Assistance to assessing options improving market conditions for bio-methane and gas market rules

Final report

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Acronyms

List of acronyms

Acronym	Explanation
BAL NC	Balancing Network Code
BG	Biogas
BGP	Biogas plant
BGUP	Biogas upgrading plant
BM	Biomethane
BMIP	Biomethane injection plant
CBM	Compressed biomethane
CCS	Carbon capture and storage
CEAP	Circular Economy Action Plan
CEC	Citizen energy community
CEN	Comité Européen de Normalisation (European Committee for Standardization)
CEP	Clean Energy for all Europeans Package
CH4	Methane
CHP	Combined heat and power (plant)
CNG	Compressed natural gas
CO_2	Carbon dioxide
COS	Carbonyl sulfide
CTP	Climate Target Plan
d	Relative density
DM	Dry material
DMS	Dimethyl sulfide
DSO	Distribution system operator
EBA	European Biogas Association
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETR	Energy Transition
EU	European Union
FM	Fresh matter
FLH	Full-load hours
FSRU	Floating storage regasification unit
FTE	Full-time equivalent
GHG	Greenhouse gas

Acronym	Explanation
GRIPS	Gas Regional Investment Plans
GTM	Gas Target Model
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulphide
HHV	Higher heating value
IEA	International Energy Agency
IO NC	Interoperability network code
IP	Interconnection point
ISO	Independent system operator
ITC	Inter-transmission system operator compensation
ITO	Independent transmission operator
JRC	Joint Research Centre
LHV	Lower heating value
LCOE	Levelized cost of energy
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LSO	LNG system operator
LTC	Long-term contract
LTS	Long-term Strategy
MOP	Maximum operating pressure
MS	Member State
N_2	Nitrogen (atmospheric nitrogen)
NC	Network code
NDP	Network development plan
NECP	National Energy and Climate Plan
NG	Natural gas
NH_3	Ammonia
NMVOC	Non-methane volatile organic compounds
NRA	National regulatory authority
NS2	Nord Stream 2
O_2	Oxygen
OTC	Over-the-counter
PGC	Process gas chromatograph
RAB	Regulated asset base
REC	Renewable energy community
RFCP	Reverse flow compression plant

Acronym	Explanation
RPM	Reference price methodologies
S	Sulfur
SMR	Steam methane reforming
SNG	Synthetic natural gas
SOFC	Solid oxide fuel cell
SSO	Storage system operator
TAR NC	Transmission Tariff Structures Network Code
TPA	Third-party access
TSO	Transmission system operator
TYNDP	Ten Year Network Development Plan
UIOLI	Use-it-or-lose-it
UIOSI	Use-it-or-sell-it
VIU	Vertically integrated undertaking
VTP	Virtual trading point
WACC	Weighted average cost of capital
WI	Wobbe index

Country codes of EU Member States

Code	Country name	Code	Country name
AT	Austria	IE	Ireland
BE	Belgium	IT	Italy
BG	Bulgaria	LT	Lithuania
CY	Cyprus	LU	Luxembourg
CZ	Czech Republic	LV	Latvia
DE	Germany	MT	Malta
DK	Denmark	NL	The Netherlands
EE	Estonia	PL	Poland
ES	Spain	PT	Portugal
FI	Finland	RO	Romania
FR	France	SE	Sweden
GR	Greece	SI	Slovenia
HR	Croatia	SK	Slovakia
HU	Hungary		

Country codes of third countries

Code	Country name	Code	Country name
AL	Albania	MK	North Macedonia
AZ	Azerbaijan	NO	Norway
BA	Bosnia and Hercegovina	RS	Serbia
BY	Belarus	RU	Russia
CH	Switzerland	TM	Turkmenistan
DZ	Algeria	TN	Tunisia
LY	Libya	TR	Turkey
MA	Morocco	UA	Ukraine
ME	Montenegro	UK	United Kingdom

Country codes of LNG exporting countries

Code	Country name	Code	Country name
AN	African North	PE	Peru
AU	Australia	SS	Sub-Sahara
ME	Middle East	TT	Trinidad and Tobago
NO	Norway	US	United States

1 CONTEXT

The **EU Green Deal**, as presented by the European Commission in late 2019, fixes the objective to make Europe the first climate-neutral continent, i.e., to achieve net-zero greenhouse gas emissions by 2050. In order to meet this target, a review of major EU Directives and Regulations is required.

One of the obstacles to overcome is the fact that the current energy system is still built on **several parallel, vertical energy value chains**, where specific energy resources are rigidly linked with specific end-use sectors. This very segregated approach cannot deliver a climate-neutral economy in a cost-efficient way, and it is technically and economically inefficient.

The **EU Strategy for Energy System Integration**[1] proposes concrete policy and legislative measures at EU level to gradually shape a new integrated energy system, aiming at the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors. It sets energy efficiency at the core of a more circular energy system and foresees an electrification of end-uses where deemed possible and cost-efficient (as electricity may be decarbonised in a more cost-efficient manner than other energy carriers).

The Strategy also considers the **use of renewable and low-carbon fuels** (such as hydrogen, renewable gases and liquids) as a key prerequisite for deep decarbonisation, notably for sectors that are difficult to electrify directly (e.g., specific end uses in transport or industry). Biomethane as an equivalent substitute for natural gas enables the decarbonisation of methane gas supply. In addition, biomethane allows to make use of biological waste which fosters the objectives outlined in the Circular Economy Action Plan. Furthermore, hydrogen can be produced from renewable electricity (other alternatives include steam methane reforming combined with CCS), and is a potential significant contributor to the decarbonisation of the European economy if combined with an important deployment of renewable electricity generation technologies.

Finally, the EU's Energy System Integration Strategy calls for a **more integrated, 'multi-directional' energy system** in which consumers play an active role in energy supply. Vertically integrated, decentralised production units (such as biomethane or hydrogen producers) and customers are expected to contribute actively to the overall balance and flexibility of the system. In addition, the existing gas network provides ample capacities across the EU to integrate renewable and low-carbon gases. The major challenge consists of ensuring it is effectively exploited for the sake of a cost-efficient energy system transformation.

The **EU's 2050 long-term strategy** (LTS) provides clear indications about the **potential future role of low-carbon gaseous fuels in the EU energy system**. The LTS lines out different pathways towards deep decarbonisation of the EU economy. It is common to all scenarios that demand for gaseous fuels is likely to decline by 2050. Yet, in particular the share of natural gas in gaseous fuels is projected to reduce to 20% or less, with most of the remaining 80% gaseous fuels being of renewable origin (i.e., hydrogen, biogas, biomethane or synthetic methane).
Other recent studies such as the study on "The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets" realised by Trinomics, LBST, Artelys and E3M as well as a range of other studies (e.g. the 2020 Guidehouse study "Gas Decarbonisation Pathways for 2020 – 2050") confirm the **important role that gas infrastructure may still play in decarbonised energy system**, even if the volumes of gas flowing in the European network will reduce, with profound modifications of the structure of the flows across Europe. It is therefore of primary importance to ensure that the gas infrastructure and the gas markets develop in a manner that enables the decarbonisation of hard to abate sectors and supports the emergence of a hydrogen

[1] (European Commission, 2020g)

value chain. Without a proper update of the gas markets and the infrastructure planning practices, the transition to a net-zero economy could be much costlier, or even at risk.

To **tap the potential benefits** of biomethane, make use of the existing gas infrastructure for the integration of low-carbon gaseous fuels, operate the markets efficiently, and enable investments in relevant infrastructure projects it is necessary to **review the existing regulatory framework for gas markets**.

The European Commission is currently reviewing the internal **gas market Directive (Directive 2009/73/EC)[2] and the Regulation No 715/2009[3]** on access to natural gas transmission networks. The revision is part of the Fit for 55 Package to facilitate a GHG emission reduction by at least 55% by 2030, in compliance with the European Commission's Climate Target Plan. The revision should aim to create a level playing field for the different low carbon energy solutions in the gas sector, to further harmonise and align the planning and management of different energy infrastructures.

Various assessments have identified specific **shortcomings in the current regulation**:

- Frontier Economics, CE Delft, THEMA, COWI (2019): Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU
- Schönherr, Philippe and Partners, GIC (2020): Upgrading the gas market - Regulatory and administrative requirements to entry and trade on gas wholesale markets in the EU
- Trinomics, LBST, E3M (2020): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure
- Trinomics, LBST, E3M, Artelys (2018): The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets
- EY and REKK (2018): Quo Vadis EU gas market regulatory framework – Study on a Gas Market Design for Europe
- ACER (2019): Bridge Beyond 2025: an ACER Recommendation and joint ACER-CEER paper

In order to prepare a proposal for an updated regulatory framework, an **impact assessment** is conducted. The impact assessment will have to focus on those market failures, barriers and regulatory gaps that may require addressing through reforming the EU regulatory framework for (methane) gas. The focus will be on distortions that directly affect market participants and network operators and are related to the regulatory framework for gas markets. Out-of-market arrangements (e.g., support schemes or the ETS) that do not directly affect the remuneration to market participants inside the market or to network operators through network tariffs are not covered by the impact assessment. On the other hand, design features of the out-of-market measures that affect market functioning are part of the distortions as meant above.

Considered measures relate to:

- **Integrating bio-methane 'upward' into the gas market**; contemplated measures in this area relate to the inclusion of the distribution level production

[2] (European Commission, 2009a)

[3] (European Commission, 2009b)

into wholesale market organisation (entry-exit system and balancing) and enabling reverse flows from the distribution to the transmission grid;

- Enhanced cross-border coordination on gas quality and EU-wide requirements for **blending hydrogen and bio-methane into the natural gas networks**;
- A reform of the current mechanism of **intra-EU cross-border entry/exit tariffs** towards ACER's Gas Target model (GTM)[4], in order to avoid tariff pancaking and facilitate a fully integrated and liquid EU internal gas market;
- The review of the regulatory framework for **LNG infrastructure** to facilitate an efficient and optimal use of LNG infrastructure, enabling the unconstrained import of low-cost as well as low-carbon gases;
- **Integrated infrastructure planning** at national level relevant for TYNDP, including gas, electricity, hydrogen and heating and cooling infrastructure at DSO and TSO levels.

The **present report aims to support the preparation of the impact assessment** of options improving market conditions for biomethane and gas market rules. For this, the present report is focused on providing quantitative, partially model-based assessments of the policy measures in discussion, relying in particular on the EU energy system model METIS. They are complemented with semi-quantitative and qualitative analyses where a quantitative approach is considered inappropriate.

The report is structured as follows:

- **Section 2** provides an overview of the **major problems and short-comings** to be addressed with the policy measures under consideration. Two major problems are addressed. Problem 1 reflects the lack of a level-playing field for renewable and low-carbon gases in the existing framework for gas infrastructure and markets. Problem 2 consists of the fact that current national network planning does not fully facilitate the transition towards an integrated, low-carbon energy system.
- **Section 3** introduces the different **available policy options** they may be envisaged to overcome the shortcomings outlined in Section 2. All policy options represent a package of individual policy measures which are shortly introduced in Section 3.
- **Section 4** provides an in**-depth assessment of all individual policy measures** notably with respect to their economic, environmental and social impacts. The assessment of the policy measures is realised along the two problems and major topics identified in Section 2 and considers different degrees of ambition.
- **Sections 5 and 6** provide a **comparative assessment of the options** related to the Problems 1 and 2.

[4] (ACER, 2015; ACER, 2019)

2 PROBLEM DEFINITION

2.1 Problem 1: Lack of level-playing field for renewable and low-carbon gases in the existing framework for gas infrastructure and markets

This section introduces the general context of lacking level playing field for renewable and low-carbon gases (compared to natural gas), followed by a detailed description of the major drivers.

2.1.1 Context

The description of the context provides an overview of the current and future role of renewable and low-carbon gases, prior to the introduction of the actual problem and the related opportunities at risk.

2.1.1.1 The current situation of renewable and low carbon gases in Europe

Today, renewable and low-carbon gases represent a minor role in the EU energy mix. Biogas is primarily used on-site to generate heat and electricity. For 2019, the European Biogas Association (EBA) reported 146 TWh of biogas production in the EU27[5]. Figure 2-1 illustrates the distribution of biogas production by MS in 2019. The bulk of the nearly 19,000 biogas plants are installed in Germany, Italy and France. Average plant sizes in the Member States vary between 0.2 MW and 1.8 MW.

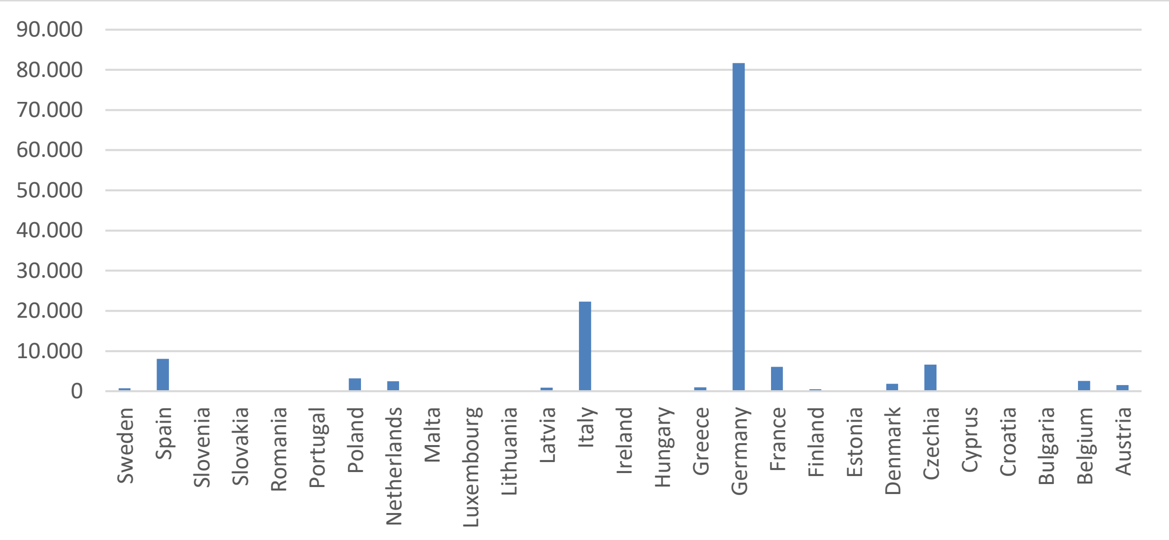

Figure 2-1: Total biogas production in 2019 (in GWh). Source: (EBA, 2020).

The upgrade of biogas to biomethane summed up to about 21 TWh in 2019 at the EU27 level. Compared to a natural gas consumption of about 3850 TWh, this means that biomethane covers less than 1% of the annual gas demand in the EU.[6]

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[5] (EBA, 2020), excluding biogas that is further upgraded to biomethane.

[6] Natural gas consumption in 2019 was 3970 TWh and thus about 3% higher than in 2020. This effect may be explained by a mild winter and the decrease in consumption due to the Covid crisis. Source: (European Commission, 2020f)

EBA reported 725 biomethane plants across Europe (cf. Figure 2-2). The major biomethane producing countries are Germany, Sweden and France. In 2019, 88% of the biomethane production was injected into the gas grid. More than 90% of the biomethane volume not injected into the grid, was generated in Sweden, where it is mainly used in the transport sector, thanks to a favourable support mechanism.[7] Another reason is that Sweden does not dispose of a largely developed gas network infrastructure which implies limited opportunities for biomethane injection into the gas grid.[8]

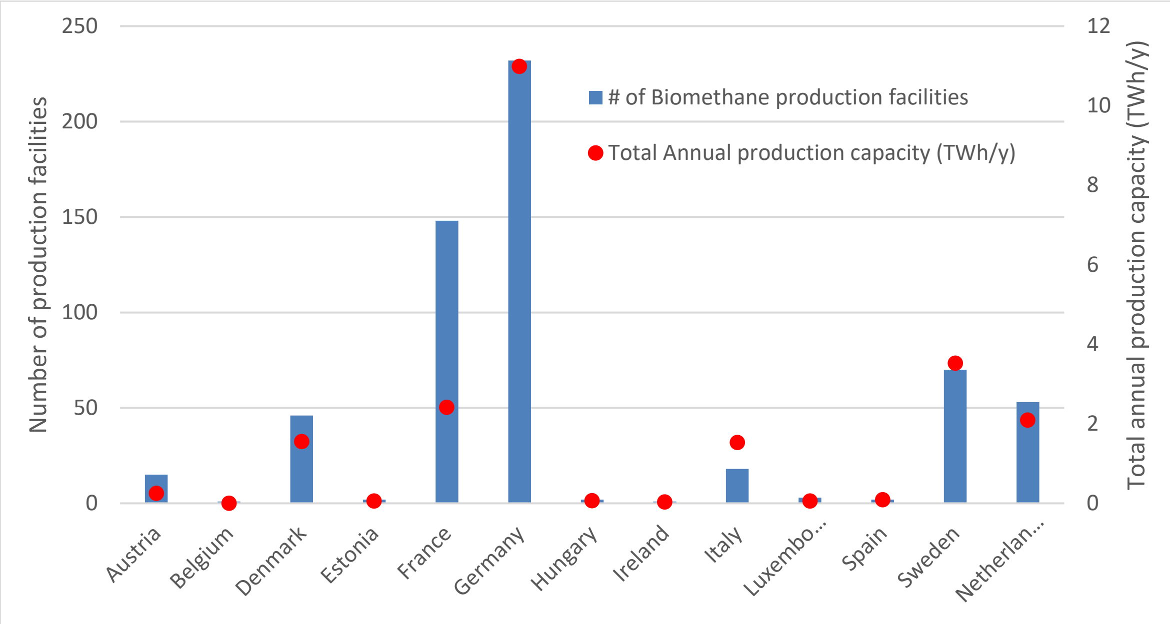

Figure 2-2: Number of biomethane production facilities and total annual production capacity in 2019. Source: (EBA, GIE, 2020).

Biomethane plants in the EU rely for feedstock mainly on energy crops (~50%, mainly in Germany), agricultural residues (~25%), bio- and municipal waste (~15%), sewage sludge (~5%), waste from the food and beverage industry (~4%), and landfill (~1%).

Blending (green) hydrogen into natural gas grids and the production and injection of **synthetic methane** only exist at the scale of pilot projects.

According to the IEA Hydrogen projects database[9] there are currently 68 **power-to-hydrogen projects** in operation in the EU. These projects have a total electrolyser capacity of 49 MW_{el}. Using the Higher Heating Value of hydrogen, this leads to a total potential hydrogen production of 300 GWh_{H2} (considering an average efficiency of 70%). This is less than 1% of the current hydrogen demand (about 325 TWh) and even more insignificant compared to the total gas and energy demand in Europe. Yet, most power-to-hydrogen projects play an important role as pilot projects to enable further commercial expansion in the future.

Almost half of the projects are located in Germany with a total electrolyser capacity of 29.9 MW_{el} (cf. Figure 2-3). The large majority of the power-to-hydrogen projects are

[7] The biomethane is mainly used as bio-CNG and to a limited but increasing extent, as bio-LNG. The bio-CNG market is relatively developed in Sweden, relying on favourable support mechanisms, among others a tax exemption for green fuels including biomethane until 2020. Cf. (EBA, 2020)

[8] (Energigas Sverige, 2019)

not connected to the natural gas grid and use dedicated hydrogen pipelines or are directly used for transport or industrial applications. The 3 projects that are connected to the natural gas grid are located in Germany, France and the Netherlands and have a combined electrolyser capacity of 2 MW_{el}.

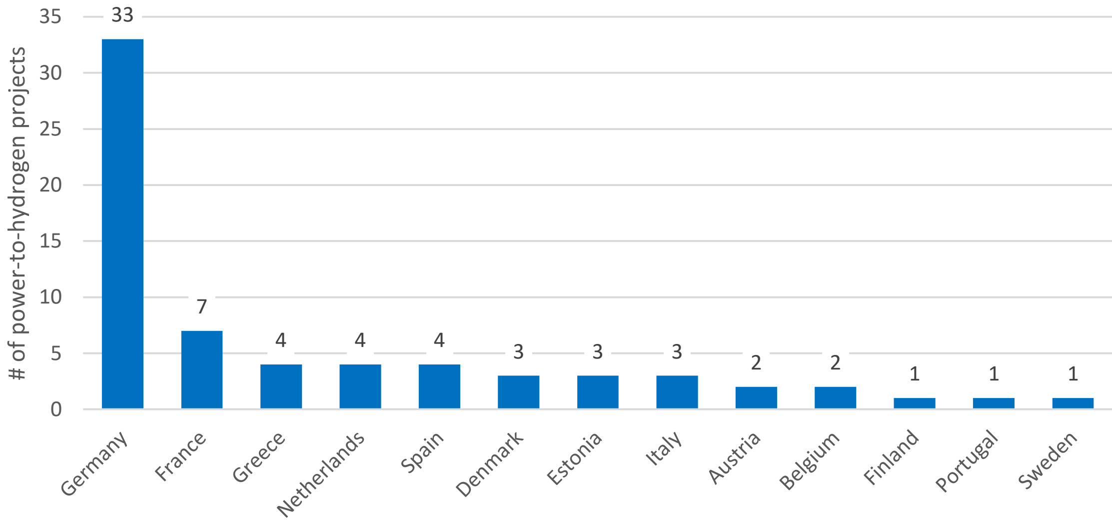

Figure 2-3: Number of power-to-hydrogen projects in the EU. Source: (IEA, 2020b).

According to the IEA hydrogen projects database, there are in the EU also 21 **power-to-synthetic methane** projects in operation in which the hydrogen produced from electrolysis is converted to synthetic methane.[9] 11 projects are located in Germany, 3 in Denmark, 2 in France and 1 in Austria, Italy, Poland, Spain and Sweden. The projects have a combined electrolyser capacity of 10.6 MW_{el} which leads to 7.4 MW output capacity taking into account conversion losses.

In addition to the current PtG-projects, many other projects with more significant production capacities are under construction or in the development stage.

By 2030, the EU aims at 40 GW of electrolyser capacity[10]. At the global level, the IEA projects electrolyser capacities to reach 850 GW (150 Mt of low-carbon hydrogen) by 2030 and 3000 GW (435 Mt) by 2045.[11]

2.1.1.2 The role of renewable and low-carbon gases by 2030 and 2050

Despite their minor contribution to the current EU energy mix, the role of renewable and low-carbon gases will become much more important in light of the EU's 2030 and 2050 energy and climate objectives. Figure 2-4 depicts the consumption mix of gaseous fuels by 2030 and 2050 under the different scenarios of the Climate Target Plan. While

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[9] (IEA, 2020b)

[10] As announced in the EU's Hydrogen Strategy (European Commission, 2020a)

[11] (IEA, 2021)

in 2030 the major part of gas demand is still met by natural gas, its share is expected to drop to less than a third by 2050.

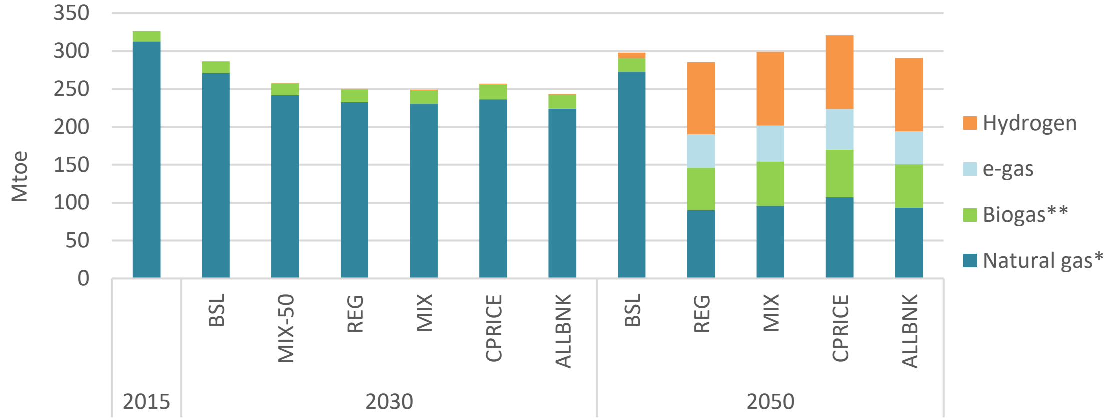

Figure 2-4: Consumption of gaseous fuels per gas type (*natural gas includes manufactured gases, **biogas includes waste gas). Source: (European Commission, 2020d).

The MIX H2 scenario which complies with the 55% GHG emission reduction target by 2030 and with the objective on green hydrogen production as set out in the European Commission's Hydrogen Strategy[12]. Further, biogas will account for 124 TWh, waste gas for 23 TWh and biomethane for 50 TWh in 2030.[13] The production of synthetic methane could reach about 2 TWh (cf. Table 2-1). By 2030, domestic natural gas consumption is expected to decline to about 3250 TWh. This illustrates that renewable and low-carbon gases still play a minor role in 2030, yet this year represents a pivotal moment. Beyond 2030, the deployment of these gases is expected to significantly accelerate (as already becomes evident from the 2035 numbers in Table 2-1) and will represent a substantial share in the gas supply mix by 2050.

Table 2-1: Overview of the EU27 production of gaseous fuels and domestic natural gas consumption by 2030 and 2035 under the MIX H2 scenario. Source: European Commission.

(TWh)	2030	2035
Biogas production	124	294
Waste gas production	23	24
Biomethane production	50	70
Hydrogen (directly used)	200	590
Hydrogen (distributed via pipelines)	-	6
Synthetic methane production	2	16
Domestic natural gas consumption	3245	2829

[12] (European Commission, 2020a)

[13] Compared to current figures of about 167 TWh of biogas production (cf. (EBA, 2020)), this would imply a shift from biogas to biomethane.

As indicated in Table 2-1, biomethane is expected to play a more important role in 2030 compared to blended hydrogen and synthetic gases. However, it is important to note that the CO_2 abatement costs of biomethane are relatively high. The biomethane cost potential curve introduced in Section 4.1.1.3 can be translated into a CO_2-abatement cost-curve. Under the given assumptions (cf. Annex, Section 8.2), biomethane CO_2 abatement costs vary from ~80 €/t_{CO2} to ~200 €/t_{CO2} for urban anaerobic digestion, ~325 €/t_{CO2} for thermal gasification and from ~400 to ~900 €/t_{CO2} for rural anaerobic digestion (cf. Figure 2-5).[14]

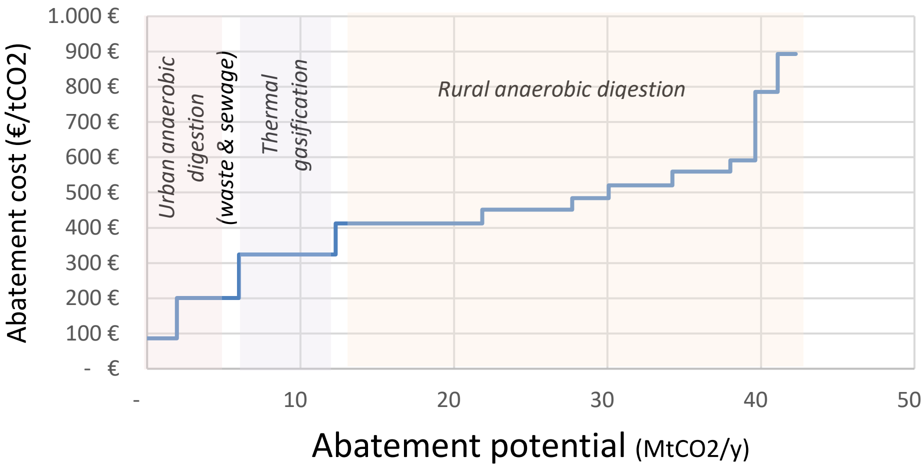

Figure 2-5: CO_2 abatement costs of biomethane, considering the EU potential. Source: own calculations.

Thus, CO_2 abatement costs of biomethane tend to be significantly higher compared to other decarbonisation technologies, as indicated in Figure 2-6.[15]

[14] The abatement cost curve assumes a reduction in CO_2 emissions from biomethane of -185 kgCO2/MWh HHV. The price for avoided natural gas consumption is assumed to equal 20 €/MWh.

[15] It is to be noted that on the one hand, other benefits of biomethane are not taken into account. For instant, urban anaerobic digestion can avoid direct methane emissions that would have occurred without the transformation to biomethane. Other services provided by biomethane, as waste treatment or the production of fertilizers are not considered either, and could reduce the biomethane cost and the CO_2 abatement cost. On the other hand, biomethane production also generates direct emissions (for the cultivation or collection of feedstocks, or the construction of the plants), which are not taken into account here. This effect may increase the CO_2 abatement cost presented and reduce the abatement potential.

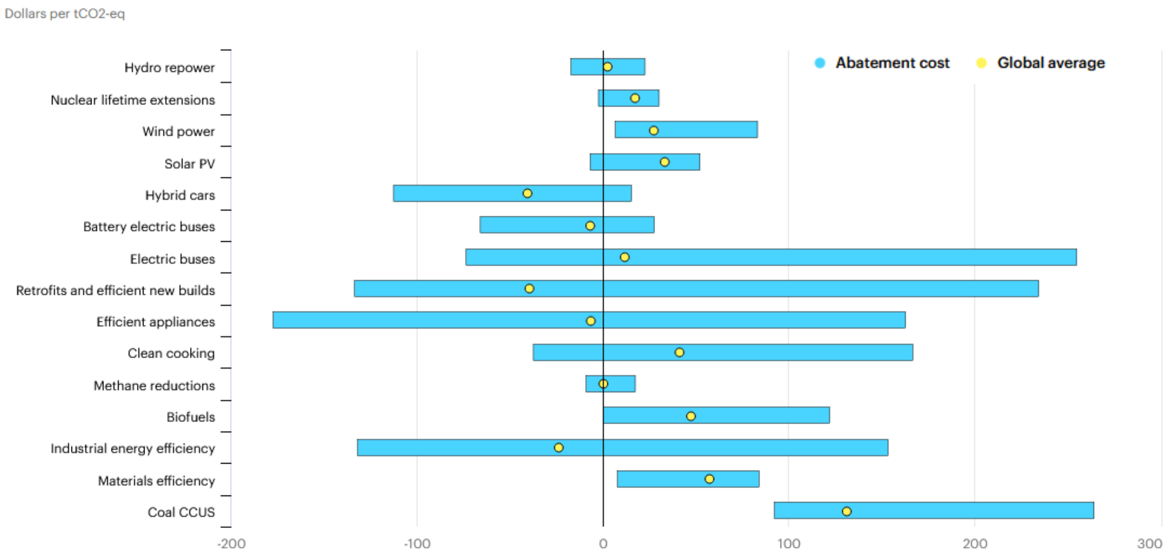

Figure 2-6: GHG abatement costs for selected measures of the Sustainable Recovery Plan. Source: (IEA, 2020c)

2.1.1.3 The problem: Lack of a level-playing field for renewable and low-carbon gases in the existing framework

Different policies are in place to support the deployment of renewable and low-carbon gases at the national and EU level.

For biomethane, several EU-countries have put in place support schemes, for instance direct or indirect support or quotas.[16]

The EU has come up with its Hydrogen Strategy, similar to different national initiatives (such as Germany, France, Portugal, Spain and the Netherlands) which outline explicit targets for the roll-out of hydrogen technologies (electrolyser capacities, hydrogen charging stations etc.).

In April 2021, the European Commission published the final Delegated Act under the EU taxonomy (as part of the EU sustainable finance package).[17] Even though it does not yet contain a distinct position on natural gas and related technologies, it defines a greenhouse gas (GHG) emission threshold for hydrogen of 3 t_{CO2e}/t_{H2} on a lifecycle basis, thereby favouring green hydrogen and enabling carbon-efficient blue and turquoise hydrogen to qualify as taxonomy-aligned.[18]

EU and national research programs support the realisation of research and innovation projects to trigger cost reductions in the production of renewable and low-carbon gases and test their integration into the gas infrastructure.

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[16] See for instance (REGATRACE, 2020).

[17] (European Commission, 2021g)

[18] Grey hydrogen applies the conventional way of hydrogen production via steam methane reforming (SMR) of natural gas (i.e. the separation of natural gas into hydrogen and CO_2). If the CO_2 is captured and stored (CCS), the hydrogen is labelled blue. Green hydrogen is produced by the electrolysis of water, meaning the breakdown of water into hydrogen and oxygen by means of renewable electricity. Turquoise hydrogen is created when natural gas is split via methane pyrolysis into hydrogen and solid carbon. This process does not generate CO_2 but makes use of fossil natural gas as raw material.

However, even if sufficient public support will be provided to effectively build, it may not be taken for granted that the expected and required renewable/low-carbon gases capacity (such as projected under the Climate Target Plan or the more recent MIX H2 scenario) will actually be able to properly penetrate the market. This is linked due to the fact that **the current legislative framework for gas does not represent a level playing field for renewable and low-carbon gases compared to natural gas**.

The Gas Market Directive states under Article 2 that "the rules established by this Directive for natural gas, including LNG, shall also apply in a non-discriminatory way to biogas and gas from biomass or other types of gas in so far as such gases can technically and safely be injected into, and transported through, the natural gas system".[19]

However, the specific characteristics of renewable and low-carbon gas supply differ from those of natural gas (for instance more decentralised production facilities, connected to other grid nodes, producing gases of diverging chemical characteristics). Thus, they face barriers for market and grid access, which represent a comparative disadvantage versus natural gas supply as the incumbent competing energy carrier. Further, renewable and low carbon gases have to comply with gas quality standards that are defined based on the characteristics of fossil methane. Finally, import and trade of renewable and low carbon gases may be hindered by market inefficiencies that concern natural gas alike. This includes for instance intra-EU entry and exit tariffs that impede the implementation of a fully integrated, internal EU gas market, as well as a potentially sub-optimal utilisation of LNG import capacities[20].

The lack of a level playing field for renewable and low-carbon gases compared to natural gas is further accentuated by the fact that their costs are substantially higher than the wholesale price for natural gas.

Under current framework conditions, biomethane (and other renewable and low-carbon gases) feature significantly higher levelised costs of energy compared to current natural gas prices. As illustrated in Figure 2-7, LCOE for biomethane ranges between 30 and more than 100 €/MWh[21], depending on the plant size, the substrate used, the costs for grid connection, electricity costs etc. In contrast, the wholesale price for natural gas under the MIX H2 scenario is assumed to equal around 20 €/MWh by 2030.[22] Even with an EU ETS price of around 50 €/t_{CO2} (as spotted since early May 2021), which represents a cost increase of about 9 €/MWh for natural gas, the cost gap is still significant.

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[19] (European Commission, 2009a)

[20] To a certain extent, this may also apply to import pipelines, if they are not timely repurposed.

[21] Cf. Section 4.1 for further details.

[22] The actual natural gas price varies between countries due to the entry/exit tariffs for intra-EU cross-border interconnection points which may add a single-digit cost on top of the gas price.

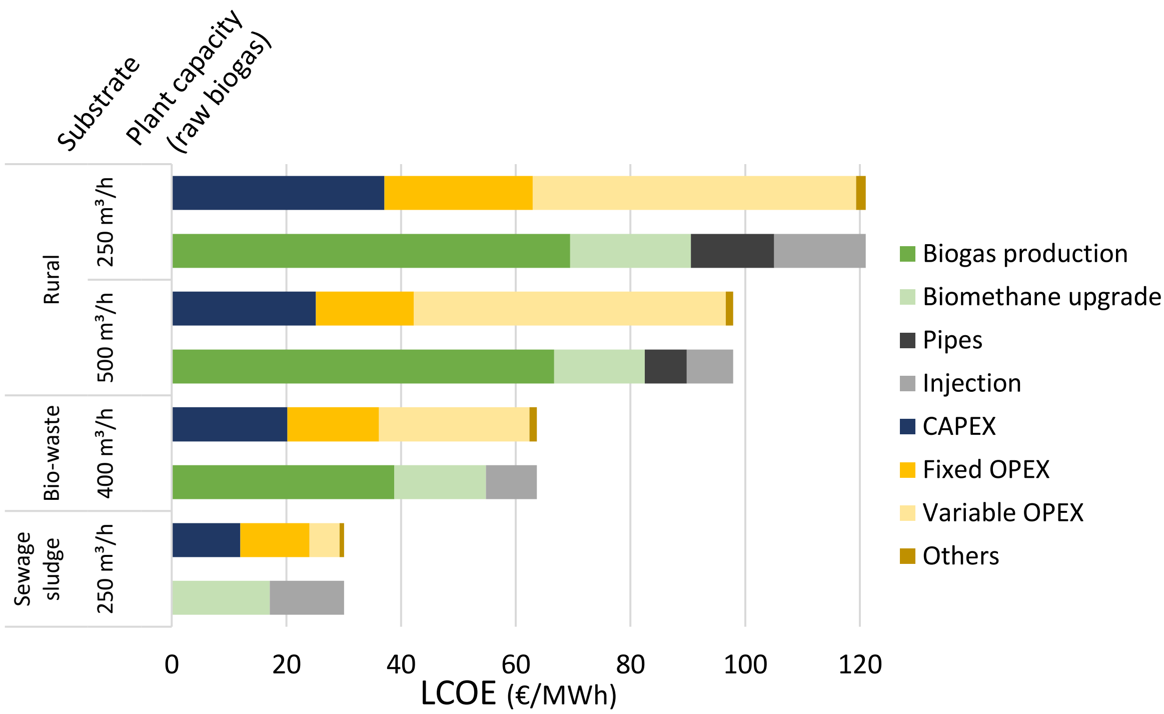

Figure 2-7: Overview of biomethane cost structure (LCOE). Source: own calculations based on external data (cf. Annex, Section 8.2.2).

