethane and of the volume of gas fed into the public gas grid. The criteria checked by the auditors refer to the legal feed-in tariff categories, such as inputs for the biomethane production or the capacity of the facility. The Biogasregister cannot be used for sustainability certification. As with the GoOs of Vertogas in the Netherlands, there is however the possibility to mark the produced biomethane within the Biogasregister as certified for sustainability.

It should be noted that the Biogasregister normally does not issue GoOs that are fully in the spirit of the RED, where the certificate can be sold separately from the commodity. When used for the application under the EEG and EEWärmeG, the Biogasregister operates as a mass balance system and explicitly not as a book and claim system. In that case, the issued GoOs are normally directly linked to a normal gas sales contract (Schlacke, 2012). However, the possibility to issue and trade GoO and commodity separately does exist in theory, but the Biogasregister stresses that there are very limited usage possibilities right now.

⁴¹ CertiQ is the IB for GoOs for renewable electricity in the Netherlands, see www.certiq.nl

3.2.3 Costs and market values

Costs of the GoO process

In the Netherlands, the typical transaction costs for a cycle of issuance, one trading action and cancellation of a GoO for 1 MWh of energy are roughly € 0.067 for renewable electricity (CertiQ, 2014) and € 0.246 for biomethane (Vertogas, 2013).

In Germany, the typical cost for a cycle of issuance, one trading action and cancellation of a GoO for 1 MWh of energy is slightly lower. According to the Guarantee of Origin Fee Ordinance (*HkNGebV*⁴²), the costs are roughly € 0.04 for green electricity. The costs amount to € 0.16 for biomethane (DENA, 2014).

Market prices for GoOs

In the Netherlands, GoOs can be traded separately from the commodity, and therefore they have a market value. GoO prices for electricity have been volatile. For example, GoOs for 1 MWh of green electricity from Dutch wind had a market value of € 0.62 in May 2012, but only € 0.20 one year later (STX Services, 2012; 2013).

Market prices of GoOs for biomethane are not formally published or publicly disclosed. Based on informal information, the market price for a GoO for 1 MWh of biomethane is approximately € 4 to 8, and thus roughly € 0.04 to € 0.08 per Nm³. As explained in Section 3.1.6, the price of a GoO on the bioticket market would be substantially higher: € 0.163 per Nm³. However, to be able to trade the GoOs on that market the biogas-producing installation must not have received SDE(+) subsidy.

In Germany, GoOs are not normally traded separately from the biomethane. GoO certificates have a purely administrative function and do not have a market value other than the share of the EEG tariff that the biomethane producer receives from the electricity producer. The 'green value' of biomethane can be deduced from figures published by the Federal Network Agency (BNetzA, 2013). In 2012 the average selling price of biomethane was 7.02ct/kWh (with high fluctuation), while the price for natural gas was on average 2.50ct/kWh. An indicative price difference between green and fossil gas in 2012 was thus € 0.045/kWh, or € 45 per MWh. This difference is accordingly only a result of the EEG tariff, and not due to the intrinsic (stand-alone) value of the GoO certificate.

3.2.4 Conclusions

The RED has led to harmonised national legislation on GoOs for green electricity and heat. This very much facilitates international trade in green electricity.

The RED does not apply to biomethane. As a consequence, legislation on GoOs for biomethane has not been harmonised in Germany and the Netherlands. The green value of biomethane can easily be traded within the Netherlands, using GoOs issued by Vertogas. In Germany the trade of biomethane as a commodity is possible, using the Biogasregister. Separate trade of the 'green value', using GoOs, is in principle possible but not attractive under the present promotion policies, including the EEG and EEWärmeG.

Import and export of biomethane is restricted as long as no international harmonisation of GoOs certification systems is realised. Issuing bodies on both sides of the border may cooperate to achieve a sufficient harmonisation. Preparatory steps for harmonisation have been taken by the national biomethane registries of Germany, Denmark, Austria, Switzerland, France and the UK (GreenGasGrids,

⁴² German: *Gebührenverordnung zur Herkunftsnachweisverordnung*. Released in 2012.

2013). So the readiness to harmonise is present. However, the mentioned countries apply a strict mass balancing system. They therefore do not allow the separate trade of the physical gas and the GoO when the gas passes a boundary between balancing zones. To remove this problem they plead for the European gas grid to be considered as one balancing zone. The acceptance of this idea is probably an issue for the long term.

It should be noted that there may be other restrictions for international trade based on rules in the national subsidy schemes for the production of the gas. For example, the EEG states that the use of foreign biomethane is prohibited (see Section 2.3).

3.3 Sustainability certification of biogas and biomethane

Biogas or biomethane can be used as renewable energy in the transport sector if it is produced in a sustainable way according to the minimum sustainability criteria as laid down in the RED and Fuel Quality Directive (FQD⁴³).

The European Commission has recognised 17 voluntary sustainability certification schemes⁴⁴, which can be used to provide proof of sustainability of the produced renewable energy. There are several factors that can influence the playing field with regard to the sustainability certification of biogas and biomethane. These factors include the regulatory and institutional settings in Germany and the Netherlands and the differences between the voluntary sustainability certification schemes.

3.3.1 Sustainability requirement

The RED and FQD are the first legislation to include binding minimum sustainability criteria for biofuels and bioliquids both produced and imported in the EU. The sustainability criteria in the RED are set out in articles 17, 18, 19 and Annex V, and can be summarised as follows:

Table 6. Overview of main sustainability criteria in the RED.

Parameter	Obligation according to the RED	From
Reduction life cycle GHG emissions	35% reduction	2010
	50% reduction	2017
	60% reduction	2018
Areas with high carbon stocks in soil and/or vegetation	Raw material not to be taken from permanently forested areas with trees of more than 5 metres height or a canopy cover of more than 30%	2012
	Raw material not to be taken from water rich areas such as peat lands and wetlands	2012
Protection of biodiversity	Raw materials not to be taken from primary forest and other wooded land, namely wooded land of native species without indications of human activity	2012

⁴³ FQD = Fuel Quality Directive (Directive 2009/30/EC - amendment to Directive 98/70/EC on environmental quality standards for fuel).

⁴⁴ A list of recognised sustainability certification schemes is available at the website of the European Commission: http://ec.europa.eu/energy/renewables/biofuels/sustainability_schemes_en.htm

	Raw materials not to be taken from areas designated by law or by the relevant competent authority for nature protection purposes	2012
Indirect land use change (ILUC⁴⁵)	Only monitoring and reporting. Proposal for additional measures has been published in 2012	2017
	CO ₂ bonus of 29 g/MJ for cultivation on marginal and degraded soils (Annex V, C(7))	?
Local environmental quality (soil/air/water)	Only reporting	-
Social criteria	Only reporting, review planned for 2014	-

3.3.2 Regulatory setting

In Germany, the sustainability requirements of the RED have been implemented into national legislation in 2009 with the Biofuel Sustainability Regulation (*Biokraft-NachV*⁴⁶) and the Biomass Electricity Sustainability Regulation (*BioSt-NachV*⁴⁷). The BioSt-NachV is not relevant for biomethane production since it only treats liquid biomass. The Biokraft-NachV defines the sustainability requirements for those biofuels, which are credited against the biofuel quota fixed in the 36th ordinance on the implementation of the Federal Immission Control Act (*BImSchG*).

In the Netherlands, legislation (*Regeling hernieuwbare energie vervoer, Regeling brandstoffen luchtverontreiniging*) implementing the RED and FQD was introduced in May 2011, with the legislation retroactively coming into force as per 1 January 2011.

3.3.3 Voluntary sustainability certification schemes

While the RED stipulates the minimum criteria which all renewable transport fuels have to meet, a series of certification schemes have been developed to enable market stakeholders to prove their compliance with those minimum criteria. Although these schemes are all EU approved, there is considerable variation between the various schemes that are used. Figure 3 shows that in Germany the certification schemes REDcert and ISCC (DE-versions) are the most relevant sustainability certification schemes. These schemes are accredited by the German Federal Office for Agriculture and Food (BLE⁴⁸). It seems plausible that both schemes are dominant for certifying biomethane, since these schemes have to be used for double counting in Germany⁴⁹. Out of 2,359 participants, 44.17% use the REDcert DE system and 38.19% the ISCC DE system. The figure illustrates that in the Netherlands ISCC (EU) is by far the most dominant voluntary sustainability certification scheme (76.2%) used by the market. ISCC EU and NTA8080 are the dominant schemes used to certify the main feedstock for producing biogas, household waste⁵⁰.

⁴⁵ An elaborate explanation of ILUC is provided on the website of the European Commission: http://europa.eu/rapid/press-release_MEMO-12-787_en.htm

⁴⁶ German: *Biokraftstoff-Nachhaltigkeitsverordnung*. Originally released in 2009.

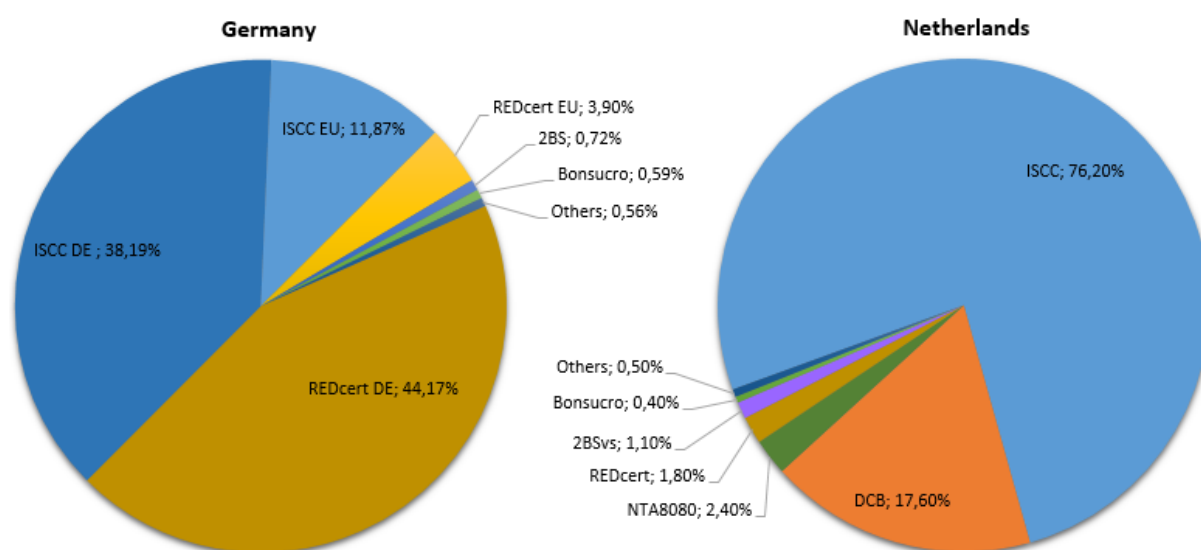
⁴⁷ German: *Biomassestrom-Nachhaltigkeitsverordnung*. Originally released in 2009.

⁴⁸ German: *Bundesanstalt für Landwirtschaft und Ernährung*.

⁴⁹ Share of biomethane in the renewable energy mix in the German transport sector increased from 0.05% in 2011 to 0.73% in 2012 (BLE, 2013).

⁵⁰ Share of biogas in the renewable energy mix of the Dutch transport sector remained stable at 3.3% in 2012 as compared to 3.2% in 2011 (NEa, 2013).

Figure 3. Sustainability certification schemes used in Germany and the Netherlands, 2012 (BLE, 2013; NEa, 2013).



3.3.4 Sustainability schemes applied in the Netherlands and Germany

The previous sections illustrated how the schemes are used in Germany and the Netherlands. Table 1 provides an overview of the differences that exist between the schemes, and between Germany and the Netherlands, as described in the next sections.

Table 7. Key features of sustainability certification schemes used in Germany and Netherlands.

Topic	RSB	NTA8080	REDcert EU	ISCC EU	Germany	Netherlands
Double counting	Yes	Yes	Yes ⁵¹	Yes ⁵²	REDcert DE / ISCC DE	Voluntary schemes + declaration
Registration	Yes	Yes	Yes	Yes	Nabisy	NEa ⁵³
Virtual trade	No	No	No	No	No	No

Double counting

In the Netherlands, a separate verification for double counting issued by an independent verification body has to be provided to NEa if requested, according to the specification for allowed feedstock as laid down in article 17 (and appendix III) of the Renewable Energy in Transport Regulation (*Regeling Hernieuwbare Energie Vervoer*) (NL Agency, 2013). The double counting rule does also exist in

⁵¹ In its newsletter of September 2013, REDcert announced “REDcert EU certified system participants may only accept waste and residues or products made from them as sustainable if they originate from REDcert EU or ISCC EU certified companies. Waste and residual materials or products made from them from other EC-approved certification systems may not be accepted as sustainable as long as these systems have not been checked by REDcert and approved as equivalent” (REDcert, 2013).

⁵² In its newsletter of March 2013 ISCC announced that “delivery notes or proofs of sustainability related to waste, residue and/or material eligible for double- or quadruple counting which are issued under other certification systems shall in the future **not be accepted** by an ISCC certified unit anymore”. Given that ISCC EU is the dominant scheme, it may force market participants to certify against ISCC EU. (Square Commodities, 2013).

⁵³ NEa = Dutch Emissions Authority (*Nederlandse Emissieautoriteit*). From mid-2015, the NEa is launching a central registry (Korenromp, 2013).

Germany. However, in Germany, under the 36th ordinance on the rules on the biofuel quota (36. BImSchV), it is required that the entire chain of custody for waste and residues must be certified against a national scheme (ISCC DE / REDcert DE) in order to be used for double counting, if the waste/residues or the final product which is made of waste/residues is sold in Germany (Bureau Veritas, 2007). The EC has not established control mechanisms for the origin of waste and residual materials and it is not included in the EC recognised voluntary sustainability schemes. German legislation does include these control mechanisms and it is included in ISCC and REDcert DE schemes⁵⁴.

Sustainability reporting

Although the systems of information collection are differently organised in the Netherlands and Germany, the differences are not of significant importance. In the Netherlands the fuel suppliers at the end of the value chain (excise warehouse, 'AGP') are the economic operators which have to submit the proof of sustainability for biogas to be eligible for the national biofuel quota, while in Germany the reporting burden is imposed on the entire chain instead of on the last interface only. However, in the Netherlands the NEa will crosscheck the claim of the AGP with the submitted balances by the biogas producers to verify its validity⁵⁵.

Registration

In Germany BLE operates the 'Sustainable Biomass System' database (*Nabisy*). In this database all economic operators have to submit their sustainability data. In the Netherlands there is no central registry operated by the NEa, but this is planned to be operational as per mid-2015⁵⁶. Currently, the NEa receives all data from AGP and biogas producers separately and does the crosscheck of the submitted data.

Virtual Trade

In all cases, virtual trade⁵⁷ is not allowed nor accommodated. According to the BLE⁵⁸ there are two main barriers for virtual trade:

- 1) The German tax authority requires feed-in and feed-out in Germany, e.g. only if biomethane is fed into the German grid and consumed in Germany, it is allowed to count towards the national target. If biomethane is imported via the gas grid from other countries, customs is not able to control it and therefore it is not allowed. Should the biomethane be transported via rail or road traffic, it is allowed.
- 2) Trade of sustainability certification is considered to fall under the book-and-claim method in terms of the mass-balancing system and therefore it is not allowed.

According to the NEa, one additional barrier can be added to this:

- 3) It is stated in appendix 1C of the Dutch Renewable Energy in Transport Regulation that produced biogas has to be physically injected into the Dutch transmission grid in order to be eligible for the national quota. The EU methodology for statistical calculations for sustainable

⁵⁴ Source: interview Karl-Heinz Schnau, BLE, 4 April 2014.