This cost gap can be addressed by a much higher carbon price, by direct financial transfers (such as addressed under the Renewable Energy Directive or more specifically in national support schemes), by an appropriate design of EU and national legislation on gas markets and grids that reduces costs (including risk-related capital costs) for renewable and low-carbon gases and by an asymmetric regulation granting a favourable treatment for renewable/low-carbon gases.

2.1.1.4 Opportunities at risk

A constrained grid and market access for renewable and low-carbon gases in combination with persisting market inefficiencies put at risk the achievement of the 2050 decarbonisation target, and in particular the 55% GHG emission reduction target by 2030, as renewable and low-carbon gases might not be able to contribute to emission reductions in the mid- to long-term to the extent required according to current model assessments (notably the MIX H2 scenario).

More specifically, several prospective studies (including the European Commission's model-based analysis of the MIX H2 scenario) have revealed that the year 2030 represents a pivotal moment in the energy transition process. In the run-up to 2030, all legislative cornerstones need to be established in order to significantly and effectively accelerate the decarbonisation of the European energy sector, including the integration of renewable and low-carbon gases.

The constraints to cost-efficiently deploy the available domestic renewable and low-carbon gas resources may entail losses in terms of social welfare as local/domestic potentials to increase value added are not fully tapped. Market inefficiencies may result in higher energy costs for EU customers and businesses, affecting the competitiveness of European businesses at the global level.

A lacking level playing field for renewable and low-carbon gases also puts at risk the EU's strive for global leadership in technology supply for the energy transition in the domain of renewable and low-carbon gases (reverse flow compressors, hydrogen blending, biomethane upgrading, thermal gasification etc.).

The injection of growing volumes of renewable and low-carbon gases (incl. biomethane and hydrogen) into the gas network (both at transmission and distribution levels) is changing the parameters of gas transported and used in the EU. Differences in gas quality and in technical specifications (network, appliances) between Member States could lead to market segmentation and trade restrictions.

Ultimately, leaving biogas potentials from agricultural residues and waste (from sewage sludge, municipal waste or landfills) unused represents a missed opportunity to make an additional step towards a circular economy as outlined under the European Commission's Circular Economy Action Plan (CEAP)[23].

The different drivers for this problem are outlined in Sections 2.1.2 to 2.1.6.

2.1.2 Driver 1.1: Constrained market/grid access for decentralised producers of renewable and low-carbon gases connected to distribution grids

2.1.2.1 Production of biomethane mostly placed at DSO level

For efficient biomethane marketing, access to the wholesale market, i.e. the virtual trading point (VTP), represents a key prerequisite. Yet, current market organisation and legislation in Member States does not necessarily foresee the integration of distribution grids in entry-exit zones and the participation of the distribution level in the wholesale market. Consequently, the tradability of decentrally produced gases at the VTPs is limited, blocking (smaller) facilities from becoming active components of the energy system. This is making the business case for upgrading biogas to biomethane and injecting it into the grid less competitive compared to alternative options such as producing heat and power from biogas or using biomethane at local level e.g. for transport purposes which in principle limits scaling up of production.

The majority of the biomethane plants is connected to the gas grid (90%). Numbers from the European Biogas Association indicate that about half of the biomethane capacity is connected to the transmission grid and half to the distribution grid, cf. Figure 2-8.[24] However, as there is no common EU-wide definition of distribution and transmission grids, actual numbers may slightly differ.

[23] (European Commission, 2020b)

[24] The majority of biomethane plants connected to the transmission grid uses mainly energy crops (68% of all transmission grid capacity) while plants connected to the distribution grid are more likely to rely on agricultural residues (48% of all distribution grid capacity), cf. (EBA, GIE, 2020).

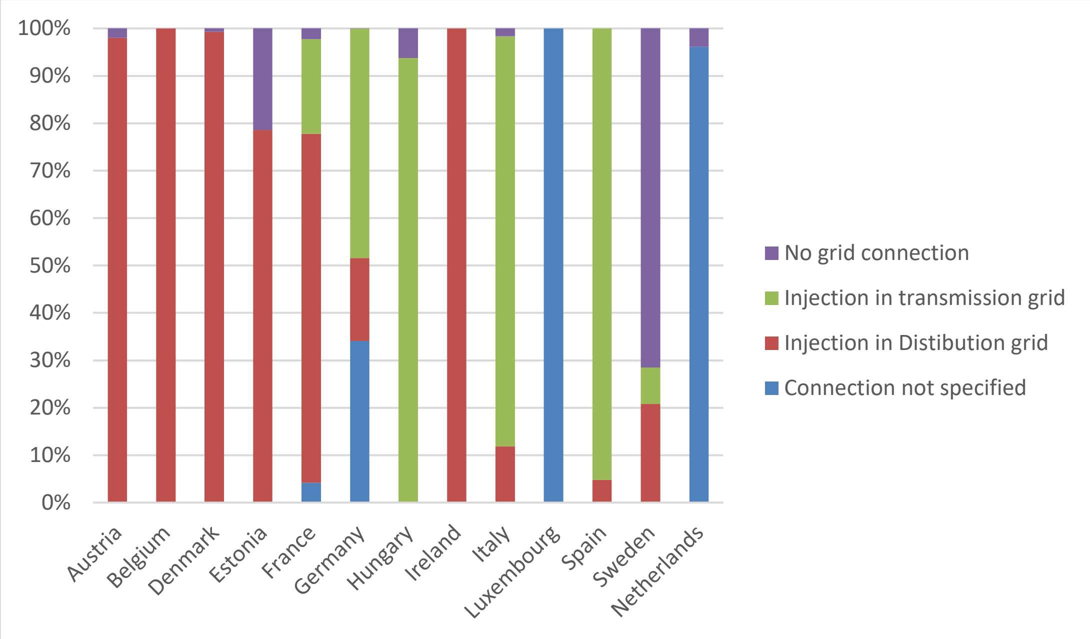

Figure 2-8: Annual biomethane production capacity (TWh) by network connection level. Source: (EBA, GIE, 2020).

The French TSO GRTgaz indicates that 88% of the biomethane plants currently in the waiting list for grid connection will be connected to the distribution grid, they represent 78% of the total injectable biomethane volume.[25]

It is likely that similar trends apply for other EU MSs for several reasons. Injecting biomethane into distribution grids may be realised at lower pressure levels, requiring a smaller dimensioning of the compressor (if any needed at the exit of the biogas upgrading plant) and lower operational costs (notably for electricity). On the other hand, an injection at the transmission level requires the construction of pipelines for grid connection that need to operate at higher pressure levels (as gas compression typically takes place at the biogas upgrading site) and the reduction of gas pressure for injection from transmission to distribution grid causes losses as it requires pre-heating when decompressing the gas.[26]

A survey among NRAs revealed that entry-exit (balancing) zones include distribution grids in 10 countries (AT, BE, ES, DE, FR, CZ, PL, FI, IT, PT).[27] Romania and Croatia explicitly stated that the entry-exit zone does not contain distribution grids. For Slovenia, Greece and Latvia, this issue is not yet of relevance as there is no biomethane injection yet. The survey did not gather information for SK, SE, EE, IE, LU, LT, NL and DK.

[25] (GRTgaz, 2017)

[26] The connection to transmission grids represents nonetheless a relevant option, for instance in case of higher geographical proximity of the biomethane plant to a transmission than to a distribution grid or if the distribution grid's absorption capacity is close to saturation (due to low demand levels or a significant pre-existing level of biomethane injection). For further information, see the paragraph on reverse flows, further below.

[27] In Hungary, one single plant injects at DSO-level with specific trilateral agreement for virtual access to TSO level.

Thus, the trend of connecting biomethane plants to distribution grids would accentuate the problem of non-access to the wholesale market in those countries where distribution grids are not yet integrated in the entry-exit zone, thereby deteriorating the economic viability of biomethane projects.

2.1.2.2 Mono-directional gas flows from transmission to distribution grids and the need for reverse flow compressors

Biomethane plants connected to distribution grids may face another barrier in addition to the potentially restricted access to the VTP: physical injection at the distribution grid level may be capped by the minimum demand levels in the local network as gas flows are typically mono-directional (from the transmission to the distribution level); surplus gas injection may hence not be accommodated in the grid if no remedial action (such as reverse flow compressors) is undertaken.

Three major effects need to be noted in this regard.

Gas demand in distribution grids features typically a strong seasonal variation, notably in distribution grids where gas is mainly used for space heating purposes via centralised heating (heat or CHP plants connected to district heating networks) or decentralised heating (gas boilers in individual apartments or buildings). Thus, the minimum demand level typically occurring during summer represents the dimensioning factor for maximum biomethane injection. Figure 2-9 illustrates the monthly distribution of national gas demand in 2014 in four selected European Member States. The illustration clearly demonstrates the significant difference between gas demand levels in summer and winter time.[28] In distribution grids, this ratio may be even more pronounced as the share of industrial consumers (which feature a more constant demand throughout the year) is lower than in the national average. This means that the consumer structure of a distribution grid significantly affects its ability to integrate biomethane production (disregarding reverse flow compressors or alternative remedial measures to avoid injection curtailment).

Secondly, gas demand is expected to decline in the coming decades. This trend is primarily driven by enhanced building and equipment energy performance, energy efficiency efforts in the manufacturing industry and a general shift towards electricity. A decline in gas demand reduces the minimum gas demand level and thus the ability of distribution grids to integrate biomethane injection.

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[28] While gas demand follows the seasonal variation indicated in Figure 2-9, gas flow patterns are likely to differ as summer months are typically used to fill gas storages (in order to limit gas import flows in winter time).

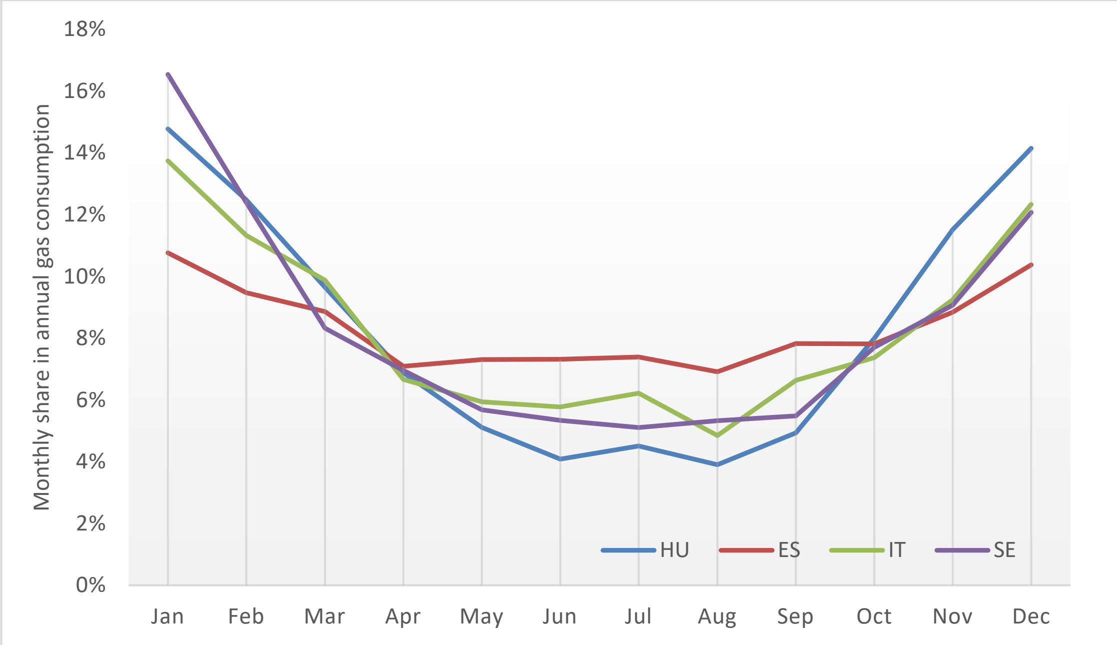


Figure 2-9: Normalised monthly gas consumption profiles for selected countries in 2014. Source: (ENTSOG, 2018).

Thirdly, biomethane injection profiles in the gas grid are relatively stable and do not show a large seasonal, monthly or daily variance (cf. Figure 2-10). Biomethane plants feature on average around 8000 full load hours per year, or an availability rate of 91%. This high load factor is related to the fact that it is economically beneficial to maximise the utilisation of a biomethane plant (notably the fermenter) by opting for a minimal dimensioning of the plant. As the feedstock inputs can change during the year, producers store them and control the amounts that are used as input for the anaerobic digestion process.

This implies that the relatively constant biomethane injection profile strongly contrasts the seasonally varying demand profiles of distribution grids, thus limiting distribution grids' ability to integrate biomethane. In case distribution grids reach biomethane saturation and if no remedial measures are taken, biomethane injection needs to be curtailed. This represents a substantial risk for biomethane producers and may have a deterrent effect on potential investors.

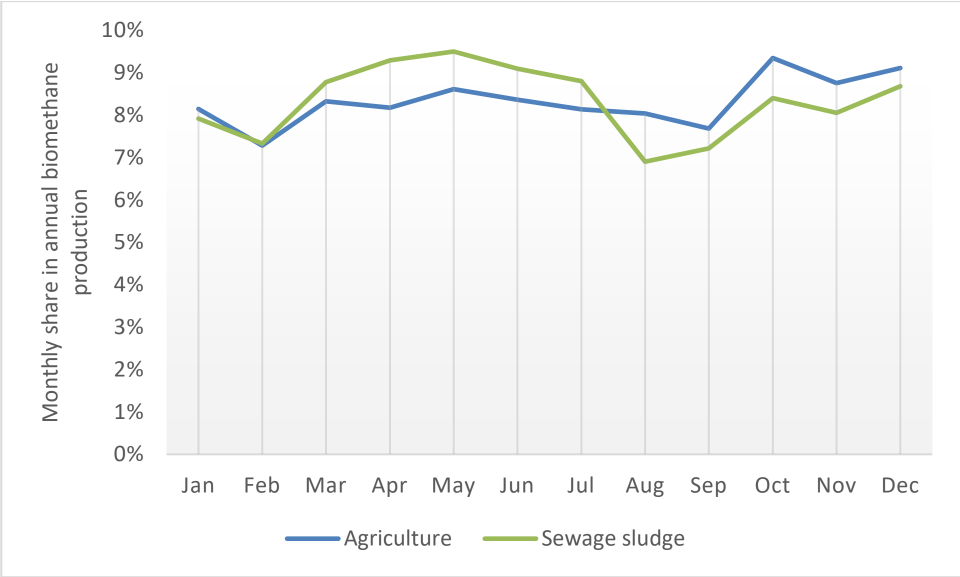


Figure 2-10: Biomethane production from agricultural substrates and sewage sludge in France in 2018. Source: (GRDF, 2021).

Today, distribution grid saturation does not appear to be a widespread issue. However, the expected rise in biomethane production and the parallel decline in gas demand make the occurrence of such situations increasingly likely.

Different measures may be envisaged to overcome the capping of biomethane injection:

- Reverse flow compressors that facilitate the injection of gas from the distribution to the transmission grid
- Meshing of distribution grids
- Increase of local gas consumption
- Adaptation of the biomethane injection profile (requires an over dimensioning of the fermenter)
- Shifting of gas demand towards periods with low consumption
- Installation of local gas storage
- Direct connection of biomethane plants to the distribution grid
- Direct use of biogas for heat/power generation, in particular if there is a local need for heat (e.g. district heating network).

A detailed description and discussion of the different options is provided in the Section 8.2.4.

Reverse flow compressors may be considered as one of the most appropriate options in terms of costs and technical feasibility. Up to now only a small number of reverse flow projects have been realised. However, French TSO GRTgaz estimated in 2017 a potential need for 150 reverse flow compressors by 2030, equalling investment costs of about 450 M€.[29]

Most of the European MSs have not yet put in place national legislation to incentivise network system operators to install reverse flow compressors where necessary. Only Austria, Spain and France appear to have such policies in place (with France obliging

[29] (GRTgaz, 2017)

the network operators to realise such investments if the related costs do not exceed a certain threshold and by obliging biomethane producers to pay a higher DSO tariff[30]). In Italy, a pilot project is under way. In the other EU-countries, such an obligation does not exist as saturation of biomethane injection at the distribution grid level does not occur yet.

2.1.3 Driver 1.2: Grid connection as potential barrier and relevant cost element

2.1.3.1 Biomethane producers depend on the network operators for grid connection in case of lacking legislation and are likely to bear the costs

Biomethane plants may be connected to the transmission or the distribution grid, upon request to the TSO or DSO. In certain countries there exists no standard rule set on how to treat these requests. In addition, the cost sharing related to network connection differs significantly across Member States. In several MSs, costs need to be partially or fully borne by the biomethane producer. Similarly, some MSs require producers of renewable and low-carbon gases to pay network injection tariffs whereas others opted for their exemption. These factors may prevent from upgrading biogas to biomethane and its injection into the gas grid, and favour power and heat generation from biogas or supplying biomethane at local level.

Currently, a **connection obligation** exists in 16 EU Member States, while at least five countries do not dispose of such a national obligation. (cf. Table 2-2)[31]

Table 2-2: Connection obligation for network operators across EU MSs. Source: (ACER, 2020a).

Connection obligation exists	No connection obligation	No information available
AT, HR, CZ, DK, EE, FR, DE, HU, IE, IT, LV, LT, LU, NL, SI, ES	BE[32], PL, PT, SK, SE	BG, CY, FI, GR, MT, RO

Only very few connection requests were denied in the past. The denial was in most cases related to the fact that the connection was not considered economically feasible (exceeding predefined thresholds determined in national legislation), due to the existence of gas quality-sensitive end-users downstream, or to insufficient capacity downstream where reverse flow is not installed.

The allocation of **grid connection costs** between the network operator and the biomethane producer is handled quite heterogeneously across the EU. For example, some Member States apply relatively favourable connection terms for producers (in comparison with the grid connection terms for end-users) in order to support

[30] (Ministère de la Transition Ecologique, 2019)

[31] Information based on (ACER, 2020a). In Belgium, a connection obligation is under development.

[32] In Belgium, connection obligation under implementation.

biomethane producers. Based on an analysis of cost allocation regimes in general terms, one can distinguish between three major cost allocation types[33]:

- **Deep cost allocation** where producers pay all costs associated with the connection. This allocation is applied in Ireland, Italy and Spain;
- **Shallow cost allocation** where producers pay the cost for the physical grid connection and the system operator pays the necessary network reinforcement beyond the connection point (for example costs for reverse flow facilities or meshing of distribution networks). This allocation is applied in Austria, Czech Republic, Denmark, Finland and Sweden;
- **Super shallow cost allocation** where producers pay only partially or not at all for the physical grid connection, and system operators bear the majority of costs for the whole network reinforcement beyond the connection point and all/part of the physical connection. This allocation is applied in the following Member States, with the physical grid connection costs allocated in different ratios: Belgium (Wallonia), Estonia, France, Germany and Lithuania.

When it comes to **grid injection tariffs**, in several Member States injection tariffs are lower for biomethane and hydrogen compared to tariffs for the injection of natural gas in transmission grids. Among others, there is no injection tariff for biomethane in both the TSO and DSO grid in France, Germany and Sweden (cf. Table 2-3). Additionally, there are no biomethane injection tariffs in the DSO grid in Italy, the Netherlands and Spain. In case of hydrogen, there is an exemption from injection tariffs in both the TSO and DSO grid in Germany. Injection tariffs for hydrogen are zero in the DSO grid in the Netherlands, Sweden and Spain. However, for several Member States no specific information was available. Given the current low penetration of biomethane and hydrogen, it is expected that tariff structures may change or may be updated in the near future in many Member States, depending on the priority to stimulate the deployment of renewable and low-carbon gases but also in function of the evolution of gas injection and the related costs that need to be allocated.

[33] This clustering builds upon information from (REGATRACE, 2020)

Table 2-3: Overview of national grid injection tariffs by gas type and network type. Source: own compilation[34].

	Injection Tariffs (€/MWh)					
	Biomethane		Hydrogen		Natural gas	
Country	TSO	DSO	TSO	DSO	TSO	DSO
Austria					n/a	
Croatia					0.97	
Denmark	0.42	*	0.42		n/a	
Finland	0.39				n/a	
France	0.00	0.00**	n/a	n/a	0.29	
Germany	0.00	0.00	0.00	0.00	0.64	
Hungary					1.29	
Italy	0.40	0.00	0.00		0.40	
Ireland					n/a	
Netherlands	0.20	0.00	0.20	0.00	n/a	
Romania					0.00	
Spain	0.45	0.00	0.45	0.00	0.45	
Sweden	0 ***	0.00	0 ***	0.00	n/a	

* DK: the biomethane producer pays for costs related to connection and use-of-system. But the DSO typically recovers the distribution compression costs and gas metering via the general grid fees. Hence the biomethane producer pays only for the direct costs related to connection, while the other costs are socialised.

** FR: Tariffs are due if meshing of distribution networks or shared network extensions (tariff of 0.4 €/MWh) or reverse flow investments (tariff of 0.7 €/MWh) are needed[35]

*** SE: the entry-exit split in the Swedish gas transmission network is 0.3%/99.7%[36]

Notably, France and Germany are the two largest biomethane producers in the EU. Both countries have legal obligations on TSO/DSO to connect biomethane plants, require a substantial part of grid connection costs to be borne by the network operator and do not apply grid injection tariffs for renewable and low carbon gases – in addition to favourable support schemes currently in place. This illustrates that the lack of connection obligation and the burden of putting grid connection costs and grid injection tariffs onto biomethane producers may hinder biomethane deployment.

[34] (Energinet.dk, 2020) and (Energistyrelsen, 2016) for Denmark, (Gasgrid, 2020) and (Auris Kaasunjakelu Oy, 2021) for Finland, (CRE, 2020a) and (CRE, 2020b) for France, (CMS, 2021) for Germany, (Arera, 2015), (Arera, 2015) and (SNAM, 2020) for Italy, (Autoriteit Consiment & Markt, 2021) and (Autoriteit Consiment & Markt, 2016) for the Netherlands, (Enagas, 2021) and (Comisión nacional de los mercados y la competencia, 2020) for Spain and (Swedegas, 2021) and (WEUM, 2021) for Sweden.

[35] (CRE, 2020c)

[36] But only very low volumes are injected.

2.1.4 Driver 1.3: Intra-EU entry/exit tariffs hinder the establishment of a fully integrated, liquid and interoperable EU internal gas market

The current tariffication scheme of gas transmission systems may hinder the deployment of renewable gases.

2.1.4.1 Heterogeneous tariff design and tariff pancaking

In the majority of the EU-MSs, TSOs transport two kinds of flows:

- **National flows** from one external/internal entry point (other TSO, LNG terminal, storage, domestic production) to one internal exit point (DSOs, industrial consumers, gas-fired power plants),
- **Transit flows** from one external/internal entry point (other TSO, LNG terminal, storage, domestic production) to one external exit point

The costs of transporting these flows embed operation & maintenance costs for equipment (pipelines, metering and compressor stations), but also the cost for new investments aiming at diversifying the gas sources and answering to potentially growing gas demand. At the transmission level, these costs are borne by the national TSOs. They are recovered via grid tariffs taking into account the **allowed revenues** of the TSOs, which are determined by the NRAs. The methodology how allowed revenues are determined is not homogeneous among the MSs, thus they are not necessarily directly correlated with the investment and O&M expenditures.

To collect the allowed revenues, the TSOs have several options, one being to apply tariffs for the use of their pipelines at different levels (through capacity reservation or commodity tariffs). These tariffs can be distinguished by three categories:

- The **internal exit tariffs** (at internal exit points), which are paid only by the national grid users
- The **external exit tariffs** (at external exit points), which are paid by non-national grid users
- The **external/internal entry tariffs** (at external and internal entry points) paid by both national and non-national grid users (depending on whether the flow crossing this point is destined to the national consumers or other markets)

The revenue repartition between these three kinds of tariffs is a complex matter. Transit countries may have an interest in increasing their external entry and exit tariffs and decrease their internal exit tariffs to transfer the costs of transportation to other countries instead of their national consumers, but increasing too much these tariffs may result in shippers/traders choosing a different route. On the other hand, a country that would rely too much on internal exit tariffs may apply an unfair weight on its consumers, while the national services brought by the TSO also benefit other consumers.

Thus, the current EU tariff repartition is the outcome of historical decisions and negotiations between TSOs and NRAs both at national and EU scale. The current EU gas market is still characterised by important entry-exit tariffs with high variations between the different countries, as depicted in Figure 2-11.

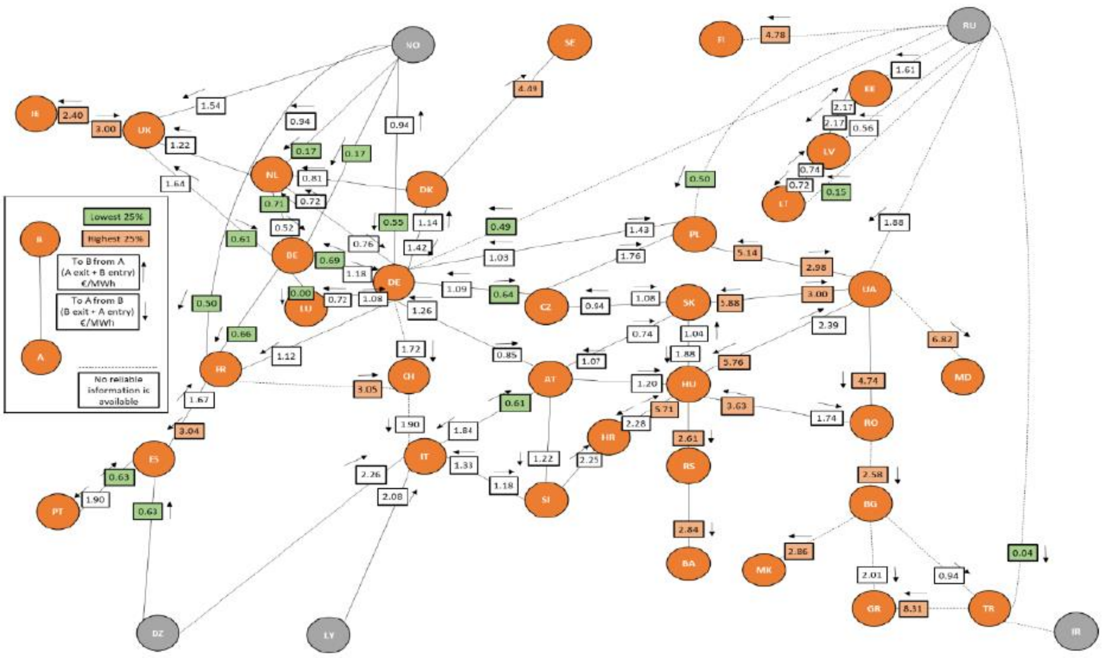


Figure 2-11: Average external entry and exit tariffs in the CESEC region in 2018. Source: (ECRB, 2018).

A problem arising from the current tariff configuration is the **non-homogeneity of the current tariff setting procedure** as all countries apply their own methods. Thus, the current tariff pancaking is complexifying the gas trade across Europe and increasing the management costs of trading which requires market actors to consider all kinds of different tariffs and their updates. This may result in biased gas flows and obstacles to trading, ultimately hindering the establishment of a fully integrated, liquid and interoperable EU internal gas market.[37]

One recent change on the tariff repartition is the modification of long-term booked capacities at interconnection points: while historical booking concerned rather over-the-counter (OTC) agreements defined bilaterally, the improvement of capacity allocation mechanisms in recent years allowed to shorten the duration of these bookings (the current usual products being yearly, quarterly, monthly, daily and within day, the latest being often offered at a tariff which substantially exceeds the tariff for a yearly booking) and to increase the offering of more short-term bookings, to increase the flexibility options for market participants. As illustrated in Figure 2-12, these evolutions are likely to further change the profile of booked capacity in the coming years.

[37] (Chyong, 2019; Cervigni, Conti, Glachant, Tesio, & Francesco Volpato, 2019)

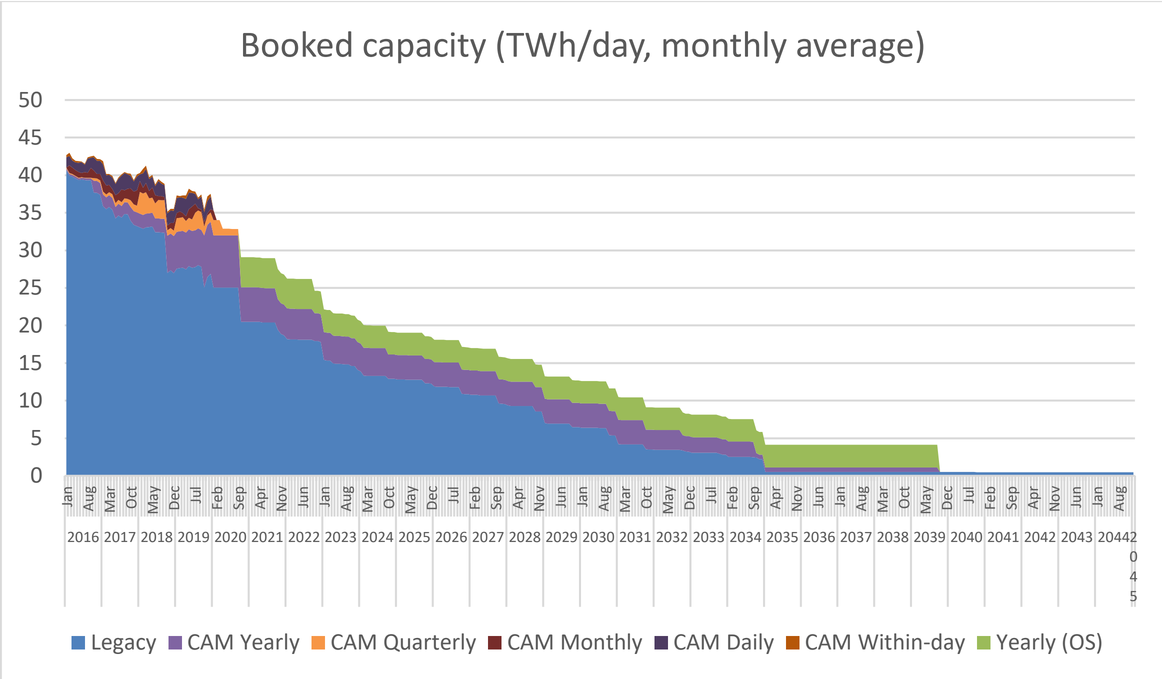
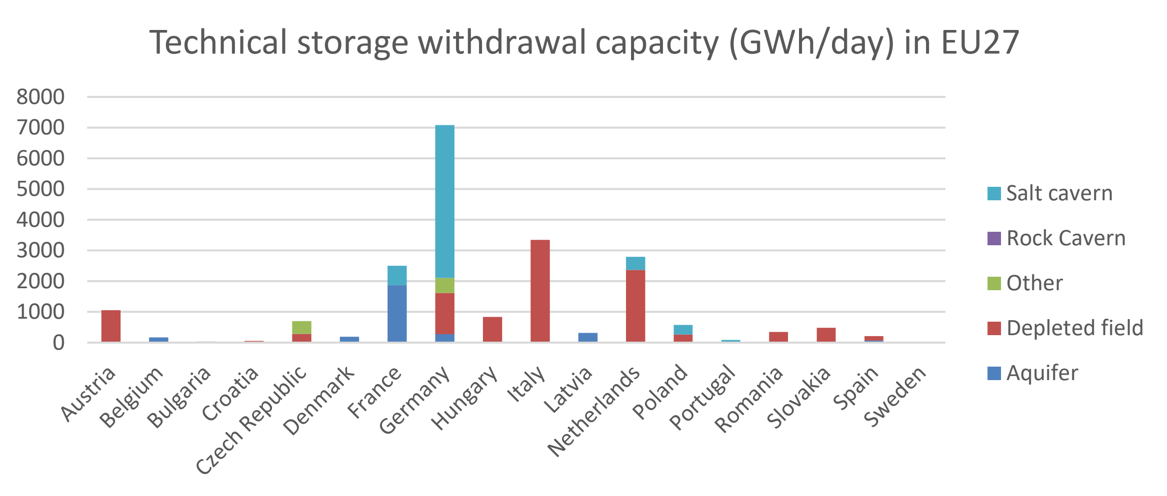


Figure 2-12: Long-term booked capacity in 2019. Source: (ACER, CEER, 2019).

In addition to pipelines, the gas system in Europe disposes of large storage capacities (cf. Figure 2-13), which mainly serve seasonal flexibility needs.



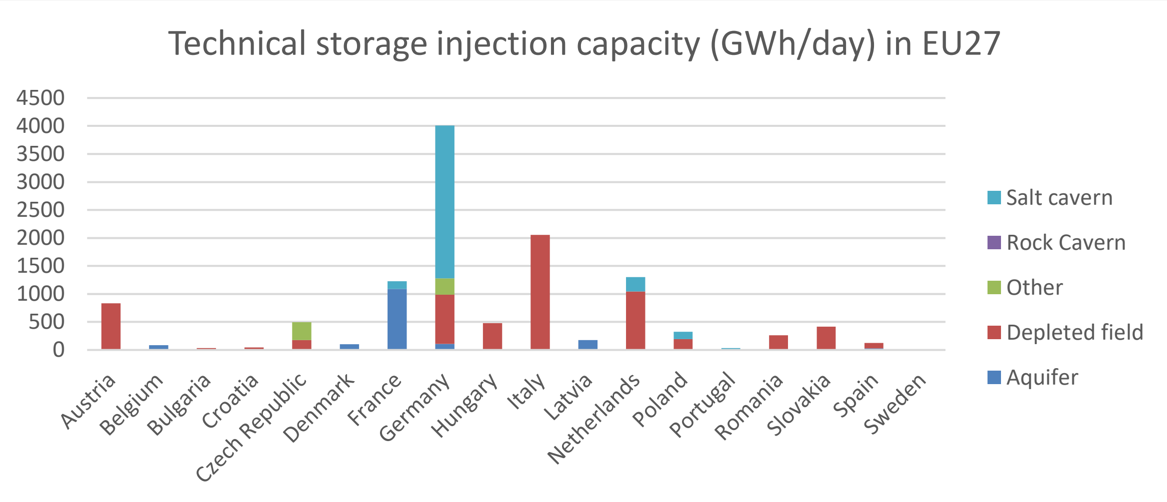


Figure 2-13: Technical storage withdrawal and injection capacities (existing and under construction) in EU27. Source: (GIE, 2021a).

The tariffs to use gas storage infrastructures amount to around 0.7 €/MWh for both entry from storage to network and exit from network to storage. Discounts are possible and some MSs apply negotiated tariffs. Similar to the entry/exit tariffs the heterogeneity of these tariffs implies that arbitrage between different storage options is difficult to consider for market participants, and common tariff principles for all gas storages might hence contribute to increased efficiency and transparency of the gas market.

Moreover, as the production of renewable and low-carbon gases is in general not flexible (for instance, biomethane production is mostly constant over the year, cf. Section 2.1.2), the access to gas storage is needed to facilitate the integration of renewable and low-carbon gases, and a high local storage tariff may hinder the development of new projects that would require the use of this storage.

2.1.4.2 Sub-optimal conditions for import and trade of renewable and low-carbon gases

In the context of an increase of biomethane and low-carbon gases production within the EU, the gas market fragmentation linked to intra-EU tariffs must be avoided to allow these new gases to circulate easily across the EU, hence increasing their competitiveness and ensuring the European consumer to have access to gas which is locally sourced within the EU. To facilitate intra EU trade, a methodology common to all

TSOs that avoids inequal treatment of transport costs of gas between MSs would also contribute to fair competition between biomethane and low-carbon gas producers in different MSs.

As the production of renewable and low-carbon gases within the EU is not expected to meet the long-term gas demand, it is very likely that a substantial share of the future gas supply will rely on imports.

Current biomethane imports to the EU are insignificant. This might change in the future given possible cost reductions of biomethane in non-EU countries and regional differences in production costs. Therefore, it is worthwhile to consider the availability and potential costs of future biomethane imports. Figure 2-14 provides an overview of estimated biomethane potentials available for export by 2040 based on an estimate of the International Energy Agency (IEA)[38,39]. Using the IEA data, the global biomethane export potential is estimated at 8084 TWh in 2018, rising to 9731 TWh in 2040. Import costs to the EU ranged in 2018 between €12/MWh and €98/MWh, in 2040 import costs are estimated in the range of €13/MWh and €70/MWh (including shipping costs), depending on the source region and other variables. Compared to domestic biomethane, imports might be less costly.