⁵⁵ Source: Interview Mr. Gerlagh, NEa, 24 April 2014.

⁵⁶ Source: presentation Mr. Korenromp, <https://www.emissieautoriteit.nl/mediatheek/over-de-nea/presentaties/5.%20Presentatie%20Rene%20Korenromp.pdf>.

⁵⁷ Virtual trade refers to the transfer or trading of the sustainable features of renewable energy (e.g. biomethane) separate from the underlying commodity, for example using a certificate.

⁵⁸ Source: interview Karl-Heinz Schnau, BLE, 4 April 2014.

biogas does not allow for the situation in which the gas is produced in Germany, transported via the grid over the border and consumed in the Netherlands. Therefore, the value of a sustainability certificate is zero when the underlying commodity is not in the national grid, thereby taking away an incentive for virtual trade.

3.3.5 Outlook

There are three developments on the horizon:

- 1) The introduction of greenhouse gas emission targets instead of renewable energy targets in the transport sector in Germany from 2015 onwards. BLE indicated that the double counting rule will disappear in Germany by the end of 2014 as the focus will be on GHG emission performance (double counting is still allowed but there is no added value in the German market, so it is expected that biofuels produced from waste and materials eligible for double counting will be exported to other countries). The policy in the Netherlands remains focused on renewable energy targets in the transport sector as indicated by the Ministry of Infrastructure and Environment⁵⁹. The main reason for this is that the Ministry expects that the FQD will expire, implying that a specific CO₂ reduction target for the transport sector after 2020 will disappear. However, the Ministry does expect that emission reduction will be part of EU renewable energy policy after 2020.
- 2) The introduction of a central registry in the Netherlands from mid-2015. The main reasons for introducing a centralised system are to reduce the complexity and administrative burden for economic operators. The company submitting the data to the system (so called 'inboeker') is solely responsible for delivering the proof of sustainability. In general the reporting requirements shifts from the fuel supplier to the 'inboeker' (in the case of biogas the producer), but the NEa indicated that for biogas the reporting requirement will stay with the fuel supplier for the time being⁶⁰.
- 3) Alongside with the introduction of the new registry, a connection between the Vertogas GoO registry and the new registry will be established to verify information submitted to the registry (not yet formally arranged in Dutch legislation). This is made possible with new legislation ('Regulation on Guarantees of Origin') which indicates that for liquid biofuels a GoO combined with a sustainability certificate can be issued by Vertogas (green gas certificates). With this, the Ministry of Infrastructure and the Environment wants to create the possibility to facilitate the import of green gas certificates from other countries (if they meet the requirements)⁶¹. This provides the fuel supplier, who has an account in the new registry, with the opportunity to convert the green gas certificates into new GoO and submit this to its account at Vertogas. The GoO can be converted in 'Renewable Fuel Units' (HBEs⁶²) at the registry and used to fulfil its quota obligation. In other words, this would create the situation that gas injected into a national grid outside the Netherlands can be used in the Netherlands to meet the national targets. Yves Bot, Advocate-General at the European Court of Justice, appears to agree with this line of reasoning in the case of Essent Belgium B.V. against the regulator (VREG)⁶³. This court case is about whether the national legislation (*Electriciteitsdecreet*) prevents import of electricity GoOs from other countries to meet the

⁵⁹ Source: interview René Korenromp, Ministry of Infrastructure and the Environment, 28 May 2014.

⁶⁰ Source: e-mail Timo Gerlagh, NEa, 23 June 2014.

⁶¹ Source: e-mail Timo Gerlagh, NEa, 23 June 2014.

⁶² Dutch: *Hernieuwbare Brandstofeenheid*.

⁶³ Source: case C204/12 – C208/12,

<http://curia.europa.eu/juris/document/document.jsf?docid=137309&mode=req&pageIndex=1&dir=&occ=first&part=1&text=&doclang=NL&cid=84065>.

national quota obligation with the help of renewable energy certificates (RECs⁶⁴) and thus whether it is contrary to the free movement of goods in Europe. The advocate-general states that the national legislation allows for state aid in the form of RECs, but excludes the GoO of other countries from being used for meeting national targets. He notes that this last point is contradicting the free movement of goods in Europe that cannot be justified by mandatory requirements of environmental protection. As the environmental criteria are defined in the national legislation, there would be no reason for excluding imported GoO from other countries for meeting national targets. To date, however, no final ruling by the European Court of Justice has been made regarding this case.

⁶⁴ A REC represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source (EPA, 2014).

4. KEY DIFFERENCES AND IMPLICATIONS

In the previous two chapters, the institutional, legal and regulatory settings with regard to the biogas and biomethane sectors in Germany and the Netherlands have been described. In this chapter the main differences between the two countries are summarised, and their potential implications briefly analysed. The main differences of the biogas and biomethane playing-field relate to biomethane injection into the natural gas network, feed-in of renewable energy into the electricity grid, feed-in subsidies and tariffs, administrative biofuel trade in the transport sector, sustainability certification, and GoOs.

4.1 Overview of differences

4.1.1 Biomethane injection into the natural gas network

The injection of biomethane into the natural gas network is arranged differently in the Netherlands and Germany. Key differences between the two countries include cost sharing issues and the legal and regulatory framework.

COSTS SHARING. A main difference between Germany and the Netherlands is the way that the costs for the gas grid connection are shared between the injector (the biomethane producer) and the DSO. In the Netherlands, the injector has to take on all costs of the connection. In Germany on the other hand, costs are shared between the injector and the DSO: costs for most parts of the connection are shared between the DSO (75%) and the injector (25%). The costs incurred by the DSO in Germany are socialised through the gas transport tariffs for end users.

CONTRACT CAPACITY BALANCING. The balancing period for biomethane injection in Germany is one year, thus injectors may adjust their production upward and downward as much as required during the year. In the Netherlands, biomethane producers are bounded by the capacity stated in their contract. They have to inject in accordance with their prediction given to the DSO. The DSO maintains the overall balance in the system and restores the balance at the end of the gas day, if necessary. In addition, producers are never allowed to inject more biomethane than the instantaneous gas demand in the same network. German injectors have the certainty that feed-in capacity is available for them at all times, as the DSOs are obliged to expand the network in case of insufficient capacity.

GAS NETWORK SPECIFICATIONS. While in the Netherlands biomethane injection takes place into L-gas networks, in Germany both L-gas and H-gas networks are used, with H-gas being dominant. In both countries the majority of the biomethane is fed into distribution networks with a low to medium pressure.

LEGAL FRAMEWORK AND CERTAINTY. The legal framework in Germany provides more certainty than its Dutch counterpart. In Germany, biomethane injection is regulated through the GasNZV and GasNEV, and compliance with these regulations is monitored by the Federal Network Agency (BNetzA). In the Netherlands the ATvGR regulation provides the legal framework, but DSOs can unilaterally set additional conditions, reducing the certainty for biomethane producers.

GAS QUALITY REQUIREMENTS. Gas quality requirements are slightly different in the Netherlands and Germany, partly induced by the use of L-gas and H-gas respectively. These differences do however not induce significant level playing field issues.

OBLIGATION TO CONNECT. The German legal framework includes a stronger obligation for DSOs to connect biomethane producers than the Dutch system. In the Netherlands, DSOs can refuse injection on the basis of inadequate capacity. In Germany on the other hand, the DSO cannot use insufficient network capacity as a reason for refusal, and therefore they are obliged to reinforce network capacity if a biomethane producer wants to inject.

RESPONSIBILITIES SHARING. Based on the abovementioned legal framework, in Germany the DSOs are responsible for the composition of the gas in their grids. Producers are thus no longer responsible for the gas quality after injection in the grid. In the Netherlands, the DSOs are fully indemnified from all liabilities and the injector therefore remains responsible for the gas quality, also after injection. In reality, the biomethane is blended with gas from other sources after injection, resulting in a lack of clarity about the responsibility for gas quality issues.

4.1.2 Feed-in of renewable energy into the electricity grid

There are few differences between Germany and the Netherlands with regard to the regulatory framework and common practice of the feed-in of renewable energy into the electricity grid. In both countries the shallow charging method is applied: electricity producers have to pay for their own grid connection, but grid reinforcement as a result of the obligation to connect is paid by the DSOs. The only real difference between the two countries is found in the payment method for the renewable energy.

VALUE OF FED-IN RENEWABLE ELECTRICITY. In Germany, the value of fed-in renewable energy is directly determined by the feed-in tariff of the EEG, while in the Netherlands producers have to sell their energy individually. As a result, German DSOs are responsible for the payment of green electricity, and this can be socialised through the *EEG-Umlage*. Dutch DSOs are not involved in the trading of electricity.

4.1.3 Feed-in subsidy and tariff schemes for biomethane

Both in the Netherlands and in Germany, renewable energy support schemes are active. In Germany, only renewable electricity is supported⁶⁵, while in the Netherlands also subsidy for renewable gas and heat can be obtained. There are significant differences between the two systems in terms of their regulatory frameworks as well as the height and duration of the subsidies.

SUBSIDY AND TARIFF RATES. While in the Netherlands the payment of the SDE+ subsidy is going directly to the biomethane producer, in Germany only electricity producers receive the EEG tariff. The payment received by biomethane producers therefore depends on their agreement with a CHP producer that receives the tariff. A comparison between the Dutch SDE+ rates and the estimated share for the biomethane producer of the German EEG tariff shows that the payments are higher in Germany. Considering a comparable facility in both countries, and feeding into the L-gas grid⁶⁶, payments in

⁶⁵ In the EEG, electricity producers have been able to receive a higher tariff payment when injected biomethane is used for electricity production ('technology bonus').

⁶⁶ See Section 2.3.7 for a comparative calculation based on a model biomethane facility.

Germany would amount to 66.6 cents per Nm³, while in the Netherlands the revenue would be 59.2 cents per Nm³. Considering the longer duration of the German subsidy, the absolute total revenue is significantly higher in Germany.

DURATION OF PAYMENT. The German EEG scheme provides more long-term certainty than the Dutch scheme. The EEG tariff is granted for a 20-year term, while the SDE+ subsidy for biomass plants is awarded for 12 years.

SUBSIDY AND TARIFF RATE SETTING. The German EEG scheme provides certainty with regard to the tariff rate that renewable electricity producers receive. The scheme is only available for electricity, for which fixed tariffs are determined per kWh fed into the public grid. The tariff depends on the rated power of the plant and on the feedstock that is used. A degression to the tariff is applied annually, meaning that the tariff for new facilities decreases with a certain percentage every year. In the Netherlands, the subsidy is available for electricity, gas as well as heat. A base SDE+ subsidy rate is determined annually for each category. This provides more flexibility for the subsidy rate to reflect current market conditions, but there is less certainty with regard to future rates compared to the degression system of the EEG.

FINANCING BUDGET. The German EEG scheme provides an unlimited budget, as the *EEG-Umlage* for electricity consumers can in theory be increased as much as necessary to finance the renewable energy production. In the Netherlands, the SDE+ scheme is financed from tax revenues, and therefore the budget is set by the government. By using a system of ‘competitive bidding’, application for subsidies for all renewables takes place in categories from low to high subsidy rates, in order to make the scheme as cost-effective as possible. An effect of the Dutch system has been that potential producers claim subsidy money as early as possible, even though the feasibility of their plant may be not sure yet. As a result, the budget allocated to the SDE+ scheme has not always been effectively used for renewable energy production.

APPLICATION PROCESS. In Germany, all producers that feed renewable energy into the electricity grid receive the EEG tariff⁶⁷. No application for subsidy is therefore necessary. In the Netherlands, biomethane producers need to file an application for the SDE+ subsidy. The applications are then reviewed based on their financial viability on a first come, first serve basis. After receiving a grant agreement, the plant should be built and operated identical to the subsidy proposal, and be operational within four years.

ELIGIBLE FEEDSTOCK. In both countries, positive lists for eligible feedstock for digestion are used. In Germany, the *EVK* classes make that there is a differentiated feed-in tariff per type of feedstock. In the Netherlands there is no such differentiation. The applicable positive lists, along with national regulations and circumstances, have led to more use of maize in Germany, and more use of manure in the Netherlands.

DESTINATION CLAUSE. In the Netherlands, biomethane producers with a grant agreement receive SDE+ subsidy when injecting into the natural gas grid, regardless of the final use of the biomethane. Although biomethane for which subsidy has been received is not allowed to be counted towards the blending obligation for transport fuels, the commodity itself can still be sold to the transport sector. In Germany,

⁶⁷ Only facilities built before 2001 are not eligible for the EEG payments. In addition, producers can choose to refrain from receiving EEG payments if they are able to market their energy directly elsewhere.

the EEG tariff is only available for feed-in of renewable electricity. Biomethane producers can therefore only indirectly receive the subsidy when the biomethane is sold to a CHP plant that receives the EEG tariff. This can be seen as a *de facto* destination clause.

MARKET AND FLEXIBILITY PREMIUMS. In 2012, a new direct marketing approach has been established in Germany. As a result, renewable energy producers can choose to market their own energy, instead of opting for the fixed tariff of the EEG scheme. When using the direct marketing approach, producers receive a ‘market premium’, which is socialised through the DSOs as part of the EEG scheme. Producers are allowed to switch between the direct marketing and the conventional EEG scheme on a monthly basis. Another premium introduced in Germany in 2012 is the ‘flexibility premium’ for electricity produced from biogas or biomethane, as an incentive to invest in additional production capacity in order to produce in compliance with timely differing demand patterns. In the Netherlands, the SDE+ scheme in itself applies the concept of direct marketing. A flexibility premium is not available, as producers are required to stabilise production in line with their quoted and contracted capacities.

SUSTAINABILITY REQUIREMENTS FOR SUBSIDY. For receiving the EEG tariff in Germany, no sustainability requirements are imposed. In the Netherlands, for some forms of liquid biomass facilities, sustainability has to be proven. For other categories, a biomass declaration (*biomassaverklaring*) suffices.

ACTIVITIES OF THE DSO. In the Netherlands, there is no role for the DSOs with regard to payments of feed-in subsidies. In Germany, the DSO is required to pay the EEG tariff to the renewable electricity producer, and market the electricity. The difference between the EEG tariff and the market price – i.e. the loss that the DSO makes – is then reimbursed through socialisation with help of the *EEG-Umlage*.

4.1.4 Administrative biofuel trade in the transport sector

In both the Netherlands and Germany, actors bringing fuels into the transport sector are obliged to blend in a certain share of biofuels. The obligations can be fulfilled either by direct blending of the biofuel, or by administrative trade. Administrative trade in the Netherlands happens through trading of surplus blending performances, called ‘biotickets’. In Germany, not the performances but the obligations themselves are traded.

BLENDING OBLIGATIONS. In 2014, in the Netherlands the blending obligation of biofuel is set at a share of 5.5% of the total energetic value sold, while this percentage is 6.25% in Germany. In both countries the blending obligations are required to be at least 10% by 2020 by European regulation. Starting in 2015, target in Germany are defined in terms of emission reduction targets instead of blending obligations. An advisory committee⁶⁸ has advised the Dutch government to take a similar approach, but no decisions have been taken yet.

OPT-IN. Biomethane producers that participate in the blending obligations systems as an ‘opt-in party’ – supplying biomethane to the transport sector either directly or through the public gas grid – in the Netherlands are also subject to the blending obligation themselves. Therefore, 5.5% of their production (in 2014) is for their own obligation, while they can sell biotickets for the remaining 94.5%. In Germany, no official opt-in clause exists, but biomethane is recognised as a biofuel and therefore biomethane producers can sell 100% of their production to obliged parties.

⁶⁸ Dutch Sustainable Biomass Commission (Commissie Corbey, 2014).