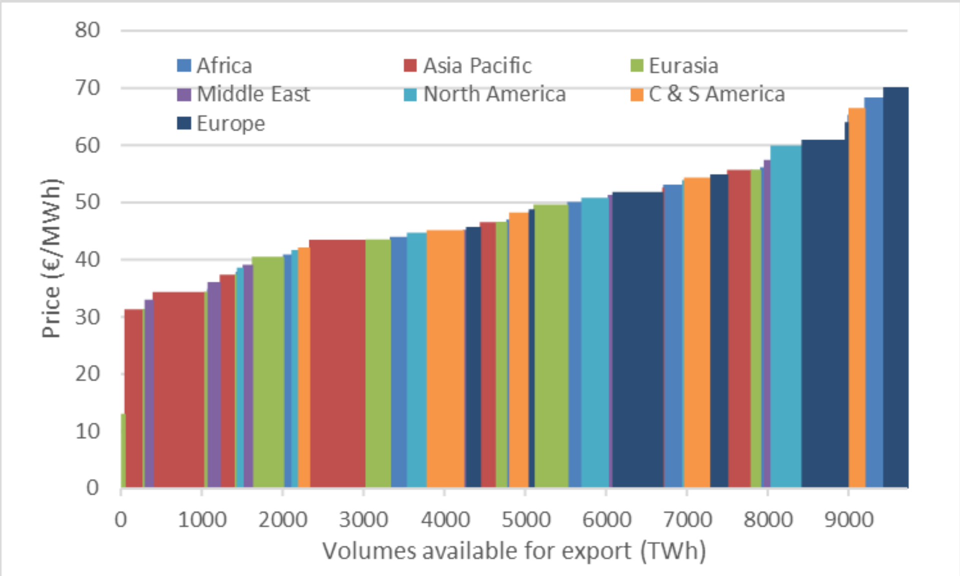


Figure 2-14: Potentials and costs of biomethane imports in 2040. Source: (IEA, 2020d).

The heterogenous determination of intra-EU entry and exit tariffs and their potential pan-caking (in combination with a sub-optimal utilisation of LNG terminals, cf. Section 2.1.6) may hinder an efficient trading of gas. This applies in particular to small-scale decentralised producers of renewable and low carbon gases.[40] Such inefficiencies may

[38] (IEA, 2020d)

[39] The IEA data is converted in order to include shipping costs and to exclude the European potential. As a result, the non-EU European potential is not included but this is expected to have limited impact on the resulting cost curve.

[40] NB: Internal entry/exit tariffs favour domestic gas production compared to gas imports from/via other EU countries. Given that a relevant part of renewable and low-carbon gases is likely to be produced within the

constrain the exploitation of domestic resources and import potentials and thereby risk to increase the overall costs of the decarbonisation of gas supply

2.1.5 *Driver 1.4: Gas quality rules are driven by quality of fossil methane*

Current **gas quality standards** are defined based on fossil methane. Yet, the current standardisation and harmonisation framework lacks elements to facilitate the injection of renewable and low-carbon gases. It consists only of non-binding CEN standards at European level (cf. Box 2-1) and a cross-border coordination and dispute settlement framework for IPs (in the Interoperability and Data Exchange Network Code). As renewable gases do not necessarily comply with these standards, their injection may be hindered. While biomethane and synthetic methane have very similar characteristics compared to fossil natural gas (methane share >90%), hydrogen-blended natural gas features very different chemical and physical characteristics. This affects its integration in the gas grid, as not all gas infrastructure components are able to cope with blended gases.

The injection of growing volumes of renewable and low-carbon gases (incl. biomethane and hydrogen) into the gas network (both at transmission and distribution levels) is changing the parameters of gas transported and used in the EU. Hydrogen has different properties such as a lower specific energy content which reduces the calorific value of the gas mix and the methane number (important for gas engines), and can affect combustion properties.[41] The properties of biomethane can vary per feedstock or upgrading technology, so that biomethane can vary in characteristics such as Wobbe index and concentration of compounds such as sulphur or oxygen.[42] Differences in gas quality specifications between Member States can lead to **market segmentation and trade restrictions**. Constraints will arise especially from high blending rate regions to regions with a lower blending rate. Cross-border flows are currently managed on a bilateral basis. Depending on the injection rates of hydrogen and biomethane, this raises the need for system-wide adaptations to ensure the functioning of the whole methane gas system and gas quality management that considers the possibly adverse effects of gas quality fluctuations on the operation of the system and on end-users. This requires a significant EU-level, regional or bilateral coordination and between the different stakeholders along the value chain (gas producers, TSOs, DSOs, LSOs, NRAs, equipment suppliers and consumers, etc.).

Box 2-1: Current gas quality regulation

Current gas quality regulation

In a context of increased injection of hydrogen and biomethane and consequent decentralisation of gas supply (while in the past only few non-EU and EU sources injected gas in the system), EU-level coordination of gas quality standards is one way to improve the management of gas quality and provide clarity to network users, from

EU, the potential removal of entry/exit tariffs may expose renewable and low-carbon gases to intensified competition, cf. Section 4.3).

It should be noted that if injection tariffs for renewable and low-carbon gases are waived, while entry/exit tariffs are applied to natural gas, the former benefit from a comparative advantage when used domestically in comparison to natural gas imports. This advantage would diminish if internal entry/exit tariffs were removed.

[41] (THYGA, 2020)

[42] (ENTSOG, 2018)

producers to storage operators and end-users. Currently, **European standards for gas quality exist but are not binding**, with Member States setting the actual mandatory gas quality specifications (possibly referring to European standards).

The CEN standard EN 16726:2015 "Gas infrastructure - Quality of gas - Group H" provides a harmonised H-gas quality standard covering specifications for:

- Relative density
- Oxygen
- Carbon dioxide
- Hydrocarbon dewpoint
- Water dewpoint
- Methane number
- Total sulphur without odorant
- Hydrogen sulphide and carbonyl sulphide
- Mercaptan sulphur without odorant
- Contaminants

The EN 16726 standard is not mandatory and Member States have their own gas standards which may deviate from the CEN standard. In 2016, ENTSOG published an impact analysis of referring to the EN 16726 standard in the interoperability network code, and thus making it **binding for cross-border gas flows**. ENTSOG concluded that "despite providing certainty on the rules and removing any contracting difficulties, [a reference to the EN 16726 standard in the interoperability network code] would face significant legal barriers and produce widespread negative impacts across segments and Member States".

In addition, CEN has published the **EN 16723 specifications for biomethane** in the case of injection in the natural gas network (part 1) and for use as automotive fuel (part 2). This standard provides additional specifications for biomethane injection on top of those of EN 16726, namely regarding CO, NH3, amine, dust impurities, and others.

However, the standard **EN 16726 did not include specifications on the Wobbe index** (WI). CEN is continuing the work towards an eventual inclusion of the WI, and a report on the matter was scheduled to be finalised in 2020. The proposal for including WI specifications foresees:

- One WI specification for entry points allowing the injection of both LNG imports with high WI and of renewable gases with lower WI. The range covers 46.44 – 54.00 MJ/m3.
- Several exit-point WI class specifications with specific stability criteria and ensures the availability of local information on the Wobbe index. Along with these pre-defined specified classes, one 'extended' class would cover a wider WI bandwidth and contain measures to address e.g. hydrogen-sensitive end-users.

CEN is also conducting work in order to update / develop relevant **standards considering blended / pure hydrogen**. Relevant foreseen standardisation work covers natural gas quality (revision of EN 16726 by 2023), gas analysis (for e.g. sensors, pressure regulators and valves) installations (such as underground storage sites and pre-mixing stations), grid integrity and end-users.

The gas network code on interoperability and data exchange foresees a number of requirements regarding gas quality and odorization (chapter IV), including for TSOs to manage cross-border trade restrictions due to quality differences, publishing data on gas quality, and providing information to sensitive gas users.

2.1.5.1 Characteristics of biomethane and potential impacts on gas quality

First, biomethane has generally a lower Wobbe index (WI) and calorific value than natural gas from most EU and especially non-EU sources (exceptions are DE, HU, IE, NL as well as Libyan gas which has a lower average WI, while DE and IE gas has a lower gross calorific value).[43] Also, the Wobbe index of biomethane can be intrinsically variable given the different biomass feedstocks and production processes. Gas quality fluctuations can also occur in case of fluctuating biomethane injection rates (on a system level biomethane production does not exhibit significant seasonality, but there can be daily and intra-daily fluctuations) and due to demand fluctuations.

For low blending rates the influence of biomethane on the average gas WI or calorific value is not substantial, but considering the higher expected production of biomethane the situation might change. The lower and varying calorific value of the gas at high biomethane blending rates could lead to issues related to metering and billing to end-users, as flow meters could incorrectly measure the user's energy consumption.

Secondly, higher biomethane blending rates can increase the concentration of certain components that could potentially negatively impact gas infrastructure or network users. The main trace components in biomethane are:

- Sulphur - Sulphur can be present in biomethane in different concentrations depending on the feedstock used. Sulphur can among others corrode metal components in the gas grid. However, in most cases biomethane is de-sulphurized after upgrading.[44] Oxygen is formed during the most commonly used desulphurization method.

- Oxygen - Biomethane has on average a higher oxygen content than natural gas. Additionally, desulphurization can further increase the oxygen content of biomethane. A high oxygen content can influence several system components such as increasing the precipitation of solids in the gas, which could lead to clogging or function as nutrient for micro-organisms present in the gas.

- Carbon dioxide – Non-upgraded biogas consists of about 40% carbon dioxide. However, biogas upgrading to biomethane removes most carbon dioxide.[45]

- Siloxane – Siloxanes can be present in biomethane generated from solid and sewage waste, which constitutes a minority of the produced biomethane in the EU. The presence of siloxanes can lead to oxidation in several components such as gas engines and gas turbines.[44]

- Micro-organisms – Different micro-organisms can be present in biomethane. The effect of these micro-organisms is not well studied yet and their impact is therefore unknown but expected to be limited.[46]

[43] (CEN, 2020; ENTSOG, 2020e)

[44] (GERG, 2019)

[45] (GIE, 2011)

[46] (Netbeheer Nederland, 2018a)

The increased injection of biomethane of varying quality might raise the need for well-functioning cross-border flow management. Among others, biomethane can be naturally rich in sulphur. To remove the sulphur generally oxygen is used, which leads to a high oxygen content in the gas. As an example of such an issue, Danish gas has a high oxygen content because sulphur has to be removed on a large scale as a result of high biomethane production. This can lead to difficulties for border flows to Germany where gas standards do not allow a high oxygen content, mainly due to the tolerance of underground gas storages close to the DK-DE border. High oxygen contents could also impact underground storages and industrial users in other countries, as indicated by a number of European network operators in the present study survey. This is currently addressed through adding locally natural gas to the biomethane to reduce the oxygen concentration. In case of future higher penetration rates of biomethane, and thus a higher oxygen content, such a solution might not be sufficient anymore. While the EN 16726 standard allows oxygen concentrations of up to 1% if there are no sensitive network users such as underground gas storages, network operators could be required to manage gas quality by mixing gas with lower oxygen content, enforcement of specifications (requiring biomethane producers to reduce the oxygen content prior to injection), or gas quality management at sensitive storage or end-user points (e.g. by purification). Network operators are working with network users to understand their actual limitations, as some sensitive network users may be able to tolerate higher oxygen content.

Feedback from stakeholders confirms that oxygen is the main component which may lead to gas quality issues. However, this is mainly the result of the currently low reference concentration for oxygen. It seems that obstacles involving oxygen are in the first place regulatory and that the technical obstacles for allowing a higher oxygen content are limited. Therefore, regulators and network operators do not see this issue as a major barrier. Biomethane producers are concerned however on the impacts that the costs to meet strict oxygen concentration specifications could have on the economic feasibility of biomethane projects. Producers thus argue that taking measures to reduce oxygen concentrations at the entrance to storage sites would be a more cost-effective solution.

2.1.5.2 Limitations for hydrogen blending both at TSO and DSO levels

It is possible to mix hydrogen with natural gas, but hydrogen-blended natural gas features very different chemical and physical characteristics than *pure* natural gas. If hydrogen-blending into gas grids exceeds specific thresholds, this implies substantial additional investments to upgrade the existing grid infrastructure (distribution and transmission pipelines, gas metering and monitoring) and end-user equipment (power generation plants, gas engines, residential appliances industrial equipment) and make them blending-ready (cf. Figure 2-15).

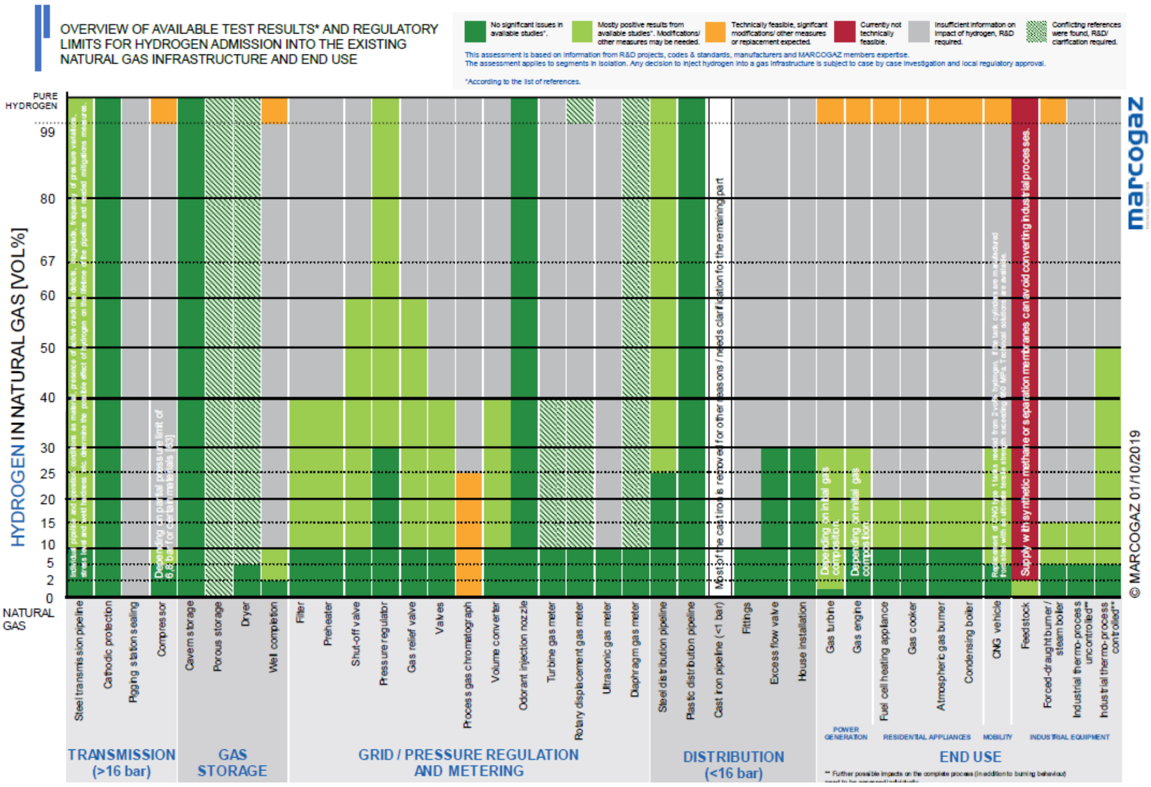


Figure 2-15: Maximum hydrogen blending rates into current gas infrastructure components. Source: (Marcogaz, 2019).

While the associated costs for blending rates up to 20% may be limited (cf. Figure 2-16), they substantially rise for higher blending rates. These costs depend of the extent of integration of hydrogen blended gas. If hydrogen blended gas is only distributed at the level of some specific grids (with possibly different blending levels per grid), the costs may be limited. If the ambition is to set a national level of hydrogen blending at the transmission level (resulting into the acceptance of this level for all distribution grids) the costs may be substantially higher as:

- Equipment not supporting hydrogen must be equipped of deblending stations, with if possible pure hydrogen consumption nearby
- For a level of maximum X% of volume of hydrogen blended, the whole transmission network must be refurbished to support between 0 and X% of hydrogen at any time to cope with the local variations of hydrogen and natural gas injected

Though blending hydrogen into transmission natural gas grid can be seen as a way of developing the hydrogen industry and a first step towards a fully decarbonised gas grid, the adaptation costs are quite significant.

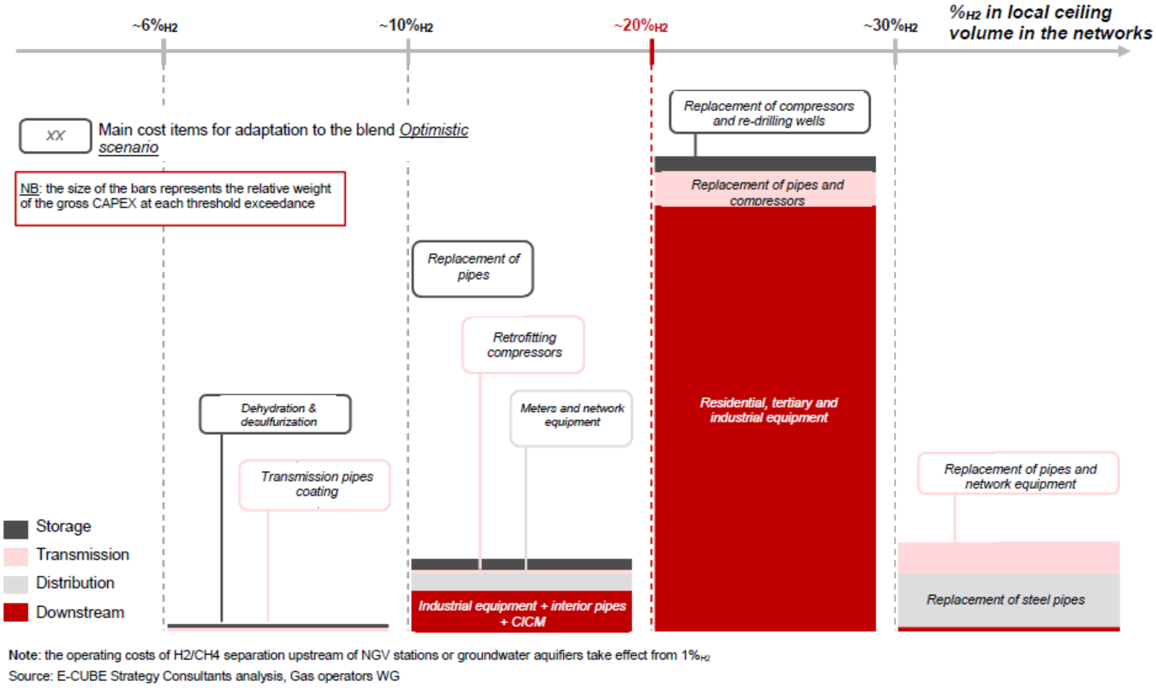


Figure 2-16: Summary of adaptation costs (CAPEX) at different hydrogen blending levels.[47] Source: (GRTgaz; GRDF; Teréga; Storengy France; Géométhane; Elengy; Réseau GDS; Régaz Bordeaux; SPEGNN, 2019).

2.1.5.3 Heterogenous hydrogen blending levels in the EU

Currently, allowed hydrogen admixture rates are determined per Member State and vary significantly (cf. Figure 2-17). The highest allowed hydrogen admixture rates are in Germany (10%[48]), France (6%), Greece (6%) and Spain (5%). Allowed hydrogen admixture blending rates are lower in Finland (1%), Ireland (0.1%mol), Italy (0.5%), Lithuania (0.1%mol) and the Netherlands (0.02%). Belgium, Czechia and Denmark do not allow hydrogen blending while in all other 15 Member States there is no regulation yet. Thus, national hydrogen admixture regulation highly varies and might raise a need for closer cooperation and alignment between Member States as it otherwise entails the risk of a fragmented EU gas market and trade restrictions.

[47] Adaptation costs relative to the volume of equipment concerned.

[48] Percentages are in%vol if not indicated otherwise.

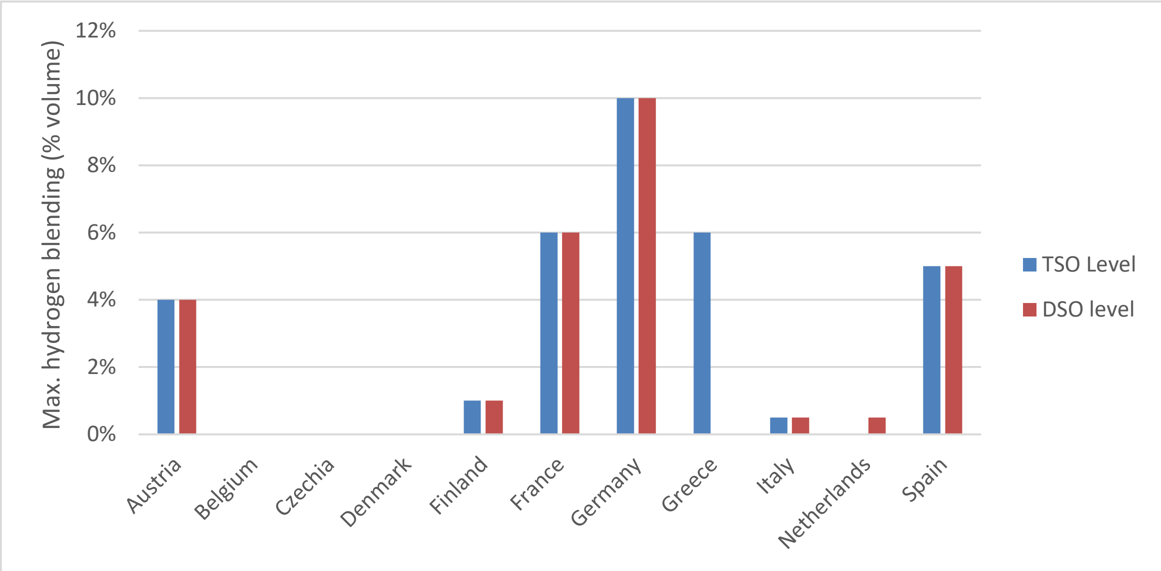


Figure 2-17: Maximum hydrogen blending regulation or objective. Source: (ACER, 2020a), (FCHJU, 2021).

2.1.6 Driver 1.5: LNG terminals equipped to receive only fossil methane, underutilisation

LNG is playing a growing role in the natural gas system in Europe, notably due to low prices of natural gas in Asia and increasing liquefaction capacities in the USA and Australia. The volumes of imported LNG doubled since 2018 and now represent almost a quarter of the natural gas supply in EU. The total send-out capacity equals 4840 GWh/d.[49] Nine countries operate a total of 18 LNG terminals (2019 numbers, cf. Figure 2-18). Thirteen additional countries are planning to build one or more LNG terminals, with a cumulated additional send-out capacity of nearly 750 GWh/d (15.4% of the current LNG send-out capacity).[50] This suggests that LNG imports are expected to increase in the coming years.

[49] Send-out capacity calculated based on the possible annual capacity, peak capacity can be potentially higher. Source: (ENTSOG, 2020a)

[50] Planned capacities indicated based on the TYNDP advanced FID scenario.

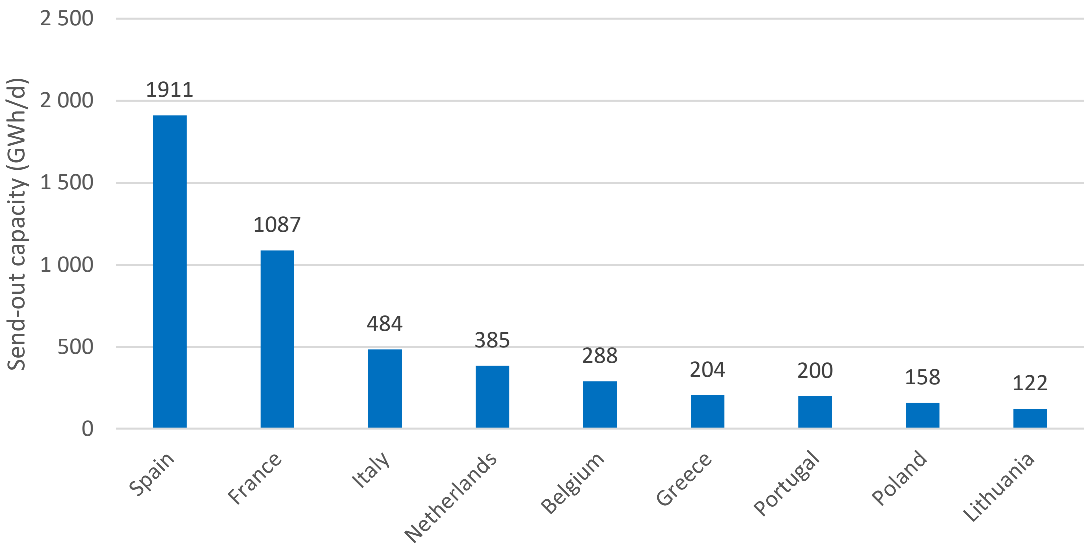


Figure 2-18: Overview of large-scale LNG terminal send-out capacity per Member State in 2019. Source: (ENTSOG, 2020a).

The LNG market has significantly changed since the adoption of the Third Energy Package and rules applicable to LNG terminals in the EU. Efforts were made to further integrate the gas markets within the EU, to increase the transparency and flexibility offered by LNG terminals, to move towards shorter term capacity reservations and to enable small scale LNG and smaller players to develop.

2.1.6.1 LNG integration in gas market and transparency could be further improved

However, some barriers and market failures still persist. **Access to liquid gas markets via LNG terminals can be limited**. Some terminals are more isolated than others and do not have access to liquid gas hubs. This may restrain the trading opportunities for their customers, causing a distortion in the fair competition and limiting the flexibility of products exchange. At some terminals, **insufficient connection** with the natural gas network acts as a bottleneck limiting potential LNG imports.

Another potential barrier regards the **lack of transparency** in tariff setting, capacity availability and allocation. LNG tariff structures and rates vary across the different EU MSs, combining one or more factors like fixed or variable costs, capacity factors, storage costs, etc. as shown in Figure 2-19.

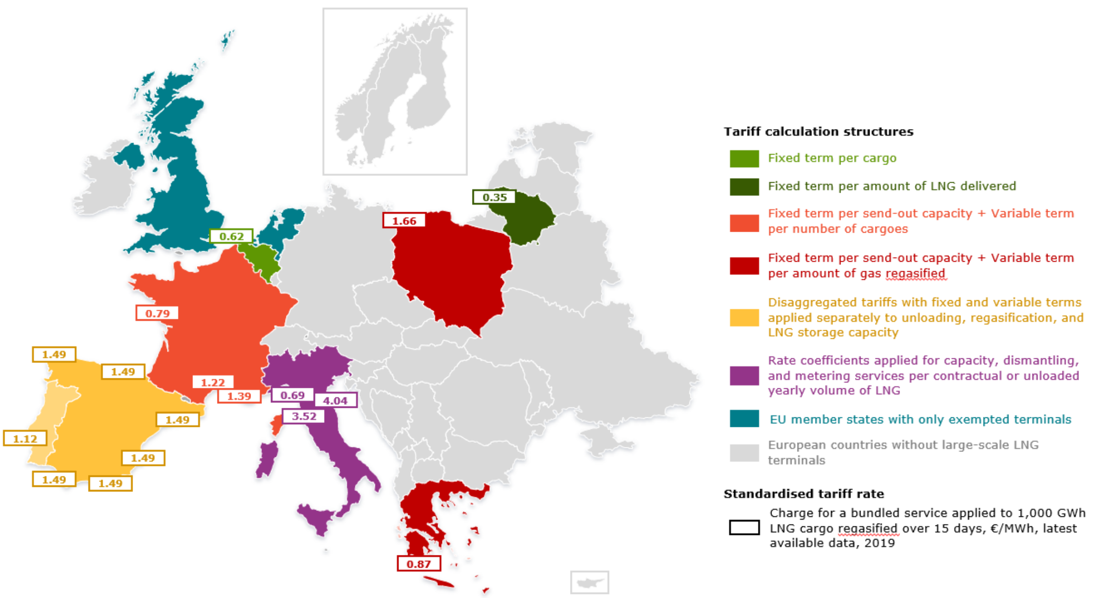


Figure 2-19: Tariff calculation methodologies and charge for a standardised bundled service (€/MWh) in EU Member States with regulated LNG terminals. Source: (Trinomics; REKK; enquidity, 2020).

The lack of a harmonized tariff structure and standardised products, as well as the limited access of certain LNG terminals to a liquid gas market, combined with some cross-subsidisation through regulator-approved discounts, do not encourage a fair competition between LNG terminals. Smaller players are particularly penalised by non-transparent capacity allocation mechanisms and tariffs as they face more difficulties to keep the overview and to switch between terminals.[51]

2.1.6.2 Potentially sub-optimal capacity allocation and utilisation of LNG capacities

One possible consequence of these regulatory barriers is a **sub-optimal use of LNG facilities**. Even if LNG volumes significantly grew over the past years, the LNG terminal capacity utilisation rates remain somehow low. Currently, the send-out capacity utilisation of LNG terminals in Europe ranges from 30% to 50% of the total capacity, as shown in Figure 2-20.

[51] For further detail on the shortcomings related to market access and market liquidity, see (Trinomics; REKK; enquidity, 2020)

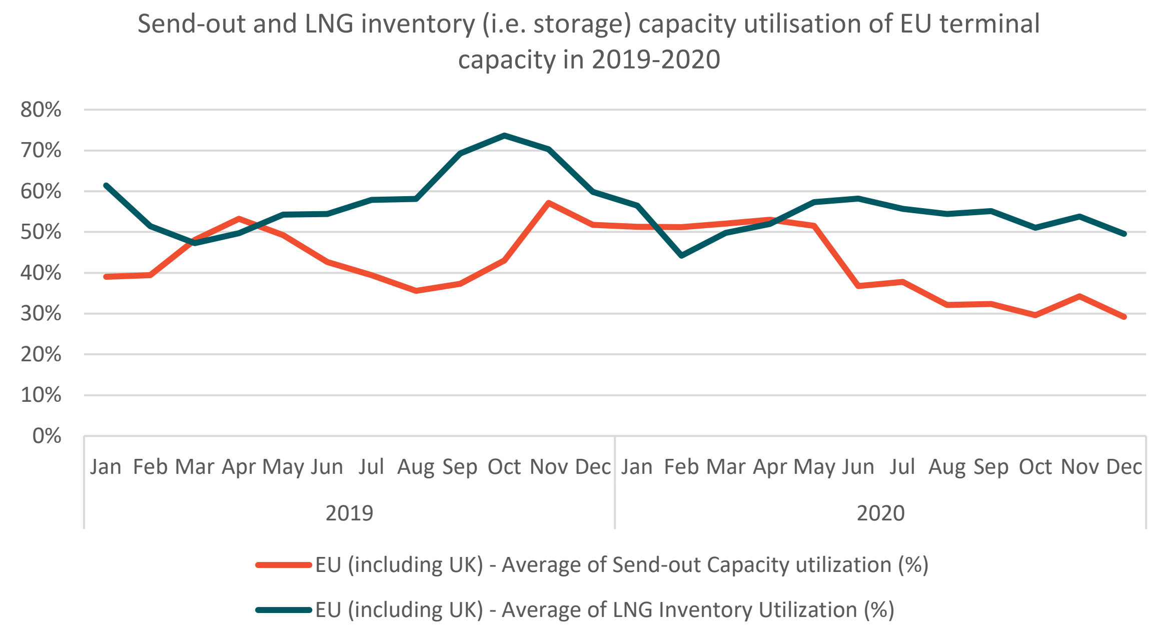


Figure 2-20: Average utilisation rates of LNG send-out and storage capacities in Europe. Source: (GIE, 2021b).

This low utilisation reflects a potential problem of terminal illiquidity when prices for LNG are lower than for gas being imported through pipelines. In these cases, the LNG terminals' utilisation rate should increase quickly, but historical data shows that this shift does not necessarily materialise as expected. Also, during continuous periods where LNG was cheaper than pipeline gas, LNG terminals were not used at full capacity, which may be related to the existence of long-term supply contracts for pipeline gas with a take-or-pay clause. For instance, in Spain during January and March 2018 the LNG spot prices plus regasification costs[52] were lower than the natural gas prices (cf. Figure 2-21), but the utilisation rate of the Spanish LNG terminals was mostly below 50% during this period (cf. Figure 2-22). In Europe, such situations occurred for nine LNG terminals in the past 3 years.[53]

[52] The regasification costs considered in the analysis relied on the data from (Trinomics; REKK; enquidity, 2020).

[53] The results of the detailed analysis may be found in Annex xxx.

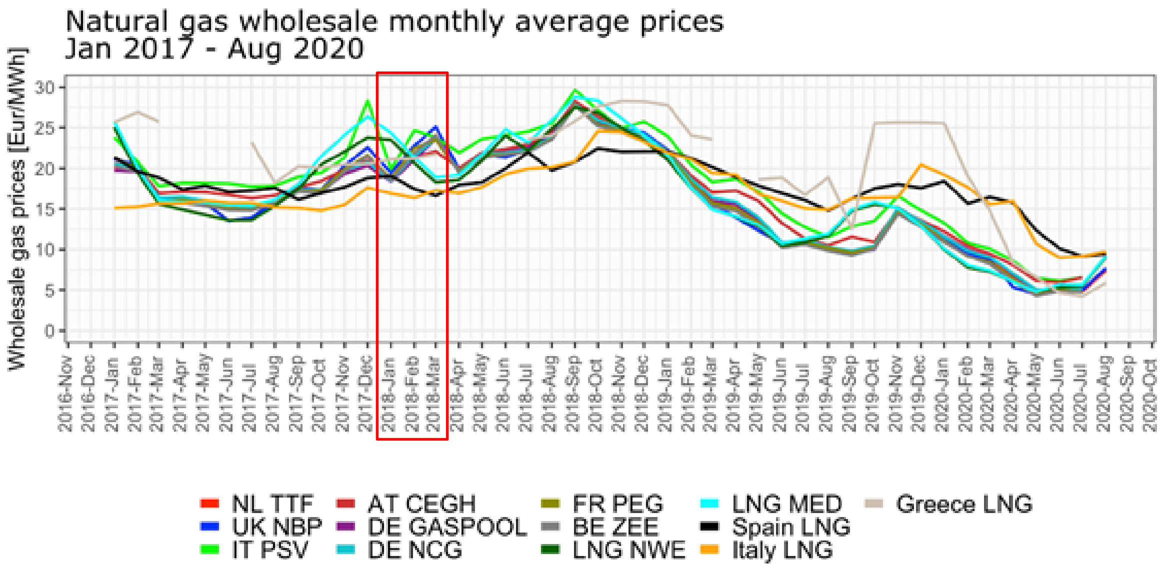


Figure 2-21: Monthly natural gas wholesale prices, January 2017 - August 2020. Source: (IHS Markit, 2021; European Commission, 2021c).

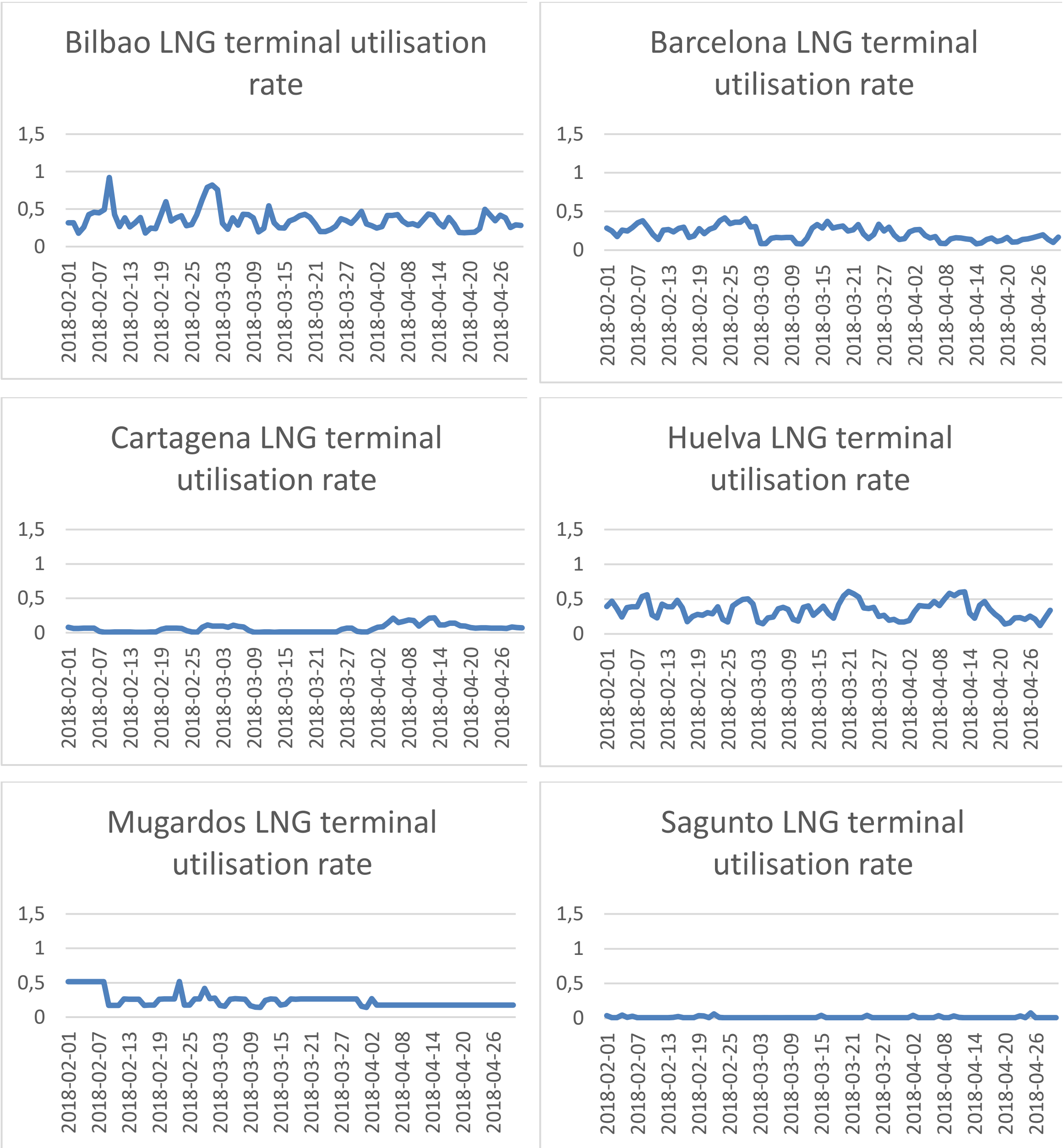


Figure 2-22: Utilisation rate of the Spanish LNG terminals, January 2018-April 2018. Source: own calculations based on data from (GIE, 2021b).

In addition to the before mentioned factors, a low utilisation level may also be explained by long-term primary capacity bookings in combination with rather inadequate rules and instruments for secondary capacity allocation (making booked but unused LNG terminal capacities available to competing market participants), as required under Article 22 of the Gas Market Directive. In addition, some LSOs do not maximise the utilisation of their terminal via use-it-or-lose-it (UILOI) or use-it-or-sell-it (UIOSI) operations. Ultimately, capacity allocation mechanisms are not necessarily market-based, thus providing misleading market signals.[54]

[54] (Trinomics; REKK; enquidity, 2020)

The low utilisation of send-out capacities may also **affect the EU's strategy of decarbonising** the natural gas system in Europe. Even if today's LNG facilities are primarily used for the import of natural gas from third countries, they could act in the future as facilitators for the import of renewable and low-carbon gases into Europe. In the future, it might also become interesting to transport liquefied gases, including renewable and low-carbon gases, between European LNG terminals by ship, thereby further integrating the European gas market. Several services are offered at LNG terminals that enable such intra-EU trade:

- **Reloading:** The liquefied gas is transferred from the LNG terminal storage tank to a ship. This can be done for large-scale ships with a capacity of more than 30 000 m^3, and small-scale ships.
- **Transshipment:** Transferring of LNG between ships. This can be done between ships moored at separate berths (berth-to-berth) or between one ship moored to a berth and the other ship alongside the ship (ship-to-ship).

2.1.6.3 LNG terminals designed to import methane

The possibility and related costs of adapting LNG terminals to transport liquefied renewable and low-carbon gases is a key question to understand the potential role of LNG to support decarbonisation. Biomethane, hydrogen and methanol could all be liquefied and transported using LNG facilities provided some adaptations:

- Regarding **biomethane or synthetic methane**, their properties are similar to natural gas. Therefore, in case the biomethane or synthetic methane meets the gas quality specifications, no changes are needed in LNG terminals.[55] Administrative measures may be needed for shippers regarding the management of guarantees of origin / sustainability certificates as well as guaranteeing the gas meets technical specifications, but no investments or additional O&M are necessary.[56]
- Regarding **hydrogen**, its production from renewable sources by electrolysis of water can also be considered for import, taking advantage of significant power-to-hydrogen capacities abroad (especially some nearby countries like Norway, Morocco and Saudi Arabia[57]). However, technical differences between methane and hydrogen (such as the boiling temperature of hydrogen, lower than the one of methane) do not allow using existing LNG infrastructure as such and require its adaptation. Moreover, the energy density of hydrogen being around 15% of the one of LNG (for a pressure between 350 and 700 bar) the transport costs are likely to be much higher.[56] As the costs for adapting the liquefaction, transport, storage and regasification stages are significant, this could be a barrier to the import of hydrogen.
- Another solution to import hydrogen from non-EU production facilities is to transform hydrogen to **ammonia and methanol** and make use of LNG ships and terminals to transport these energies: their boiling temperatures, -33°C and 65°C, respectively at atmospheric pressure being much higher than those of H_2 and CH_4, the liquefaction, transport, storage and regasification stages can be executed at higher temperatures or lower pressures and the associated costs are smaller for ammonia and methanol than for hydrogen. Thus, synthesizing methanol and ammonia abroad make the import steps easier and less expensive

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[55] (Frontier Economics, 2020)

[56] (GIE; GLE, 2020)

[57] (Frontier Economics, 2018)

than importing hydrogen. However, in the absence of current demand for these energy carriers, the development of new uses is still to be studied.

As some options for using LNG infrastructure to transport low-carbon gases sound promising, a continuous effort to remove regulatory barriers is required. Addressing the residual barriers and market failures on the EU LNG (gas) market will enhance the liquidity, transparency and flexibility in the internal gas market and ensure an efficient usage of infrastructure, and may support the decarbonisation of the EU gas market.

2.2 Problem 2: Current national network planning does not fully facilitate the transition towards an integrated, low-carbon energy system

Network planning requirements were included in the Third Energy Package[58] in particular to ensure that non-ownership unbundled transmission system operators (TSOs) do not underinvest.

The Energy System Integration Strategy[59] sets out that "Energy system integration – the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors – is the pathway towards an effective, affordable and deep decarbonisation of the European economy in line with the Paris Agreement and the UN's 2030 Agenda for Sustainable Development".

Hence, the focus of network planning practices has to shift from avoiding underinvestment to avoiding uncoordinated non-future-proof investments in network elements for a specific energy carrier, towards coordinated and effective network planning to achieve decarbonisation while limiting the risks for lock-in effects and stranded assets.

Currently, in 20 out of 27 EU MSs the preparation of national gas network development plans (NDPs) is energy carrier-specific (cf. Figure 2-23 and Figure 2-24). Moreover, the NDPs strongly differ with respect to their geographical coverage, their frequency of publication, their legal nature, their process timeline etc. This hinders a coordinated planning between Member States and a harmonised integration of NDPs in the preparation of the EU-wide TYNDP.

Hence, there is a deficient consideration of energy system integration in the current network planning approaches. At the EU-level, the ENTSOs collaborate on a joint scenario development, and are working towards a joint cost-benefit analysis methodology for specific projects[60].

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[58] (European Commission, 2009a)

[59] (European Commission, 2020g)

[60] (Artelys, 2019)

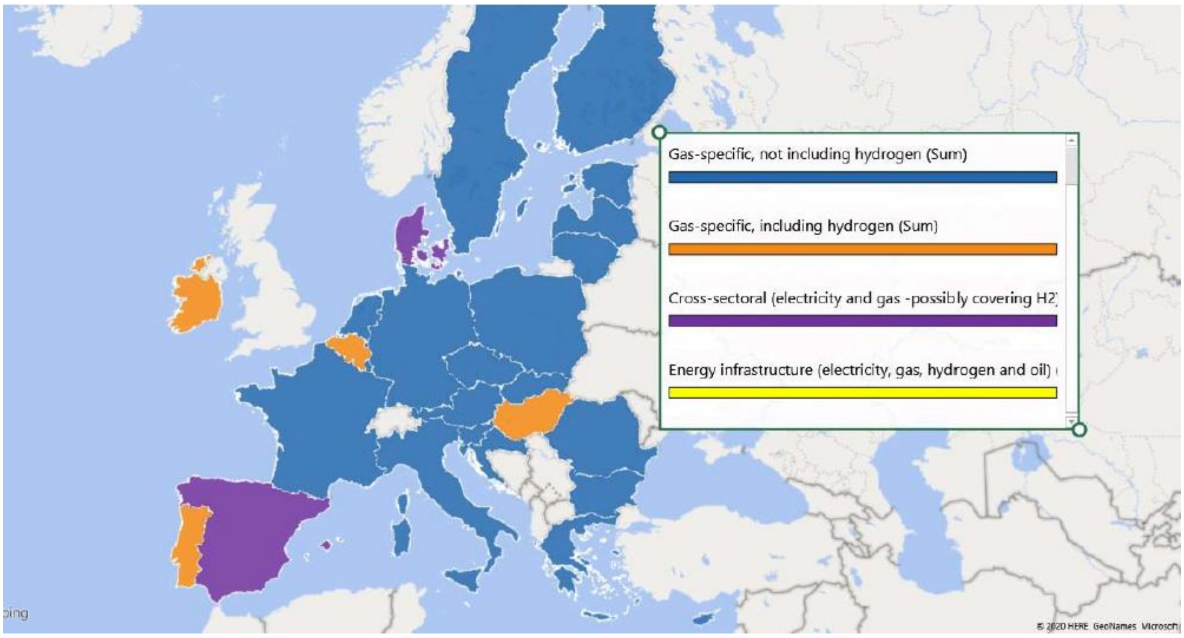

Figure 2-23: Scope of NDPs. Source: (ACER, 2020b).

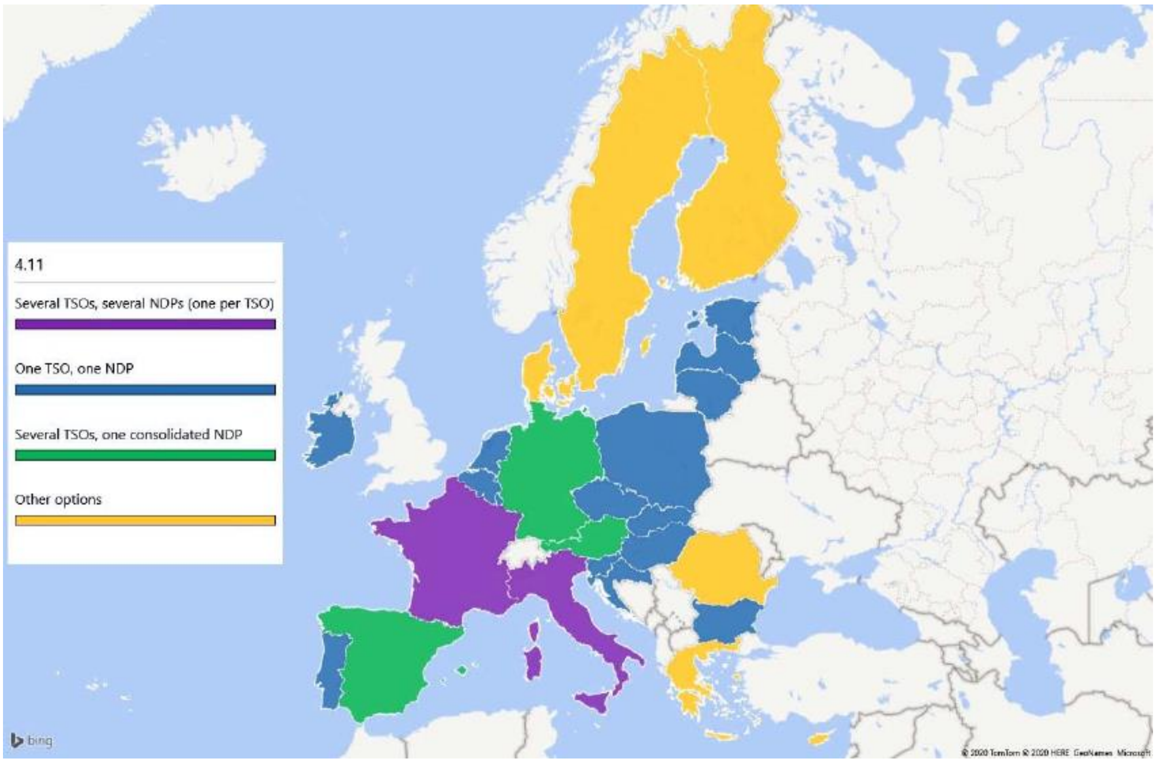

Figure 2-24: Number of NDPs per MS. Source: (ACER, 2020b).

2.2.1 Context

2.2.1.1 The future energy system will be increasingly integrated

According to the scenarios developed in the Long-Term Strategy and the Climate Target Plan, and the accompanying strategies (mainly the European Commission's Sector Integration Strategy and the Hydrogen Strategy), interlinkages between energy carriers and sectors of the economy will significantly increase on the pathway towards 2050, as the transition from fossil fuels to decarbonised fuels and renewable energy sources materialises. The 2050 energy system will involve decarbonised versions of the current energy carriers, such as heat, gas and electricity, and new energy carriers will appear. Hydrogen will likely be key in achieving a fast and cost-effective energy transition, as it helps to increase the penetration of renewable energy sources and decarbonise hard-to-abate sectors of the economy. The energy supply mix will change drastically, driven by the uptake of renewable energy sources and low-carbon gases to decarbonise end-uses.

Overall, many of the energy technologies and infrastructures can further optimise their contribution to decarbonisation when development plans are integrated, allowing the best use of available resources, reducing the risk of stranded assets, and providing the best information base for (potential) investors.

According to the Long-Term Strategy scenario 1.5TECH, electricity will represent half of 2050 EU final energy demand (compared to 22% in 2015), while hydrogen will represent 10% of final energy demand (around 800 TWh), e-gas 7%, and biomass (including biogas and biomethane) 14%. Natural gas is the only fossil fuel remaining, yet limited to 2% of total final demand, while other fossil fuels are completely phased-out.

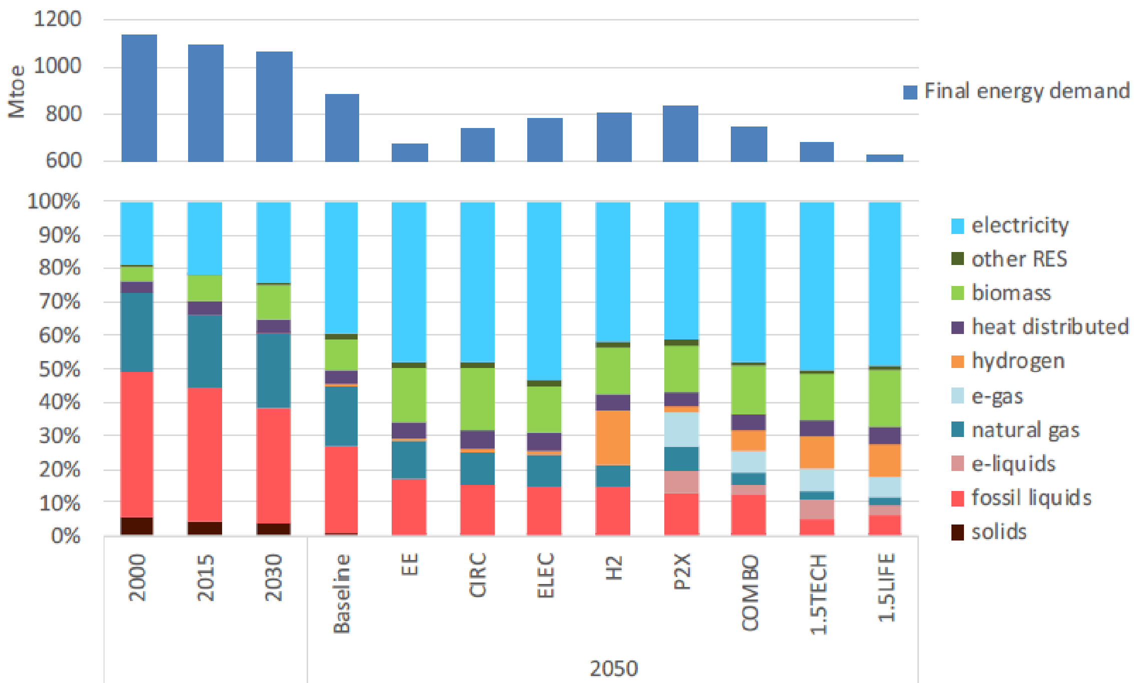

Figure 2-25: Share of energy carriers in final energy consumption. Source: (European Commission, 2018a).

This diversified energy supply mix relies on strong interlinkages between the energy carriers. Hydrogen production by electrolysis increases electricity demand to 7500 TWh, the largest share of it being dedicated to hydrogen generation (3500 TWh). Part of the hydrogen generated is further converted along the P2X chain, resulting in 523 TWh of e-gas and 473 TWh of e-liquids. In addition to synthetic methane, gas consumption is met with 827 TWh of biogas and biomethane and 721 TWh of natural gas.

Hydrogen also takes an active role as an energy storage solution (also called "chemical storage") as 105 TWh of hydrogen are generated at times of abundant electricity supply and later used to run hydrogen-fired power plants. In the 1.5TECH scenario, e-gas does not prove to be an economically interesting solution for chemical storage, however under other scenarios of the LTS it would reach 60 TWh (P2X scenario).

Table 2-4: Consumption per sector for some energy sources according to the 1.5TECH scenario. Source: (European Commission, 2018a).

Consumption (TWh)	Natural Gas	Biogas	e-gas	Hydrogen	e-liquids
Non-energy	174	-	-	-	-
Power	361	558	-	105	-
Industry	47	116	128	337	-
Buildings	81	81	256	81	-
Transport	47	70	140	372	473
Total	**721**	**826**	**523**	**896**	**473**

These energy carriers are used at different levels in intermediate applications and end-use sectors (e-liquids are exclusively used in the transportation sector), and are all linked together in a unique system, which converts electricity into hydrogen, a portion of which being further converted into e-gases (power-to-gas), while allowing both hydrogen and biogas to be converted back into electricity (gas-to-power), consequently translating these synergies between energy carriers into a cost-efficient decarbonisation of the European economy.

Given the strong level of integration between energy carriers and sectors, the planning of the energy system should be adapted to ensure synergies and interdependencies are appropriately reflected and taken into account when assessing the evolution of the role of the energy infrastructure. Planning the evolution with one energy carrier-specific focus would not allow for flexibilities between carriers to be appropriately reflected (from e.g., the flexibility of gas-/hydrogen-fired power generation, flexibility of electrolysers, flexibility of hybrid heat pumps) and the associated benefits to be identified. At present, most of the national practices related to the development of development plans are still focusing on a single energy carrier.

2.2.1.2 General overview of current national development plans

At present, national plans face some limitations that restrict their ability to identify benefits related to the interlinkages between energy carriers and their role in creating a cost-effective integrated energy system. These limitations may result from a lack of communication between stakeholders, missing consideration of some parts of the energy system, and low integration with other EU actors.

National plans are at present in most cases prepared for individual parts of the energy system in a siloed approach. Even if the majority of the gas TSOs appear to acknowledge the benefits of considering planning assumptions of the electricity system within their scenario-building process, there are no joint development plans in most countries, therefore not properly valuing the potential synergies between energy carriers and the uptake of system integration.

Most gas and electricity NDPs miss detailed information on hydrogen infrastructure, and are limited to some indicative investment plans. District heating is often out of the scope of current NDPs, as is also often the case for planned or potential CO_2 networks. Consequently, their integration into the planning assumptions is limited.

Development plans are in general limited to the transmission system, with some DSOs being involved in the scenario-building process. Yet the uptake of renewable gases may increase reverse flows from distribution to transmission grids and consequently require the direct participation of DSOs in the design of national development plans. Similarly, except when the LNG terminals and storages are operated by the TSO, development plans often disregard storage or other assets.

Furthermore, current plans are not prepared in a coordinated and harmonised manner across the EU. Commonly, the scenarios are set up in the context of the energy transition in Europe and national energy policy priorities, in line with the NECPs. Most NDPs also foresee an (explicit) linkage to the TYNDP scenario framework which also ensures an implicit linkage to EU policy goals. However, in a narrower perspective, deviations from the latest energy and climate policy targets are still structurally possible.

Sometimes, this lack of coordination and harmonisation is also reflected within a Member State, where several TSOs are active and do not set up efforts to consolidate their national development plans into a single one. Such a lack of coordination limits their ability to plan for a cost-efficient energy system.

Finally, national plans do not necessarily consider the integration of low-carbon/renewable energy carriers through the selection of appropriate projects. The NDPs do in general also not include information on a dedicated sustainability indicator specifically linked to project selection, and the sustainability criteria are only captured through the dimension of the cost benefit and risk assessment, or scenario framework.

2.2.1.3 Opportunities at risk

Given the limited integration between the different energy infrastructure plans, they may compromise the development of the required infrastructure to cost-efficiently meet the decarbonisation target. As such, the development of energy vector specific national plans that consider only fragments of an interconnected energy system put at risk the achievement of 2030 Climate Target Plan objectives and on a longer perspective the 2050 decarbonisation target.

The lack of overall coordination between the different parts of the energy system infrastructure in setting a national scenario and strategy, and the lack of building a joint plan that properly reflects the interlinkages between the different energy carriers translates into sub-optimal planning and in potentially inefficient investments. Interlinkages provide synergies allowing to reach the targets with a reduced level of investments, without compromising security of supply. These synergies can only appear when the energy infrastructure is considered as a whole in the national development plans.

2.2.2 Driver 2.1: Current infrastructure development plans do not properly account for the complementarity of energy carriers

2.2.2.1 Expected evolution

Traditionally, each system operator prepared its own network development plan owing to a set of varied factors. First, due to limited interlinkages between the energy sectors (notably electricity and gas), planning activities for each sector could be conducted relatively autonomously without a relevant risk to ignore any essential opportunity to generate synergies.

This has led to different planning practices in each sector. There were also methodological barriers to (quantitative) sector-integrated planning approaches, as analytical tools to model both sectors at sufficiently high granularity only became available quite recently thanks to enhanced computation performance, energy system modelling techniques, data availability and mathematical approaches to solve complex problems[61].

Recently, the interlinkages between the electricity and gas sectors have received more attention, which is also reflected in a shift towards more integrated planning approaches. A prominent example is the joint scenario development of ENTSOG and ENTSO-E that underpin their respective TYNDPs.

Integrated energy systems rely on the coupling between energy carriers to achieve a cost-effective decarbonisation. To avoid curtailment electricity can be converted in hydrogen and its derivatives (e-gas and e-liquids) while gaseous fuels provide flexibility to the power system when needed, either on the supply side for peak generation or on the demand side as substitutes to electricity consumption for some end-uses, notably heat supply. Hybrid assets such as hybrid heat pumps may alleviate the constraints of the infrastructure by switching from electricity to gas at times of peak electricity demand.

The share of hydrogen and biomethane in final energy demand will become increasingly important. These energy carriers will make use of the existing infrastructure, either for biomethane injection and transport or for hydrogen by blending or by repurposing some underused sections of the network.

The proposal on updated guidelines for trans-European energy infrastructure puts forward that TEN-E will include dedicated new and repurposed hydrogen networks with cross border relevance and power-to-gas facilities above a certain threshold with cross-border relevance.

2.2.2.2 How NDPs across the EU treat at present the topic

The majority of gas TSOs appear to acknowledge the benefits of at least considering planning assumptions of the electricity system, within their scenario-building process. Most gas TSOs either conduct a fully integrated assessment of the gas and power systems or at least consider in their future gas demand scenarios the expected developments for the electricity system.

Hydrogen having emerged only recently as a potential solution for decarbonising end-uses, and being expected to play a role in the late 2030s, its consideration in the current plans is limited. With the exception of Italy, detailed information related to hydrogen infrastructure could not be retrieved from the plans. However, most plans provide some sort of indicative investment plan or future concept or make reference to infrastructure delineated in external studies. According to the ACER report[62], hydrogen is covered in the NDPs of Belgium, Denmark, France and Ireland.

Furthermore, some plans only consist of a partial picture of the infrastructure, as gas assets that are operated in a non-regulated way are occasionally treated on a different footing compared to regulated assets.

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[61] (Bødal, 2020)

[62] (ACER, 2020b)

2.2.3 Driver 2.2: Limited cooperation between DSOs/TSOs in network planning

2.2.3.1 Expected future evolution

The increased level of integration between energy carriers and sectors also involves different infrastructure levels: decentralised production of biomethane and renewable electricity, is likely to also occur significantly at the distribution level, leading to increased need for TSO-DSO cooperation in the planning processes (e.g., to consider reverse flow assets).

Furthermore, decreasing levels of gas demand are expected in the future, notably in the residential and tertiary sectors due to enhanced building insulation and electrification of heat provision. This evolution of the demand should encourage enhanced TSO/DSO coordination as these demand levels are mainly connected to distribution grids. In the residential sector, the gas consumption for space heating is expect to fall by 42% by 2030 compared to 2015 (cf. Table 2-5).

Table 2-5: Gas consumption in buildings for space heating, according to the MIX H2 scenario. Source: European Commission.

Gas consumption (TWh)	**2015**	**2030**
Residential	680	393
Tertiary	370	260
Total	**1050**	**653**

The rising injection level of biomethane requires an intensified DSO/TSO cooperation, as biomethane is substantially injected at the distribution grid level (see Section 2.1.2). According to Table 2-6, around 46% of biomethane volumes are injected at the distribution level. In combination with the previous effect, reverse flows become more likely in the medium- to long-term perspective, implying a more dynamic exchange of gas flows between the distribution and the transmission grid levels. Consequently, this could also impact capacity requirements at the transmission level.

Table 2-6: Annual production capacity of biomethane plants per network connection level (TWh). Source: (EBA; GIE, 2021).

Country	No grid connection	Connection not specified	Injection in distribution grid	Injection in transmission grid	Total
Austria	0.01		0.25		0.26
Belgium			0.01		0.01
Denmark	0.01		1.54		1.55
Estonia	0.01		0.05		0.06
France	0.05	0.10	1.78	0.48	2.42
Germany		3.75	1.92	5.32	10.99
Hungary				0.06	0.07
Ireland			0.03		0.03
Italy	0.03		0.18	1.32	1.53
Luxembourg		0.06			0.06
Spain			0.00	0.08	0.09
Sweden	2.52		0.73	0.27	3.53
Netherlands	0.08	2.02			2.10
Total	2.72	5.93	6.50	7.54	22.69

In the near future, local industrial clusters may be the first-movers in developing hydrogen infrastructure. They would potentially rely on decentralised and local hydrogen injection, while transmission grids might be operated with e.g., lower blending shares or via separated infrastructure (see Section 2.1.5).

2.2.3.2 How NDPs across the EU treat at present the topic

Direct DSO participation in scenario-building exercises is explicitly mentioned in Denmark, France, Ireland and the Netherlands. In Germany the applicable national law states that DSOs shall cooperate and feed information on all relevant matters into the NDP creation process. For most of the NDPs in the other MSs, exchange or consultation with DSOs are considered, but no dedicated role for the DSOs is explicitly mentioned. Yet in countries like Czech Republic, Germany and Italy, which count 73, 717 and 250 DSOs respectively, the coordination cost may be significant (cf. Table 2-7). It should be noted that they have in general a national association that can coordinate these interactions.

Table 2-7: Number of DSOs per Member State in 2018. Source: (CEER, Implementation of TSO and DSO Unbundling Provisions – Update and Clean Energy Package Outlook, 2019).

Country	Number of DSOs	Number of DSOs with <100 000 customers
Austria	20	14
Belgium	14	3
Bulgaria	25	25
Croatia	35	33
Cyprus	0	0
Czechia	73	70
Denmark	3	1
Estonia	24	24
Finland	9	9
France	25	22
Germany	717	692
Greece	3	1
Hungary	10	5
Ireland	1	0
Italy	250	Approx. 240
Latvia	1	0
Lithuania	5	3
Luxembourg	3	2
Malta	0	0
Netherlands	8	2
Poland	54	52
Portugal	11	7
Romania	49	49
Slovakia	1	0
Slovenia	15	15
Spain	18	8
Sweden	6	6
Total	**1 380**	**1 043**

2.2.4 Driver 2.3: NDPs do not necessarily facilitate the integration of renewable/low-carbon fuels via sustainability indicators

2.2.4.1 Expected future evolution

Low-carbon and renewable energy carriers are not expected to follow the same structure of flows as does natural gas. Whereas natural gas is mainly supplied through extra-European pipelines and LNG terminals, and from a few domestic sources with declining production, biomethane and low-carbon gases supply is rather domestic, and significantly decentralised at the DSO level (see 2.2.3 and Table 2-6).

2.2.4.2 How NDPs across the EU treat at present the topic

Information on a dedicated sustainability indicator, which would help in selecting projects facilitating the integration of renewable and low-carbon gases, cannot be retrieved from the NDPs. However, in a more implicit way almost all plans encompass some sort of sustainability criteria, most commonly taken into account through a dimension of the cost benefit and risk assessment or the scenario framework. Ireland has for instance implemented a green gas certificate scheme, which comes closest to a specific sustainability indicator, though outside the scope of the NDP.

2.2.5 Driver 2.4: Current national planning of transmission systems happens in an uncoordinated manner

2.2.5.1 Expected evolution

The establishment of national gas development plans (NDP) is governed by Directive (EU) 2009/73. Article 22 tasks the TSOs to submit a ten-year network development plan related to the development of the transmission infrastructure to the competent regulatory authority.

The interactions TSOs have to establish with storage operators and LNG terminal operators, as well as with other TSOs, when developing their NDPs are limited to taking reasonable assumptions into account, as can be read from Article 22(3):

When elaborating the ten-year network development plan, the transmission system operator shall make reasonable assumptions about the evolution of the production, supply, consumption and exchanges with other countries, taking into account investment plans for regional and Community-wide networks, as well as investment plans for storage and LNG regasification facilities.

While there is no coordination mechanism related to network development plans between these different entities foreseen in Directive (EU) 2009/73, an obligation to cooperate is introduced in Regulation (EU) 715/2009. More specifically, Article 12 mentions that TSOs shall, among other obligations, establish regional cooperation within ENTSOG to contribute to the publication of the ENTSOG TYNDP, and publish regional investment plans every second year.

To meet this obligation, TSOs have formed regional groupings that are developing biennial regional investment plans known as "GRIPS" (Gas Regional Investment Plans):

- GRIP North-West
- GRIP South
- GRIP CEE
- GRIP BEMIP
- GRIP Southern Corridor
- GRIP South-North Corridor

The latest plans are available on ENTSOG's website[63]. A first assessment shows that they are of unequal level of detail: while some include lists of projects and the result of their assessment, other are limiting the scope to presenting initiatives TSOs are involved in.

Finally, TSOs are also cooperating in the context of the Regional Groups established under Regulation (EU) 347/2013, together with representatives of Member States, NRAs, ACER and the EC. However, this coordination does not structurally lead to network development plans being better coordinated.

In the future, when the revised proposal for the TEN-E Regulation will have been adopted, electricity TSOs may have to cooperate to establish sea-basin level integrated network development plan. The current version of the proposal does not foresee any role for gas or hydrogen TSOs in that process however.

In summary, there are limited obligations to coordinate network development plans across several dimensions:

- Between gas system operators: cooperation between TSOs, SSOs and LSOs within a country could be reinforced to guarantee that all gas system operators establish consistent development plans.
- Between countries: while cooperation is enshrined in the rules mentioned above, they do not result in a joint network development plan but rather in biennial exercises that are of unequal levels of depth across regions.
- Between energy vectors: while ENTSO-E and ENTSOG cooperate to establish common scenarios and are working on a joint CBA methodology, national-level processes are in general not yet coordinated, which can lead to inefficient planning practices, especially if investment plans are based on inconsistent visions of the evolution of the national systems and CBAs fail to recognise the interlinkages between the power and gas sectors, which are expected to increase in the coming decades.,

2.2.5.2 How NDPs across the EU treat at present the topic

The three main national gas systems having multiple TSOs are Germany, France and Italy. For the case of gas TSOs in Germany, the integration in planning is the current practice. For Italy, a formal obligation to publish a coordinated document co-authored by the various TSOs is enforced. This includes inter-alia the coordination on the methods for the evaluation of investment options via cost-benefit analyses, with a common methodology, selection of input parameters, and reference values to be used. For France, the two TSOs collaborate to build common scenarios, but there is no obligation to develop a common NDP.

2.2.6 Driver 2.5: Absence of explicit reference to national (or EU) energy and climate targets in NDPs

2.2.6.1 Expected evolution

In order to get on the path towards becoming a climate-neutral economy by 2050, as defined in the Paris Agreement pledge and developed in the Long-Term Strategy[64], the EU has set itself energy and climate targets for 2030. These targets have been enforced

[63] https://www.entsog.eu/gas-regional-investment-plans-grips

[64] (European Commission, 2018a)

as part of the "Clean energy for all Europeans package", including the Renewable Energy Directive[65] and the Energy Efficiency Directive[66].

As part of the European Green Deal[67], the Commission proposed in September 2020 in its 2030 Climate Target Plan[68] (CTP) to increase the greenhouse gas emission reduction target to 55%. The proposal has been accepted by the European Parliament and will be enforced in new legislation in July 2021, including the revision of the renewable energy and energy efficiency targets in the respective Directives to more ambitious levels. According to the CTP Impact Assessment[69], the RES-share will reach "between 37.5% to 39%, final energy savings between 36% to 36.5% and primary energy savings between 39% to 40%".

The Regulation on the Governance of the Energy Union and Climate Action[70] has been set up by the EU to ensure planning, monitoring and reporting of progress towards its 2030 climate and energy targets and its commitments under the Paris Agreement. The Governance Regulation requires for Member States to submit National Energy and Climate Plans (NECPs) in which they detail the policies that put them on track to meet the targets defined at the EU-level over ten-year periods. NECPs were finalised in 2019 and as per Articles 14(1) and 14(2) of the Governance Regulation, are to be updated by 2023 (draft update) and 2024 (final update) in light of the increased climate and energy ambitions.

In light of the climate ambition targets and the evolving policy framework, national development plans need to be consistent with the overall policy framework and energy and climate targets. The risk for TSOs and DSOs is to set investment decision-making processes based on outdated assumptions, which would not reflect the required pace in terms of decarbonisation, energy efficiency and roll-out of renewable energy sources. Infrastructure investments based on assumptions that are not aligned with the EU targets could compromise meeting these targets both at the MS and EU-level, or could increase the cost of meeting them.

In order to ensure that network investments are made on the appropriate basis, TSOs and DSOs need to consider the EU targets/scenarios and the national targets/NECPs in their scenario building process, at least for one of the scenarios.

With respect to targets defined at the EU-level, currently the sum of NECPs is not ambitious enough to reach the EU goal[71]. In addition, the NECP revision in light of the newly agreed ambition only occurs by 2024. Consequently, the NDP scenario has both to be fully consistent with the NECP (or feature a higher ambition level), but also to be compatible with the targets defined at the EU and national level.

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[65] (European Commission, 2018b)

[66] (European Commission, 2018c)

[67] (European Commission, 2019a)

[68] (European Commission, 2020e)

[69] (European Commission, 2020d)

[70] (European Commission, 2018d)

[71] (European Commission, 2020c)

2.2.6.2 How NDPs across the EU treat at present the topic

Most NDPs are not aligned to EU or often national decarbonisation targets as they were developed or published before the National Energy and Climate Plans were made available. However, commonly the scenarios are set up in the context of the energy transition in Europe and national energy policy priorities. Certain NDPs also foresee an (explicit) linkage to the TYNDP scenario framework which also ensures an implicit linkage to EU policy goals. However, in a narrower perspective, deviation from the latest energy policy targets is still possible. For instance, in the case of the German NDP stakeholders have stipulated the assumptions' regarding gas consumption could be outdated and could overestimate the future gas consumption in light of the more recent energy policy developments. The NDPs of Greece, Ireland and Italy include reference to a dedicated NECP scenario.

2.2.7 Driver 2.6: Insufficient involvement of all concerned stakeholders

2.2.7.1 Expected future evolution

Deployment of renewable energy generation implies large infrastructure needs both on land and on sea, and this deployment may be hindered by limited public acceptance. Beyond the increased cost borne by final consumers on their bills for renewables support, locally, citizens can be concerned by the visual and noise impacts of renewable and grid installations, which may directly depreciate property value in their neighbourhood. Rising acceptance issues put at risk the actual implementation of infrastructure projects and ultimately the achievement of decarbonisation targets.

The energy transition involves a rising number of players. Decentralised energy producers, like energy communities, want to seize a larger role in the development of their energy infrastructure. Only 4 000 of them were established by 2019, but it is estimated that 50% of households could belong to an energy community by 2050[72]. Rising consumer empowerment has to be reflected in setting the national development plans.

2.2.7.2 How NDPs across the EU treat at present the topic

Comprehensive stakeholder consultation processes are in place in the majority of Member States. Information on a stakeholder process were not retrieved for Belgium, Denmark and Lithuania. However, according to the ACER report Denmark and Lithuania do carry out a public stakeholder consultation. In Belgium relevant stakeholders are consulted informally. A distinguishing feature of the consultation process is the fact that TSOs and NRAs have different roles in setting and following up the process and also their interaction in this regard. In general, the ACER report reveals that quite some heterogeneity is still existing as regards the specific types of stakeholders consulted in each Member State. A further harmonisation could be needed.

[72] (JRC, 2020)

3 WHAT ARE THE AVAILABLE POLICY OPTIONS?

In order to facilitate the injection of renewable and low-carbon gases in methane gas networks, it will be necessary to provide a level-playing field for these gases vis-à-vis natural gas. Therefore, the options considered aim to remove any barriers for the deployment of renewable and low-carbon gases related to the connection at the TSO or DSO levels, lack of access to wholesale markets, gas quality issues, the technical suitability and availability of LNG terminals to receive such gases, and long-term gas supply contracts.

In addition, integrated planning practices at all levels will be needed in order to ensure the achievement of energy and climate policy objectives at the lowest cost while maintaining security of energy supply. Therefore, the options considered here also include measures to increase the level of planning integration at the national level.

In this section, a business-as-usual Option 0 as well as five high-level policy options which combine individual policy measures are presented. Option 0 is presented in Section 3.1, while the five policy options are presented in Section 3.2.

3.1 What is the baseline from which options are assessed?

In Option 0 – business-as-usual, none of the EU-level policy measures for the problem areas are in place. This may lead to barriers regarding the integration of renewable and low-carbon methane gases and blended hydrogen (due to lack of a level playing field, barriers to inject into the TSO/DSO grids or to access wholesale markets, gas quality issues and the capacity of LNG to receive these gases). Option 0 would also lead to a more fragmented infrastructure planning at the national level (between TSO and DSO levels, between energy carriers and regarding the involvement of LNG terminals operators, storage operators and network users, among others). Table 3-1 presents the main characteristics of Option 0, which is further described below.