CARRYOVER. Carryover of biofuel quota surpluses to the following year is allowed in both countries. In the Netherlands, a maximum of 25% of the annual commitment can be carried over, while in Germany no carryover limits exist.

SANCTIONS FOR NON-COMPLIANCE. Both in Germany and in the Netherlands, non-compliance with the blending obligations results in penalty payments. However, in Germany sanctions replace the missed obligations, and as a result the price of the sanction functions as a *de facto* price cap. In the Netherlands, sanctions do not replace the obligations, which have to be compensated in the following year. Non-compliance with the obligation may constitute a criminal offence.

DOUBLE COUNTING. Both in Germany and the Netherlands, certain advanced biofuels can be counted double towards the blending obligation. As the blending obligation in Germany will be replaced by emission reduction targets in 2015, the double counting system will be abolished.

PRICES OF BIOTICKETS AND OBLIGATIONS. In Germany, the energy tax refund defines a biomethane obligation floor price of 1.39 cents/kWh, while the sanction for non-compliance caps the price at an upper limit of 6.84 cents/kWh. In 2012, average obligation prices of 3 to 4.5 cents/kWh were reported, corresponding to € 0.30 to 0.45 per cubic metre of biomethane. In the Netherlands, the price of biotickets fluctuated between approximately € 0.12 to 0.21 per cubic metre of biomethane. The price related to administrative trade of blending obligations has thus been considerably higher in Germany. All of these prices refer to biofuels from single-counting biomass.

4.1.5 Guarantees of origin for renewable energy

GoOs provide an important mechanism for market actors to prove and claim 'green' performances. GoOs are electronic documents providing proof that a given share or quantity of energy was produced from renewable sources.

POSSIBILITIES FOR ADMINISTRATIVE TRADING. In theory, both in the Netherlands and in Germany GoOs can be traded independently from the associated commodity. However, in practice this is only an option in the Netherlands. Dutch biomethane producers can sell GoOs independently from the biomethane, and receive additional revenue from the GoOs in addition to the commodity price and the SDE+ subsidy. In Germany, GoO certificates have a purely administrative value and do not have a market value.

TRANSACTION COSTS. In the Netherlands, the transaction costs for GoOs for both renewable electricity and biomethane are slightly higher than in Germany. Transaction costs for 1 MWh of biomethane are approximately € 0.246 in the Netherlands and € 0.16 in Germany.

MARKET PRICES. Because GoOs can be traded independently in the Netherlands, there is a market value for the GoO certificates. The GoO market is not transparent and prices fluctuate heavily, but the market value for GoOs for biomethane is estimated at approximately € 0.04 to € 0.08 per Nm³. In Germany, there is no market value for GoOs detached from their associated commodity.

4.1.6 Sustainability certification of biogas and biomethane

Biogas and biomethane are subject to sustainability requirements when used for certain applications, including the transport sector. The European Commission has recognised 17 voluntary sustainability certification schemes.

REPORTING BURDEN. In the Netherlands, the fuel supplier at the end of the value chain (excise warehouse, 'AGP') has to submit the proof of sustainability to the NEa. In Germany, all interfaces in the value chain have to provide a proof of sustainability to the next. In the end, the last interface (the fuel supplier) should submit all sustainability certifications of the entire chain to the BLE.

VIRTUAL TRADE. Virtual trading of sustainability certificates is not allowed nor accommodated. However, sustainability can be traded in combination with GoOs. Considering that GoOs in the Netherlands can be traded independently from the underlying commodity, there is more flexibility for virtual trade in the Netherlands. In Germany, GoOs and therewith sustainability certificates can only be traded together with the commodity, due to mass balance accounting requirements.

5. CONVERGENCE FRAMEWORK

In chapter 4, the main differences between the German and the Dutch biomethane regulations have been identified. Some of these differences are explicitly (such as the EEG feed-in tariff) or implicitly (such as the lack of an European mass balancing system) prohibiting cross-border trade of biomethane. In a next step and within this chapter, a theoretical framework for the analysis on costs and benefits of possible convergence scenarios is presented. The main idea behind this framework is based on the economic literature on federalism and deals with a qualitative assessment of possible costs and benefits that could arise from a harmonisation of German and Dutch biomethane policies.

In chapter 6, harmonisation scenarios are defined and the convergence framework developed in this chapter is applied with respect to the expected policy changes within the scenarios. The framework is applied for both countries, Germany and the Netherlands.

5.1 Introduction

The convergence framework is based on theoretical work on fiscal federalism (see e.g. seminal work of Oates (1972)). The theorem on federalism states that a jurisdiction's decision to harmonise its policies depends on

- 1) the heterogeneity of preferences of the jurisdictions; and
- 2) the costs incurred by cross-border interdependencies.

Heterogeneous preferences with respect to biomethane could e.g. be articulated through different sustainability standards for the biogas inputs (such as positive and negative lists for subsidies and tariffs), or different preferences with respect to renewable energy promotion in general. Costs occurring from cross-border interdependencies reflect inefficiencies in resource allocation. We simplify the theorem in such way that it can be applied to evaluate the incentives for Germany and the Netherlands to harmonise relevant biomethane policies and allow for bilateral trade.

5.2 The federalism approach

Federalism refers to the (formal and administrative) institutional setting in which different levels of government are organised. Horizontal federalism covers the interactions and coordinating activities between jurisdictions at the same level – e.g. Germany and the Netherlands as nation states. Vertical federalism refers to the hierarchical levels of jurisdictions – e.g. EU, Member States, regional and local governments.

The specification of a federal system determines to a large extent how interdependencies between different jurisdictions are coordinated. The theoretical literature on this topic first analysed fiscal policies and later turned to environmental and regulatory policies (Oates, 1999). The idea developed by the fiscal federalists is straightforward: it states that the harmonisation of policies of two (horizontal) jurisdictions depends on two patterns. First the heterogeneity of preferences of the jurisdictions and second the costs incurred by cross-border interdependencies.

Cross-border interdependency exists when a decision of one jurisdiction influences the welfare of another and vice versa (Paavola, 2007). One example of interdependencies between jurisdictions is via

trade relationships. Let us take the example of jurisdiction A and B. Jurisdiction A considers the abolition of a trade restriction for a product. According to economic theory a trade restriction is inefficient if it hinders the cost efficient firm from trading its product across administrative borders. In this case maintaining the restriction can yield higher consumer prices in jurisdiction A due to inefficient production. At the same time trade barriers protect home-based production and yield benefits in terms of employment, income and taxes or can guarantee a specific quality or environmental standard.

Fiscal federalism theory assumes that a benevolent decision maker (a social planner) bases a decision on the aggregated costs and benefits of its citizens. Additionally, the planner needs to take into account the reaction of the neighbouring country which can introduce, maintain or abolish trade barriers itself. The situation can be formalised in a strategic Nash-game where two players (social planners) maximise their welfare while anticipating the reaction of the other. A typical utility function (simplified from Loeper (2011)) applied in this context is:

$$U_i(x) = V_i(x_i) - \beta_i W(|x_i - x_j|),$$

where $V_i(x_i)$ embodies local preferences (i.e. whether the local policy meets the specific needs of its residents) and $\beta_i W(|x_i - x_j|)$ is the interdependency cost borne by jurisdiction i for having a different policy than j . The function W is weakly increasing and $W(0) = 0$, i.e. if the policies are harmonised there are no interdependency costs. We assume that before harmonisation was considered the policy strategy of each jurisdiction i was to maximise V_i . The change towards more harmonisation ($x_i \rightarrow x_j$) can then be interpreted as the adaptation cost borne by jurisdiction i for changing its policy from V_i maximised to $V_i(x_i)$ (i.e. $\Delta V_i = \text{Adaptation costs}$). The welfare performance of harmonisation and autarchy depend on the specific shapes of W and V .

Both countries maximise U_i with respect to their trade-related biomethane policy x_i . Depending on each player's specified welfare function as well as the institutional setting, this game can have different outcomes (for an illustration see Table 8):

1. Both jurisdictions anticipate the other's strategy not to harmonise its trade policy, thus both maintain their trade barriers. This behaviour can result in an inefficient solution (prisoner's dilemma: A and B would be best off if they free-ride on the others attempt to harmonise policies. Since both anticipate the other's strategy (free-riding), A and B will maintain the trade barrier). In the case of the prisoner's dilemma it would need a federal authority that implements one uniform policy to enable level-playing field trade conditions.
2. If for both countries the 'autarchy' benefits are symmetrically higher than the gains from trade, the autarchy scenario can result as the efficient solution.
3. The two jurisdictions bargain over the policy and stipulate their common policy in a legal contract (prisoner's dilemma with transparent negotiation).

Summarising, the federalism approach deals with the decision-making of jurisdictions on changing their policy from the baseline to the policy harmonisation scenario. It asks which level of government is optimal to maximise overall welfare. Is there a need for one uniform policy, does it have to be enforced by a federal authority, or do jurisdictions have incentives and the legal institutions to coordinate their policies? Or, finally, is there no need for harmonisation at all?

In the following the federalism approach is applied to develop a qualitative framework for analysing benefits and costs of harmonising biomethane policies in Germany and the Netherlands. There will

thus not be quantitative estimates on benefits and costs, but we present structured arguments and findings resulting from the project’s detailed policy analyses (chapters 2, 3 and 4).

Table 8. Illustrating example of two symmetric jurisdictions (A and B) deciding on policy harmonisation

		B	
		No Harmonisation	Harmonisation
A	No Harmonisation	-1 / -1	2 / -3
	Harmonisation	-3 / 2	1 / 1

Notes: A and B have the same welfare function: $U = \text{Sum of heterogeneity benefits} + \text{cross-border effect costs}$.

Assume the sum of the benefits of heterogeneity to be € 2 and the costs from the cross-border effect (opportunity costs with respect to the free trade scenario) to be € 3. The resulting payoffs are illustrated in the table. The Pareto optimal situation would be if both harmonised their policies. Without reliable negotiation and information sharing the result will be that both do not harmonise their policies.

5.3 Convergence framework features

Would a policy harmonisation be beneficial for the Netherlands and Germany? What are the main barriers and opportunities of biomethane policy harmonisation? Who would be affected in what way? These are the guiding questions for developing the convergence framework. It builds on the two categories from the fiscal federalism theory – the heterogeneity benefits and the interdependency costs. In the baseline scenario bilateral trade of biomethane is prohibited or hindered through different policies in both countries. We assume a policy change towards more harmonisation. The expected policy changes will be described for both countries. We evaluate the impact of these changes on different social groups. These groups will (a) gain from policy harmonisation due to a reduction of cross-border interdependency costs, while others will (b) face adaptation costs because the harmonised policy does not match their heterogeneous preferences anymore, or at least less than before. We work with three ratings which are:

- minus (-) for a negative impact,
- plus (+) for a positive impact, and
- neutral (o) for no impact.

We select a question mark (?) if we cannot assess the direction of impact. The assessment is based on desktop research and interviews conducted within the project. Since quantified and financial data is limited and not representative we do not provide a cost-benefit-ratio in the end, but intend to share differentiated arguments on the barriers and opportunities of opening up the biomethane market for international trade through harmonisation.

We identified the following aggregated stakeholder groups and divided them into different categories:

1. Direct stakeholders:
 - Biomass producers
 - Biomass traders and shippers
 - Biomethane producers

- Biomethane traders and shippers
 - Grid operators for gas and electricity
2. End users
 - Electricity/CHP producer
 - Industry
 - Transport
 - Private households
 3. Indirect stakeholders
 - Investors
 - Tax payers
 - Government

Table 9 serves as a guideline framework for identifying the main barriers and opportunities of enabling cross-border trade in biomethane. The findings that are reflected within the tables are then given and further evaluated within chapter 6 with respect to expected adaptation costs and possible effects on competition and trade. Trade will be further differentiated into (1) raw materials trade, (2) commodity trade, and (3) title trade.

Table 9. Scenario analysis framework

Policy	Guarantees of Origin	Gas grid connection	Electricity grid connection	Feed-in subsidies and tariffs	Biomethane in transport	Sustainability certification	CO ₂ allowance trading	Key effects of this scenario per stakeholder
Key Difference								
Scenario effect on								
Direct stakeholder								
End users								
Indirect stakeholders								
Key Effects per theme								

6. ASSESSMENT OF SCENARIOS

Based on the convergence framework as introduced in chapter 5, two distinct scenarios are analysed. In this chapter, the scenarios are introduced (Section 6.1) and subsequently both scenarios are assessed.

6.1 Introduction of scenarios

In both scenarios, full harmonisation (or full institutional convergence) of policies and regulations takes place in the Netherlands and Germany. In scenario 1, Germany adopts the regulatory framework of the Netherlands, while in scenario 2 the German system is adopted in the Netherlands.

Main regulations	Scenario 1: Germany adopts the Dutch framework	Scenario 2: the Netherlands adopts the German framework
<i>Biomethane injection into natural gas network</i>	<ul style="list-style-type: none"> - Connection and Transport Conditions Gas Regional Network Operators (ATvGR) - Additional Terms ('Version 14') - Ministerial regulation on gas quality 	<ul style="list-style-type: none"> - Gas Network Access Regulation (<i>GasNZV</i>) - Gas Network Fees Regulation (<i>GasNEV</i>)
<i>Feed-in of renewable energy into the electricity grid</i>	<ul style="list-style-type: none"> - Dutch Electricity Act 	<ul style="list-style-type: none"> - German Energy Act (<i>EnWG</i>) - Renewable Energy Act (<i>EEG</i>)
<i>Feed-in subsidy and tariff schemes</i>	<ul style="list-style-type: none"> - SDE+ - Fertilisers Act - NTA 8003 	<ul style="list-style-type: none"> - EEG 2012 - Biomass Regulation (<i>BiomasseV</i>)
<i>Administrative biofuel trade in the transport sector</i>	<ul style="list-style-type: none"> - Environmental Management Act - Decree on Renewable Energy and Transport - Regulation on Renewable Energy for Transport 	<ul style="list-style-type: none"> - Federal Immission Control Act (<i>BImSchG</i>) - Energy Tax Act - Regulation on Biofuels Quota
<i>Guarantees of origin for renewable energy</i>	<ul style="list-style-type: none"> - Regulation on Guarantees of Origin for Sustainable Electricity - Issuing body Vertogas 	<ul style="list-style-type: none"> - Renewable Energy Act (<i>EEG</i>) - Renewable Energy Heat Act (<i>EEWärmeG</i>) - <i>Biogasregister</i>
<i>Sustainability certification of biogas and biomethane</i>	<ul style="list-style-type: none"> - Regulation on Renewable Energy for Transport - Regulation on Fuels and Air Pollution 	<ul style="list-style-type: none"> - Biofuel Sustainability Regulation (<i>Biokraft-NachV</i>) - Biomass Electricity Sustainability Regulation (<i>BioSt-NachV</i>).

6.2 Effects of scenarios on stakeholders

Within this section the effects of the institutional convergence scenario's on various stakeholder groups are explored. The various stakeholder groups considered were introduced in Section 5.3.

The main idea behind isolating different stakeholder groups, is that the assumed switch to another policy regime is likely to result in changes with regard to the role and position of each individual stakeholder group. For instance, it is known that the terms and conditions of the German EEG feed-in tariff scheme provide more and longer term certainty about project revenues, and thus is more attractive for investors relative to the Dutch SDE+ scheme.

6.2.1 Direct stakeholders: biomass producers

Biomass producers typically are those companies that are cultivating food and feed products. This requires the use of arable land, which – especially in Germany – is perceived as an environmental problem, as more and more land is converted to e.g. maize land for energy production (*'Vermaisung'*). One key difference between the two countries is that within Germany a larger share of primary (or cultivated) biomass is used for biomethane production, while in the Netherlands most existing biomethane facilities (mainly) use agro-food residues and waste from food, feed and household waste processing industries. As a result, it is to be expected that a switch to a regime that prefers the use of cultivated biomass for biomethane production will favour this stakeholder group more in Germany (relative to the Netherlands). In contrast, a regime favouring the use of secondary biomass resources, is not likely to favour this stakeholder group.

Below short conclusions are drawn for the stakeholder group of biomass producers in both scenarios.

Scenario 1: Dutch framework

The lowered incentive to use primary products within the Dutch tariff scheme would have the biggest influence on biomass producers, as it is to be expected that demand for secondary biomass will grow. A narrower definition of allowed biomass (differences in 'positive lists') puts some additional limits on available biomass and could have some (regional) biomass price effects, however it also lowers the biomass reporting and monitoring efforts. With regard to sustainability certification (if biomethane is to be used in transport), the biomass producer no longer has to be certified, as this is restricted to the excise warehouse.

Scenario 2: German framework

A change to the German feed-in system may or may not trigger Dutch biomass producers to cultivate more (primary) biomass, due to scarcely available arable land and relatively high intensity land-use for (generally more profitable) food and feed applications. Nevertheless, cultivation of some uneconomical food/feed crops could be crowded out or some marginal lands are likely to be used for biomass production. Given that there is relatively more biomass supply scarcity, the Dutch biomass producers thus can benefit from this (expected) higher demand, and resulting upward pressure on prices for primary raw materials (up to the level where biomass imports from Germany become economical).

6.2.2 Direct stakeholders: biomass traders and shippers

Biomass traders and shippers are likely to gain with increasing levels of (cross-border) trades in biomass materials. Within the Netherlands, the majority of biomethane production facilities are part of a larger agro-food or waste processing company⁶⁹. As such these facilities are often supplying

⁶⁹ In Germany, there is a relatively higher share of biomethane production facilities which are owned and operated by farmers or agricultural cooperatives. Those facilities are generally supplied with larger shares of primary (cultivated) biomass resources, such as maize.

themselves with secondary biomass resources (either coming from the nearby agro-food processing factory, or nearby waste separation and collection processes). As a result, it is to be expected that in any regime that favours the use of secondary biomass resources, the biomass traders and shipper stakeholder group is likely to lose as less trading and shipping services are required, relative to a scheme where the use of primary biomass use is favoured.

Scenario 1: Dutch framework

As the Dutch regime seems to favour the use of secondary resources, the activity level of the German biomass traders and shippers is likely to remain stable as the market expands (assuming that existing facilities may still use primary biomass resources). In turn, with an expected increased use of secondary biomass resources, the transaction costs associated with biomass origin reporting/monitoring or sustainability certification are likely to be lower.

Scenario 2: German framework

As the German framework favours the use of primary biomass, the Dutch biomass traders and shippers could benefit from increased activity levels. However, this increase is limited by the availability of both primary biomass and (open market) secondary biomass resources. Also in German border regions it might become economically attractive to start producing biomass for the Dutch biomethane market, as biomass cultivation potentials in the Netherlands are limited. This could result in an increase in (cross-border) trading/shipping activities. Overall we expect this stakeholder group to only marginally benefit from a regime change. In fact it is expected that this stakeholder group benefits from a non-harmonised regime where for example differences in the 'positive lists' in the two countries provide scope for cross-border biomass trade.

6.2.3 Direct stakeholders: biomethane producers

The producers of biogas and biomethane are more facilitated in scenario 2. Aspects such as the arrangement of the grid connection and the sale of biomethane have to be carried out by the biomethane producers in scenario 1 (Dutch regime), while in scenario 2 (German regime) they are supported by the DSOs.

Scenario 1: Dutch framework

German biomethane producers would face significant changes. Most of them are expected to be negative as they will be required to invest more and accept higher risks. The grid connection costs have to be solely covered by them, which means that investments made by the biomethane producer will be higher. This will increase their dependency on a bank loan or other means of financing the investment. This may negatively affect the chances of successful implementation of biomethane plants. On top of that the biomethane producer will have to accept a higher level of project development risk, as all environmental and construction permits need to be completed, without having the certainty of being able to get the feed-in subsidy. So, even before a project is operational, there are substantial project development risks involved as subsidy budget might simply not be allocated to that specific project.

In addition, under the Dutch regime the biomethane producers stay liable for the gas quality even after the injection. At the same time, they are able to receive feed-in tariff payments directly from the government without negotiations, but those payments are likely to be somewhat lower than the privately negotiated prices achieved under the EEG, where the electricity producer pays the biomethane supplier/producer.

Scenario 2: German framework

Overall it is estimated that the German regime is more favourable for biomethane producers relative to the Dutch system. This is mainly caused by the feed-in premium scheme, which provides higher support level and longer duration of support, and the change in grid-connection regime, as part of investment burden is transferred to the DSO and a longer balancing period is allowed. In this scenario, there is more flexibility for producers to inject biomethane into the natural gas distribution network, considering the longer balancing period, and there are less administrative and financial risks related to the planning and development of biomethane plants.

6.2.4 Direct stakeholders: biomethane traders and shippers

Biomethane traders and shippers have an interest in bioenergy trade via the public gas grid. A policy regime that increases biomethane production volumes, and favours biomethane trading over raw materials (cross-border) trading, will result in a positive stimulus for this stakeholder group. The German regime (scenario 2) seems more favourable for biomethane production activities and as such is more likely to benefit this stakeholder group.

Scenario 1: Dutch framework

This scenario would lead to more administrative and operational costs, as biomethane traders and shippers have to maintain their entry and exit portfolios in hourly balance. The shorter balancing period under the Dutch regime increases the responsibility for maintaining stable and predictable production patterns, and thereby reduces the scope for optimising trade portfolios. The Dutch regime introduces some additional project risks due to the loss of a legally firmly established preferential access and hence higher risk of disconnection. Stricter biofuel targets may increase the amount of biomethane supplied to the transport sector, but only to the level where the revenues from biomethane sold in transport are higher compared to the feed-in subsidy level. In addition, the change to the Dutch regime could possibly result in somewhat lower transaction costs due to less strict reporting and monitoring requirements. The flexibility of GoO trading due to the Dutch mass balancing system basically expands the geographical market, and therefore the revenue opportunities.

Scenario 2: German framework

In this scenario, there are less stringent (entry-exit) portfolio balancing responsibilities, and increased operational flexibility due to the longer balancing period. Increased levels of biomethane are likely to enter the market, leading to increased trading volumes, although this is potentially limited by the domestic raw materials supply and the economic efficiency of imports from Germany. In addition, there are lower project development risks, as subsidies will be available. The lack of flexibility of GoOs in the German mass-balancing system basically limits the geographical market, and therefore limits the revenue opportunities (although there may be still gains from harmonisation).

6.2.5 Direct stakeholders: gas and electricity DSOs

There are significant differences between both scenarios for DSOs. Financial and operating responsibilities are higher for gas grid operators in scenario 2 (where the Netherlands adopts the German framework), and also electricity grid operators have more tasks and responsibilities in this scenario.

Scenario 1: Dutch framework

The financial and operational obligations of gas grid operators are lowered as there is no firm legal obligation to connect producers anymore and the balancing conditions for biomethane injection become far more strict (one hour instead of one year balancing period). The DSO does not share the investment and operational costs for the grid connection.

The stricter balancing regime in combination with a less rigid obligation to connect producers helps to avoid uneconomical investments. However, this also could prevent the development of larger-scale biomethane production projects due to possible grid congestion in regional distribution grids.

The major impact for the electricity grid operators is due to the change in the tariff scheme structure. The DSO is no longer responsible for the collection and reimbursement of tariff payments. This might lower the administrative burden.

Scenario 2: German framework

Gas grid operators would be affected by an expansion of their legally mandatory tasks (75% investment and 100% operational share in biomethane plant grid connections). Under the German regime these extra costs can be socialised via network tariffs, so there should be no net negative impact on this part.

The German balancing regime could, however, result in additional costs for frictional balancing issues in lower tier grids, which the DSOs are principally responsible for. The investments to overcome balancing problems can be uneconomical, and the German regime therefore is likely to be less cost-effective.

In this scenario the electricity grid operators will become responsible for the collection and reimbursement of feed-in tariff payments, which increases their operational responsibilities and administrative burden.

6.2.6 End users: the power sector

The electricity production sector is a potential end-user for biomethane. The German policy regime favours this type of end-use for biomethane as the feed-in tariffs are paid directly to electricity producers. Within the Netherlands the feed-in premiums are paid directly to biomethane producers, which means that there is no direct need to supply the biomethane to the electricity production sector.

Scenario 1: Dutch framework

The power sector does not receive direct feed-in tariff payments for biomethane use. Power facilities might be able to buy GoOs. As this implies higher costs with no direct reimbursement through higher tariff payments, this seems unlikely to happen. German electricity producers using natural gas might be worse off – under the Dutch regime – as a result of higher ODE charges, since in the German scheme the EEG-*Umlage* is only levied on electricity use (and not on gas consumption).

Scenario 2: German framework

The German EEG system requires biomethane to be converted into electricity, as the feed-in tariff is granted to electricity producers, not to biomethane producers. Therefore, alternative end-use routes are de facto excluded. However, the Dutch scheme more or less has a similar impact, given that biomethane produced with feed-in subsidies does not count towards the renewable fuel blending target (in order to avoid double counting), so this alternative end-use is also not possible in scenario 1. Furthermore, the EEG surcharge will (partly) substitute the RED tax. Only surplus biomethane, that is not subsidised through the feed-in scheme, is likely to have an alternative end-use.

6.2.7 End users: the industry sector

The industry sector includes a broad range of activities where natural gas or biomethane can be used either as process input (e.g. to produce petrochemical products) or as combustion gas (e.g. to produce electricity or heat for the main processes). End use of biomethane from the grid in this sector is not specifically stimulated, as the administrative use of GoOs for biomethane is not eligible under the EU's Emissions Trading Scheme (direct use of biogas/biomethane could be eligible). In addition, some industries that are making biofuels for the transport sector could have an incentive to use GoOs for biomethane. Within the Dutch scenario the opportunities for administrative use of biomethane are better, due to differences in the GoO certification schemes (mass-balancing).

Scenario 1: Dutch framework

Industrial stakeholders would be able to (administratively) trade GoOs (not necessarily linked to the commodity biomethane) and compete with the power sector in this regard, even though the incentives to do so are not well established. Industries using natural gas might profit from lower grid usage fees due to a lower cost burden on the DSOs (grid connection costs are socialised in a different manner than in the German regime); but this depends on the gas transport tariff setting for small, medium and large gas users.

Scenario 2: German framework

Minimal impact on this end-user category (only when biomethane is used for power production). Especially when GoOs have been administratively used before, the German regime does not facilitate this. Due to the additional cost burden for gas DSOs, the gas transport tariffs could increase, while REB tax declines. The net impact could be either positive or negative for this end-user group as it depends on the initial level of REB and/or any possible REB exemptions.

6.2.8 End users: the transport sector

The fuel supplier is assumed to be the end user of biomethane in the transport sector. Under both the German and the Dutch regime sustainability certification requirements apply, and also both regimes

accept some form of double counting for more sustainable biofuels. The key difference relates to the way in which the quota obligations are met. In Germany the obligations to blend are traded, while in the Netherlands the actual blending performances are traded.

Scenario 1: Dutch framework

A switch to the Dutch regime would not likely lead to significant changes as, generally speaking, the same or similar conditions apply. The use of biomethane in transport might increase once the quota blending / bioticket price rises to levels comparable (or above) the feed-in tariff prices. However, in this scenario there would be minimal flexibility in switching between both the quota blending or feed-in tariff regime.

Scenario 2: German framework

The availability of the EEG feed-in tariff is likely to make biomethane fuel in transport a niche (non-existent) option, as the EEG budget is unlimited and the bioticket prices currently are too low. However, if quota blending prices rise to levels comparable (or above) the feed-in tariff, the German market premium scheme allows biomethane producers to switch between the quota blending and feed-in tariff regime on a monthly basis.

6.2.9 End users: households

Households typically use natural gas for heating purposes. Under the Dutch regime, there are no robust incentives to use biomethane and as a result biomethane use for this stakeholder category is voluntary. Under the German regime there are some incentives for use of renewable heat (which can be produced with biogas or biomethane).

Scenario 1: Dutch framework

There might not be a lot of impacts on private households. The share of electricity from biomethane might drop and the importance of biomethane in the heat market might increase through the use of certified heat using GoO by retailers. Households using natural gas might profit from lower grid usage fees due to a lower cost burden on grid operators.

Scenario 2: German framework

Increased levels of biomethane-based electricity and reduced levels of biomethane-based domestic heating available.

6.2.10 Indirect stakeholders: investors

The perspectives for investment in biomethane production differ, based on the cost and responsibility burden allocations in both scenarios. As the costs and responsibilities in scenario 2 are more with the government and DSOs, the certainty for investments is higher.

Scenario 1: Dutch framework

The risks for investors under the Dutch system is expected to be significantly higher due to a higher degree of uncertainty (e.g. shorter duration of support, higher project development risk due to limited budget) and a higher cost burden (e.g. gas grid connection). Even the additional income through the trade of GoOs is unlikely to encourage/trigger a level of investments similar to that under the German EEG regime.

Scenario 2: German framework

This scenario provides an overall better and more robust perspective for investing in biomethane production, considering the lower degree of uncertainty and the lower cost burden for biomethane producers.

6.2.11 Indirect stakeholders: tax payers

The main difference between both scenarios with regard to tax payers is that only in scenario 1 the feed-in subsidy is paid from tax money. In scenario 2, feed-in tariffs are paid by DSOs, and funding is socialised among electricity consumers (and additional gas grid connection costs are socialised amongst gas consumers). Knowing that tax payers and electricity/gas consumers are not exactly the same functional groups, some distributional impacts can be anticipated as a result of the two distinct cost socialisation methods. Overall it is expected that in scenario 2 the overall costs are higher as the German regime is overall more generous and triggers a higher activity level. Therefore also the overall financial burden on society is likely to be higher in this scenario.

Scenario 1: Dutch framework

As the feed-in tariff is paid by the government from tax revenues, tax payers are likely to pay more under the Dutch scheme. However, the total financial burden is expected to be lower, as the government sets a budget limit, in contrast to the unlimited budget for EEG feed-in tariffs in Germany.

Scenario 2: German framework

In the German system, feed-in tariffs are not financed through the tax system. Financing of feed-in tariffs as well as grid connections are funded through EEG levies by the DSOs. The overall financial burden on society is likely to increase, especially considering that the budget for the feed-in tariff in the German system is infinite.

6.2.12 Indirect stakeholders: government

In scenario 1 there is a fixed government budget for feed-in subsidies, with defines flows of tax money. In scenario 2, the government has placed the financial flows for renewable energy support schemes entirely outside its responsibility.

Scenario 1: Dutch framework

The government is more directly involved in the collection, distribution and control of the budget for feed-in subsidies. This might induce some administrative costs for government agencies. Also administrative efforts might be needed due to the establishment of GoO trading. The method of allocating subsidies might create some inefficiencies due to hoarding (or a rat-race) for limited subsidy budgets. There is strong evidence that this has led to opportunistic behaviour and false claims on subsidy budgets for projects that will never be realised. This has resulted in significant amounts of subsidy budget not being spent (or being spent only much later).

Scenario 2: German framework

In this scenario, the government leaves most activities to the DSOs and the market, and the direct involvement is therefore much lower. However, the unlimited growth of the costs of the EEG scheme for society is possibly problematic, as costs cannot be controlled. Therefore, the government might find itself forced to retake control over the feed-in scheme.