Table 3-1: 2030 Option 0 characteristics

Category	Criteria	Option 0
Renewable and low-carbon gas access	Biomethane potential	Issues related to TSO-DSO coordination, connection and market access limit exploitation of the biomethane potential. A majority of the biogas production is not upgraded to biomethane in the EU for economic reasons and in some case existing regulatory barriers, although countries exhibit different patterns.
	Biomethane	Deceleration to below 15% CAGR observed in 2017-2019 (5% CAGR in 2020-2030 leads to approx. 44 TWh in 2030[73]). A large majority of biomethane is injected in gas grids.
	Of which at TSO/DSO level	Same as currently, with equal distribution of production capacity connected to each level (with possibly a slightly larger share to the DSO level). A majority of producers are connected at the DSO level but have a lower average capacity than at the TSO-connected producers. A reduced use of energy crops for biomethane production may lead to a lower share of plants connected at the TSO level.
	Blended hydrogen	No significant volumes of hydrogen blended in methane gas grids. Some small projects may be connected in a few Member States.
	Synthetic methane	No significant volumes of synthetic methane injected in methane gas grids. Some small projects may be connected in a few Member States.
Gas imports	Natural gas	Moderate decrease in natural gas imports at EU level reflecting overall reduction in natural gas consumption.
	Synthetic methane	

[73] Actual deployment levels may vary substantially, although a CAGR lower than 15% could be expected.

Category	Criteria	Option 0
	Biomethane	Not significant, any volumes imported do not require any adaptation of pipelines / LNG terminals
Gas transport	EU cross-border gas trade	Cross-border gas trade decreases resulting from the overall reduction in gas consumption
	Utilisation of gas pipeline infrastructure	Utilisation of pipelines decreases resulting from the overall reduction in gas consumption
	LNG inflows / terminal utilisation	Moderate decrease to stable utilisation of LNG terminals utilisation reflecting lower gas demand.
	Seasonal gas storage	Reduced utilisation, repurposing or decommissioning of some storage facilities resulting from the overall reduction in gas consumption.
	Reverse flows to TSO network	TSO-DSO coordination issues and lack of harmonised rules for developing reverse flow leads to country-specific developments
	Need for de-odorisation	Not significant
Gas demand	Sectoral gas demand	Stable compared to MIX H2. In case reduced biomethane supply slightly impacts demand, this would affect especially methane gas demand in the built environment.

While in Option 0 no further legislative measures at the EU level would be adopted, new developments would arise from the measures foreseen in the 3rd energy package (full implementation of current network codes and development of new ones), from the process for developing or amending network codes and guidelines, legislative initiatives by Member States, and voluntary cooperation at the regional and national levels. Particularly the changes in the national regulatory frameworks and voluntary cooperation might address some of the policy barriers in the gas sector.

Concerning the **problem of constrained access of renewable and low carbon gases to gas TSO and DSO networks and markets**, the need for improvements regarding TSO-DSO coordination, and lack of obligations for network operators to connect gas producers in some Member States could negatively affect the deployment of renewable and low-carbon gases, especially in Member States where such mechanisms are not yet in place. For example, an enabling regulatory framework is established in France mandating TSO-DSO coordination and establishing a clear process for the connection of biomethane producers and allocation of the costs, including of necessary reverse flow installations or meshing of distribution networks (when economically reasonable). However, TSO-DSO coordination rules on connection requests are absent in around half of the Member States at least.

In several Member States an obligation to connect exists, but this is still an issue in PL, PT, SK and SE, although some Member States may be working in this direction.[74] As of 2020 only 7 Member States had significant biomethane development (AT, DK, FR, DE, IT, and NL, with SE having a high biomethane production, but with many plants not connected to the gas network).[75] Their experience could support other Member States to develop such a connection obligation framework through exchange of best practices, but, without initiative at EU level, it is likely that by 2030 a regulatory patchwork would still exist regarding connection obligations and TSO-DSO coordination measures.

Access to wholesale markets for biomethane producers may also still be restricted in some Member States. Currently in several Member States, DSO-connected biomethane producers do not have access to wholesale markets (e.g. SI, EL, RO, LV, HU, HR). This may not be currently a barrier as several of these Member States do not have yet any biomethane producers connected to their networks (or have developed ad-hoc solutions

[74] (ACER, 2020a)

[75] (EBA; GIE, 2021)

for the few existing ones), but it may constitute a barrier for future producers. For countries where DSO-connected producers already have access to wholesale markets, various solutions exist. The balancing zone may for example be defined to include distribution networks or on the contrary be limited to the transmission level (with DSOs, suppliers or other parties being responsible to forecast and pay for DSO-level residual imbalances). In the latter case, DSO-connected producers may still have access to wholesale markets (e.g. through virtual arrangements) even if they are not directly responsible for imbalances. However, even if such measures exist, different solutions can be applied per Member State with varying effectiveness regarding ensuring a level access to renewable and low-carbon gases. Moreover, even in countries where entry-exit or balancing zones include the DSO level, the lack of reverse flow capacity (where no obligation is in place for network operators to provide such capacity) will most likely constrain production and trade once the sector further develops.

The market and network access integration challenges are expected to also apply to hydrogen producers that intend to inject hydrogen in methane networks. Given the lack of experience with hydrogen blending in most Member States (in 2020, mostly FR and DE have pilot projects blending hydrogen)[76], even if network and market access issues are addressed for biomethane in certain Member States, there is the risk that such regulations and procedures may not apply to hydrogen blending in some countries. Anyhow, hydrogen blending in methane networks would not be significant by 2030 in Option 0 (and policy options as well) as it would be more valuable for direct utilisation in the industry and transport sectors. Therefore, this would not represent a barrier except for eventual individual hydrogen blending projects in Member States where hydrogen injection is not yet allowed or in case hydrogen injection volumes would by 2030 significantly exceed the volumes considered under the present scenarios.

The lack of connection cost incentives (i.e. shallow allocation to renewable and low-carbon gas producers, with socialisation of network reinforcement costs) reflecting the sustainability and security of supply benefits may reduce the deployment of biomethane. Even if connection costs only represent a modest share of total biomethane production costs, this could still have an impact on the economic feasibility.

Different injection charges are applied in the EU. Biomethane producers do not pay injection charges in e.g. France (as long as network reinforcement for reverse flows or meshing of distribution networks is not necessary) or Germany. The existing German charge for biomethane remunerates renewable gas producers (comprising biomethane but also power-to-gas) and is set at 7 €/MWh.[77] While in practice acting as a feed-in tariff, it is implemented as a 'reverse' network charge. But in many other countries, renewable and low-carbon gas producers pay similar injection charges as natural gas producers (e.g. Italy). Without some harmonisation at the EU level, it is likely the situation persists in 2030, with renewable and low-carbon gas producers facing different connection and injection costs across the EU, thereby resulting to an unequal playing field.

Cross-border gas trade would decrease resulting from the overall reduction in gas consumption unless lower biomethane production volumes are compensated by higher natural gas imports (yet impacts on specific interconnection points would depend on regional developments). Tariffs at intra-EU interconnection points would still be applied, in the current range of 0.15-2 EUR/MWh (commodity-based equivalent tariffs), except in integrated balancing zones, such as is currently the case for FI-EE-LV, DK-SE and BE-LU markets. By 2030, additional mergers of balancing zones could occur, but non-marginal tariffs would still be in place for most intra-EU interconnection points.

[76] (IEA, 2020b)

[77] (BNetzA, 2020)

Also, for the **problem of constrained access of renewable and low carbon gases due to gas quality issues**, no further legislation at the EU level would be developed in Option 0. Cross-border management of gas quality and information sharing would rely on existing procedures defined in the interoperability and data exchange network code. The EN 16726 standard would be revised to include entry and exit bandwidths for the Wobbe Index following the conclusion of on-going work. Other EN standards could be revised or developed relating to hydrogen production and gas infrastructure & end-use.[78] However, these standards would remain non-binding unless specific Member States adopt them.

Therefore, the definition of acceptable hydrogen blending levels and other relevant aspects (such as acceptable variations of hydrogen concentrations) at cross-border interconnection points and in national transmission or distribution networks would be left to Member States. Currently, interconnection agreements may not provide specifications regarding hydrogen concentrations, although ENTSOG's interconnection agreement guidance example mentions a limit of 1.5%vol.[79]

Revising interconnection agreements to define acceptable hydrogen blending levels would require first a national assessment of acceptable levels, including discussions and pilots with network users to understand their actual tolerances and constraints. While a few Member States and network operators are more advanced in understanding these aspects (e.g. DE, FR), it is assumed in Option 0 that, by 2030 only a few interconnection agreements would have been revised to define mutually acceptable hydrogen levels. However, as hydrogen blending would not be significant in Option 0 by 2030 according to the MIX H2 scenario, this would not have a negative impact on the gas market integration, unless some Member States actually chose to develop hydrogen blending by then.

Regarding biomethane, the main gas quality issue would be oxygen concentrations, which might affect underground gas storages and a few sensitive industrial users. Due to the biomethane network and market access barriers listed above, the deployment of biomethane would in Option 0 decelerate compared to current growth rates. Moreover, the EN 16726 standard allows oxygen concentrations of up to 1% if there are no sensitive network users such as underground gas storages. Additional measures could be taken by individual network operators to manage gas quality, e.g. by mixing gas with lower oxygen content or gas quality management at sensitive storage or end-user points (e.g. by purification). Thus, oxygen concentration levels might be an issue only for certain system points (e.g. close to underground gas storages) which would require tailored solutions at the national level or by individual actors.

On **LNG terminals**, maintaining the current EU regulatory framework in Option 0 implies that some barriers to development of the LNG market identified in Trinomics et al. (2020) would not be addressed.[80] Network bottlenecks impacting gas market access for some LNG terminals would be resolved by 2030, as NRAs and TSOs are working towards it with the development of the gas infrastructure. However, addressing other barriers would depend on national authorities and the development of the LNG market, including:

- Terminal capacity allocation: lack of short-term capacity accessible in primary markets and reallocation of unused capacity;
- Transparency: lack of transparency and harmonised principles on tariff structures and levels that restrict the comparison between terminal rates and

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[78] (CEN - CENELEC, 2019)

[79] (ENTSOG, 2016)

[80] (Trinomics; REKK; enquidity, 2020)

affects the market development. Uneven information provision by terminals to all potential users in a non-discriminatory manner;

- Flexible services: need for development of unbundled (or bundled if needed by the market) services and more flexibility in contracted products.

It can be expected that voluntary initiatives by the LNG sector would address some of these issues. Removing barriers in the LNG sector can have a positive impact on the utilisation rate of the terminals and the competition in the gas market. Measures addressing some of the barriers above could increase LNG imports with around 100 to 250 TWh/y between 2025 and 2030, compared to the reference scenarios of the LNG terminals regulatory framework study[80] (EU27 LNG inflow amounted to 1 173 TWh[81]). The reliance on national and voluntary initiatives to address barriers in the LNG sector would have more moderate effects on terminal utilisation, tariffs and total LNG inflows.

The possibility to provide network entry tariffs discounts to LNG terminals would remain, and thus existing discounts to terminals would in principle also remain. HR, GR, IE, LT and PL provide entry tariff discounts to LNG terminals.[82] Current entry tariffs for LNG are deemed low and are not seen as a barrier for the development of LNG in the EU.[83]

In Option 0, LNG imports could remain restricted to natural gas, although no adaptation of LNG terminals would be necessary in case competitive biomethane or synthetic methane from non-EU sources were available. IEA data[84] indicates the global biomethane export potential is estimated at 8084 TWh in 2018, rising to 9731 TWh in 2040. Import costs to the EU in 2020 range between €12/MWh and €98/MWh, and in 2040 are estimated in the range of €13/MWh and €70/MWh, depending on the region from which the biomethane would be imported and other variables. Therefore, significant biomethane volumes could be available to the EU, especially at prices as of €30/MWh. However, the remaining barriers to efficiently utilising LNG terminal capacities as tariff pancaking as described in Section 2.1.4, would still form barriers to biomethane imports, and put it at a disadvantage to other gas sources.

No further EU-level legislation would be developed regarding **network planning.** Some Member States, national regulators and/or network operators may adopt additional measures regarding use of common electricity and gas scenarios, inclusion of hydrogen and heat networks and other aspects such as involvement of distribution networks, LNG terminals and gas storage operators, but it is likely that national situations regarding integrated network planning will be diverse.

While most Member States have currently a single gas NDP (with the exception of FR and IT), there is still limited cooperation between electricity and gas TSOs in planning, and also limited participation of gas DSOs. In Option 0, this situation is likely to change only slowly by 2030, given the complexities in developing e.g. common scenarios, which may require several NDP iterations.

Regarding other planning aspects such as the assessment of infrastructure decommissioning needs, the use of sustainability indicators to avoid investing in unsustainable infrastructure and the scenario alignment with the National Energy and Climate Plan (NECP) and/or National Long-Term Strategy (LTS), these would also depend on national initiative. The development of NDPs with a scenario aligned to the NECP/LTS is likely to be more common practice, as some NDPs already contain such scenarios (e.g. in NL) and as the NECP/LTS naturally provide policy guidance which can

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[81] (Eurostat, 2020)

[82] (ACER, 2020c)

[83] (Trinomics; REKK; enquidity, 2020).

[84] (IEA, 2020d)

be used by TSOs and DSOs in planning processes. Hence, multiple and even a majority of NDPs could have at least one scenario aligned to national energy policy targets. However, as NDP processes generally do not address pipeline decommissioning nor include a sustainability indicator, by 2030 these practices should be in place in some Member States at most.

Therefore, in Option 0, biomethane would develop on average below recent growth rates, as increased biomethane development may be restricted in some Member States by non-existing or inadequate regulation or technical specifications. The 15% CAGR (compound annual growth rate) observed in 2017-2019 would be difficult to sustain. A lower 5% CAGR would lead to a biomethane volume of around 44 TWh in 2030. Currently, 54% of the biomethane production capacity is connected at the transmission level.[85] In Option 0, by 2030 the proportion of biomethane injected at each network level might remain roughly the same, although if energy crop-based plants reduce their output due to e.g. phasing out of subsidies in Germany, this could lead to a reduction in the capacity connected to the transmission level.

Hydrogen blending would in Option 0 not be impacted compared to the MIX H2 scenario, as there is no significant blending in the latter due to the lack of specific policies. Some blending might occur in specific pilot systems. In Option 0 and also in the MIX H2 scenario, the injection of synthetic methane would not be significant in 2030.

Compared to the MIX H2 scenario, fossil gas consumption could in Option 0 increase slightly to compensate for the reduced biomethane production. Biomethane production could amount to a rough estimation of around 44 TWh, or around 2-3% of gross gas supply. If natural gas does fill in the biomethane production gap, this would lead to a slight increase in total greenhouse gas emissions of the EU energy system. However, if the target decarbonisation level of 55% compared to 1990 emissions is to be maintained, this would require a greater electrification of the EU energy system using renewable and low-carbon sources, further imports of renewable and low-carbon gases, and/or increased energy efficiency by 2030, although a slight increase in emissions is more likely.

3.2 Description of the policy options for Problem 1

This section describes five policy options for addressing Problem 1, each composed of a combination of individual policy measures and addressing the problems identified in Section 2 to different extents.

Following an analysis of the coherence of each of the options regarding potential synergies and conflicts between the contained individual policy measures, the following policy options were defined:

- **Option 1 - allow RES gases full market access**: Maintenance of the existing gas market model, with improvements to provide a level playing field in market access for renewable and low-carbon gases (compared to natural gas), promote a reinforced cooperation between Member States regarding gas quality, and incentivise voluntary initiatives for transparency on access to LNG terminals;
- **Option 2 - allow and promote RES gases full market access**: Maintenance of the existing gas market model, with some improvements in addition to Option 1, especially to promote renewable and low-carbon gases, and avoid gas quality issues due to hydrogen blending;
- **Option 3 - allow and promote RES gases full market access, tackle issue of long-term supply natural gas contracts and removal of cross border tariffs for RES gases:** Similar to Option 2, with the addition of requirements

[85] (EBA, GIE, 2020)

for LNG terminals (and gas storage) operators, limits on long-term gas supply contracts, in order to facilitate further the development of renewable and low-carbon gases, and elimination of intra-EU cross-border transmission tariffs for renewable and low-carbon gases;

- **Option 4 - allow and promote full RES gases market access, tackle issue of long-term supply natural gas contracts, EU standards for gas quality and removal of cross border tariffs for all gases**: Modification of the current gas market model by eliminating intra-EU cross-border tariffs for all methane gases (with implementation of an inter-TSO compensation mechanism and recovery of missing money from internal exit tariffs), and introduce a maximum EU-wide hydrogen blending level.
- **Option 5 - Incentivising the injection of local renewable and low-carbon gases at the distribution level** : Adoption of measures to facilitate injection of decentralised renewable and low-carbon gases, in particular at the distribution level and focus on local supply and consumption of renewable and low-carbon gases, while the methane gas market might become fragmented (at least in certain Member States or regions), with limited or no reverse flows;

The five policy options represent coherent regulatory interventions at the EU level which vary in the following dimensions:

- The application of measures further promoting a level playing field to gas and broader energy market participants (especially network and market access to renewable and low-carbon gas producers);
- The existence of measures promoting renewable and low-carbon gases, to address remaining barriers to a level playing field and reflect positive climate and system externalities of these gases;
- The application of intra-EU cross-border transmission tariffs to certain or all methane gases;
- The application of measures to impose additional limits to long-term natural gas supply contracts;
- The level of integration of the methane gas market (i.e. centralised markets vs local supply and consumption).

Table 3-2 indicates how the policy options relate to the three dimensions indicated above.

Table 3-2: Main dimensions for definition of the four options

	Option 1	Option 2	Option 3	Option 4	Option 5
Further promoting a level playing field	✓	✓	✓	✓	
Promoting renewable and low-carbon gases		✓	✓	✓	✓
Elimination of cross-border tariffs			To renewable and low-carbon gases	To all methane gases	
Limits to long-term gas supply contracts			✓	✓	
Integration of the methane gas market	Integrated	Integrated	Integrated	Highly integrated	Local

Each sub-section below describes one of the policy options regarding the individual measures included, the expected high-level impacts on the gas sector, and the extent to which the problems defined in Section 2 are expected to be addressed by 2030 due to the introduction of the policy measures. Table 3-3 presents an overview of the impacts of the options on the gas sector, while the description of the specific policy measures is presented in Sections 3.3 and 3.4.

Table 3-3: Characteristics of options in 2030 regarding methane gases and blended hydrogen

Criteria		Option 1	Option 2	Option 3	Option 4	Option 5
Renewable and low-carbon gas access	Biomethane potential	Elimination of some barriers (on TSO-DSO coordination, market participation of distribution-connected producers) lead to potential similar or close to MIX H2	Elimination of barriers and new incentives to renewable and low-carbon gases lead to economic potential equal or higher than MIX H2			Local market nature and repurposing (or, less likely, decommissioning) of some methane networks lead to lower economic potential
	Biomethane production	MIX H2 level achievable, the majority of which is injected. Minor issues may arise in the few MSs which do not have connection obligations in place yet.	High level achievable, reaching the MIX H2 level or more (upgrading a larger share of the biogas produced)			High growth achievable for biomethane-based MS/networks, but EU volumes lower than MIX H2
	Of which at TSO/DSO level	Increased importance of distribution level given costs advantages, compared to currently more balanced T/D split in capacity terms.				
	Blended hydrogen	Not significant if MIX H2 materialises, but blending could take place in (clusters of) Member States.				
	Synthetic methane	Not significant				
Gas imports	Natural gas (by pipeline or LNG terminals)	Same as MIX H2		Same as MIX H2. Limits on long-term gas supply contracts could facilitate biomethane/other renewable and low-carbon gases to replace part of NG imports.		Lower than MIX H2 for MSs deploying renewable/low-carbon gases at local level and/or with relevant decrease in gas demand, same for other MSs
	Biomethane	Biomethane imports possible, given LNG terminals are suitable with no/little modifications, but depend on renewable energy policies of the EU, Member States as well as the strategies of potential exporting countries.		Biomethane imports possible, given LNG terminals are suitable with no/little modifications, but depend on renewable energy policies of the EU, Member States as well as the strategies of potential exporting countries. Removal of tariff pancaking may provide additional incentive.		Very limited and MS-specific, depending on whether national transmission system is maintained, converted to H2, or (less likely) decommissioned
	Synthetic methane	Not significant or marginal / not requiring any adaptation of pipelines or LNG terminals				
Gas infrastructure	EU cross-border gas trade	Increased gas trade compared to Option 0, with eventual minor restrictions	Increased gas trade compared to Option 0, with no restrictions due to gas quality, even if blending occurs in certain clusters of Member States.			Reduced cross-border natural gas trade and limited/non-existent cross-

Criteria		Option 1	Option 2	Option 3	Option 4	Option 5
		due to O2 content. If blending occurs in certain MSs, some fragmentation of the internal gas market in clusters can occur.				border trade of renewable and low-carbon gases
	Utilisation of gas pipeline infrastructure	Improved utilisation compared to Option 0 due increased reverse flow of renewable/low-carbon gas volumes, and gas quality coordination.				Eventual repurposing to hydrogen of some networks leads to similar/lower utilisation for remaining gas infrastructure.
	LNG inflows / terminal utilisation	Similar inflows compared to Option 0 or small increase (< 100 TWh/y) due to industry-led initiatives, displacing pipeline imports.	Moderate increase (100-200 TWh/y) due to specific rules, displacing pipeline imports.		Moderate increase (100-200 TWh/y). Entry tariff discount removal not expected to negatively impact inflows significantly	Limited increase (<50 TWh/y), focused on specific MSs which maintain the role of the methane gas transmission system.
	Seasonal gas storage	Reduced utilisation / decommissioning of some storage facilities accompanying the overall reduction in gas consumption				Decommissioning / conversion to hydrogen in regions where methane is phased out
	Reverse flows to TSO network	Obligations lead to multiple reverse flow projects in countries with significant biomethane development, as long as MS/network operators develop procedures for connection.	Obligations lead to multiple reverse flow projects in countries with significant biomethane development			Limited need for reverse flow
	Need for de-odorisation	Not significant				
Gas demand	Sectoral demand	Methane gas demand similar to MIX H2, given increases in biomethane production are modest to total gas demand, and (partially) displace fossil gas consumption. Eventual higher gas prices due to biomethane or hydrogen deployment could reduce total gas demand, but not necessarily to a significant extent.				Equal to MIX H2 in Member States where methane maintains its role, decreased consumption for countries with a strong hydrogen target for 2030 already or relying on other solutions, e.g. stronger electrification.

3.2.1 Description of Option 1

Aiming to **facilitate the level-playing field to renewable and low-carbon gases**, in **Option 1** a requirement would be in place for Member States to define entry-exit zones including the distribution level and requiring network operators to ensure physical reverse flow capabilities when required would be in place. Also, reinforced cross-border coordination and transparency on gas quality and national blending levels would be implemented. Finally, industry-led initiatives to enable LNG terminals to receive renewable and low-carbon gases would be incentivised.

As a consequence of the adopted measures, in Option 1 barriers in some Member States related to the access of biomethane to wholesale markets are resolved, which allows a greater exploitation of the biomethane potential compared to Option 0. However, the lack of measures to facilitate the connection of biomethane or harmonising the (exemption of) injection tariffs to biomethane and other gases still constitutes a (minor) barrier. Most Member States have or should have by 2030 connection obligation rules in place, but the allocation approach for connection and injection costs should still differ per Member State.

A deployment somewhat close to the MIX H2 scenario can be expected. The increased integration of biomethane leads to a higher proportion of plants being connected at the distribution level where possible, avoiding the higher costs to compress to high pressures, with reverse flow facilities in place where needed. This can be compounded by the phasing-out of energy crops as a feedstock for biomethane production (especially in Germany) if no new support schemes which include the feedstock are introduced.

A framework for cooperation around gas quality may facilitate punctual hydrogen blending close to interconnection points (but there would by 2030 be no significant hydrogen blending at the EU level under the MIX H2 scenario). Therefore, the EU wide high-level principles could allow some projects for hydrogen blending at the transmission level close to system borders. However, overall impacts on reducing emissions from the EU energy system by 2030 in this case would be very limited.

However, if higher hydrogen blending levels are achieved in certain (groups of) Member States, the framework for cooperation would facilitate cross-border gas exchanges and avoid a significant fragmentation of the internal gas market, although the lack of EU-wide acceptance levels would mean that flow constraints could arise between different clusters of Member States. Depending on blending levels, deblending facilities may be needed for sensitive network users when alternative solutions such as adaptation of processes is not possible. Moreover, the cooperation framework could have an impact in enabling eventual investment decisions for the period after 2030. The cooperation framework would lead to administrative costs especially for TSOs to implement the required processes in coordination with neighbouring TSOs, and for ACER and/or NRAs to monitor the arrangements.

As only very limited adaptation costs are needed for LNG terminals and pipelines to receive/transport biomethane, the levels of biomethane will depend strongly on other factors such as renewable energy policies and measures taken by non-EU countries to develop their export capacities. Given the high production costs, synthetic methane imports are not expected by 2030, even if LNG terminals and pipelines are able to accommodate it without adaptation cost.

Current network entry tariffs for LNG terminals do not represent a barrier, with five Member States providing discounts as allowed by the TAR network code.[86] Therefore, if discounts were removed in order to eliminate potential distortion of competition with

[86] (Trinomics; REKK; enquidity, 2020)

pipeline imports (as in the green gases integrated market option), no significant impacts on LNG inflows would be expected.

In Option 1**,** there is increased gas trade compared to Option 0. Biomethane volumes are higher due to the elimination of some barriers to the deployment of biomethane. Moreover, there is improved coordination of gas quality issues, better addressing eventual barriers to cross-border trade due to oxygen concentrations issues arising from biomethane injection which could affect sensitive storages and end-users. All these aspects should lead to a better utilisation of methane infrastructure (pipelines, storage and LNG terminals) compared to Option 0. Coupled with the reverse flow obligations to network operators, which should lead to multiple reverse flow projects in Member States with significant biomethane development, this should increase the access of renewable and low-carbon gas producers to cross-border markets.

Total and sectoral methane gas demand[87] would be similar to the MIX H2 scenario, as renewable and low-carbon methane gas production volumes would be close to MIX H2, thus allowing the achievement of decarbonisation targets with a similar methane gas demand (eventual higher gas prices due to biomethane or hydrogen deployment could slightly reduce total gas demand). In case incentives to renewable and low-carbon gases lead to a production volume higher than in the MIX H2, this would lead especially to the displacement of fossil gas. Total and sectoral methane gas consumption would also be close (or slightly above) Option 0, as the difference in biomethane production is small compared to total gas consumption in 2030, and the increase in biomethane consumption would displace (at least partially) natural gas.

3.2.2 Description of Option 2

In **Option 2**, the current existing gas market model is maintained, with some improvements, to guarantee a level playing field for renewable and low-carbon gases (as in Option 1) but especially to provide incentives and removing other barriers to renewable and low-carbon gases (reflecting their system and climate benefits).

Compared to the level playing field option, in order to **facilitate the level-playing field to renewable and low-carbon gases** the present option would add an obligation for network operators to connect renewable and low-carbon gas producers (with a firm capacity assurance), and introduce a reduction or exemption of injection charges to those producers in order to reflect the system benefits (i.e. avoided network costs) and climate benefits (reductions in greenhouse gas emissions). EU rules for gas quality with minimum hydrogen cross-border acceptance levels would be in place (as opposed to the less specific principles of the level playing field option). Measures would be in place to increase access to LNG terminals and gas storages, including through improvements in the legal framework for transparency, congestion and market access.

The measures facilitating the connection and injection for biomethane producers in the option lead to a greater deployment of biomethane (achieving levels close to or above that observed in the MIX H2 scenario). While many Member States currently already have such a connection obligation, the EU-wide requirement will lead further ones to establish such obligations, and in addition with a requirement that firm capacity is provided for the injection. As important will be the need to develop clear processes for the connection of biomethane and other gas producer, which should reduce uncertainties for these producers and facilitate investments. Depending on the impact of the reduction or exemption of injection charges adopted per Member State, the biomethane production levels could exceed that of the MIX H2 scenario (with a higher

[87] Pure hydrogen demand changes for e.g. transport and the resulting changes in demand for liquid fossil fuels are out of scope of this analysis.

share of the biogas produced upgraded to biomethane and injected in gas networks). As in Option 1, biomethane plants are increasingly connected to the distribution level, although if sufficient economic incentives are in place for which energy crops qualify, larger biomethane plants can be connected to the transmission level. Otherwise, biomethane plants are connected to the transmission level mostly where distribution networks are limited / non-existent or already saturated, and where meshing distribution networks is not possible.

The rules on gas quality could, as in Option 1, facilitate the injection of biomethane in certain network areas close to intra-EU interconnection points with sensitive gas storages and end-users. However, as these cases should be limited, the difference in impacts between specific rules (as in this option) versus reinforced cross-border coordination on gas quality management and transparency on national hydrogen blending levels (as in Option 1) for the management of gas quality should be limited.

As there is no significant hydrogen blending in the MIX H2 scenario (same as in Option 0) the rules on gas quality and the minimum hydrogen cross-border acceptance levels should have limited impact in that case, although some punctual blending may occur and be facilitated by the measures. However, if hydrogen blending takes place in certain (groups of) Member States, the minimum hydrogen cross-border acceptance levels could lead to substantial benefits by avoiding that different blending levels lead to constraints in gas flows, fragmenting the internal gas market and potentially even leading to security of supply issues for certain Member States. The EU wide common gas quality regulatory framework concerning hydrogen blending would also facilitate any investment decisions for hydrogen blending in the period after 2030. Given the measures to incentivise the injection of renewable and low-carbon gases in the present option, hydrogen blending would in the present option after 2030 be more likely than in the level-playing field option. By requiring Member States, regulators and network operators to have in place processes for managing, overseeing and allocating costs for gas quality management with clear responsibilities and minimum acceptable level for hydrogen blending, the measure could allow for these processes to be refined by 2030 (or earlier) and in this way enable investment decisions for projects being commissioned after that date. However, the actual benefits of the measure concerning hydrogen blending depend on when blending would actually materialise Establishing further cross-border regulatory requirements for gas quality would involve some administrative costs incurred by ACER and ENTSOG as well as by NRAs and TSOs to monitor the implementation of the measures, but if this task is incorporated within current monitoring obligations in the interoperability network code, costs to ACER and ENTSOG would likewise be limited.

Similar positive impacts to Option 1 regarding gas infrastructure utilisation and gas trade characterise the green gas ambition option. But the positive impacts should be slightly stronger due to the increased deployment of biomethane and better coordination and transparency regarding gas quality.

As in the level playing field option, the increased biomethane production compared to Option 0 should displace fully or partially fossil gas consumption, leading to a similar total gas demand and greenhouse gas reductions (eventual higher gas prices due to biomethane or hydrogen deployment could slightly reduce total gas demand). In case demand from gas supplied by networks increases compared to Option 0, emissions could decrease slightly, but the emissions reduction effect would be dampened as part of the additional biomethane produced would actually displace biogas consumed locally, which would instead be upgraded to biomethane.

3.2.3 Description of Option 3

Option 3 builds on Option 2. The difference is that Option 3:

- Includes a requirement for LNG terminals (and gas storage) operators to conduct a market test/screening and create development plans every two years for on their suitability to accept renewable and low-carbon gases, including hydrogen;
- Limits the duration of new long-term supply contracts to 2049 at most and also eliminates the possibility for Member States granting derogations (as defined under Articles 35 and specified under Article 48 of the Gas Market Directive) from the third-party access requirements of Article 32;
- Removes cross-border tariffs from interconnection points within EU for renewable and low-carbon gases, facilitates voluntary regional gas market mergers (Guidance by the Commission), and includes measures for transparency of allowed revenues of network operators and costs benchmarking.

Regarding the promotion of a level-playing field for renewable and low-carbon gases, the requirement for LNG terminals (and gas storage) operators regarding the market test/screening and development plans would lead to a significant change in the volumes of import of those gases by 2030 only in case they are to be competitive with LNG imports in the first place. This would require suppliers (and consequently consumers) to be willing to pay a relatively high guarantees of origin price (which is unlikely), or alternatively for a high carbon price to be in place. Therefore, the impact of the measure would depend on the level of the EU ETS or of existing or future national carbon pricing mechanisms. As the competitiveness of renewable and low-carbon gases is likely to increase beyond 2030, forward-looking market assessments and development plans might allow LNG terminal operators to identify future demand and plan the necessary investments to accept such gases by 2040 or 2050. In any case, these impacts would apply especially if the terminals were to be repurposed for pure hydrogen imports or other derivatives, as the LNG terminals should be able to accept biomethane and synthetic methane with no or very limited modifications.

Still concerning the promotion of a level-playing field for renewable and low-carbon gases, the impacts of the limitation of the duration of new long-term gas supply contracts to 2049 would depend on a number of factors. First, whether existing gas supply contracts are sufficient to meet forecasted gas demand to 2030 and 2050. Considering the demand of the MIX H2 scenario for those years, there is a 'supply gap' which could be filled by renewable and low-carbon gases.

Therefore, the second factor on whether the contract duration limitation would have an impact is whether shippers are expected to sign significant new long-term gas supply contracts with producers. While it is likely that long-term contracted volumes will decrease, some new long-term contracts could be signed which would have a duration of 2050 and beyond, unless the proposed measure prevents this or as long as shippers do not trust EU and national measures to achieve full net decarbonisation by 2050 will largely phase out natural gas consumption. Concerning LNG, most of the medium and long-term gas supply contracts signed in 2019 were destined for Asian markets. One specific LNG supply contract for Poland was signed, with a 2023 expected start and a duration of 20 years.[88] Concerning pipeline imported gas, it must be noted that as the lowest-cost option, Russian gas is able to out-compete other pipeline import sources. In 2017 Gazprom has extended a long-term ship-or-pay transit contract with an EU TSO until 2050,[89] which could facilitate any long-term supply contracts to that year. Therefore, if shippers still see a role for natural gas in 2050, new Russian long-term supply contracts could be signed.

[88] (GIIGNL, 2020)

[89] (Yermakov, 2021)

Hence, the measure to limit the duration of new long-term gas supply contracts to at most 2049 could impact some specific contracts. This would provide some more room for biomethane and other renewable and low-carbon gases to fill in the supply gap, which otherwise would be filled in by these long-term contracts due to take-or-pay clauses.

The measure to remove the possibility of new Member State derogations (as defined under Articles 35 and specified under Article 48) to third-party access requirements of Article 32 could complement the effect of the new gas supply contract duration limit measure by ensuring these new contracts do not limit access from renewable and low-carbon gases to infrastructure. It could also disincentivise further investments in gas infrastructure.

In Option 3, cross-border tariffs for intra-EU interconnection points for renewable and low-carbon gases are removed, with shippers employing guarantees of origin to obtain the tariff exemption from TSOs. The measure could facilitate the exploitation of the least-cost biomethane potentials across the EU and trade between Member States. The impact of the measure will depend on whether gas prices will become the main driver for biomethane production by 2030, or (as is likely) whether support schemes will remain necessary. In the latter case, biomethane trade across the EU would still depend on the opening of support schemes to biomethane producers located in other Member States. If that occurred, the elimination of cross-border tariffs could reduce the level of support needed. The reduction in the levels of support require would be compounded by the more efficient exploitation of the EU biomethane potential (which would likely constitute a more important factor in reducing the LCOE of biomethane). In order to ensure cost recovery for gas TSOs, the lost revenue would be recovered from the remaining gas tariffs, e.g. from intra-EU IP tariffs to natural gas.

The impact of the measures on the deployment of renewable and low-carbon gases compared to Option 2 should be therefore small, especially by 2030, where similar deployment levels as in Option 2 could be expected. Beyond 2030 the impact could be more significant, albeit still modest.

3.2.4 Description of Option 4

Option 4 is largely similar to Option 3 in most aspects and policy measures. However, in the present option the gas market model is significantly upgraded by eliminating intra-EU cross-border tariffs for all methane gases for uncongested interconnection points (with auctions employed to determine tariffs in case of congestion).[90] Internal entry tariffs for renewable and biomethane gases production would also be set to zero. Pipeline tariffs would be determined based on the capacity-weighed distance to a point in the centre of Europe, with entry tariffs for LNG terminals being set to zero (as a variant, non-zero tariffs to LNG terminals could be determined with the same method as for extra-EU interconnection points). The missing money arising from setting intra-EU cross-border and some internal tariffs to zero would be recovered from internal exit tariffs to end-consumers, with an inter-TSO compensation mechanism set-up in order to re-allocate revenues. In Option 4 the duration limit on new long-term gas supply contracts that in Option 3 was set at 2049 would be set at an earlier year.

Moreover, in this option a EU regulatory framework for the management of gas quality employing natural gas as a basis to define acceptable gas quality standards would be in place, along with minimum and maximum hydrogen acceptance levels. As long as the

[90] For storage, tariffs are considered to remain unaltered. Biomethane is supposed to rely on public support and being produced in any case (and at any cost including tariff) in all scenarios. Other renewable gases are not explicitly considered.

gas quality standard employed would allow for a sufficiently wide Wobbe Index entry range comprising also typical biomethane values, this should facilitate the injection of biomethane in methane networks. Moreover, the standard could reduce the cost for production and injection of biomethane in the network, as long as the specification of oxygen concentration levels was not too strict or allowed for higher limits in the absence of sensitive network users (such as gas storage assets).