6.3 Adaptation costs of scenarios

In both scenarios, the institutional setting in one country will converge with that of another. As a result, adaptation costs in scenario 1 are mainly expected for German stakeholders, and in scenario 2 for Dutch stakeholders. Stakeholders from the country of which the framework is implemented are not expected to experience major changes, except for possible increasing competition for biomass, biogas, biomethane and/or certificates.

At this point it needs to be also noted, that the described adjustments are going to be associated with a longer transition period. Assuming that the state subsidy guarantee will be held by the government, the newest biogas facilities are entitled to the state support for the next 20 years (Germany) or 12 years (Netherlands).

Scenario 1: Dutch framework

Overall, the adaptation costs for switching to the Dutch regime are expected not to be a significant hurdle for convergence. Aligning the rules and regulations (and its execution) to the Dutch regime would not create too high costs, as it would mainly imply some legislative changes and amendments. However, the shift in the terms and conditions of each policy is rather significant and is likely to result in a significant hurdle for policy convergence.

The adaptation (or transaction) costs one could think of relate to changing the basic legislation for support schemes and other relevant policy instruments, such as 'positive lists', feed-in tariff scheme, grid access and balancing regime, etc. On top of that it might be that the costs of monitoring a certain scheme go up/down, as a result of its higher/lower complexity which makes monitoring and enforcement more complex (and thus more expensive). Also a more stringent balancing regime could result in reduced efforts (and costs) of network operators to maintain grid parity, which they typically socialise in their transport fees.

Scenario 2: German framework

Some adaptation costs are expected in relation to changes in the gas grid connection regime, and in aligning the feed-in tariff scheme with the German (including the way in which the funds are collected). Overall, the adaptation costs (to switch to the German regime) are considered not to be a hurdle for convergence. The shift in the terms and conditions of each policy is rather significant and is likely to result in a significant hurdle for policy convergence.

Some sources of adaptation (or transaction) costs relate to making changes in legislation for support schemes and other relevant policy instruments, such as 'positive lists', feed-in tariff scheme, grid access and balancing regime, etc. On top of that it might be that the costs of monitoring a certain scheme go up/down, as a result of its higher/lower complexity which makes monitoring and enforcement more complex (and thus more expensive). A less stringent balancing regime could result in higher costs for network operators to maintain grid parity, which they are likely to socialise in their transport fees.

6.4 Scenarios' effects on competition and trade

Competition between Dutch and German biomethane pathways can take place in different 'arena's' or different submarkets. Such competition is best observed by looking at trade flows or competitive advantages of one country over another. The relevant trade flows for biomethane pathways, are:

- a- Trade in raw materials / biomass
- b- Trade in biogas-biomethane
- c- Trade in certificates (administrative trade)

The key question to ask, is what the effect of a different scenario (1 or 2) could have on these three types of trade. One could, for example, consider an extreme case where the feed-in premium for biomethane in country A is twice as high as in country B. For raw materials trade, this would make it more interesting to transport biomass over much longer distances to the digestion facility. Of course in reality such effects on competition are much more subtle. Even in a fully converged institutional setting the preferred modes of trade could differ or change. For example in the Dutch regime administrative trade of GoOs is better facilitated, which might come at the expense of either raw materials or biomethane trading. This section will briefly explore to what extent the more or less preferred modes of cross-border trade could be in either scenario 1 or 2.

6.4.1 Raw materials trade

Some stakeholders that were consulted throughout this project indicated that there is scope for cross-border raw materials trade as a result of institutional differences, mainly as a result of differences in 'positive lists' that are considered eligible for biomethane production. Removing such institutional differences is likely to result in a lower level of such cross-border trades in raw materials.

Scenario 1: Dutch framework

More strict regulations on eligible biomass inputs is expected to result in a lower level of raw materials trade for biomethane production purposes, and might therefore also have an influence on trade. Also given the fact that the Dutch framework has a stronger preference for secondary biomass resources to be used for biomethane production, its supply is by definition more limited as compared to the German scheme which is (relatively) more favourable for primary (cultivated) biomass, which has a higher supply elasticity.

Scenario 2: German framework

For the Netherlands, the shift to the German regime is likely to have a positive effect on the raw materials market and the raw materials trading. 'Positive lists' are harmonised, but for the Netherlands feed-in support is more long-term and robust. As a result, it can be expected that some additional biomethane production will come online. This increase is limited by the price and availability of eligible primary feedstock, as well as secondary biomass resources (which are already quite intensively used). So, cross-border raw materials trade (resulting from institutional differences) are likely to decrease, but in the Netherlands the level of domestic raw materials trade could increase as a result of the switch to the German regime. This growth in trade is likely to come from a somewhat higher use of primary biomass resources, which supply is likely to come from marginal lands, which are not yet used for more profitable purposes (such as animal feed or food cultivation).

6.4.2 Commodity trade: Biomethane and Green Certificates

Biomethane trade relates to the trade of the gas molecules that have been injected into the grid. This is not necessarily linked to the green character or green properties of the biomethane. The green properties of biomethane are often certified with the help of certification schemes. In the German regime the mass-balance accounting method is more stringent, resulting in the situation where the biomethane and its green (certified) performance are mostly traded as one package. The Dutch regime allows for separated trading of the biomethane energy and the green certificates (Guarantees of Origin).

Scenario 1: Dutch framework

Biomethane trade under the Dutch regime will have more the character of conventional trade in natural gas, since the green performance is traded separately via administrative transactions, which can be done via an (inter)national registry. Under the Dutch regime, therefore a higher level of administrative trade is expected (as a preferred mode of trade). As a result of this decoupling of the biomethane and the certificates trade, a larger 'green market' with different end-users – can in principle be served (e.g. industry, electricity, households, transport). In theory also a larger geographical market can be served with such certificates, as trades are no longer linked to the physical limitations of the gas grid through which the biomethane molecules have to be transported (this can often be a problem if and when interconnection capacities are fully booked).

Scenario 2: German framework

Biomethane certificate trade under the German regime is much more limited as the GoO and the biomethane itself cannot be traded separately. Due to more stringent mass-balance accounting principles, the coupled biomethane-certificate trades are also more limited in geographical scope, which typically does not accept trades between different entry-exit zones. Under the German institutional regime, therefore, cross-border trade in biomethane and certificates, is likely to remain limited.

6.5 Conclusion

Within this chapter we have explored what impacts a full institutional convergence on the various market stakeholders (Section 6.2) and what the preferential mode of cross-border trade (section 6.4) could be. In addition to that we have briefly discussed the potential level and extent of adaptation costs when switching to new regime (Section 6.3).

Regarding the adaptation / transaction costs related to the switch to another regime we conclude that such costs are not high enough to serve as a real barrier to institutional convergence. In addition, we find that the costs and benefits of a full institutional convergence are not equally shared between the relevant market stakeholders. In most cases, we expect that there will be stakeholders that would benefit from full convergence and some would oppose any further convergence.

In general we could conclude that there will be stakeholders who lose / gain relative to the old (non-harmonised) situation, but there will also be stakeholder groups that prefer a certain harmonised regime - either Dutch or German - as both regimes have a different 'preference' for the three different modes of cross-border trade (either raw materials, biomethane or certificates trade).

7. SUMMARY, CONCLUSIONS AND FUTURE-ORIENTED REFLECTIONS

7.1 Introduction

This report has described the Dutch and German policy regimes for biomethane and their key differences in detail, followed by a framework for assessing policy convergence on this issue in the two countries, worked out in two scenarios. In fact, this study has tried to inventorise all the detailed differences in policies and measures that may affect the competitiveness of biomethane production in the Netherlands and Germany; and has used this information for assessing in a hypothetical setting how free trade of biomethane between the countries could be affected by such institutional differences.

The driver for any discussion on full institutional convergence is the ambition to create an efficient and effective internal EU market for goods and services. The integration of energy markets across the EU, the convergence of the corresponding institutions, and the creation of an internal energy market by 2014, is a clear example of the EU goal to try to create such a truly European market.

Economic theory suggests mutual national welfare gains by removing barriers to cross-border trade and avoiding unfair competition. The process of removing barriers to trade is usually accompanied by strategies to harmonise the corresponding underlying national institutional regimes in order to create a 'level playing field'. A so-called 'level playing field' is considered to be an important precondition for international trading conditions to be fair. Theory suggests that a competitive market with free international trade triggers market stakeholders to offer their products or services, in this report related to biomethane production and trading, at the lowest competitive costs. In reality, however, such costs are affected by a wide variety of policies and measures that may – because they are different from one country to another – distort the competition that is assumed to exist between the nations. So, the EU's Single Market Act⁷⁰ aims to create an internal market and remove obstacles to the free cross-border trade in goods, services, capital and labour. Despite such EU level regulations, considerable differences in the national institutional regimes persist, also in the area of biomethane (see Chapters 2-4).

Under various EU regulations, directives and communications on, amongst others, competition, state aid⁷¹ and renewable energy, the Netherlands and Germany have implemented a broad range of national policies and measures. National legislation may reflect differences in political preferences and objectives. National political decisions on renewable energy policies have created a patchwork of national policies in the EU. Throughout the EU these policies predominantly stimulate the production of renewable energy, and, on the whole, less so its end use. This is also true for the handful of EU Member States that have specific policies in place for biomethane. Most of these countries use a feed-

⁷⁰ Single Market Act: http://ec.europa.eu/internal_market/smact/docs/single-market-act2_en.pdf

⁷¹ Guidelines on State aid for environmental protection and energy 2014-2020 (Communication 2014/C 200/01): [http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628\(01\)](http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628(01))

in premium or tariff scheme as their primary instrument to trigger investment in biomethane production.

This concluding chapter first explores conceptually the main impacts of a hypothetical situation of full institutional convergence regarding the biomethane sector (Section 7.2). Next, it will be analysed what the current variety in terms of renewable energy support schemes, etc. between the Netherlands and Germany means for national biomass production conditions, and for competitiveness assuming increasing trading opportunities between the countries. Also it is reflected on the issue how realistically countries would be prepared to adjust their national feed-in regime to those of other countries, and what regime differences do exist across Europe in this regard (7.3). Section 7.4 attempts to explore the potential application of an alternative institutional framework for biomethane that is not depending on feed-in subsidy schemes. Here the possible application of quota obligations and certificate trade-based regimes will be analysed as a possible alternative.

Section 7.5 builds further upon that by exploring what role biomethane can play in different end-use sectors for heating/cooling, electricity and transport if one would assume cross-border certificate trading under a quota obligation. It also explores what basic institutional and political conditions should be met in order to have an efficiently operating EU market for biomethane .

7.2 Impacts of institutional convergence

In a paper on harmonising regulatory mechanisms, Dutz (2004) suggests: *“With the gradual reduction of cross-border trade barriers, domestic [...] regulations [...] have become an increasingly significant factor affecting the relative prices of exports, imports, and domestic production.”* He also states: *“The effects of inefficient domestic regulations transcend national borders, distorting and reducing not only trade but also investment levels.”* This suggests that a higher level of institutional convergence may increase the efficiency and effectiveness of international competition. However, any strategy of institutional reform will generate a number of not only positive but also negative national impacts. Specifically for the Dutch-German case study on biomethane, the following three subsections describe three different impact categories in more detail:

1. **Improved international competition:** the primary objective of institutional convergence.
2. **Distributional impacts:** effects of redistribution of tasks, responsibilities, receipts, costs, funds, etc.
3. **Transitional impacts:** specific effects in the transitional phase from one regime to another.

7.2.1 Improved international competition

As national economies become more and more interrelated, institutional differences can cause political, economic and sometimes social effects. The first challenge is to verify if such differences can result in market distortions, and if so what policy action is needed to address this. Insofar as institutional convergence – as a solution - is promoted the challenge will be what level and depth of harmonisation is needed (e.g. full convergence or partial convergence).

Subsidy competition could be one such side-effects as it can create significant inefficiencies with regards to public spending. The EU (2014-2020) state aid guidelines for environmental protection and energy are developed with the intention to regulate public support measures at the Member State level, so that they are proportional, cost-effective and do not create market distortions.

In addition to the abovementioned forms of fiscal and subsidy competition, there can also be non-financial institutional competition, driven by (subtle) differences in regulations, norms and standards. Such competition may also distort the market. One illustrative example is given in Section 2.3 that relates to the differences between Dutch and German regulations stipulating which biomass resources are allowed to be used. Such differences can create scope for suboptimal biomass trading.

The key message in this section is that as a result of well-designed institutional convergence there are potential gains for overall welfare. However, it also shows that institutional convergence is complex and multifaceted, because it can manifest itself in several different policy areas affecting a series of linked economic activities (e.g. biomethane pathway activities). Convergence therefore is not a simple process of each Member State adopting exactly the same regime for biomethane, and the norms and standards for biomass use, etc. Any institutional convergence strategy should try to address convergence in a more holistic manner and not simply pick individual instruments and consider convergence in isolation from the broader institutional context.

7.2.2 Distributional impacts

Another impact of institutional convergence in the field of biomethane is related to changes in the allocation of receipts, costs, funds, tasks and responsibilities. As institutions change, also certain stakeholders are directly and indirectly affected in a positive or negative manner. The following key examples of distributional impacts have been identified:

- Investment burden for gas grid connections;
- Balancing responsibilities for biomethane producers;
- Funding mechanism for support schemes; and
- Project development risk profile as a result of policy design.

Investment burden for gas grid connections

The investment burden relates to the division of investment and operational costs between the biomethane producer and the DSO. This division is different for biomethane in both countries, as described in Section 2.1, and therefore institutional convergence would shift the burden in at least one of the countries. Overall, the German regime seems more secure and favourable for the biomethane producer, as its total capital requirements and operational expenses are lower relative to the Dutch regime. However, the German grid connection regime for biomethane is considered the least cost-effective, as the German DSOs have a more firm legal obligation to grant and facilitate grid access to biomethane production projects. As a result the DSOs might be more obliged to participate in (possibly uneconomical) biomethane grid injection investments.

Balancing responsibilities for biomethane producers

An institutional change towards a new regime can also result in a different distribution of balancing responsibilities. The most noticeable difference between the Netherlands and Germany relates to the balancing period applicable to producers injecting biomethane into the gas grid. The challenge is to maintain a good balance of biomethane (and natural gas) injection and offtake in the appropriate period. Unbalanced portfolios can receive a certain penalty for not maintaining their proper injection and offtake planning.

The balancing periods in Netherlands and Germany are 1 hour and 1 year, respectively. A longer balancing period effectively implies that biomethane can be (temporarily) stored in the gas grid for a

longer period of time. As a result, a producer can optimise its portfolio by selling the biomethane on the right moment within the given timeframe. An hourly balancing period, as in the Netherlands, leaves very little room for such optimisations. The German regime provides the flexibility to potentially benefit from seasonal price fluctuations. Daily or seasonal price fluctuations can be significant (often several cents per m³ on the wholesale gas price at the spot market). As a result, the German regime offers a broader scope to maximise biomethane sales revenues by using the gas grid as a de facto temporary storage medium.

So, temporary storage has a certain economic value for the biomethane producer. In the Netherlands, for example, GasTerra offers virtual pipeline storage products called Standard Bundled Units (SBUs). One SBU is equivalent to a share of storage in the gas grid, where the owner has the flexibility to virtually 'bank' about 150 m³ of natural gas in the applicable balancing zone for a given period. SBUs are auctioned, and the price can range⁷² from minimal to several eurocents per m³. With the hourly balancing regime in the Netherlands, biomethane producers who want more portfolio flexibility will need to purchase SBUs, while in Germany, biomethane producers have free storage access for a considerable period (and in practice for a considerable amount). In a more integrated market with increasing cross-border trade in biomethane, also this 'economic value' of a different balancing regime could result in market distortions.

Funding mechanism for support schemes

Without public support, biomethane cannot compete with conventional natural gas. That is why biomethane production is somehow supported by public funding. The source of such funding differs, however, between the Netherlands and Germany. So, a different funding mechanism of the public support scheme will result in a different cost distribution among stakeholders. This could affect the competitive position of energy intensive industries, or the purchasing power of households and SMEs.

In the Netherlands, the feed-in subsidy scheme is financed by collecting an additional charge on the energy bills of gas and electricity users. Each year the budget for renewable energy support is set by the government. In Germany, the *EEG-Umlage* is charged by DSOs on electricity users only, and the budget is in principle unlimited. In addition to that there are some 'hidden' costs for gas users associated with the gas grid connection and the balancing regime for biomethane.

Project development risk profile

The basic design features of the SDE+ and EEG feed-in schemes have significant implications for projects' risk profiles. The duration of the support plays an important role in this, but the conditions under which the funding is granted are at least as important to determine a project's risk profile. In Germany the EEG budget is unlimited, as it is an open-ended scheme. In the Netherlands the annual budgets are fixed, which requires project developers to formally apply for a subsidy. Even though the project development cycle of a biomethane facility is highly comparable in Germany and the Netherlands, the mere fact that in Germany a project developer is certain to obtain a subsidy changes the entire risk profile. This could significantly affect the capabilities of project developers to attract external finance.

⁷² On 19 November 2014 over 4.5 million SBUs were auctioned at the ICE Endex exchange at an average price of € 2.87 (or about € 0.02 per m³ of gas). In the past SBU trading prices have been as high as € 6.28 (or about € 0.04 per m³ of gas). Source: Energeia, Newsletter, 28 November 2014.

In order to be eligible for an SDE+ subsidy in the Netherlands, a project developer needs to have successfully completed all project development steps, from engineering to permitting. The project development stage can take up to 1.5 years, and can cost somewhere in the range of € 100,000 to 200,000. Without being certain of obtaining a subsidy for a project, these up-front expenses are a significant barrier – especially for smaller projects and independent project developers. Although the project development phase in Germany is quite similar to the Netherlands, investors are more likely to (pre-)finance the project development stages as there is certainty about the obtainment of the feed-in tariff.

7.2.3 Transitional impacts

The third category of impacts relates to the transitional phase during the switch from one regime to another. In general, any policy or institutional change could affect the vested interests or existing rights that stakeholders have under the ‘old’ regime. In addition, there are potential costs from stranded investments if regulations are altered unexpectedly. The key question is how a regime change would affect the various stakeholder groups in society, both those subject to the ‘old’ regime and those subject to the ‘new’ regime. A further question relates to the substantial political transaction costs from a regime change.

Overall, it can be argued that the German system is more beneficial for biomethane producers relative to the Dutch system. A switch to the German system, therefore, is more likely to be considered favourable by biomethane producers in the Netherlands. However, such a regime change typically affects only new biomethane production installations, as the existing installations will most likely still be subject to the old regime. The competitive position of these existing installations in the Netherlands vis-à-vis the newcomers is likely to deteriorate, for instance with regards to the price they are able to pay for biomass.

Resolving this fundamental transition issue requires careful consideration of costs and benefits linked to the vested interests of the relevant stakeholders that are likely to ‘lose’ as a result of the regime change. Under the rule of law, retroactive policy changes are generally considered unfair or even unlawful. Therefore, policy makers often opt to not apply the new regime to stakeholders already operating under the existing regime, but only apply the new regime to ‘new’ stakeholders as per a certain date. In order to protect the interests of these stakeholders, that have to compete with facilities under the new regime, one could opt for one of the following transition trajectories:

- Shock transition: in a quick transition the relative ‘losers’ of the regime change could for example obtain a one-off compensation. A shock transition requires a fast and coordinated policy reform, where different policies and regulations are reformed in a short time-span⁷³.
- Gradual transition: the ‘old regime’ is slowly phased out, and no compensatory measures are taken. In the case of policy harmonisation, the institutional regimes of two or more countries will converge step by step ideally as an integrated part of a certain institutional convergence strategy.

In the Netherlands, the phase-out period of a gradual transition would take at least 12 years (when the biomethane facilities under the old regime receive their last year of support), while in Germany

⁷³ But the process of institutional reform, and eventual convergence, may be rather slow, as the appropriate choice of institutions depends on a society’s structural characteristics (Djankov, et al., 2003).

this would take 20 years. Given these long transition periods, it could be argued that a quick transition with compensatory measures might be more efficient⁷⁴.

In sum, during a transition, the administrative and operational costs linked to monitoring and operating different policy instruments are likely to increase. However, the potential costs related to competitive distortions could even be higher. The convergence analysis performed in Chapter 6, shows clearly the complexities associated with institutional convergence in two EU Member States. This holds a fortiori if one puts such convergence in the European perspective with all its Member States. Developing an institutional convergence strategy for the entire EU seems preferred here, but is likely to be difficult to implement, not only because of political reasons, but also as there currently is still a lack of practical experience with and evidence of successful institutional convergence in the field of renewable energy support. In order to address that more research in this field might be needed, probably accompanied by some pilot and field testing on a more modest geographical scale (e.g. two regions or two countries).

7.3 Limitations of scenarios based on feed-in schemes

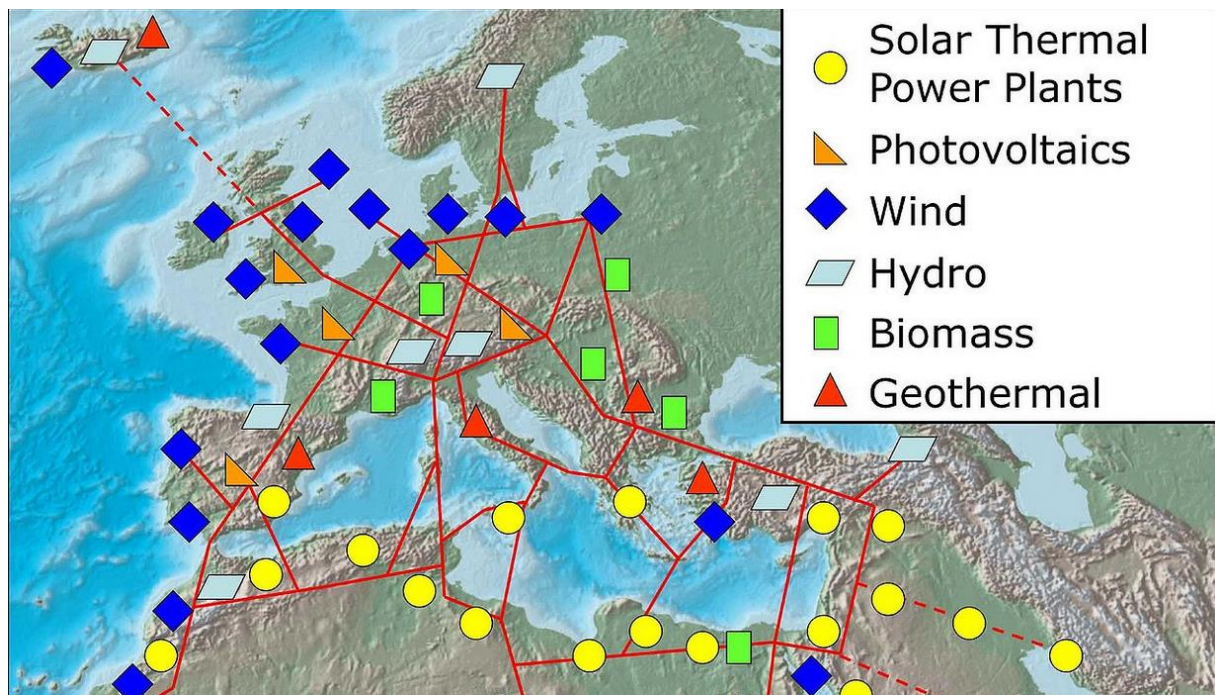
The basic idea behind the assessment of institutional convergence in chapters 5 and 6 has been to check what role institutional convergence could play in increasing the effectiveness and efficiency of a potential Dutch-German biomethane market. The convergence analysis performed in chapter 6 was based on the existing institutional regimes, which are strongly dominated by feed-in support schemes. That analysis did not reflect on what kind of institutions would be best able to reap the maximum level of benefits from cross-border trade. Although the current Dutch and German schemes show some strong key differences that can cause market distortions, both biomethane regimes are primarily driven by a stimulus on biomethane production (SDE+ and EEG, respectively).

By focussing support on the production side (and not on supply to the market and end-use), some barriers to cross-border trade have arisen and will persist if not removed. First of all, both the EEG and the SDE+ require that in order to receive the subsidy the investment in production has to take place domestically. Potential lower cost options in other EU Member States are thereby excluded from participation. This feature is at odds with the common logic of international trade and competition where specialisation of those countries with a competitive advantage in producing specific types of renewable energy leads to the lowest production cost (see Figure 4 regarding renewable energy production, for illustration purposes).⁷⁵ This basic principle also holds for biomethane, which is highly dependent on key production factors, such as biomass, finance, technologies, and specialised labour.

⁷⁴ While switching from the Dutch to the German regime, the compensation could entail that existing biomethane facilities are granted the right to enter the EEG scheme for a time-span of 20 years with deduction of the number of years they already have received SDE support. On top of that a one-off financial compensation could be granted to biomethane facilities for that part of the grid-connection investments that would have been paid by DSOs under the German regime. A key requirement for this is that the Dutch DSOs are allowed to socialise the extra costs (for biomethane grid connections) in their gas transport tariffs. Such a quick transition is more likely to be accepted by a large share of the biomethane facilities as it will improve their economic position. A transition from the German to the Dutch regime is expected to face more resistance as it would have the opposite effect, as the existing German biomethane producers would face a deterioration of their financial-economic position⁷⁴ if they would have to accept the Dutch regime.

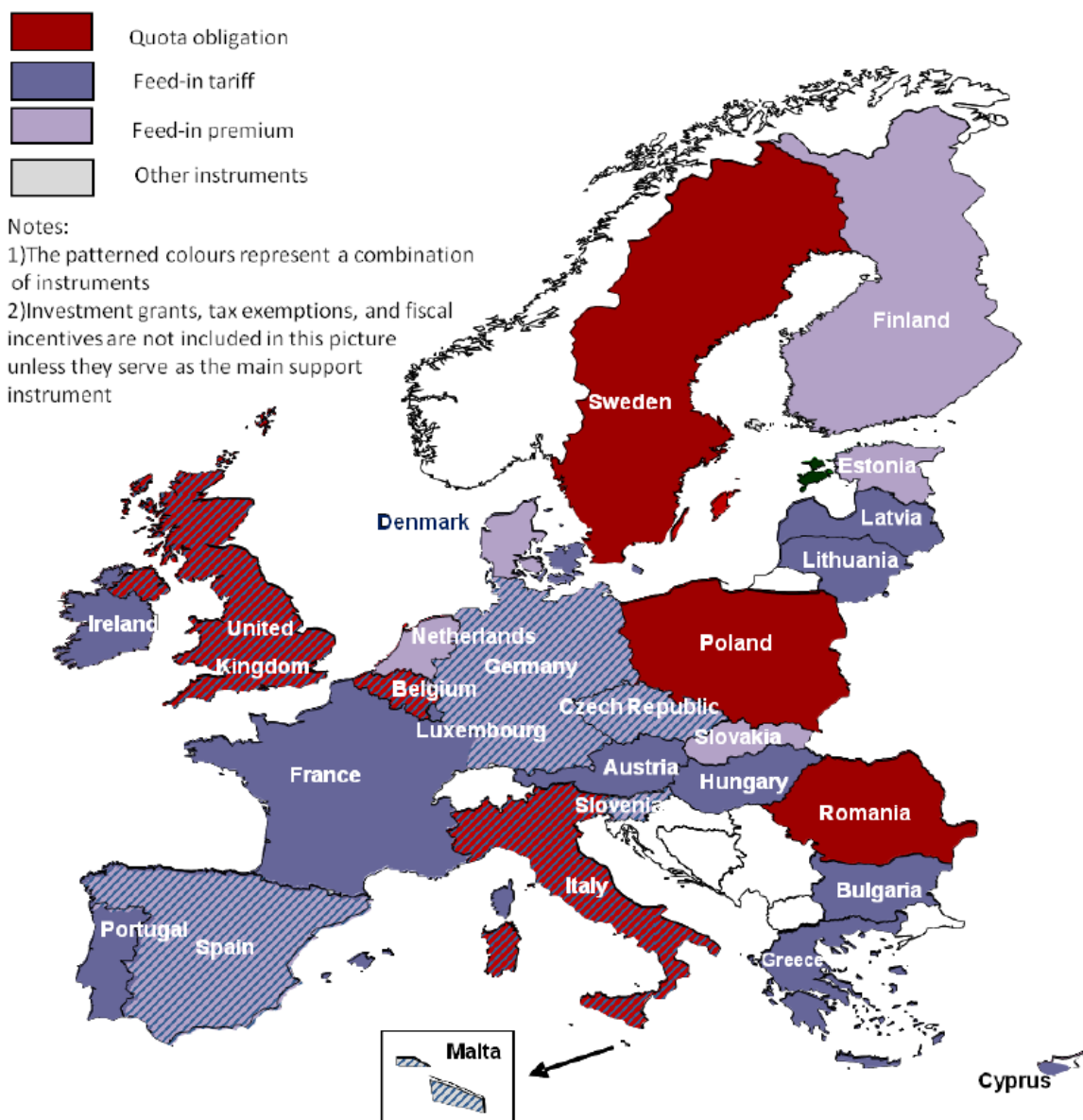
⁷⁵ I.e. install wind energy in regions with most suitable wind conditions, and install solar panels first in areas with most suitable conditions, etc.

Figure 4. Conceptual design of renewable energy production in and around the EU (DESERTEC, 2008)



An important argument for maintaining the nationally fragmented situation results from the fact that all EU Member States have adopted national renewable energy targets. By 2020 the share of renewables in gross final energy consumption should be 14% in the Netherlands, and 18% in Germany. These national targets have triggered most EU countries to use their national budgets for supporting their own domestic renewable energy producers, across Europe mainly via feed-in support schemes (see Figure 5).

Figure 5. Map of renewable energy support schemes used in EU (Ragwitz, et al., 2012)



The popularity of feed-in schemes is partly determined by the relatively high degree of control governments can exert on the instrument. This means that if certain unintended and unanticipated events occur, the feed-in schemes can be adjusted within a relatively short period. This set-up however hampers the potential cost-effectiveness gains that international trade and competition could bring. A possibility to increase the cost-effectiveness of feed-in tariff schemes, could be to merge all national feed-in scheme budgets to develop a tendering programme at the EU level. Such an EU scheme would allow stakeholders in all EU member states to participate in the competitive bidding process, which could also unlock more low-cost renewable energy production potential. Nevertheless, in the current political climate in most EU Member States it is considered highly unlikely that national budgets reserved for promoting the national production and use of renewable energies will be shared with other EU Member States. As a result, the EU market for renewable energies could remain strongly fragmented with resulting low levels of cross-border trade and competition.