As for options 2 and 3, the EU-wide minimum hydrogen acceptance level would facilitate hydrogen blending in case this would take place to some extent by 2030, and avoid a fragmentation of the EU internal gas market. The maximum hydrogen blending acceptance level would provide benefits in case an individual Member State with an ambitious blending level would force neighbouring Member States to incur significant costs for adapting their own gas systems.

Alternatively, the EU regulatory framework for the management of gas quality could in the future employ a biomethane-based gas standard. In practice this could mean a lower and wider range for the allowed calorific value and Wobbe index, and higher allowed concentrations for some of the trace components present in biomethane, especially oxygen. This would facilitate the injection of biomethane by reducing the production and injection costs, as costs associated with further purification to reduce oxygen concentration or in some cases to enrich the biomethane would not be necessary. However, a biomethane-based standard could represent a barrier to imports of LNG, as on average LNG supplies have a higher gross calorific value and Wobbe Index than biomethane.[91] In that case, natural gas supply from most EU and non-EU pipeline sources (Algeria, UK and Danish gas in particular can have higher Wobbe Index) might need to be treated to meet the 'new' domestic biomethane-based standard, in case it the Wobbe Index range was not wide enough. There would also be associated costs with making sure infrastructure and network user equipment and appliances were compatible with the new specifications.

As all measures to provide a level playing field / promote renewable and low-carbon gases are the same as in Option 3 (assuming a natural gas-based standard), the present option would lead to a similar level of renewable and low-carbon gases production in the EU. The reconfiguration of biomethane production patterns across Member States would in the present option result in a reconfiguration of cross-border flows. Otherwise, similar effects are observed as in Option 3, such as a potential slight increase in total cross-border flows due to the increased biomethane production compared to Option 0.

The setting of a duration limit on new long-term gas supply contracts to a year before 2049 would have a stronger impact than setting the limit to 2049 as in Option 3. As noted in the description of Option 3, long-term contracts being signed recently (and long-term capacity bookings which can be used to service those contracts) extend to 2043 and afterwards. Setting the duration limit to new gas supply contracts to a year before 2049 is likely to impact more new contracts. This would provide a larger 'supply gap' which could be (partially) met by renewable and low-carbon gases. However, whether renewable and low-carbon gas production would meet this supply gap would depend on other factors which may be more important, such as public support levels or a tangible carbon price.

Option 4 would see similar demand patterns as Option 3.

[91] (ENTSOG, 2020e)

3.2.5 Description of Option 5

Option 5 would not aim at further integration of the internal gas market (although existing measures and future network codes could still promote it). Instead, the expectation of increasing decentralisation of the methane gas sector in the EU means that in the options measures would be adopted to incentivise decentralised renewable and low-carbon gases, which would be injected and consumed locally without relying on integrated markets. In some Member States or regions, the methane gas market could become more fragmented due to the conversion of methane networks to hydrogen, with limited or no reverse flows from the distribution to the transmission level.

Therefore, measures included in the option to **facilitate the level-playing field to renewable and low-carbon gases** would include the obligation for network operators to provide a connection with associated firm capacity to producers, and for Member States to provide exemptions or reductions of injection charges for renewable and low-carbon gases. Moreover, specifically for this option measures facilitating energy communities would be in place, particularly allowing them to supply and trade gas locally, i.e. circumventing established wholesale gas markets. Given further integration of the internal gas market in the option would not necessarily occur, gas quality measures would be limited to reinforced cross-border coordination and transparency on gas quality and national blending levels. Likewise, measures for LNG terminals and storage would be limited. The option for Member States going for a negotiated access for LNG terminals would be introduced (as currently is possible for gas storages), and industry-led initiatives for improving the transparency, access rules, and product flexibility for LNG terminals would be incentivised.

Option 2This leads to decentralised, local green methane gas markets, with strong biomethane development in the remaining methane networks, but limited elsewhere (or with use of liquefied or compressed biomethane for transport with limited or no use of methane networks, as presently in Sweden). Part of the biomethane development at the distribution level is driven by energy communities, enabled by specific policy measures. Therefore, aggregated biomethane production levels are lower than in the MIX H2 scenario, even if specific Member States may achieve or exceed those levels in 2030. New biomethane plants are connected mainly at the DSO level. As for Option 2, the obligation for network operators to provide a connection with firm capacity ensures that in all Member States a procedure for the connection is established and that a connection cannot be refused without justified economic or technical reasons. The lack of an obligation for network operators to provide reverse capacity may restrict the capacity of biomethane that can be connected to distribution networks with low local gas demand. Nonetheless, Member States may still adopt a regulatory framework for planning necessary reverse flow capacity investments. Meshing of distribution networks may also be an alternative to enable the connection of biomethane to these networks. Hydrogen blending is not significant in this option, as when the cost-benefit analysis is favourable, dedicated hydrogen networks are developed instead.

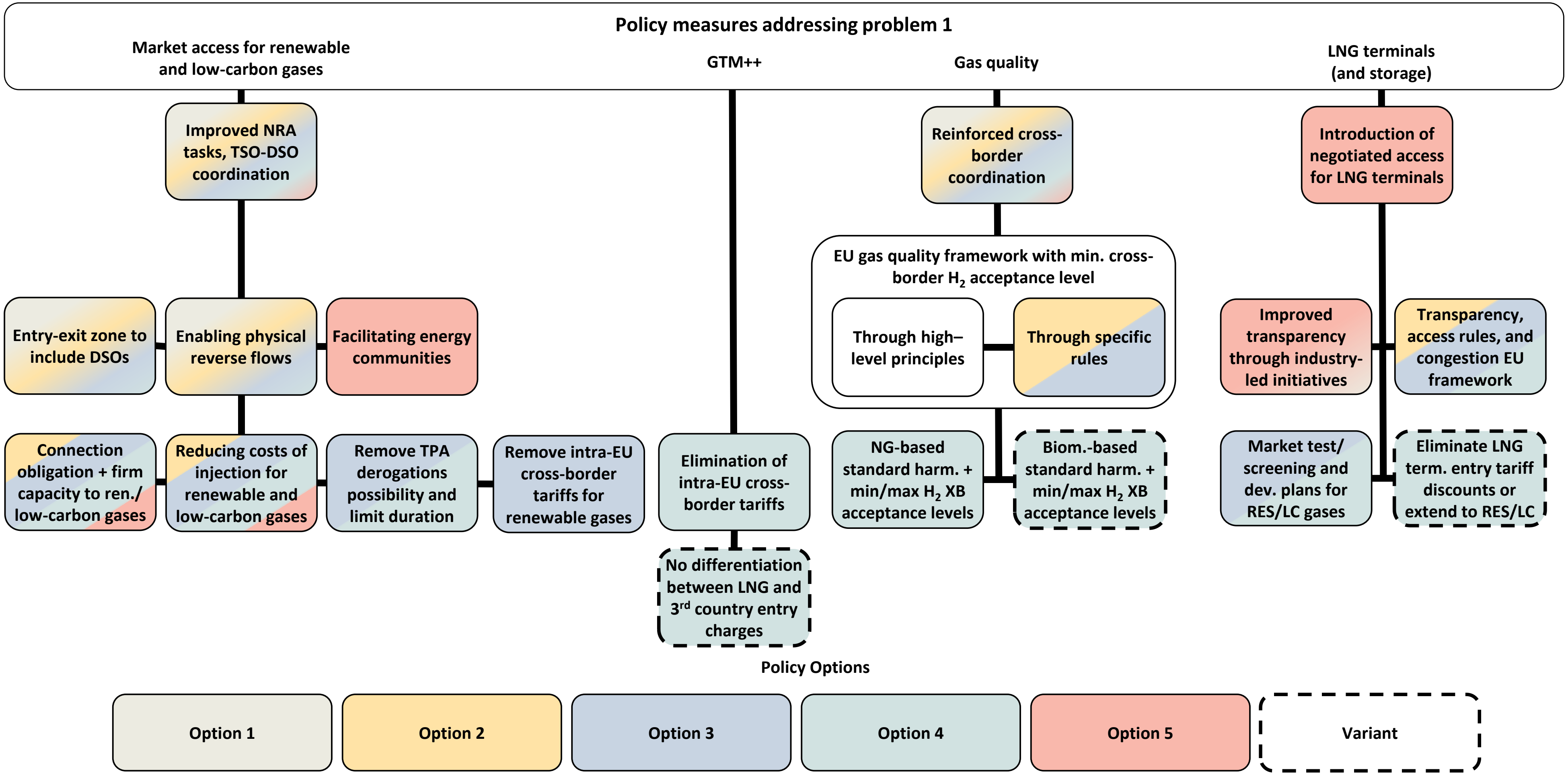
Due to the decentralisation of the methane gas market in the EU, reduced cross-border trade and utilisation of transmission-level methane infrastructure would be observed in countries and regions (partially) converting it to hydrogen (or decommissioning it, although less likely). In countries with a biomethane-focused strategy at the distribution level and maintaining their transmission-level infrastructure for transport of natural gas, limited increases in infrastructure utilisation and LNG inflows would occur, on a case-by-case basis. Except in these cases, reverse flow installations are not deployed. Given the lack of an EU regulatory framework for gas quality with minimum acceptable levels for hydrogen blending, eventual hydrogen blending in the period to or after 2030 could lead to cross-border trade restrictions and a fragmentation of the internal gas market. The framework for cooperation on gas quality would allow cooperating Member States to address some of the trade restrictions, potentially leading to the formation of clusters of Member States. Depending on blending levels, deblending facilities may be needed for sensitive network users when alternative solutions such as adaptation of processes is not possible.

Due to the conversion of methane infrastructure in certain systems under Option 5, a reduction of methane gas demand for certain Member States would occur, which would be compensated by alternatives – mainly electrification, energy efficiency or pure hydrogen / derivatives end-use. This reduction of methane gas demand would impact especially industry if certain sections of the gas transmission system – to which large industrial users are directly connected - are converted to hydrogen. Eventual higher gas prices due to the lower integration of gas markets could further reduce total gas demand.

3.3 Summary of specific measures comprising each option for Problem 1

Figure 3-1 and the tables below overview the specific measures contained in each option for Problem 1. The specific measures for Problem 1 are described in detail in this section, while the measures for addressing Problem 2 are presented in Section 3.4.

Figure 3-1: Overview of policy measures included in each policy option for Problem 1



Notes: Refer to the next sections for a full description of all measures;

Further variants are conducted for the Option 1 to allow the individual assessment of all measures.

Table 3-4: Summary table of measures included in the different options addressing Problem 1

<table>
<tr><th></th><th>Option 0</th><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th><th>Option 5</th></tr>
<tr><td rowspan="8">Market access for renewable and low-carbon gases</td><td rowspan="10">No additional measures</td><td colspan="5">1. Improved NRA tasks, TSO-DSO coordination</td></tr>
<tr><td colspan="4">2 Entry-exit zone to include DSOs</td><td>2.2 Facilitating energy communities</td></tr>
<tr><td colspan="4">2.1 Enabling physical reverse flows</td><td></td></tr>
<tr><td rowspan="2"></td><td colspan="4">3.1 Connection obligation with firm capacity to new renewable and low-carbon gases</td></tr>
<tr><td colspan="4">3.2 Reducing costs of injection for renewable and low-carbon gases</td></tr>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">3.3 Remove TPA derogations possibility for new gas supply contracts and limit duration…</td><td rowspan="2"></td></tr>
<tr><td>…to 2049</td><td>…to year before 2049</td></tr>
<tr><td colspan="2"></td><td>3.4 Remove intra-EU cross-border tariffs for renewable gases only</td><td colspan="2"></td></tr>
<tr><td rowspan="2">GTM++</td><td colspan="3"></td><td>sub3. Removal of tariffs for intra-EU IPs, entry from renewable/low-carbon and from LNG terminals</td><td></td></tr>
<tr><td colspan="3"></td><td>sub3+. Entry tariffs at LNG terminals will be priced on the basis of distance to the middle of the EU (variant)</td><td></td></tr>
</table>

<table>
<tr><th></th><th>Option 0</th><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th><th>Option 5</th></tr>
<tr><td rowspan="3">Gas quality</td><td rowspan="6"></td><td colspan="5">1. Reinforced cross-border coordination and transparency on gas quality and national blending levels</td></tr>
<tr><td></td><td colspan="2">2.2 EU rules for gas quality with minimum H_2 XB acceptance level</td><td>3.1 Natural gas-based quality standards with min/max H_2 XB acceptance levels</td><td></td></tr>
<tr><td colspan="3"></td><td>3.2 Biomethane-based quality standards with min/max H_2 XB acceptance levels (variant)</td><td></td></tr>
<tr><td rowspan="3">LNG terminals (and storage)</td><td>2.1 Industry-led improvement of transparency, access rules, flexibility of product[92]</td><td colspan="3">2.2 Framework for improvement of transparency, access rules, flexibility of product</td><td>1. Introduction of negotiated access for LNG terminals</td></tr>
<tr><td></td><td></td><td colspan="2">3.1 Access to LNG terminals and gas storages for renewable and low-carbon gases</td><td>2.1 Industry-led improvement of transparency, access rules, flexibility of product</td></tr>
<tr><td colspan="3"></td><td>3.2 Removing the entry tariff discount from LNG (variant)</td><td></td></tr>
</table>

[92] The impacts of LNG Measures 2.1 and 2.2 are similar from a modelling perspective and therefore jointly modelled.

3.3.1 Integrating renewable and low-carbon gases into the market

The revision of the Gas Market Directive shall ensure the creation of a level playing field for renewable and low-carbon gases compared to fossil natural gas in order to pave the way for scaling-up these gases as substitute for natural gas. This involves that NRAs facilitate the uptake of green gases, the removal of market barriers and the provision of non-discriminatory grid access.

Via asymmetric regulation, the Gas Directive might create a framework that is favourable for renewable and low-carbon gases compared to fossil ones.

Finally, the revision could drive forward the implementation of a fully integrated, liquid and interoperable EU internal gas market.

Measure 1 requires an **enhanced coordination between DSOs and TSOs** with respect to the integration of production of renewable and low-carbon gases. NRAs shall bear more responsibility in preparing a regulatory framework for market and grid access that favours a level playing field between renewable and low-carbon gases compared to natural gas.

Measure 2.1 aims at providing **access of locally produced RES gases to the central trading hubs** (VTPs). The measure requires the introduction of a definition of the entry-exit system and amending the definition of a "balancing zone" to ensure that gaseous fuels injected at the distribution system level enjoy access to wholesale trading. Ensuring such access should increase marketing options and create a level playing field with gaseous fuels arriving from the transmission level.

Measure 2.2 requires **system operators to enable physical reverse flow** from the distribution to the transmission level. This option requires increased cooperation between producers and system operators at both levels to optimise capacity provision and connection management. To enhance cost-effective solutions reflecting investment and operational costs (cost of connection, reverse flow and consequent tariffication) and well-fare benefits, NRA should be tasked to conduct CBA in line with the integrated network planning approach at case-by-case basis while taking into account production/consumption patterns at the DSO level and undertake investments if other, cheaper decarbonisation options are not in place.

Measure 2.3 aims to transpose the model of **energy communities** to the gas market directive to promote renewable and low-carbon gases and to adapt the gas market rules accordingly to ensure full development of their potential. This should favour the deployment in locations where renewable gases producers may prefer to focus on local supply of gases.

Measure 3.1 obliges system operators to **ensure connection with firm capacity** to new renewable gases production facilities applying for connection.

Under **Measure 3.2**, the **cost of the injection for renewable and low-carbon gases can be reduced** on the basis of avoided network costs from the new production or on the basis of reduced CO_2 emissions based on the technology for production of renewable gas.

Measure 3.3 **removes privileges (derogations**) for new long term natural gas contracts and **limits duration** of such contracts to 2049.

Measure 3.4 **removes cross-border tariffs from interconnection points within EU for RES gases only**. The eligibility would be based on presenting the GOs to the TSO. There would also be measures to facilitate voluntary regional gas market mergers through guidance by the Commission, and measures for transparency of allowed revenues and cost benchmarking of TSOs.

3.3.2 GTM++: Reform of the current entry/exit tariffication system

In order to avoid fragmentation of the gas market and ease trading of domestic renewable and low carbon gases produced within the EU, it is suggested to reform the current tariff system by reducing the regulated tariff at-intra EU interconnection points to zero (or variable cost).

The reform of the current entry/exit tariffication system may be considered as an additional lever to facilitate market and grid access for renewable and low-carbon gases, hence the policy measures are referred to as sub-measures 3 and 3+ of the measures 3.1 to 3.3 introduced in Section 3.3.1. Yet, as they touch upon another mechanism which would have substantial on the natural gas supply chain, too, both sub-measures are addressed separately.

Sub-measure 3 implies that all intra-EU cross-border tariffs are removed. Other points that will be priced at a zero tariff are entry points from renewable/low carbon production and entry points from LNG terminal to the gas grid. Entry-points from third countries will be priced on the basis of distance to the middle of the EU.

Sub-measure 3+ corresponds to Sub-measure 3, but entry tariffs at LNG terminals will be priced on the basis of distance to the middle of the EU, similar to pipeline imports from third countries.

3.3.3 Regulatory framework for the quality of gases (incl. hydrogen blend)

The effective reduction of carbon emissions related to gas utilisation requires that renewable and low-carbon gases may be injected in existing gas systems and that the flow and trade of these blended gases is facilitated, even cross-border.

At the same time, a fully integrated, liquid and interoperable European gas market is a precondition for competitive gas prices.

Thus, European regulation needs to remove gas quality related barriers for renewable and low-carbon gases, reinforce cross-border coordination instruments and enhance system interoperability.

Measure 1 requires **reinforced cross-border coordination and transparency** on national blending levels. This implies the reinforcement of the current cross-border coordination tools, by strengthening the role of NRAs and ACER for cross-border issues and for monitoring gas quality issues, shortening and streamlining the cross-border dispute settlement process. The measure would further oblige Member States to publish national hydrogen blending levels (if any) and to be more transparent on gas quality (incl. blending) situation within the Member States and at IPs.

Measure 2.1 sets out **high-level principles** for process, roles, responsibilities and cost allocation of **gas quality handling**. It further introduces an obligation on Member States to set national hydrogen blending levels in a standardised way, i.e. **minimum level of hydrogen blend** in% by volume to be accepted by system operators and users in the MS concerned (different blending levels for specific infrastructure elements possible). Measure 2.1 further integrates the provision from Measure 1.

Measure 2.2 has the same objective than Measure 2.1, but relies on **specific EU rules** setting the regulatory framework, thus increasing the level of bindingness.

Measure 3.1 introduces, in addition to the provisions under Measure 2.2, a prohibition against the acceptance of blending levels above the maximum cap of hydrogen blends at cross-border IPs. The maximum level is to be agreed upon at the EU level.

Measure 3.2 takes the **gas quality specifications of biomethane** as a basis to defining acceptable gas quality standards. Facilitating the integration of renewable and low-carbon gases may justify treating them more favourable from a regulatory point of view, including with regard to gas quality.

3.3.4 Regulatory framework for LNG terminals

The revision of the Gas Directive shall address existing shortcomings in the LNG terminal regulation and facilitate a more efficient use of LNG infrastructure. Ultimately this benefits the liquidity, transparency and flexibility in the internal gas market and contributes to competitive gas prices in the EU.

In the long-run, efficiently operating LNG terminals may support the EU's decarbonisation efforts. Adapted LNG terminals can play a role in importing renewable and decarbonised gases (such as hydrogen or biomethane).

LNG terminals substantially contribute to the EU's security of gas supply and any new legal measures should enable them to continue to play this role.

Measure 1 provides the option for a **"negotiated" TPA** (similar to storage) to all terminals (MS or NRAs to decide on the model i.e., either negotiated or regulated TPA). It also provides an option for a "negotiated" regime (similar to storage) regime after the exemption expires.

Measure 2.1 introduces **principles concerning transparency about available capacity** and tariffs as well as access rules and flexibility in services offered, **led by industry initiatives** and supported by EU guidance. This would result in better visibility about available capacity also for RES gas producers.

Measure 2.2 has the same scope as Measure 2.1, but sets up a **binding legal framework at the EU level** for transparency, congestion and access rules (secondary trading).

Measure 3.1 requires LSOs (and SSOs) to carry out **market tests/screening** and develop plans (every 2 years) for LNG terminals (and gas storage) on the **acceptance of renewable gases**, including hydrogen.

Measure 3.2 removes the entry tariff discount in favour of LNG fossil gas or extending existing discount also to RES gases.

3.4 Network planning in light of energy system integration

There is a foremost interest to ensure a coherent preparation of single gas NDP in each MS, preferably also involving LSO, SSOs and DSOs. This applies in particular to any Member State where several TSOs are active and prepare each its own NDP. Once this is achieved, it is worthwhile to strive for a more harmonised framework for the preparation of national NDPs in order to increase the consistency between national and European network planning. This includes compliance of NDPs with national and EU climate and energy goals.

Further, national gas NDPs need to properly reflect the increasing interlinkages between the gas sector and other sectors (e.g., injection of synthetic methane, the installation of hybrid energy equipment, such as hybrid heat pumps) as well as other energy carriers (e.g., hydrogen which might be blended into the grid or require the repurposing of existing gas pipelines).

3.4.1 Measures common to all options

There are a number of **elements common to all options**:

- Information on **decommissioning** of methane pipelines

- Inclusion of one or several **indicators dedicated to measuring the sustainability** impacts of candidate infrastructure projects
- **Transparency** and **stakeholder consultation** requirements

3.4.2 Description of Option 1: National Planning

Under **Option 1**, all MSs would have to publish **a single gas NDP** per country, including also gas production, storages and LNG terminals. This should apply to all TSOs, irrespective of the unbundling model or number of TSOs. Moreover, this NDP would have to comply with the elements that are common to all measures listed above.

The option would ensure the single gas NDP considered all gas infrastructure, including potential decommissioning or repurposing to hydrogen. The calculation of a sustainability indicator would help avoid investments, decommissioning or repurposing of gas infrastructure which could lead to lock-ins and compromise the achievement of the EU and national climate targets. Moreover, these decisions at the national level would be better optimised by considering all national gas networks.

The requirements on transparency and stakeholder consultation would allow to better consider in the NDPs technological trends, gas production and demand pathways as well as (potentially) increase the acceptability of gas infrastructure investments. However, as there exists already consultation requirements for the NDP process, the effectiveness of the new requirements would vary per country.

3.4.3 Description of Option 2: National Planning based on European Scenarios

Option 2 defines specific requirements in addition to those common to all options and those included in Option 1, in order to improve the **scenario building**, namely:

- Joint electricity, hydrogen and methane scenarios
- District heating and CO_2 integrated into scenarios
- DSO participation in scenario building
- LSO and SSO participation in scenario building
- Alignment with TYNDP scenarios, anchoring the NDP exercise to EU objectives

Also, NRA would be empowered to require that a market test be performed on the actual need for hydrogen pipelines.

The joint scenario building would significantly improve the consideration of several elements such as distribution networks, LNG terminals, gas storages as well as supply and demand interactions between the gas, hydrogen, district heating and CO_2 transport sectors in the scenarios. Especially in Member States with a more important reconfiguration of the gas sector (with for example expected relevant reductions or increases in methane gas demand, and/or potential for the deployment of dedicated hydrogen infrastructure) or other sectors, it would allow to better deploy, refurbish, repurpose or decommission methane infrastructure according to EU and national energy and climate targets and ensure coherency between the scenarios used in sectoral NDPs. These benefits may not fully materialise until the period after 2030, but decisions made up until that year will be pivotal in determining the post-2030 pathway for the gas sector.

The competence of NRAs to require market tests for hydrogen pipelines could ensure new and repurposed pipelines were aligned to societal interests and avoid over-investments in the hydrogen sector.

Finally, this option foresees that sanity checks are to be performed on the consistency between the gas and electricity NDPs. This process will build on the collaboration between the electricity and gas TSOs that has to be established to build scenarios. The role of these sanity checks is to examine the potential inconsistencies resulting from the assumptions made by TSOs regarding technologies that are at the interface between the gas and electricity sectors (gas-to-power, power-to-gas, hybrid consumption technologies).

3.4.4 Description of Option 3: European Planning

Option 3 requires that a single **system wide network development plan** is established at the European level, that is to perform a joint electricity-gas network planning and to prepare an integrated system wide network development plan for methane gas, hydrogen and electricity, including with the consideration of unregulated infrastructure investments (for example, exempted) and of unregulated infrastructure plans. These requirements would come in addition to those of Option 2.

This system wide network development plan could allow to account not only for supply and demand interactions between the gas, hydrogen and electricity sectors, but also to jointly assess their operation and infrastructure investments. Therefore, the option could lead to significant investment and operational savings by taking into account the benefits of system integration and prioritising the most effective and efficient decarbonisation solutions, regardless of which sector they would take place. The option could provide benefits already to the present EU energy system, but the benefits would be amplified (compared to an approach with sectoral MS-level NDPs) as gas systems face significant changes such as reduction of demand or the need for the assessment of new or repurposed hydrogen infrastructure investments.

4 ANALYSIS OF POLICY MEASURES

4.1 Integrating renewable and low-carbon gases into the market

The assessment of future impacts relies on a number of assumptions and builds upon contextual information. Hence, the description of impacts is preceded by estimates of the future evolution of biogas and biomass potentials, a description of how they compare to the projected biomethane production under the MIX H2 scenario and the resulting marginal LCOE, an analysis of the future biomethane cost structure plus a short analysis on the potential need for public support.

4.1.1 Introduction

4.1.1.1 Biogas and biomethane potentials

An estimation of the biogas and biomethane potentials in the European Union has been carried out in the framework of the present impact assessment[93]. Methodological details and assumptions are available in the Annex (cf. Section 8.1).

Several scenarios have been built, differentiating the accessibility of feedstocks. The **total biogas potentials** (including not upgraded raw biogas and biomethane) varies from **397 to 426 TWh/year[94]** across the scenarios for the EU27 in 2030. The share of biomethane in total biogas potentials is estimated to range between 57% and 60% (but depends on the assumptions adopted, cf. Section 8.1).

In the most pessimistic scenario (with no sequential cropping and less straw devoted to biomethane production), **biomethane potentials** are estimated to equal **228 TWh/year** in the European Union by 2030. Anaerobic digestion of rural substrates (energy crops and rural residues) represents 71% of this potential (cf. Figure 4-1).

[93] Biogas and biomethane potentials estimation as well as costs of biomethane production by anaerobic digestion estimation have been carried out by Fraunhofer IEE.

[94] All gas energy values are expressed in Higher Heating Value (HHV) / Gross Calorific Value (GCV)

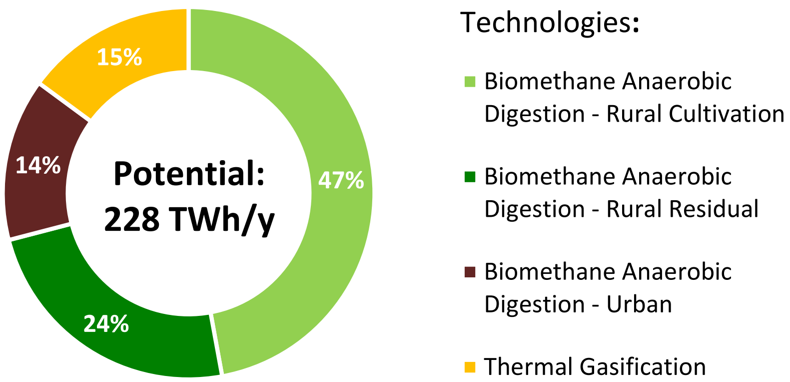


Figure 4-1: Biomethane potentials in 2030 in the EU (scenario with less straw and no sequential cropping). Source: own calculations.

Figure 4-2 presents the distribution of the biomethane potentials among the EU Member States. Potentials strongly correlate with rural surface and population. Two thirds of the potentials are located in five Member States, namely France, Germany, Poland, Spain and Italy.

The share of the different technologies and substrates in the potentials depends on the specificities of the individual Member States. For instance, countries with large forest areas present a high share of thermal gasification potentials (such as Sweden, Finland, Austria or Latvia).

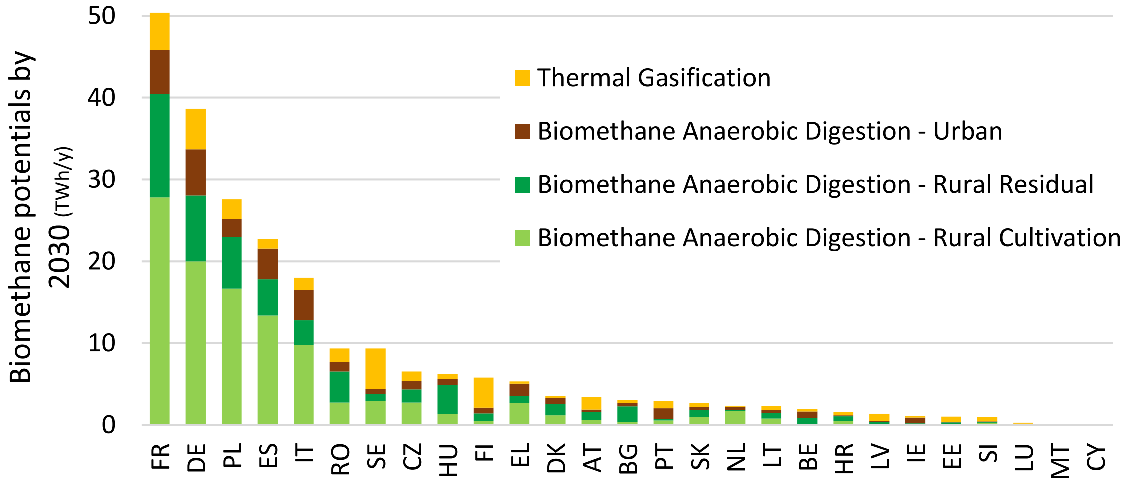


Figure 4-2: Biomethane potentials in 2030 by European Member State (scenario with less straw and no sequential cropping). Source: own calculations.

The biogas potentials quantified in the framework of the present impact assessment[95] are situated at the lower end of the potentials indicated in the literature (cf. Table 4-1) and may thus be understood as a conservative estimate.

Table 4-1: Literature review of biogas potentials in Europe.

(TWh/y)	Own calculation[93]	CE Delft[96]	DNV GL[97]	Navigant[98]	IEA[99]	ENGIE Impact[100]
2030	397 - 426	467	375	370		
2040	735 - 797				1326	
2050	1073 - 1166		1008	1020		1116

4.1.1.2 The role of biomethane in the MIX H2 scenario

In 2019, 21 TWh of biomethane were produced in the EU27. Biomethane production played a **very minor role compared to natural gas**, as it only represented **0.6% of the gross inland gas consumption**.

Biomethane production is expected to increase gradually. According to the **MIX H2** scenario, it would reach **50 TWh/year in 2030 and 70 TWh/year in 2035**. This evolution is quite in line with the most recent historic trend. In 2019, biomethane production increased by 3 TWh compared to 2018[101]. Following this trend would lead to an EU biomethane production of about 54 TWh/year by 2030 and ca. 70 TWh/year by 2035. The biomethane production under the MIX H2 scenario is thus slightly below the current trend for 2030 and close to the current trend for 2035.

Despite this increase, biomethane is expected to represent a minor share in total gas consumption of less than 2% in 2030 and about 3% in 2035 (cf. Figure 4-3).

[95] Assumptions have been taken on the availability of different types of substrates (grass silage, manure, straw, maize silage, urban bio-waste, sewage sludge etc.) for biomethane and biogas production. For more details, refer to the Annex, Section 8.2.

[96] (CE Delft, 2016)

[97] (DNV GL, 2020)

[98] (Navigant, 2019)

[99] (IEA, 2020a)

[100] (ENGIE, 2021)

[101] (EBA, 2020)

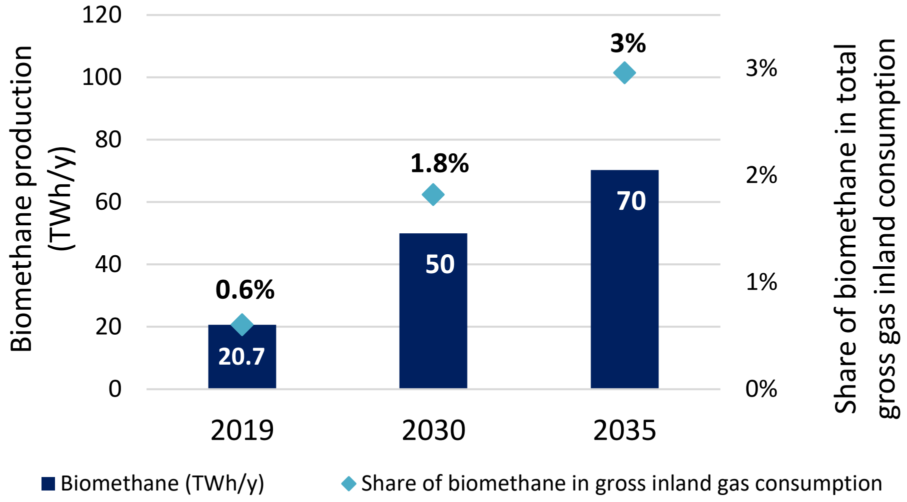


Figure 4-3: Biomethane production evolution and share in methane consumption in the European Union. Source: (EBA, 2020) for the year 2019 and MIX H2 scenario data from (European Commission, 2021e) for the years 2030 and 2035.

Table 4-2 shows biomethane as well as raw biogas production which is not upgraded in 2019, 2030 and 2035. In 2019, biomethane only represents a minor share of the total biogas production. That is, most of the biogas production is directly used on-site, to produce heat or electricity.

Until 2030, the increase in overall biogas production only affects biomethane. The production of biogas that is not upgraded to biomethane is expected to stay stable. After 2030, a significant increase of raw biogas (not upgraded to biomethane) is projected, where biomethane continues the rather linear growth.[102]

Table 4-2: Biomethane and biogas production evolution in the European Union by 2035. Source: (EBA, 2020) for the year 2019 and MIX H2 scenario data from (European Commission, 2021e) for the years 2030 and 2035.

EU27	2019	2030	2035
Biogas[103] (TWh)	146	147	317
Biomethane (TWh)	21	50	70
Total (TWh)	167	197	387

At the EU level, biomethane production projected by 2030 under the MIX H2 scenario represents 22% of the biomethane potentials identified in the framework of this study under the most conservative scenario (with less straw and no sequential cropping available for biomethane). At the country level, the picture is similar for most of the Member States with biomethane potentials exceeding by far the projected biomethane production.

[102] By 2050, the European Commission's Long-Term Strategy (European Commission, 2018a) projects total biogas production (including raw biogas not upgraded to biomethane) to reach between 650 and 730 TWh/year (representing between 28% and 30% of the gross inland methane consumption).

[103] Including waste gas

Box 4-1: Uncertainties regarding future biomethane production.

Biomethane production uncertainties

The impact assessment relies on the assumption that biomethane production will evolve as projected under the MIX H2 scenario. However, the evolution of biomethane production in Europe is subject to major uncertainties and debates. For instance, in France, the major DSO and TSO GRDF and GRTgaz expect biomethane production to range between 14 and 22 TWh/year in 2028[104], whereas MIX H2 scenario only foresees 3.2 TWh/year in 2030.

This study does not aim to evaluate the optimal role for biomethane or other renewable or low-carbon gases in the energy transition, but takes the production projected under the MIX H2 scenario as a prerequisite.

Thus, the impacts assessed in the present study could be under-evaluated if the development of biomethane overshoots the biomethane production of the MIX H2 scenario.

4.1.1.3 Biomethane costs

Complementary to the assessment of biogas and biomethane potentials, an estimation of costs for biomethane production by anaerobic digestion has been carried out for the year 2030[93]. The total levelised costs of energy (LCOE) vary **from 30 to 120€/MWh** (cf. Figure 4-4).

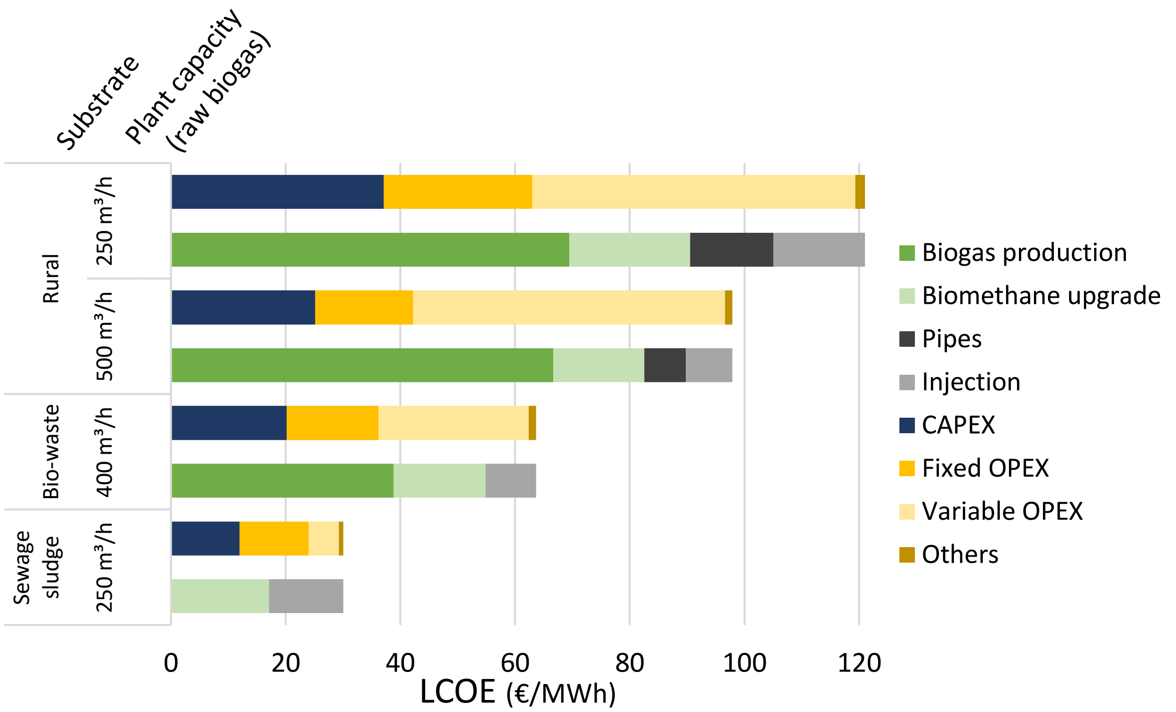


Figure 4-4: Biomethane anaerobic digestion cost structure and type of costs in 2030. Source: own calculations.