7.4 Institutional convergence based on quota obligations

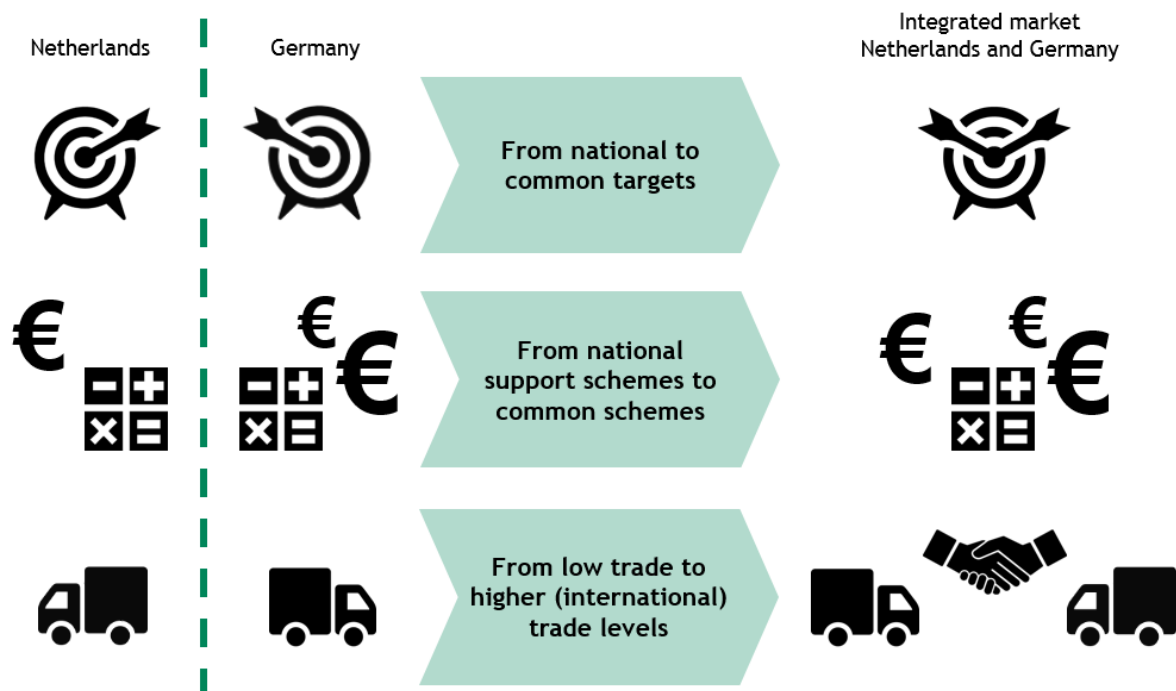
Section 7.3 has shown that institutional convergence that is primarily driven by domestic feed-in support schemes will likely result in low levels of cross-border competition and trade, especially if this occurs in a political arena with binding national targets, domestic public budgets and non-harmonised certificate systems. The national targets cause any effort in the area of renewable energy to be a national rather than a common EU task. As long as national feed-in support schemes remain the main instrument for renewable energy support, it is likely that the market for renewables remains fragmented, as it will be politically difficult to justify that some of the public funds would ‘leak’ to another country.

In this section we will tentatively explore the possibilities for an alternative regime, which may better facilitate the development of an internal market for renewable energy, and address the political challenge of sharing national funds. More specifically, it is explored if, and to what extent, quota obligation and certificate-based trading schemes, such as ‘cap-and-trade’ emissions trading, could function as alternatives to feed-in subsidy schemes.

7.4.1 From feed-in schemes to quota obligations

Figure 6 shows the current status in the German and Dutch renewable energy markets, where national targets and national budgets result in a fragmented market with low levels of cross-border competition and trade. The right-hand side indicates a situation where Germany and the Netherlands share a common responsibility to achieve a common target with the help of a common support scheme. Under such circumstances, market operators will invest in renewable energy production at the optimal location.

Figure 6. Implications of national targets and national institutional regimes on cross-border trade and competition



In 2014, the European Council has adopted the so-called '2030 framework for climate and energy policies'.⁷⁶ This framework includes common EU targets on greenhouse gas emissions, renewable energy and energy efficiency. The EU thus shifts from national climate and energy targets in the 2020 package to common targets in the 2030 framework. Therewith the EU Member States have more flexibility to meet the targets in an efficient and effective manner. The framework also advocates institutional convergence in order to minimise distortions of the internal market. Subsidies for mature energy technologies, including for renewable energy, should be phased out entirely in the 2020-2030 timeframe. It is important to notice in this regard that, by 2020, biomethane production technologies can be regarded as mature.

The state aid rules for energy and environment that are in effect until 2020 were already designed to prepare the renewable energy sector for an upcoming phase-out of feed-in support schemes. For many renewable energy technologies it would be hard to imagine a viable project without receiving feed-in support. And yet, for the period after 2020 the EU is calling for a full phase-out of such subsidies. The 2030 framework is a clear signal to the renewable energy sector that public support for renewables will be significantly different from today's support structures. New common tools and mechanisms that enable more intensified cross-border cooperation and trade in renewable energy should be developed. In addition, state aid rules should be updated to consider also other types of support schemes.

The flexibility mechanisms for the period until 2020, as described in articles 6-11 of the RED – statistical transfers, joint projects and joint support schemes⁷⁷ - to date have proven not to be very popular. An important barrier for Member States is that the net effect of using these instruments would in most cases involve a monetary transfer of public money from one Member State to another. Also because the public budgets of many EU Member States are under pressure, it is politically difficult to justify such transfers. All three flexibility mechanisms require strong government-to-government interactions and agreements, while the private sector is not stimulated to engage in cross-border trade as they remain strongly dependent on national feed-in schemes.⁷⁸

⁷⁶ Based on the European Commission's Communication COM(2014) 15 final: 'A policy framework for climate and energy in the period from 2020 to 2030'.

⁷⁷ In case of a **statistical transfer** the 'deficit country' (i.e. country not able to fulfil target with domestic actions only) would pay the 'surplus country' for its over-performance relative to their national target. This would not even require an underlying energy trade, as long as the total transacted volume of renewable energy is accounted for in the national renewable energy (statistical) accounts.

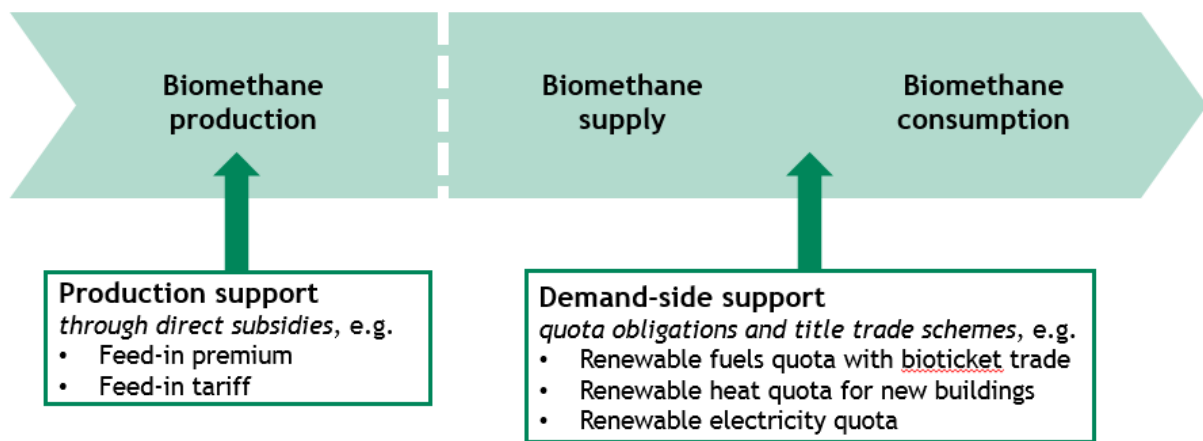
The added value of **joint projects** is quite difficult to predict, and might in some cases even be less effective as it would require more coordination efforts between two governments. This could slow down the project development stage. Moreover the two countries would also need to negotiate what part of the renewable energy produced will be included in the statistical accounts of both countries. In many cases it is likely that the share of renewable obtained is proportionate to the national financial contribution. As such, comparable projects could be developed easier at the national level.

Joint support schemes, bear within themselves the potential to be efficient and effective instruments, but are politically highly sensitive as national public budgets might leak to third countries. Such subsidy leakages have occurred in the past, and in most cases these 'leaks' have been immediately repaired to prevent any further leakage to the benefit of third countries.

⁷⁸ Already there are ideas proposed on how the EU could tackle the possible shortfall of the 2030 common EU renewable energy target of 27%. One online (blog) source suggests that the this possible target shortfall might be tendered at the EU level to all EU renewable energy producers.

Source: <http://heardineurope.blogactiv.eu/2015/02/16/eu-renewables-shortfall-to-be-put-out-to-tender/>

Figure 7. Shifting from production support schemes to supply/demand-side support schemes



In this study it is assumed that post-2020 biomethane production will no longer be eligible for feed-in support, as by that time – certainly in Germany and the Netherlands – biomethane production can be regarded as a mature technology. However, the cost-price for fossil gases (even long-distance imported LNG, pipeline gas or shale gas) is expected to remain significantly lower relative to biomethane production costs for some decades to come. Despite reductions in biomethane production costs, feedstock prices are likely to remain volatile and some form of additional support for the ‘green value’ of biomethane will be needed.

There are a few existing policy instruments that can serve as an alternative for feed-in schemes. Notably, quota obligations linked with tradable renewable energy titles (e.g. emission allowances or certificates) are good candidates. Figure 7 provides a graphical presentation of the possible evolution in time of the support from the production side towards the supply/demand side of biomethane. Quota obligation schemes typically focus on demand-side support, and therefore could belong to future policies. Examples of existing quota obligation schemes are the EU’s emissions trading scheme, the renewable fuels quota obligation in the transport sector, and the renewable heat use obligation for new buildings in Germany.

Quota obligation schemes provide market stakeholders with more flexibility in terms of how, when and where they choose to comply with a specific target. A benefit of quota obligation and title trade-based schemes is that there typically is no public money used to support specific technologies and projects. It is the market itself that will absorb and allocate these costs. An important problem with most of the current title trading instruments is that these schemes are generally not robust enough, i.e. the price of the titles is not high and stable enough, to serve as a credible and reliable alternative incentive to that of the current feed-in tariff regimes.

7.4.2 Maturity of quota obligation schemes

In this section a number of existing quota obligation schemes are briefly reviewed to check whether they could serve as an alternative to the feed-in support schemes.

- **Guarantee of Origin certificates** can be transferred to provide as proof of the renewable character of the biomethane produced, supplied and used. Currently (2015), only in the Netherlands GoO certificates for biomethane can be traded separately from the biomethane commodity resulting in an additional income stream.

- **EU Emissions Allowances:** Under the EU ETS the direct use of bioenergy (wood pellets, biogas but also biomethane) could result in a reduction of direct CO₂ emissions. In turn, this could result in a surplus of emissions allowances that can be traded against a certain market price.
- **Single- and double-counting biotickets:** Under the renewable fuels quota obligation regime both the Dutch and German scheme allow for biotickets to be traded (see Section 3.1).

The income for biomethane producers generally comprises of two main elements. The first element is the revenue of the sales of the energy itself and the second element is the ‘green premium’ that is paid by either the end-user or via subsidies. Table 10 provides an overview of the current ‘green premium’ prices for various tradable titles per Nm³ of biomethane.

Table 10. The estimated ‘green value’ of biomethane in various alternative quota-based trading schemes (all values in € per m³ of 31.65 MJ, except if otherwise indicated). The energy price is assumed to be € 0.25 per m³ of natural gas.

Support instrument	Price Total	‘Green premium’	Increase factor needed to match feed-in premium	When substitute for feed-in?
EEG (reference facility)	0.67	0.42	-	-
SDE+ (reference facility)	0.65	0.4	-	-
Guarantee of Origin ⁷⁹	-	0.06	≈7	≈ € 60/MWh
EUA (direct emissions) ⁸⁰	-	0.012	≈33	≈ € 215/tCO ₂
NL - Bioticket (single) ⁸¹	-	0.16	2.5	≈ € 21/ticket
NL - Bioticket (double)	-	0.32	1.3	≈ € 11/ticket
DE – Bioticket (single) ⁸²	-	0.26 - 0.40	1.7	-
DE – Bioticket (double)	-	0.53 - 0.79	0.9	-

The table provides an indication of the current value of the green premium in the various schemes and also shows how much the respective title price has to increase in order to be equivalent to the support level of the (reference) feed-in regime. The data show that for most instruments the tradable title prices are insufficient to generate a green premium equivalent to the feed-in subsidy. Below the most important drawbacks per tradable title type are discussed.

- **Guarantees of Origin;** While there is a market price for GoOs in the Netherlands, there is currently no strong quota obligation in place that has the potential to generate a sufficiently strong demand for these type of certificates. There are currently provisions in the Dutch SDE+ scheme that would allow the government to reduce the feed-in subsidy to compensate for additional revenue from GoOs. This also reduces the incentive to actively develop a market for these type of certificates.
- **European Emission Allowances;** Currently only direct physical use of biomethane under the EU ETS would have the potential to create a surplus of European Emission Allowances (EUAs),

⁷⁹ Calculations based on an estimated GoO certificate price ranging from € 5 – 8 /MWh (or € 0.05 – 0.08 /Nm³). Maximum GoO price assumed.

⁸⁰ Calculations based on an estimated EUA price of € 5 – 8 /tCO₂ (€ 6.5/tCO₂ average price assumed), and a CO₂-equivalent reduction of about 1.78 kg per m³ of substituted gas.

⁸¹ Calculations based on an estimated (NL) price of € 6 – 10 per (2012) bioticket (€ 8.50 per ticket assumed), applied to both single or double counting biomethane.

⁸² Calculations based on an estimated (DE) price of € 0.03 – 0.045 per kWh (2012).

which can be sold at the going market price. Current (2015) EUA prices are low and hardly provide an incentive for ETS installations to switch to cleaner energy and feedstock. The EU ETS system thus far only accepts a CO₂ emission reduction claim if the biomethane is directly supplied to the EU ETS installation via dedicated infrastructure. As a result, funding of biomethane through EUAs is likely to be an option in only very few cases. Administrative supply of biomethane via the public gas grid, with the help of GoO certificates, is not considered eligible under the EU ETS both in Germany and the Netherlands.⁸³

- **Biotickets (single and double counting);** The prices of double counting biotickets are at such a level that they can be considered equivalent to the green feed-in premium schemes. However, the key disadvantage of tradable biotickets is that there is no robust futures market that enables producers/suppliers to hedge against bioticket price fluctuations. So, the bioticket scheme currently does not provide the same long-term income certainty as the existing feed-in support schemes do. As a result of the uncertain income prospect, external financiers may be more reluctant to finance such activities.

The above discussion suggests that there are no real alternative schemes in the market that currently can 'outcompete' the feed-in tariff schemes. Neither of the three alternative support schemes provides long-term income stability. In order to overcome this: sufficiently high quota targets need to be set; spot and futures title exchanges need to be in place to address price volatility; and the various tradable title and certificate schemes need to be aligned and interchangeable. This amongst others requires a more comprehensive linking of the various certificate transaction registries, as well as a decoupling of the trading in the underlying energy commodity and the 'green value' of the renewable energy.

7.5 A level playing field for biomethane with cross-border trade

This section provides a more detailed analysis of the possible post-2020 institutional framework that biomethane producers may expect, and the position of biomethane suppliers and end-users under a quota obligation and title trade-based framework. This section also explores what basic conditions need to be met in order to have an effective and efficient market for biomethane where cross-border trade is not distorted by institutional differences.

For the quota and trade-based schemes to be effective, there are three important requirements:

1. Institutional differences between jurisdictions need to be mitigated. In other words, there should be a level playing field in place for biomethane activities, so that healthy cross-border trade can develop.
2. Quota obligations should be set at sufficiently ambitious levels to enable biomethane producers to recover the additional costs made relative to natural gas production.
3. Administrative trading should be allowed, so that the 'green value' titles of the biomethane can be traded separately from the energy commodity.

To explore what the cross-border trade in biomethane (including administrative trade based on tradable titles) could imply for both the Netherlands and Germany in their efforts of meeting their 2020 renewable energy (or climate) targets, a simple trade simulation can be made. Table 11 provides the basic data of current and future biomethane production levels in both countries.

⁸³ Supply of GoOs for biomethane to EU ETS installations can be referred to as 'administrative or virtual greening'.

Table 11. Existing current and expected future biomethane capacities, shares and renewable energy targets in the Netherlands and Germany

	The Netherlands	Germany
National RED target for 2020 (% RES in gross final energy consumption)	14%	18%
Current RES performance (% gross final energy consumption in 2013)	4.5%	12.4%
RES current share 2012	98 PJ	1144 PJ
Heating and Cooling	39 PJ	509
Electricity	44 PJ	504
Transport	15 PJ	131
RES share in 2020	310 PJ	1642 PJ
Heating and Cooling	91 PJ	604 PJ
Electricity	181 PJ	781 PJ
Transport	38 PJ	257 PJ
2012 to 2020 Distance to RES target	212 PJ	498 PJ
Feed-in capacity m ³ / hours (2013)	11.905	86.395
Number of biomethane installations (2013)	21	147
Biomethane current share in 2013 (in PJ)	1.49 PJ	22.46 PJ
Biomethane expected contribution in 2020	24 PJ	259.2 PJ

The projections for 2020 in the table are based on the data provided in the National Renewable Energy Action Plans (NREAPs) that both countries submitted in 2010. Current status and progress, however, shows that these biomethane ambitions in both countries will not be achieved (CBS, 2014; Bundesnetzagentur, 2014). Nevertheless, these numbers provide a useful reference for assessing the potential impacts of cross-border biomethane trade.

In 2020, the biomethane production for energy is expected to be roughly 19 petajoules (PJ) in the Netherlands and 207 PJ in Germany. The aggregate demand for renewable energy for all energy sectors in the same year is about 1952 PJ. Figure 8 provides a framework to simulate the potential effects of cross-border trade between the two countries. In the figure, the national renewable energy targets for Germany and the Netherlands for the transport, heating/cooling and energy sectors are considered as sectoral quota obligations⁸⁴.

⁸⁴ Please note that these quota obligations (binding national targets) for renewables are only in place until 2020. After that period, there will be only a binding common target for renewables at the EU level. Also note that only the national renewable energy targets are binding for EU Member States and that the current sectoral targets (as stated in the NREAP reports) are considered to be indicative.

Figure 8. Aggregate biomethane supply and aggregate renewable energy demand in the Netherlands and Germany in 2020 (assuming the national targets are met)

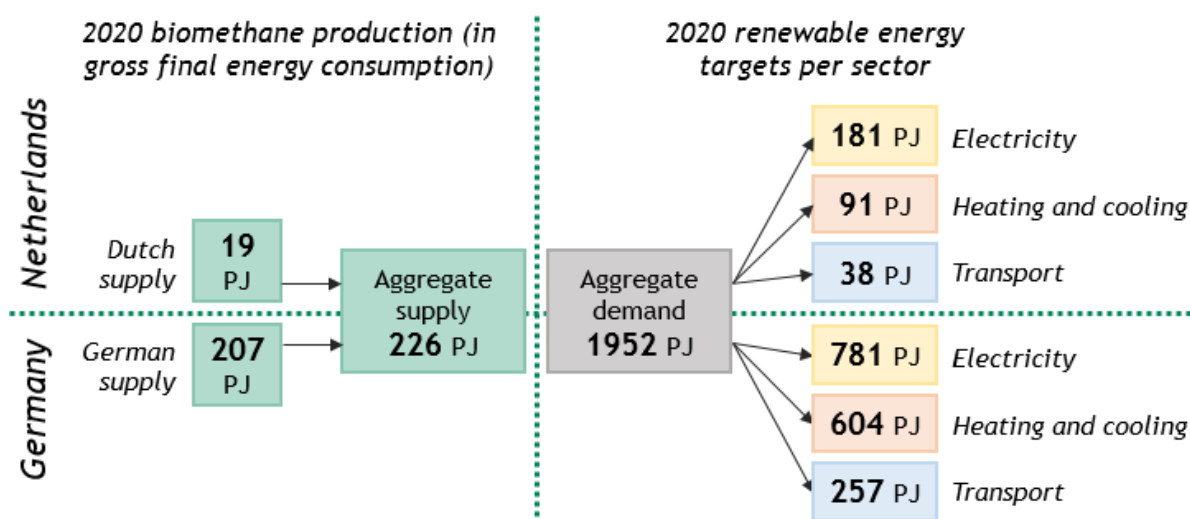


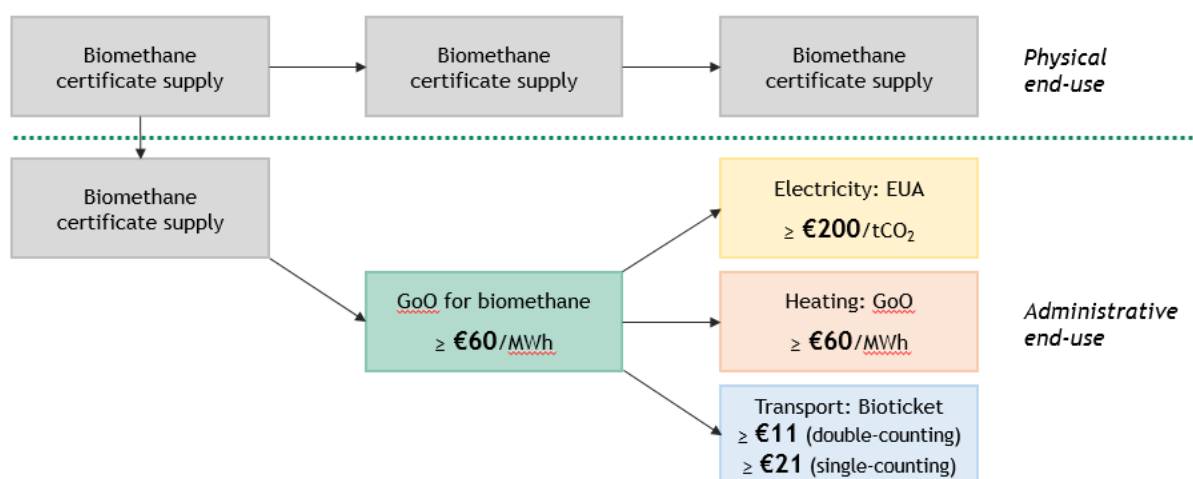
Figure 8 clearly shows that for 2020 the aggregate renewable energy demand is about nine times larger than the expected aggregate biomethane supply. A key question will be how international trade will be shaped, thus which countries and sectors are most likely to buy and sell biomethane quotas.

Considering that currently only the transport sector has a mandatory quota for renewable energy in both countries, this sector is likely to absorb most biomethane in case of a phase-out of feed-in schemes. However, with the current low price levels and high price volatility of biotickets, a certain share of biomethane producers is likely to quit biomethane production or switch to another form of energy production. If cross-border biomethane trade is mainly driven by the renewable fuels in the transport sector, it is expected that supply and demand patterns do not change dramatically, since the current reference price for biotickets both in the Netherlands and in Germany is primarily determined by biodiesel and bioethanol fuels.

If also mandatory quotas are introduced in other sectors, the picture becomes more complicated as biomethane could administratively end up in different end-use applications. The mandatory quota for the electricity sector is already in place for the large electricity producers who fall under the EU's Emissions Trading System (EU ETS). For the heating sector, GoOs for heating can be used as an appropriate trade and accounting mechanism.⁸⁵ Considering that biomethane certificates can in principle be used for either electricity, heating or transport applications, the GoO biomethane certificates at some point will need to be converted to (or exchanged for) either biotickets, EUAs, or GoOs for heating. Figure 9 provides the quota title prices, for biomethane, heat, transport and electricity, that are required to 'match' the financial support level of feed-in schemes.

⁸⁵ In the Netherlands, CertiQ also issues GoO certificates for heat, in addition to the GoOs for electricity.

Figure 9. Quota title prices required to match financial support levels of feed-in support schemes



In case the EUA price rises well above € 200 per tonne of CO₂, biomethane titles would become a viable option for EU ETS installations, provided there are no cheaper alternatives to mitigate CO₂-emissions. Currently most biomethane is (physically) consumed in heating applications. GoOs for biomethane could be converted into GoOs for heating, and would require a certificate prices of at least € 60 per MWh⁸⁶ in order to be at a level similar to the biomethane feed-in subsidies. In order to obtain such prices, the quotas should be set at an appropriate level so that there is a real scarcity situation with sufficient demand for renewable energy titles.

Such tradable titles should be ideally nominated in a common unit, for instance in terms of CO₂ equivalents (CO₂e, as in EU ETS or future transport fuel quota systems), or in MJ of gross final energy equivalents (as for GoO for heat and current biotickets in transport). In order to prevent market distortions it would be necessary to apply similar sustainability requirements for different end-use options. Currently, sustainability criteria are in place for liquid biofuels used under the EU ETS scheme, as well as all biofuels used in transport. No such mandatory sustainability criteria are currently (2015) in place for solid biomass combustion and biogas.

By linking the quota-based trading schemes for different renewable energy end-use options, one single framework for all forms of renewable energy (including biomethane) is created. This would require that all relevant transaction registries are linked, based on the same principles (e.g. mass-balance accounting and sustainability) and allow for cross-border trade. If these registries are properly linked, eventually an equilibrium price either per MJ or CO₂e will arise. A collective EU level target is an adequate starting point for such a system to develop⁸⁷, but a common EU accounting and reporting system, as well as a common EU enforcement and penalty system (for non-compliance), would contribute significantly to the strength and efficiency of such a support system.

⁸⁶ The minimum price for GoO heat can be derived from the required GoO biomethane price as it should be adjusted for thermal efficiency losses (if any).

⁸⁷ For the post-2020 period the common (binding) EU target of 27% renewable energy in 2030 seems to be an appropriate first step in this process. However, it remains to be seen if such an aggregated target, that incorporates the heating/cooling, electricity and transport sectors as well as many different renewable energy production technologies, provides clear signals to the markets as to where demand is.

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ANNEXES

Annex 1. Tariffs and annual degression in the EEG 2012 (without biomass).

Type of RE	Categories	Tariff ct/kWh (2012)	Degression per year	Notes
Hydropower	Up to 500 kW	12.70		
	Up to 2 MW	8.30		
	Up to 5 MW	6.30	1%	
	Up to 20 MW	5.50		
	Up to 50MW	4.20		
	Above 50 MW	3.40		
Landfill Gas	Up to 500 kW	8.60		
	Up to 5 MW	5.89		
Sewage Gas	Up to 500 kW	6.79		
	Up to 5 MW	5.89	1.5 %	
Mine Gas ^a	Up to 500 kW	6.84		a) non-renewable, but still covered under the EEG
	Up to 5 MW	4.93		
	Above 5 MW	3.98		
Geothermal	Not specified	25.00	5 % from 2018	Additional tariff for use of petro-thermal = 5ct/kWh
Wind onshore	Base tariff	4.87		b) paid for at least the first five years
	Start-up tariff ^b	8.93	1.5 %	
	Repowering ^b	0.50		
	Small scale < 50 kW	8.93		
Wind offshore	Base tariff	3.50	7% from 2018	c) paid for the first 12 years
	Start-up tariff ^c	15.00		
Photovoltaic	Open space	17.94	Basis: 9 % ^d	
	Sealed space	18.76	2012: 15 %	

Built-up space	
up to 30 kW	24.43
from 30 kW	23.23
up to 100 kW	21.98
from 1 MW	18.33

d) degression depends on installed capacity during the previous year

Annex 2. Biomass in the EEG 2009.

Biomass tariffs EEG 2009	Categories	Tariff ct/kWh (2009)	Degression per year	Notes				
Base tariff	Up to 150 kW	11.67	1 %					
	Up to 500 kW	9.18						
	Up to 5 MW	8.25						
	Up to 20 MW	7.79						
Renewable raw materials bonus	Up to 500 kW	7.00		1 %				
	Up to 5 MW	4.00						
Excrement bonus ^a	Up to 150 kW	4.00			1 %	a) at least 30% of input mass		
	Up to 500 kW	1.00						
Bonus on landscape maintenance material use ^b	Up to 500 kW	2.00				1 %	b) at least 50 % of input mass	
Clean air bonus ^c	Up to 500 kW	1.00					c) fulfill limit on formaldehyde	
CHP bonus ^d	Not specified	3.00					d) heat use defined on positive list	
Technology bonuses	Upgrading						1 %	e) for the use of technologies as fuel cells, thermo-chemical gasification a.o.
	Up to 350 m ³ /h	2.00						
	Up to 700 m ³ /h	1.00						
	Innovative technologies ^e	2.00						

Annex 3. Biomass in the EEG 2012.

Biomass tariffs EEG 2012	Categories	Tariff ct/kWh	Degression per year	Notes		
Base tariff ^a	Up to 150 kW	14.30	2 %	a) from 1 st January, 2014 only up to 750 kW installed capacity		
	Up to 500 kW	12.30				
	Up to 5 MW	11.00				
	Up to 20 MW	6.00				
Bio waste ^{a, b}	Up to 500 kW	16.00		2 %	b) min 90% of overall mass	
	Up to 20 MW	14.00				
Excrement ^c	Up to 75 kW	25.00			2 %	c) min 80% of overall mass
Upgrade bonus	Up to 700 m ³ /h	3.00				
	Up to 1000 m ³ /h	2.00				
	Up to 1400 m ³ /h	1.00				
EVK I ^a	Up to 500 kW	6.00	0 %			
	Up to 750 kW	5.00				
	Up to 5 MW	4.00				
EVK II ^a	Up to 5 MW	8.00				0 %
	Up to 500 kW ^d	8.00				
	Up to 5 MW ^d	6.00				

Annex 4. Biomass in the Draft EEG 2014.

Biomass rates Draft EEG 2014	Categories	Rate ct/kWh	Degression	Notes	
Base rate ^a	Up to 150 kW	13.66	From 2016, 0.5% every three month. If corridor exceeded: 1.27%.	a) Direct marketing mandatory for: - 2014: >500kW - 2016: >250KW - 2017: >100kW	
	Up to 500 kW	11.78			
	Up to 5 MW	10.55			
	Up to 20 MW	5.85			
Bio waste ^{a, b}	Up to 500 kW	15.26			b) min 90% of overall mass
	Up to 20 MW	13.38			
Excrement ^c	Up to 75 kW	23.73			

Annex 5. Example of a GoO biomethane certificate.

Certificate information

Renewable energy source

Value (in MWh)

Status Active / Inactive

Issuance date 23-2-2012

Expiry date 23-2-2014

Issuing Body Vertogas

Country of Issuance The Netherlands

Received feed-in subsidy (SDE) Yes / No

Destination

Information about production installation

Name

EAN code

Address

Zip code

City / town

Country

Production Capacity Maximum capacity in kW based upon HHV of renewable gas

Type production installation Biogas from:

- Landfill
- Waste water treatment plant
- Co-digestion of manure
- Digestion of fruit, vegetable and garden waste
- Remaining digestion
- Other (e.g. biomass gasification)

Route type	A: national or regional gas transport grid	B: Local connection	C. CNG/LNG
1-One production site with upgrading	A1	B1	C1
2-Multiple production sites with upgrading	A2	B2	C2
3-One production site without upgrading	N.A.	B3	N.A.

4-Multiple production sites without upgrading	N.A.	B4	N.A.
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Date of start
installation operations

Production information

Start date production

End date production

Meets sustainability requirements (e.g. NTA8080) Yes / No

Sustainable energy source Source type Percentage

Sludge

Landfill gas

Manure

...