These costs include the biogas production, the upgrade of the biogas into biomethane, the connection to the (distribution) gas network and the gas quality monitoring, odorisation

[104] (GRDF; GRTgaz, 2020)

and injection. Injection tariffs are however not included. The main assumptions are detailed in Box 4-2.

Biogas production represents the majority of costs, (between 57% and 68% of the costs, except for biogas production from sewage sludge).

With respect to the type of costs, most of the expenses are OPEX-related (mainly linked to the feedstocks). In the present assessment, capital expenses represent between 18% and 40% of the LCOE.

Box 4-2: Biomethane production cost drivers and uncertainties.

Biomethane production cost drivers and uncertainties

Biomethane production costs are highly dependent on a set of parameters. Without pretending any exhaustiveness, the present box attempts to summarise the main cost drivers, the associated uncertainties and to transparently state the assumptions made for the biomethane cost assessment.

All assumptions are detailed in Section 8.2 of the Annex.

- **Substrate type**: Raw biogas can be produced based on different types of feedstocks, namely sewage sludge, urban bio-waste, rural residues, agricultural manures, sequential cropping, grass silage, straw, maize silage etc.

  In this assessment, several substrate types and technologies have been considered. Figure 4-4 highlights their influence on the LCOE. In the assessment, rural anaerobic digestion is assumed to be fed with 50% of grass silage, 22% of manure, 17% of straw and 10% of maize silage.

- **Feedstock costs**: Feedstock costs represent an important share of the LCOE. The highest uncertainties rely on the cost of urban bio-waste. In some cases, the cost of urban bio-waste could be considered to be negative, rewarding biogas producers for the waste treatment service. The LCOE of biomethane produced from bio-waste would be 79 €/MWh with a feedstock cost of 20€/ton, and only 18 €/MWh with a feedstock cost of -20€/ton. In this assessment, an intermediate cost of 10 €/t of bio-waste has been considered which translates into mean biomethane production costs of about 64 €/MWh.

  Other substrates are likewise subject to uncertainties. Substrate costs considered in this assessment are representative of the German situation.

- **Plant size**: Larger biomethane plants unlock economies of scale. Moreover, average biomethane plant sizes vary significantly across Member States, from less than 200 m^3/h[105] in France up to 1000 m^3/h in Italy (cf. Indicator 1.2 in Section 10.2.2).

[105] In this assessment, biomethane plant capacities always refer to the raw biogas capacity (in m^3 of biogas / hour). However, biogas only contains between 53% and 60% of biomethane (depending on the substrate), the rest being mainly carbon dioxide. Thus, conversions between raw biogas capacities and biomethane capacities must be done carefully. For instance:

- **250 m^3/h** (raw biogas) for **rural** anaerobic digestion is equivalent to **1.5 MW HHV** and an annual production of 12 GWh HHV/year;
- **250 m^3/h** (raw biogas) for **sewage sludge** anaerobic digestion is equivalent to **1.8 MW HHV** and an annual production of 15 GWh HHV/year;
- **400 m^3/h** (raw biogas) for **bio-waste** anaerobic digestion is equivalent to **2.7 MW HHV** and an annual production of 22 GWh HHV/year.

In this assessment, a sensitivity analysis has been realised regarding the size of rural anaerobic digestion plants. Increasing the plant capacity from 250 m^3/h to 500 m^3/h unlocks cost reductions of nearly 20%.

- **Upgrading technology**: Different technologies exist to upgrade biogas to biomethane (i.e., purification and removal of the carbon dioxide).

  In this assessment, upgrading technology is assumed to be membrane separation operating at 16 bar. The output biomethane pressure highly depends on the upgrading technology.

- **Gas injection pressure level**: A post-compression is typically required to inject biomethane into the network when the upgrading output pressure is lower than the injection pressure.

  In the cost analysis detailed in Figure 4-4, the network pressure is assumed to be lower than the upgrading output pressure (16 bar). Thus, no post-compression has been considered and priced. In other analyses, divergent cost assumptions might be used to reflect injection costs at other pressure levels (for instance, 4 bar for the distribution and 40 bar for the transmission, cf. Figure 4-14).

- **Gas injection requirements**: Injecting gas to the grid requires some measurements (volume, composition of the gas etc.), conditioning and odorisation. However, these requirements vary among Member States. For instance, in Germany, quality measurements require the use of Process Gas Chromatographs (PGC), costing between 1 and 1.4 M€/plant[106]. But Process Gas Chromatographs is not required in every MSs (not in the Netherlands for instance).

  In this assessment, the cost assumptions are representative of the German requirements. Odorisation but no conditioning has been considered.

- **Distance to the gas network**: the distance of the plant to gas network determines the length of pipes required to inject the gas into the network.

  In this assessment, the distance to the gas network is assumed to be null for urban biomethane plants (using sewage sludge and municipal bio-waste). For rural biomethane plants, an average distance to the network of 8 km has been assumed.

  In zones where the average distance to the network is above 15 km, gas has been assumed not to be injected into the network, but liquefied and transported by truck, generating additional costs of 69 €/MWh. This however only applies to few zones (only 14 out of 92 NUTS 1 zones). The results of a sensitivity analysis regarding the impacts of the distance to the network on the costs are shown in Figure 4-14.

- **Cost of labour**: Staff cost variations among Member States have not been explicitly considered in this assessment. A staff cost of 21 €/hour has been considered for the biogas production step, and 35 €/hour for the upgrading and injection steps (due to higher qualification requirements). These numbers may be considered representative for the German market.

- **Cost of energy**: Energy cost variations among Member States have not been considered explicitly in this assessment. The costs considered are 82 €/MWh for electricity, 37 €/MWh for heat and 0.8 €/l for diesel.

[106] (Beil, et al., 2019) and (Mischner, Dornack, & Seifert, 2013)

- **Discount rate**: A discount rate of 5% has been considered in the present assessment. The impacts of the discount rate on costs are analysed in Section 4.1.2, (cf. Figure 4-13).

For the thermal gasification, a unique cost of 80 €/MWh has been considered, inspired by the values estimated in the 2019 *Navigant* report on behalf of *Gas for Climate*[107] (88 €/MWh in 2020 and 47 €/MWh in 2050).

Matching the substrate and technology specific costs with the Member State-specific potentials allows to draw a biomethane supply cost curve for the year 2030, cf. Figure 4-5. Differences in costs (i.e., the different cost levels) are related to different substrates, plant sizes and distances to the grid.

Exploiting exclusively the least-cost potentials of the EU to reach the European biomethane production projected under the MIX H2 scenario would lead to a biomethane marginal generation cost of 80€/MWh (cf. the intersection between the cost curve and the demand line Figure 4-5).

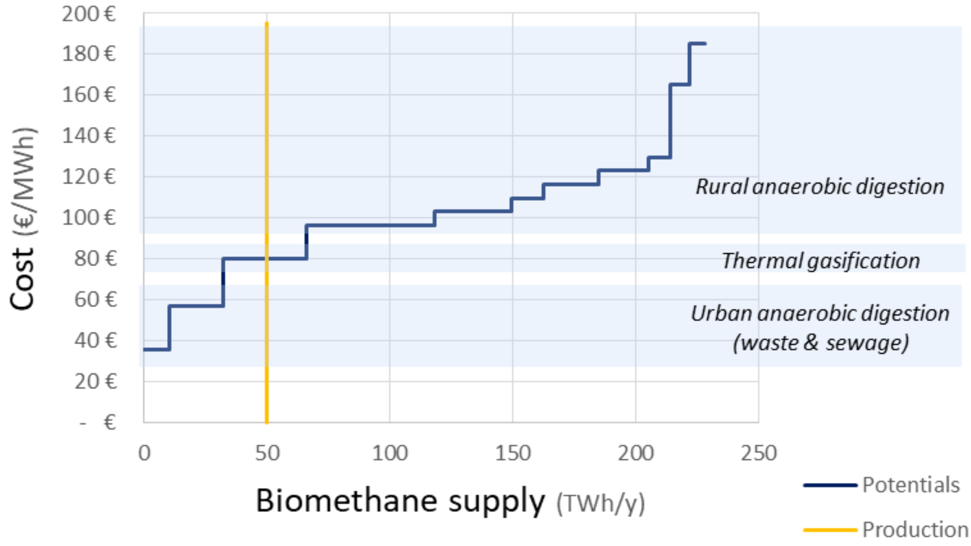


Figure 4-5: Biomethane cost curve in 2030 in the European Union. Source: own calculations.

In the following analysis, least-cost potentials are supposed to be exploited at the Member State level to meet the 2030 biomethane production projected under the MIX H2 scenario[108]. This approach allows to estimate the biomethane costs for each MS.

For instance, in Germany, reaching the 15.1 TWh/year of biomethane production under the MIX H2 scenario would require to mobilise all the biomethane potentials featuring an LCOE of 96 €/MWh and below (cf. Figure 4-6).

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[107] (Navigant, 2019)

[108] For the Member States where biomethane production as projected under the MIX H2 scenario exceeds the biomethane potentials determined in this study, the missing production is assumed to be allocated to the neighbouring countries.

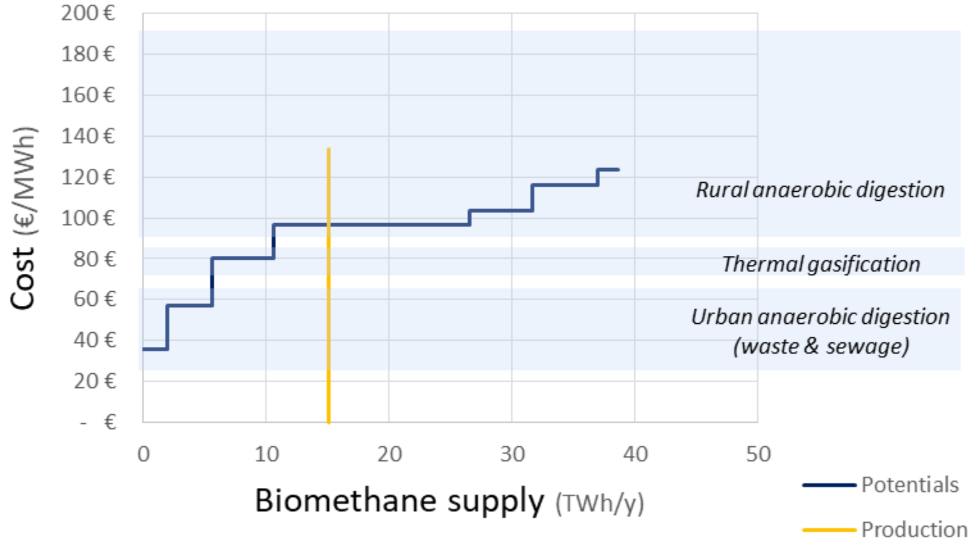

Figure 4-6: Biomethane cost curve in 2030 in Germany. Source: own calculations.

In France, reaching the 3.2 TWh/year of biomethane production under the MIX H2 scenario would require to mobilise all the biomethane potentials with an LCOE of 57 €/MWh or below (cf. Figure 4-7).

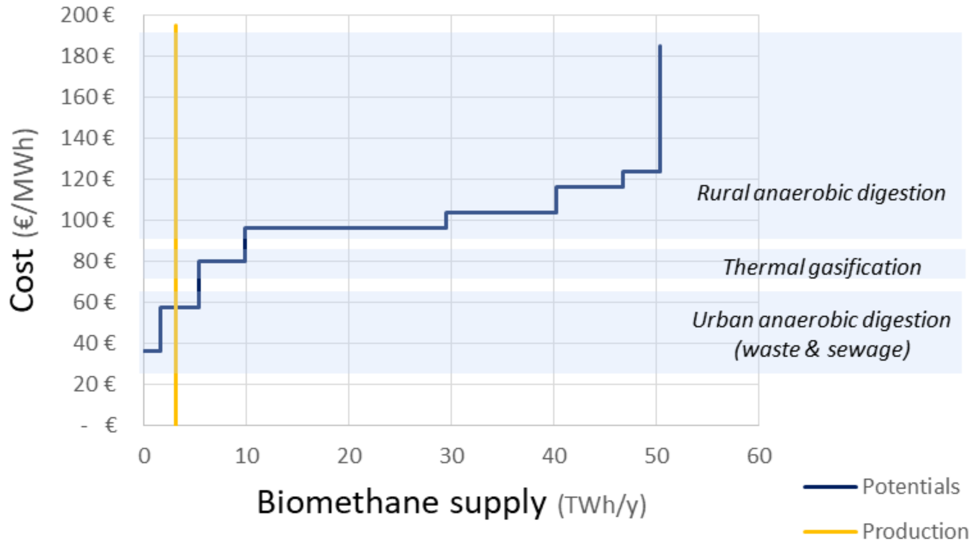

Figure 4-7: Biomethane cost curve in 2030 in France. Source: own calculations.

This example illustrates how MSs with comparatively little biomethane production under the MIX H2 scenario compared to the national potentials are likely to feature lower costs. The exploitation of least-cost potentials in each Member State leads to biomethane costs varying from 36[109] €/MWh to 116 €/MWh (cf. Figure 4-8). The average biomethane price on EU27 (weighted by the biomethane production given in the MIX H2 scenario) is **88 €/MWh**.

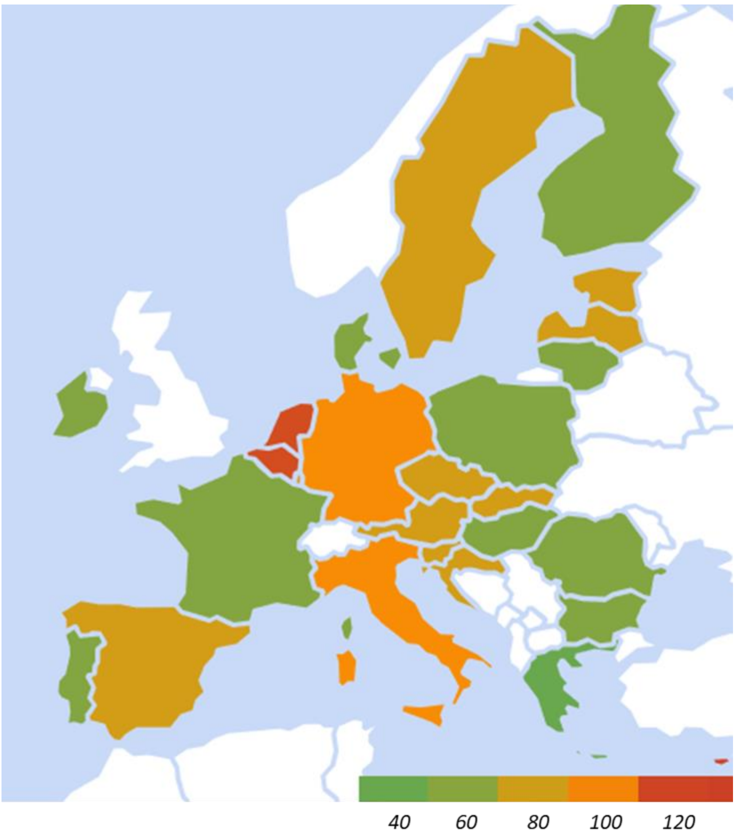

Figure 4-8: Marginal costs of least-cost potentials utilisation to reach biomethane production projected in each Member State in the MIX H2 scenario by 2030. Source: own calculations.

The exploitation of least-cost biomethane potentials to comply with biomethane production under the MIX H2 scenario at the Member State level instead of the European level is economically sub-optimal. The associated extra costs are estimated at 400 M€/year. This corresponds to a 10% increase of the total biomethane production costs compared to a coordinated exploitation of least-cost potentials across the EU.

4.1.1.4 The need for public support in 2030

In 2030, the natural gas price is expected to equal about 20€/MWh[110] and the carbon price about 46 €/t_{CO2}[110]. Considering the natural gas calorific value, the carbon price would be

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[109] The marginal LCOE for biomethane production in each Member State is determined by contrasting the biomethane production as projected in the MIX H2 scenario with the biomethane potentials identified in this study. A very low marginal LCOE is typically driven by a very low biomethane production in 2030 compared to a rather high identified potential. Both values are of course subject to uncertainty. Hence, the LCOE values should be understood as approximate indications of the cost level.

[110] (European Commission, 2021e)

equivalent to an additional cost for natural gas user of about 9 €/MWh. Thus, even considering the increase in natural gas price and the future carbon price, an important gap remains compared to the biomethane costs.

Closing the gap between the natural gas price and the biomethane production costs in 2030 via the carbon price would require a carbon price of about 350 €/t_{CO2} for a production-weighted biomethane LCOE of 88 €/MWh (cf. Figure 4-9).[111] However, other sources of revenue may enhance biomethane's competitiveness, such as revenues from guarantees of origin, or the internalisation of external benefits provided by biomethane production (as waste treatment or natural fertilizer production). Nonetheless, these effects are expected to have only a marginal influence on the gap. Thus, in the following analysis, biomethane production in 2030 is still considered to widely rely on public support.

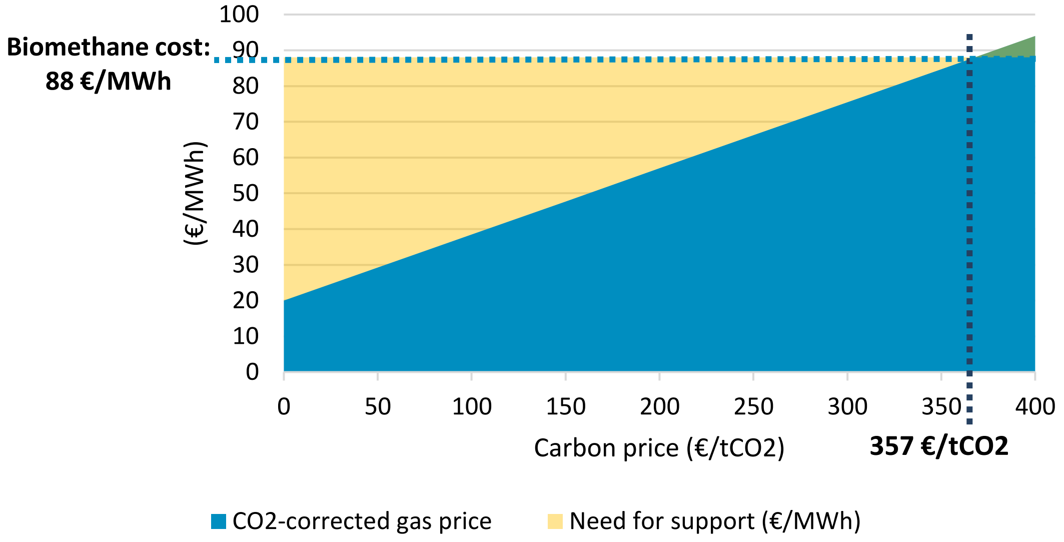

Figure 4-9: CO_2-corrected gas price and required public support to make biomethane competitive with natural gas depends on carbon price. Source: own calculations.

4.1.2 Economic impacts

4.1.2.1 Impacts common to all measures

Any increase in biomethane production brings about an **increase in overall system costs**, as long as production costs for biomethane remain high and CO_2 prices relatively low (cf. Figure 4-9). However, the enhanced utilisation of biomethane provides **secondary benefits**, such as improved security of supply and reduced energy imports. All policy measures assessed in the present analysis tend to enhance biomethane production, thus **reducing natural gas imports and dependency on foreign countries**. However, the effect remains quite limited, due to the minor role of biomethane (less than 2% of the gross inland gas consumption in 2030 and about 3% in 2035 under the MIX H2 scenario).

[111] For least-cost biomethane potentials featuring an LCOE of around 40 €/MWh, a carbon price of about 100 €/t would close the price gap between biomethane and fossil natural gas.

4.1.2.2 Policy measure 1: Enhanced coordination between DSOs and TSOs

Measure 1 requires DSOs and TSOs to coordinate with respect to the integration of renewable and low-carbon gases. There is a clear need for coordination as domestic, decentralised gas production may result in reversed flows within networks and between distribution and transmission networks. A coordinated strategy between DSOs and TSOs may lead to more cost-optimal investments that are aligned with the actual requirements arising from the deployment of renewable and low-carbon gases. However, these benefits only materialise if the provisions are sufficiently precise and binding (cf. for instance the policy measure on reverse flows, Section 4.1.2.4). The related administrative costs are expected to marginal for individual DSOs. However, in the case of an important number of DSOs (e.g. in Germany or Italy with several hundreds of DSOs), coordination efforts for TSOs might be non-negligible.

4.1.2.3 Policy measure 2.1: Entry-exit zone to include DSOs

Currently, distribution grids are already integrated into entry-exit zones in 10 Member States, covering 79% of the biomethane production projected by 2030 under the MIX H2 scenario.

The inclusion of distribution grids into entry/exit zones enables the marketing of biomethane injected at the distribution level via the VTP, ensuring access of smaller producers to the same market platforms as large producers.

If DSO grids are not part of the entry/exit zone, small biomethane producers that cannot trade their gas via the VTP need to enter into bilateral agreements with local gas suppliers or consumers. The realised price under a bilateral contract could be lower than the VTP price, due to the local biomethane buyer’s market power.

As biomethane production benefits in general from **public support**, Measure 2.1 could **help reducing the public support** level and thus related costs. Indeed, if public support is designed as a premium (where the subsidy is equal to the difference between biomethane’s production costs, including equity remuneration, and the sales price), Measure 2.1 would increase the reference market price obtained by the producer, thus reducing the premium, which lowers the costs allocated to energy consumers or tax payers.

There is little transparency about price levels of bilateral contracts between local gas suppliers and biomethane producers. Assuming that the access to the VTP grants producers a price for biomethane which is 1 €/MWh (or roughly 5%) higher than under a bilateral agreement, public support costs could be reduced by some **10M€ annually in the Member States where Measure 2.1 is not yet implemented** (with 10 TWh production[112], assuming that all MSs concerned would introduce support schemes by 2030).

If biomethane production would not benefit (any more) from public support, integration of DSO grids into the entry/exit zone provides access for smaller biomethane producers to the liquid wholesale market and thus to more favourable market conditions.

[112] Assuming 100% of biomethane plants to be connected to the distribution grid. This assumption provides the upper bound of the impact of Measure 2.1. For more detail on grid connection trends (between transmission and distribution grid), see Indicator 1.2, cf. Section 10.2.2 in the Annex.

Producers may obtain higher prices, implying higher revenues, or potentially triggering additional investments, if the higher prices make additional biomethane investments more competitive.

At the same time, producers may contribute to lower VTP prices, thereby increasing consumer rent and social welfare. However, as biomethane represents less than 2% of EU27 gas demand, these effects are expected to remain marginal.

4.1.2.4 Policy measure 2.2: Enabling physical reverse flows

In the past, gas supply flows were typically mono-directional, from transmission networks (operating at high pressure levels) to distribution networks (operating at lower pressure). Increasing biomethane injection at the distribution level raises the need for reverse flows from distribution to transmission networks (and even within the networks).

As long as gas injection at the distribution level remains at any moment of the year lower than local gas demand, there is no need to ensure reverse flow or activate other remedial measures. However, if injection into a distribution grid exceeds local demand at a given moment in time (notably during summer, when gas demand is low), the distribution grid saturates. Consequently, biomethane injection would need to be capped (and 'excessive' gas production can be stored, locally used for electricity or heat supply, or must be flared), if no remedial measures are taken. Several measures are possible to cope with local oversupply (cf. Box 4-3). The installation of reverse flow compressors is considered as one of the most economic option. Measure 2.2 implies an obligation on DSOs to install reverse flow compressors in grids where there is a risk of local biomethane oversupply. Currently, the obligation for DSOs to enable reverse flows only exists in France.

Box 4-3: Options to cope with local oversupply

Options to cope with local oversupply

Installing a reverse flow compressor is not the only option to cope with local oversupply[113]. Other technical options are:

- Meshing of distribution grids;
- Connection of biomethane plants to the network operated at higher pressure (incl. transmission grid);
- Increase of local gas consumption (with mobility for instance);
- Installation of local storage;
- Adaptation of the biomethane injection profile (requires an over-dimensioning of the fermenter)

More details are available in the Annex, cf. Section 8.2.4.

Reverse flows from distribution to transmission grids require the compression of the gas as well as its deodorisation when gas in transmission networks is not odorised, assuming that gas in distribution networks is always odorised.

Deodorisation costs (cf. Indicator 1.33 in Section 10.2.33) are subject to high uncertainty. However, as deodorisation costs are minor compared to reverse flow costs, this has a little impact on the total costs.

[113] For further information see for instance (GRTgaz, 2017).

Globally, reverse-flow compression and deodorisation cause additional costs of about **1.9 €/MWh** (cf. Figure 4-10).[114, 115]

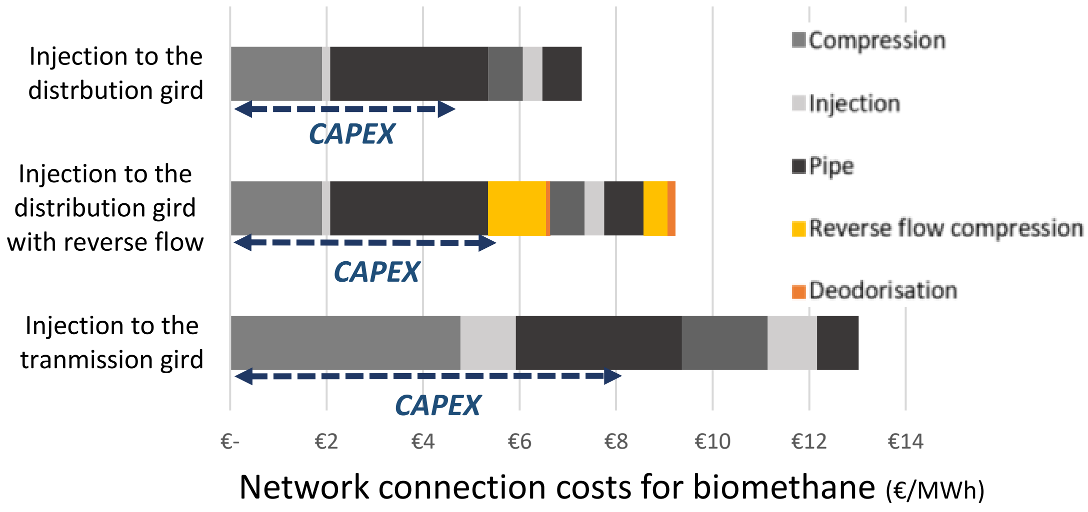

Figure 4-10: Impact of reverse-flow from DSO to TSO on biomethane network connection costs. Sources: Trinomics (based on literature review). Source: own calculations[115].

The values shown in Figure 4-10 differ from the costs presented before, due to differences in the data sources and assumptions on the injection pressure level (4 and 40 bar here, vs. 16 bar previously). The network costs for the DSO level are about twice lower than the network costs previously presented. This may be explained by the fact that the earlier figures represent plant types typical for the German which operate at higher pressure levels and tend to comply with higher gas quality requirements than in other EU MSs. The present numbers were used as they feature a higher granularity on connection costs.

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[114] Costs for reverse flow compressors are subject to high uncertainty, cf. also Box 4-4. For instance, the values shown in Figure 4-10 differ from the costs presented in the Annex I – Methodology, due to differences in data sources and assumptions on the injection pressure level and the pressure level of the distribution grid (4 and 40 bar here, vs. 16 bar previously). The network costs at DSO level are about twice lower than the network costs previously mentioned. This may be explained by the fact that the earlier figures represent plant types typical for the German which operate at higher pressure levels and tend to comply with higher gas quality requirements than in other EU MSs. The present numbers were used as they feature a higher granularity on connection costs.

[115] Plant capacity of 500 m3/h biogas, actualisation rate of 5%, lifetime of 20 years. Reverse flow compressor capacity of 20 MW (equivalent to 6 plants of 500 m^3/h).

In order isolate the impact of connection costs, the same plant capacity has been considered for connection to the distribution and transmission grid. However, in reality, plants connected to the transmission level are typically larger than the ones connected to the distribution level, unlocking economies of scale.

For the reverse-flow compressors, 1.9 €/MWh represents the specific additional cost when spreading the costs on the whole annual production of the considered plant. That is, for a plant requiring reverse-flow the LCOE would be 1.9 €/MWh higher during the whole year (even in winter, when the reverse-flow compressor is not operating).

The reverse-flow costs depend significantly on the **size of the compressor**. In this analysis, the compressor has a capacity of 20 MW (which equals the capacity of six biomethane plants with a raw gas capacity of 500 m3/h) whereas the compressor for the TSO case has a capacity of 3 MW for a single plant. This is one of the reasons why injection into the distribution grid with reverse flow remains cheaper than direct injection into the transmission grid. The other reasons are a lower utilisation of the compressor in case of a reverse-flow (as the compression up to the transmission pressure is only necessary during the summer, whereas, in case of a direct injection to the transmission grid, gas compression is necessary during the whole year), and the fact that the grid connection can be realised with low pressure pipelines, compared to direct connection to the transmission grid.

Unlocking these **economies of scales** requires to **dimension reverse-flow installations to the output capacity of several biomethane plants** connected to the same distribution network. Such an anticipatory dimension of compressors may be challenging, as it requires **coordination and visibility** on the future biomethane plant developments on a given distribution network.[116]

In order to estimate the **actual need for reverse flow compressors by 2030**, an assessment of the balance between biomethane injection and local gas consumption for distribution grids has been conducted for 2030 at the NUTS1 level. The details of the methodology are outlined in the Annex, cf. Section 8.1. The analysis did not reveal any significant issues of local oversupply at the distribution level, requiring gas reverse flows. However, the fact that reverse flow compressors from the DSO to the TSO level are already operating, for instance in Germany and France[117], suggests that the NUTS1 granularity might not be fine enough to capture all local oversupply phenomena and resulting needs for reverse flows.

Thus, a **sensitivity analysis** has been realised, assuming that **10% of all biomethane plants**[118] (except in France, where Measure 2.2 is already implemented) would face situations of local oversupply. This corresponds to a capacity of 560 MW (or roughly **190 biomethane plants** of an average size of 500 m^3/h of raw gas capacity) being affected by local oversupply.

To determine the part in biomethane production that is actually subject to reverse flow compression during the year, a generic demand profile and a generic injection profile have been contrasted. The biomethane injection profile is assumed to be flat, as biomethane production is not subject to major seasonal or intra-day variations (cf. Indicator 1.8 in Section 10.2.8) to ensure an optimal utilisation of the fermenter. The demand profile represents the reconstructed daily gas demand curve at the distribution level for the German NUTS1 zone DE8 in 2030 (DE8 being one of the most critical zones according to

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116 For example, if a given distribution network has 6 biomethane plants connected requiring reverse flow in 2030, but that two are constructed in 2023, two in 2025 and two in 2029, reverse-flow installation sharing requires to anticipate at the initial sizing and construction of the reverse-flow installation (in 2023) that other biomethane plants will connect at a later stage. First of all, this information may not be available. Moreover, even if the information is available, problems related to cost allocation (the two first biomethane plants may not pay the whole initial investment) and risk management (if the latest projects finally does not concretise) may arise.

117 In France, 3 reverse flow compressors are operating and 19 projects are approved by the French NRA (GRDF; GRTgaz, 2020). In Germany, more than 10 reverse flow installations are already operating (CEDEC, Eurogas & GEODE, 2018). The TYNDP 2020 contains several Energy Transition projects in France and Denmark related to DSO-TSO reverse flows (ENTSOG, 2020b).

118 Assuming 100% of biomethane plants to be connected to the distribution grid. This assumption provides the upper bound of the impact of Measure 2.2.

the assessment described in the Annex I – Methodology, cf. Section 8.1). For more details, see Box 4-4.

The comparison of the two profiles reveals that biomethane plants would cause potential reverse flow issues, with production exceeding local gas consumption during about 175 days of the year (48% of the year) (cf. Figure 4-11).

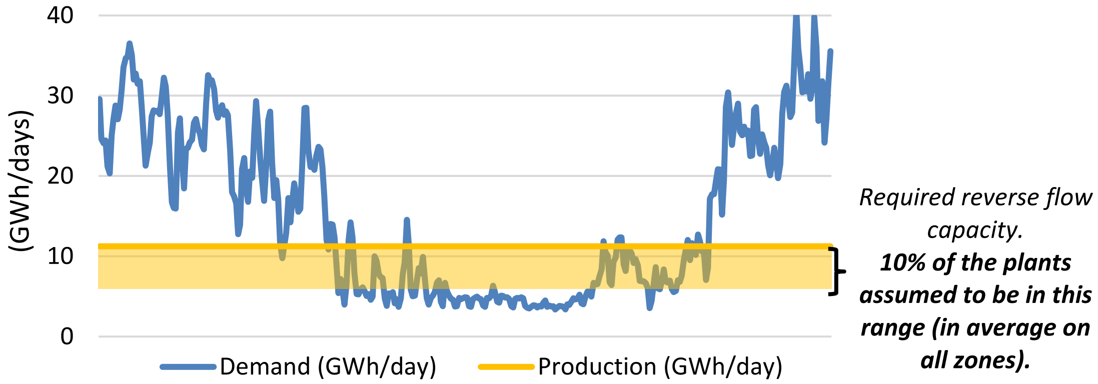

Figure 4-11: Biomethane injection and gas consumption profiles for a generic distribution network requiring reverse flow. Source: own calculations.

Without remedial measures, biomethane injection would have to be curtailed (i.e. used for onsite power/heat generation or flared). At the EU level, the total curtailment would reach up to 2.2 TWh per year (4.4% of the 50 TWh/year total biomethane production in the EU projected for 2030). This curtailed energy would need to be replaced with natural gas, generating **natural gas purchase costs of 45 M€/year**, and **CO_2 costs of 18 M€/year**[119,120].

With reverse flow compressors, biomethane could be injected to the networks during the whole year. Coping with the seasonal local oversupply of the 190 biomethane plants at stake would require about 30 reverse-flow compressors[121] across the European Union (France still being excluded from this analysis). The associated costs would be 70 M€ of investment costs (4.6 M€/year of annualised capital costs) and 3 M€/year of operational costs (cf. Figure 4-12), equivalent to the 1.9 €/MWh mentioned above (cf. Figure 4-10). These additional costs would be offset by the cost savings related to the avoided natural gas purchase and CO_2 costs of 63 M€/year.[119]

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[119] Assuming that the curtailed biomethane cannot be used locally.

[120] Moreover, one could assume that the risk of curtailment could refrain investors from constructing biomethane plants. If all plants potentially concerned by curtailment would not be built, the avoided biomethane production would mount to 4.7 TWh (annual production of the 560 MW of biomethane plants). The unproduced biomethane would be replaced by natural gas implying additional purchase costs of 94 M€/year.

[121] Assuming full capacity utilisation of reverse-flow installations during the summer period, with an individual capacity of 20 MW. Cost 2.5 M€ for a capacity of 20 MW. Lifetime of 30 years for the reverse-flow compressor and 15 years for the deodorization system. Actualisation rate of 5%

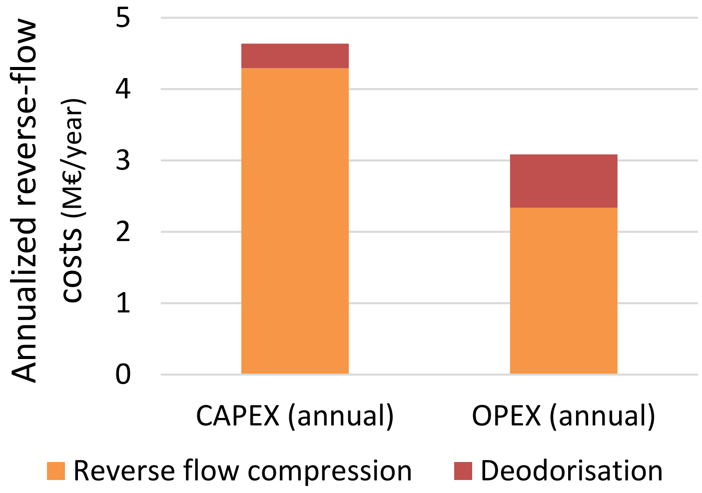

Figure 4-12: Annual costs of reverse-flow installation in the EU by 2030 if reverse-flow is required for 10% of biomethane plants. Source: own calculations.

The results of this sensitivity analysis are highly dependent on a set of parameters. Without being exhaustive, Box 4-4 summarises the main drivers, the associated uncertainties and the assumptions made for the biomethane sensitivity analysis.

Box 4-4: Uncertainties of the reverse-flow system costs sensitivity analysis

Uncertainties associated to the reverse-flow system costs in the sensitivity analysis

Several simplifications and assumptions had to be made for this sensitivity analysis:

- **Share of biomethane plants causing seasonal local oversupply at DSO level:** This is the main assumption of the analysis. In this assessment 10% of the biomethane plants (excluding France) are assumed to lead to seasonal local oversupply. This share is however difficult to estimate, as it requires fine geographical granularity information about individual distribution networks (by 2030), which is not available.

  Moreover, the needs for reverse-flow compressors are subject to a major threshold effect (which increases the uncertainty). Production from the first biomethane plants being connected to a distribution grid can be accommodated without major difficulties (even in summer). Reverse flow needs only occur above a certain level, when injection exceeds the minimum gas demand on the distribution network.

  In a similar assessment[122], the French TSO GRTgaz assumed that, in case of a biomethane production of 90 TWh/year in France, 16% of biomethane plants would require reverse flows. This value might however be overestimated, as the biomethane penetration assumed by GRTgaz is much higher than in the MIX H2 scenario (90 TWh/year of biomethane injection in France considered by GRTgaz, vs 50 TWh in the EU projected in the MIX H2 scenario).

[122] (GRTgaz, 2017)

- **Individual cost of reverse-flow installation**: In this analysis, reverse flow installations have been assumed to cost 125 k€/MW, for a 20 MW capacity[123,124]. 20 MW corresponds to the capacity of 6 to 7 rural biomethane plants with an individual raw gas capacity of 500 m^3/h.

  Cost data are however difficult to collect and uncertainties remain important, due to the little deployment of this technology. For instance, GRTgaz (French gas TSO) assumed in a similar assessment a cost of about 258 k€/MW[125], each installation covering four biomethane plants.

- **Optimal use of reverse-flow installations for several biomethane plants**: In this assessment, reverse flow installation have been assumed to be optimally used.

  As each reverse flow installation has a capacity of 20 MW (equivalent to 6-7 biomethane plants of 500 m^3/h) and with 190 biomethane plants potentially causing seasonal local oversupply, the number of required reverse flow is assumed to be about 30.

  However, as a reverse flow compressor operates on a single distribution grid, it supposes that the capacity potentially causing oversupply on each distribution grid is a multiple of 20 MW. In reality, local oversupply may appear with less than 6 or 7 biomethane plants, requiring the installation of smaller reverse flow compressors (limiting economies of scale).

  Moreover, the mutualisation of reverse flow compressors requires coordination and anticipation of the biomethane plants and projects on the same distribution network. Lack of coordination or timeline incompatibilities may lead to sub-optimal design of reverse-flow compressors, generating additional costs.

- **Number of days where oversupply happens:** The number of days in the year where biomethane production would exceed local gas consumption has been determined based on the approximate estimation for a generic distribution grid, illustrated in Figure 4-11.

  The local gas demand represents the reconstructed daily gas demand curve at the distribution level for the German NUTS1 zone DE8 in 2030 (DE8 being one of the most critical zones according to the assessment described in the Annex I – Methodology, cf. Section 8.1). The level of biomethane injection has been set to reach about 3.5 times the minimum summer gas demand for illustration purposes and to determine the mean duration of reverse flows in the generic network.

  In reality, the number of days where oversupply occurs depends on the shape of the local demand curve as well as the share of biomethane plants on the network requiring reverse flow. Thus, the first biomethane plant requiring reverse flow would only be curtailed a few days in the year. The number of days of curtailment increases with rising biomethane injection. This effect may moreover increase as the overall gas demand is expected to decrease in the future.

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[123] (KEMA, 2011)

[124] (Netbeheer Nederland, 2018b)

[125] (GRTgaz, 2017). GRTgaz mentioned 3M€ investment cost for a reverse flow installation covering four biomethane plants (without mentioning the size of the plants). In order to compare it to the costs used in the present study, the four plants have been assumed to have an individual capacity of 500 m^3/h.

4.1.2.5 Policy measure 2.3: Facilitating energy communities

The following analysis highlights the impact of facilitating the creation of gas energy communities. It first focuses on the implications of integrating certain provisions of the model of Citizen Energy Communities, as defined under the Electricity Market Directive, into the Gas Market Directive.

Two types of Energy Communities are defined in European directives: **Renewable Energy Communities** (REC) and **Citizen Energy Communities** (CEC). RECs were introduced in 2018 within the revised Renewable Energy Directive[126], while CECs were introduced in 2019 within the revised Internal Electricity Market Directive[127]. Energy communities dealing with renewable gases could be subject to the provisions of RECs. The integration of specific CEC provisions into the Gas Market Directive might facilitate the uptake of gas energy communities and the deployment of renewable and low-carbon gases. The comparison between the provisions of RECs and CECs is presented in the annex (cf. Section 8.1.2). In particular, the comparison reveals which elements of the Directives differ and which provisions related to RECs are more restrictive compared to CECs. Their main purpose is the same: to "provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits".

The major differences identified are:

- The **difference in activity**: RECs are restricted to renewable energy (including renewable gas projects), while CECs are restricted to electricity, and cover both renewable and fossil-fuel based projects.
- Greater **support from MSs** for RECs: MSs must create an "enabling framework" for the development of RECs. Main elements of this framework should be part of the NECPs. While the framework for CECs aims at ensuring a level playing field, the provisions for RECs focus more on supporting the projects[128].
- The geographical scope of the energy communities: the provisions on RECs insist on the **proximity** of the RECs to renewable energy projects, whereas for CECs it is states that "Electricity sharing enables members or shareholders to be supplied with electricity from generating installations within the community without being in direct physical proximity to the generating installation and without being behind a single metering point."
- The **energy services** provided by communities: the projects in which they can participate are described in more detail for CECs, namely "generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services"
- The **management of distribution networks**: CECs are allowed to "own, establish, purchase or lease distribution networks and to autonomously manage them", whereas for RECs the provisions only require DSOs to cooperate.

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[126] (European Commission, 2018b)

[127] (European Commission, 2019c)

[128] (bridge Horizon 2020, 2019) states ""The framework for REC […] consists out of a set of privileges which are aimed at actively supporting these initiatives, such as: 1) an assessment of the existing barriers and potential development of the communities; 2) removal of unjustified regulatory and administrative barriers; 3) tools to facilitate access to finance and information; 4) a support scheme that takes into account the specificities of renewable energy communities"

Specific provisions could be added to the Gas Market Directive to facilitate the creation of renewable gas energy communities in relation to these issues. This would include provisions **defining the energy services that can be provided by gas RECs**, similar to Article 2 (11c) of the revised Internal Electricity market Directive for CECs: "*generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services*". Defining this scope and adapting the text on vehicles may allow for a holistic local system design and integrate services for the transport sector as part of the gas RECs. This might incentivize producers to market their gas off-grid, thereby making remote potentials cost-effectively exploitable.

Adding the possibility for gas RECs to **own and manage distribution networks** could further encourage the creation of these communities. This concerns in particular the transposition of Article 16 (2b, 2c, 3c and 4) of the revised Internal Electricity market Directive, which could be applied to gas RECs as follows:

- Transposition of Art 16 (2c): "[MSs may provide in the enabling regulatory framework that *gas RECs*] are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them"
- Transposition of Art 16 (2c): "[MSs may provide in the enabling regulatory framework that *gas RECs*] are subject to the exemptions provided for in Article 38(2) [closed distribution systems]"
- Transposition of Art 16 (3c): "[MSs shall ensure that *gas RECs*] are financially responsible for the imbalances they cause in the *energy* system"
- Transposition of Art 16 (4): "MSs may decide to grant CECs the right to manage distribution networks in their area of operation […]". For gas RECs, the following provision could also be integrated if deemed necessary: "*Gas Energy Communities may have to participate in reverse flow, and in pressure regulation in the pipelines*."

This possibility to own and manage distribution networks would significantly facilitate the access of biomethane producers to distribution grids and allow for a more coordinated approach between biomethane deployment and grid development. It may thus incentivize a more anticipatory and holistic integration of renewable and low-carbon gases. In terms of impacts, having the same entity in charge for biomethane production, injection and grid expansion and management may simplify grid connection procedures, notably for small producers, thereby reducing existing barriers to the creation of these projects. These provisions may allow for a more cost-efficient grid connection and build-out, reducing societal costs. Finally, it would facilitate the creation of local, isolated networks to exploit off-grid potentials, hence increasing the penetration of renewable, low-carbon gases while limiting the need and costs for linking remote biomethane potentials to the main gas grid. At the same time, it should be noted that **mixing up regulated grid activities and unregulated production may lead to cross-subsidisation and competition distortion**.

In addition to introducing provisions based on the ones for CECs, it might be useful to alleviate RECs from certain obligations, notably regarding the quality of gas injected at DSO level, necessary proximity, safety requirements or technical connection requirements. However, such exemptions are usually decided at the level of the MSs[129].

[129] (bridge Horizon 2020, 2019)

Facilitating the deployment of gas energy communities via the before-mentioned provisions may trigger additional economic benefits[130]:

- The **increased acceptability and the implementation of more ambitious local targets**. The implication of local populations can be a way to limit public resistance against renewable and low-carbon gas projects which may shorten planning processes, avoid litigation and reduce related costs. Acceptance issues for biogas mainly concern fermenters and methanation plants. The positive impact of gas RECs on acceptability thus depends on the capacity of communities to carry out large-scale industrial activities.[131] The development of low-carbon gas projects indeed also depends on public acceptability.

  Furthermore, the local implementation of these projects enables more ambitious renewable targets[132].
- The **facilitation of the use of new technologies:** "By directly engaging with consumers, community energy initiatives demonstrate their potential to facilitate the uptake of new technologies […]"[133]. Energy Communities can potentially mitigate the need for network investments by opting for local closed networks or the off-grid utilisation of renewable gases (e.g., for transport purposes).
- The reduction of project costs as **remuneration requirements are lowered**. As the main purpose of Energy Communities is not to provide financial profits, lower profitability is needed from these projects as compared to traditional market participants. Financing the projects with citizen private capital enables lower rate of return requirements and thus lowers overall costs.[134]

4.1.2.6 Policy measure 3.1: Connection obligation with firm capacity for renewable and low-carbon gases

A legal connection obligation with firm capacity requires network operators to accept the connection request from any biomethane (or other low-carbon gas) plant. Grid operators may however be entitled to deny grid connection for technical or economic reasons (notably if the connection costs are disproportionate compared to the societal benefits brought by the connection). Any grid connection deny would have to be duly justified by the operator.

Connection obligations are already implemented or under implementation in 16 MSs[135], covering 89% of the 2030 biomethane production projected under the MIX H2 scenario. Thus, Measure 3.1 would only have a minor impact in the EU.

The main economic effect of connection obligation with firm capacity would be to provide biomethane projects developers with certainty on plant connection, thus reducing the investment risk and ultimately the actualisation rate of the projects and the

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130 (JRC, 2020)

131 This may in particular hold true for the local generation of hydrogen.

132 (European Commission, 2018c)

133 (European Commission, 2019c)

134 This effect may be partially offset by increased capital costs due to smaller plant size.

135 See Indicator 1.30: Biomethane connection obligation/request denials, cf. Section 10.2.30.

levelised cost of energy. Assuming that the actualisation rate would drop by 1%-point from 6% to 5% reduces the LCOE by 2 €/MWh (cf. Figure 4-13).

Under support scheme, this additional saving would relieve the costs for public support. For the eleven MSs where connection obligation is neither implemented nor under implementation and following MIX H2 biomethane projections, total cost savings would equal **11.1 M€/year**. Without public support, the reduction in cost might result in enhanced competitiveness of biomethane production.

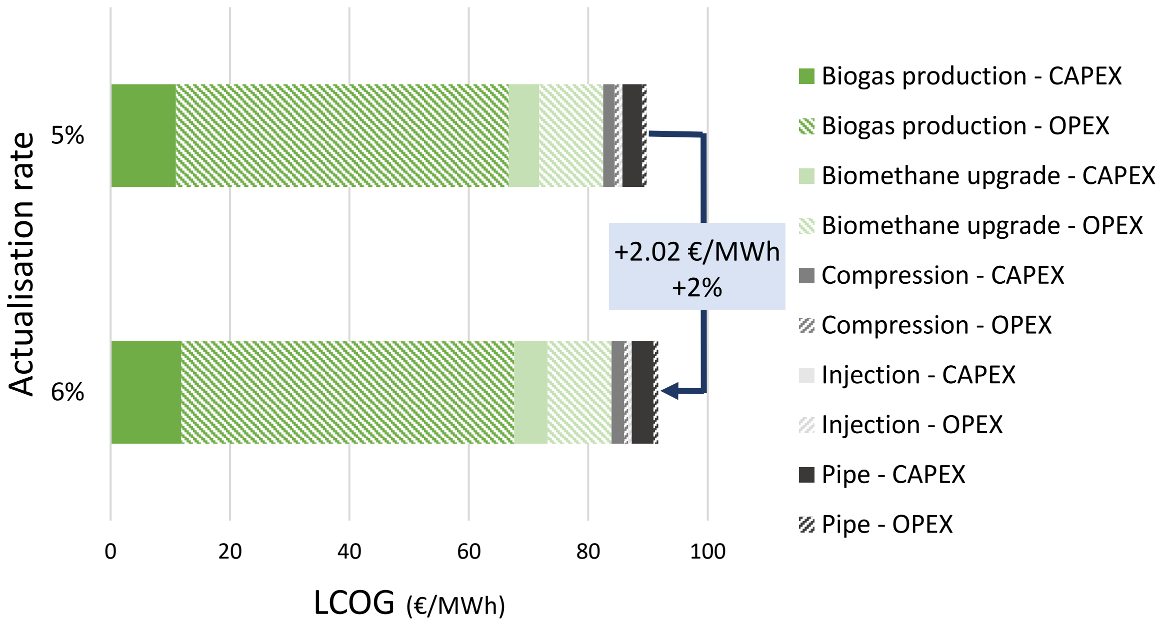

Figure 4-13: Impact of actualisation rate on LCOE. Source: own calculations[136]

Beyond the actualisation rate, enhanced investment certainty could also trigger additional investments. It could increase the biomethane production, thus reduce the greenhouse gases emissions. In some support schemes, it might not lead to higher production if the maximum volume is fixed by the authorities (e.g. quotas). However, facilitating the investment decision could exacerbate the competition to the premium support, thus reducing the support price and the cost for public support.

Beyond the connection obligation, the connection cost allocation varies widely across European Member States and may represent a more important lever to favour the production and injection of biomethane. In some MSs, the costs are shared between the network operator and the biomethane producer (for instance, biomethane producers

[136] Sources: own calculation (Fraunhofer IEE) for the biogas production and upgrade, Trinomics (based on literature review) for the connection costs. Calculations Artelys.

Source for the actualisation rates: (European Commission, 2016): the actualisation rate for RES investment under feed-in-tariff is assumed to be 1% lower than for RES investment in competitive markets.

Assumptions: rural anaerobic digestion biomethane production, size of plant of 500 m3/h biogas, connected to the distribution grid with a 10-km long pipeline. Lifetime of 20 years.

pay 60% of the costs in France[137], and only 25% of the costs in Germany[138]). In other MSs, most of the costs are carried by the biomethane producer (for instance in Spain or Italy), or no clear regulation on connection cost allocation exists yet.

Depending on the distance to the network and the connection pressure level, connection costs represent between 4% and 15% of the LCOE (cf. Figure 4-14) and their allocation may thus have a relevant effect on the economic viability of a biomethane plant.

Connection obligation is also likely to increase the amount of network investment costs. Depending on the national regulation, network costs are socialised, which could facilitate investments in biomethane plants, in addition to the investments triggered by public support. However, a higher volume of investments raises support scheme costs and thus puts an additional burden on gas consumers or tax payers.

On the other side, socialising the connection costs de-incentivises project developers and investors to exploit the least-cost potentials from a societal perspective (including the socialised connection costs). If connection costs are not paid for by the project developers, projects could be developed in more remote areas, with high biomass feedstocks availability and hence lower biomethane production costs, but high gas grid connection costs. This may lead to high CO_2 abatement costs, significantly exceeding alternative CO_2 mitigation options (e.g. on-site utilisation of biogas for heat and electricity production).

[137] According to an order of the Minister for Ecological Transition, the rate of rebate applicable to the costs of connecting biogas production facilities to the natural gas transport networks is set at 40%, up to a limit of 400,000 euros. The connection costs include the costs of the connection and the costs of the injection station. (Actu-Environnement, 2021)

[138] The German Gas Network Access Ordinance (GasNZV)) states that the operator of the biogas upgrading plant must generally bear 25% of the grid connection costs. However, in the case of a grid connection including a connection line with a length of up to one kilometre, the costs he has to bear amount to a maximum of €250,000. If a connection line exceeds a length of ten kilometres, the operator of the biogas upgrading plant has to bear the additional costs (cf. Section 33 (1) sentences 2 and 3 of GasNZV).

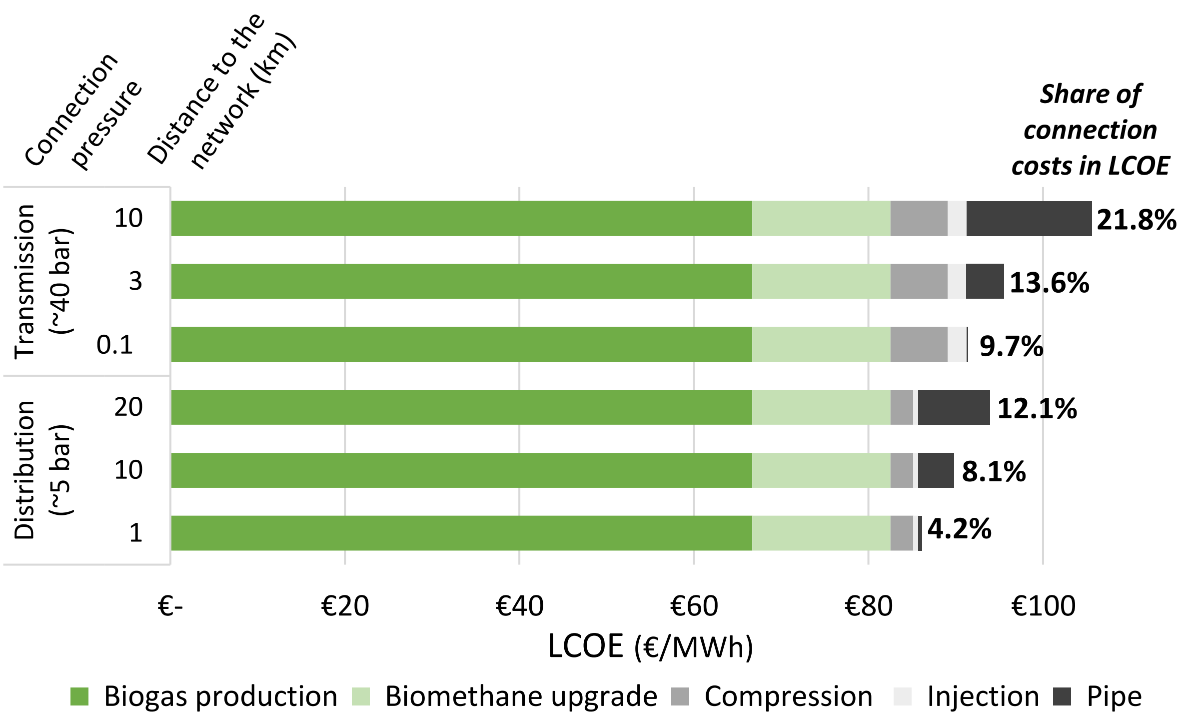

Figure 4-14: Share of connection costs in LCOE of biomethane depending on the grid type and the connection pipe length. Source: own calculations.

4.1.2.7 Policy measure 3.2: Reducing the costs of injection for renewable and low-carbon gases

To the extent known, currently, no entry-tariffs apply to biomethane injected at the distribution grid level[139]. At the transmission grid level, in some MSs, the same tariffs apply to biomethane as to natural gas (for instance 0.45€/MWh in Spain, 0.40 €/MWh in Italy). In other MSs, biomethane benefits from reduced entry tariffs, or tariff exemption (for instance in Germany and France), cf. Indicator 1.34 in Section 10.2.34.

The entry tariffs however represent in any case a very minor share of the LCOE of biomethane. Even the highest entry tariff only represents 0.5% of the total LCOE (cf. Figure 4-15).

[139] In France, tariffs are due if significant distribution level reinforcements (tariff of 0.4 €/MWh) or reverse flow investments (tariff of 0.7 €/MWh) are needed

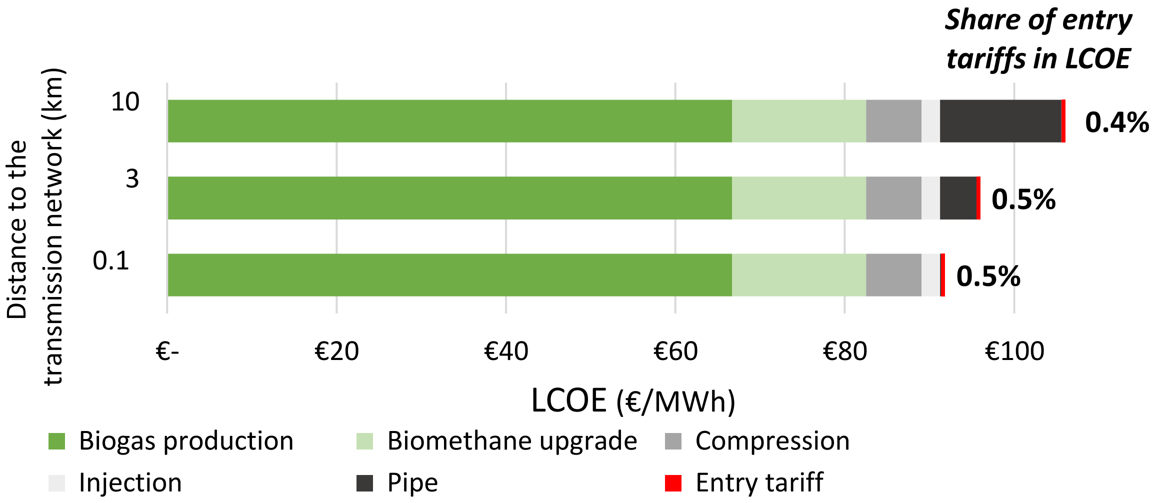

Figure 4-15: Weight of entry tariffs in LCOE of biomethane with the highest entry across all European MSs. Source: own calculations.

It may thus be concluded that if biomethane **production benefits from public support**, reduced or exempted entry tariffs slightly reduce the needs and costs for public support, as the LCOE is marginally lowered. However, the related costs would in general be reallocated to tax payers.

If biomethane **production is independent from public support**, reduced or exempted entry-tariffs slightly increase the competitiveness compared to natural gas, yet to a very limited extent.

Both impacts would be minor.

However, without some harmonisation of the tariff setting at the EU level, it is likely that a heterogeneous tariff landscape across EU MSs persists by 2030, with renewable and low-carbon gas producers facing different connection and injection costs across the EU.

4.1.2.8 Policy measure 3.3: Remove TPA-derogations for new long term natural gas infrastructure capacity contracts and limit duration of supply contracts to 2049

This measure concerns **the removal of possible derogations for third-party access** to gas infrastructure as described in Article 48 of the Gas Directive[140]. Since 2005, these derogations/exemptions concerned 16 pipelines, 17 LNG terminals and one storage facility.

If such derogations are no longer possible, it is likely that the incentivisation for new gas infrastructures will be reduced. This measure would thus hinder the development of new gas infrastructures in Europe. This is not a major issue in terms of security of supply as the METIS modelling for the MIX H2 scenario revealed that the underlying low infrastructure scenario of the TYNDP 2020 from ENTSOG would imply only very limited risks in terms of security of supply. The only MSs with a potential need for additional infrastructures compared to the low infrastructure scenario are Cyprus and Malta, and only three other non-EU countries would need additional infrastructures, namely Bosnia-Herzegovina, Montenegro and North Macedonia.

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140 (European Commission, 2009a)

Moreover, the adoption of this measure would reduce the risk of stranded assets in case of reduced gas demand in the medium and long term and could thus have a positive economic impact by redirecting investments to more future-proof technologies.

With respect to the limitation of the duration of long-term supply contracts to 2049, a look at the current situation reveals that a certain number of long-term contracts are in place, running up to 2050. Figure 4-16 illustrates the order of magnitude of the gas demand compared to the volumes of long-term natural gas supply contracts signed so far, and the projected production of biomethane and synthetic methane based on the MIX H2 scenario. In case of rising natural gas supply LTCs, the space left for biomethane and low-carbon synthetic methane risks to narrow. This may theoretically endanger the penetration of renewable and low-carbon gases as the market could be constrained to import natural gas even in a situation where biomethane would be cost competitive (e.g., due to a significantly higher carbon price). However, as the markets evolve to more short-term transactions, there is less need and less interest from shippers to conclude LTCs. Further, the carbon price would provide an incentive on its own to abandon natural gas even if purchased via LTCs. In this regard, a robust and clear signal on the evolution of the carbon price might prove more effective. Finally, the volumes for biomethane and synthetic gases projected for 2030 under the MIX H2 scenario are rather minor (and inexistent for synthetic methane) and less subject to suffer from LTCs as they benefit largely from public support (cf. also Section 4.1.1) and current LTCs would not be affected by the policy measure (and might even be renewed). Hence, the benefits for renewable and low-carbon gases by 2030 are expected to be minor.

However, from an economic perspective, this measure would increase the price of natural gas for consumers, as LTCs with a shorter duration might entail more risks and administrative costs for producers and increased flexibility for shippers and traders, which is a service that may raise the price of the contract.

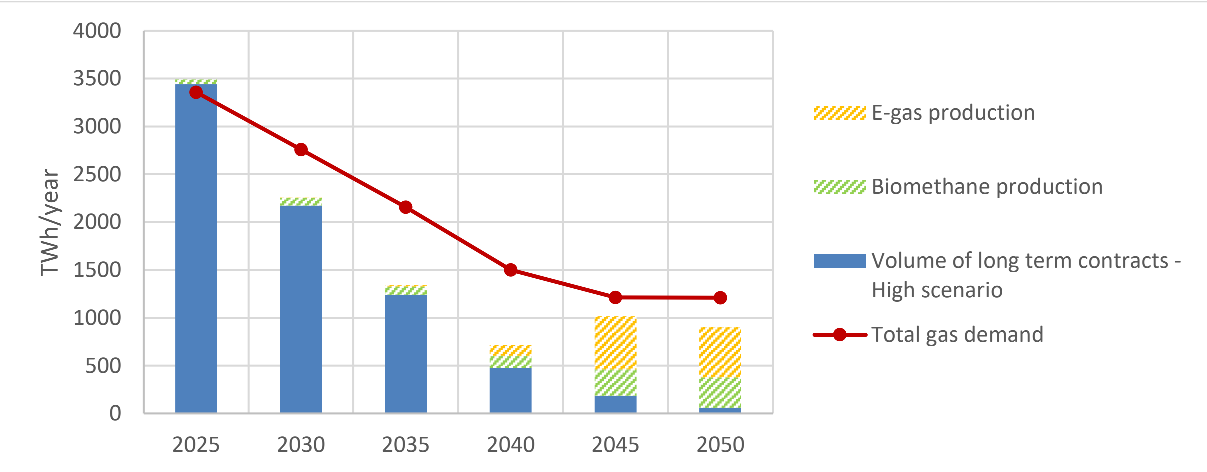

Figure 4-16: Comparison of the volumes of LTCs and methane demand in the EU until 2050. Source: LTC data from Cedigaz database, all other data from the MIX H2 scenario

4.1.2.9 Policy measure 3.4: Remove intra-EU cross-border tariffs for renewable and low-carbon gases only

The analysis of the GTM++ measures described in Section 4.2 displays the economic impacts of the removal of the intra-EU cross-border tariffs for all kinds of gas flows. The Measure 3.4 aims at removing these tariffs only for renewable and low-carbon gas flows. By 2030, this concerns primarily biomethane, according to the MIX H2 scenario. As biomethane production and trade is expected to be mainly driven by public support schemes (cf. Section 4.1.1.4) rather than market dynamics, the economic analysis made in this impact assessment does not apply the same reasoning than the analysis proposed for the GTM++ measures, which relies on the METIS market model.

In order to assess the impact of this measure, the biomethane flows between MSs have to be estimated. Nowadays, they are likely to be zero or negligible as (a) the biomethane production is small compared to the gas consumption in MSs thus it is not expected that MSs face an oversupply in biomethane production, (b) biomethane production is often localised at and limited to the distribution grid level and biomethane flows at the transmission grid level are for the moment rather low and (c) the support schemes are designed nationally, thus the MSs are not likely to support biomethane production in other MSs, and even less to import this biomethane via the cross-border IPs.

In 2030, the picture may differ. Assuming that the biomethane production volumes indicated under the MIX H2 scenario are realised by exploiting least-cost potentials at the MS level, the **volume-weighted EU average marginal LCOE of biomethane would equal 88 €/MWh** with a standard deviation of about 29 €/MWh (cf. Figure 4-8). Alternatively, MSs could rely on a common approach of exploiting least-cost potentials at the EU level[141] (cf. Figure 4-5). This would correspond to an EU-wide marginal LCOE of **80 €/MWh HHV**. Compared to the marginal LCOE of 88 €/MWh in the case MSs meet their biomethane demand domestically, **this would imply a reduction in EU-wide support scheme costs of about 400 M€ annually.**

In the case of an EU-wide exploitation of biomethane potentials, the total amount of biomethane that has to be imported/exported sums up to **18.8 TWh/year,** meaning that **62% of the production** is consumed within the producer countries and **38% of the production** has to be exchanged between Member States (cf. Figure 4-17).

141 In line with the concepts outlined in Articles 5, 8 and 13 of the Renewable Energy Directive (European Commission, 2018b).

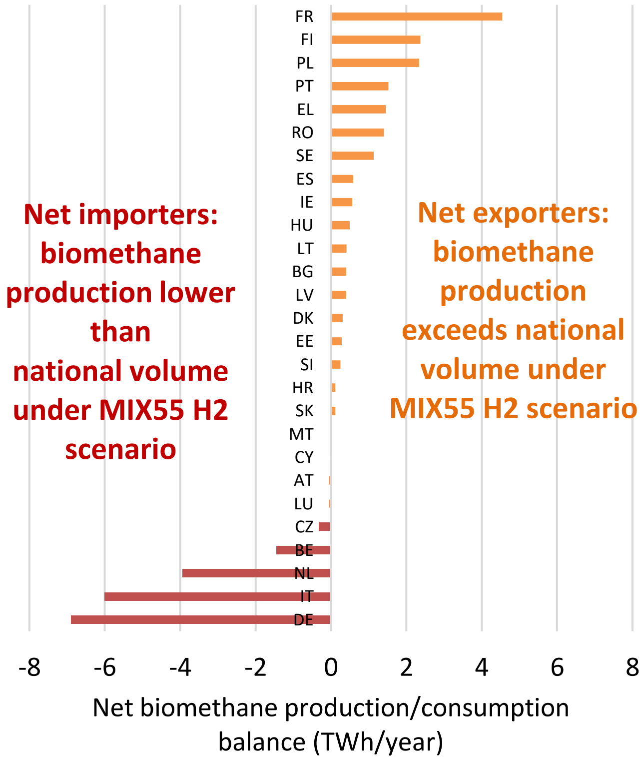

Figure 4-17: Difference between national biomethane production volumes under the MIX H2 scenario compared to an EU-wide approach of exploiting least-cost potentials in 2030. Source: own calculations.

Assuming (a) that the biomethane trades are mostly realised between neighbouring MSs (i.e., only a small proportion of biomethane has to transit through one or more MSs) and (b) that a mean commodity-equivalent entry/exit tariff of 0.66 €/MWh HHV would apply[142], Measure 3.4 exonerates biomethane producers from paying the intra-EU cross-border tariffs of **12.4 M€/year** to the TSOs**.** However, this missing revenue would need to be recovered, e.g., by a rise of the internal exit tariffs by **0.005 €/MWh HHV**, assuming an EU natural gas demand of 2674 TWh HHV in 2030.

Thus, this measure will in the end **reduce the costs for public support** (as the intra-EU tariffs do not longer need to be covered by public support granted to biomethane producers) by **increasing the gas price for all gas consumers**.

In conclusion, a regional approach to exploit the least-cost biomethane potentials can trigger cost savings of around 400 M€ per year. However, Measure 3.4 is not indispensable to make these savings materialise. The **economic impacts** of the measure are thus expected to be **marginal** and possibly null in the situation where the biomethane production is mainly consumed domestically, if the biomethane production remains low or if no exchanges of biomethane materialise.

Moreover, the related **administrative costs** to this measure should not be neglected, as its implementation will create the need for a methodology to be able to separate the tariffs paid by natural gas and biomethane that would certainly need additional monitoring efforts for the TSOs.

[142] Mean value taken from (ENTSOG, 2020d) for intra-EU entry + exit tariffs

4.1.3 Environmental impacts

The main environmental impact of biomethane production is to avoid CO_2 emissions by replacing natural gas with biomethane. Natural gas emission factor is estimated at **214 kgCO₂/MWh HHV**[143]. Biomethane emission factor is estimated at **39.5 kgCO₂/MWh HHV**[144]. Thus, producing 1 MWh of biomethane avoids on average 174 kg of CO_2-emissions.[145]

For instance, if Measure 2.2 (enabling physical reverse flows) avoids 2.2 TWh/year of curtailment, as stated in Section 4.1.2 (and assuming that for 10% of the biomethane plants local oversupply may be injected into transmission grids instead of being flared), the measure would avoid **390 ktCO₂/year**.

Regarding Measure 3.3 (removal of TPA exemption and duration limit for LTC), the environmental impact is mostly positive as such a measure would support the development of alternative gas infrastructure, and thus reduce the CO_2 emissions of the gas system.

Regarding Measure 3.4 (removal of the intra-EU cross-border tariffs for biomethane only) the environmental impacts are ambivalent. If low-cost biomethane potentials would feature higher sustainability (as environmental externalities are internalised), Measure 3.4 could facilitate the exploitation of these potentials and thus have a positive impact. At the same time, additional gas flows would increase the energy costs related to gas transfers (e.g. from use of compressors) whereas the domestic use of biomethane might have a more limited environmental impact.

143 (ADEME, 2021) Natural gas emission factor in Europe, including upstream emissions.

144 (ADEME, 2021) Biomethane average emission factor in France (including upstream emissions). Calculations GRDF, April 2020.

145 It is nonetheless important to note that alternative options to biomethane exist, that allow for a more cost-efficient decarbonisation of the EU economy. Further, it may be more efficient to use biogas on-site for power and heat generation instead of upgrading it and injecting it into the grid. From a societal perspective, the additional conversion step and injection should only be considered if there is locally no potential use for biogas. Finally, the environmental impact of biomethane strongly depends on the substrate used. It is key that biomethane production complies at least with the sustainability criteria outlined in the Renewable Energy Directive II (European Commission, 2018b) and its latest amendment. See also Box 4-5.

Box 4-5: Other biomethane environmental impacts.

Biomethane environmental impacts not taken into account in the present assessment

Beyond CO_2 emissions avoided due to natural gas consumption reduction, biomethane has several positive and negative environmental impacts. These impacts have not been evaluated in the framework of the present assessment, and are just qualitatively described below:

- **Land use change and competition (negative)**: if using energy crops as main crops, depending on national agricultural framework conditions, usage and land use competitions can occur. On the other hand, the use of energy crops - both main crops and catch crops - can lead to larger plant capacities being built, thus reducing specific plant technology costs. Another effect is to open up the use of additional manure quantities that would otherwise not be used for energy purposes (anaerobic treatment).

  Urban anaerobic digesters are not subject to usage competition, as the feedstocks are sewage sludge and bio-waste. On the contrary, urban biomethane production provides a service of waste treatment.

  For thermal gasification, the usage competition highly depends on the type of feedstock (which can be residual and post-consumer waste or waste wood and forestry residues). Usage competition is particularly salient for wood, which can also be used in biomass electricity power plants, combined heat and power plants, district heat or distributed heat.

- **Production of fertilizers (positive):** in addition to biogas, anaerobic digestion produces digestate which can be used as fertilizer, avoiding the use of chemical fertilizers.

- **Avoided negative externalities due to natural gas extraction (positive):** beyond the CO_2 emissions, the extraction of natural gas has other environmental negative externalities. Fracking can for instance impact water and air quality.

  Biomethane production enables the reduction of natural gas imports, hence reduces the negative externalities of natural gas extraction.

4.1.4 Social impacts

4.1.4.1 Support costs and costs for the final consumer or tax payer

As biomethane production benefits in most MSs from a national support scheme, most of the assessed policy measures related to renewable and low-carbon gases would reduce the need for public support:

- All of the measures would provide biomethane producers with increased certainty, reducing development risks, thus (support) costs and potentially triggering more investments;
- Measure 2.1 (access to the VTP) would increase the market value of biomethane, thus reducing the need for public support to fill the gap;

- Measure 2.3 helps to deliver affordable energy prices through, notably, a reduction in capital costs. It also ensures that the economic benefits are kept locally within the communities[146].
- Measure 3.3 may in principle lead to slightly increased gas prices, but also lead to lower overinvestments in infrastructure. The net impact with respect to the costs for end-users is difficult to quantify.
- Measure 3.4 may in principle lead to very slightly increased gas prices, but the amplitude should not be perceived by the consumers.

4.1.4.2 Impacts on the different stakeholders

The assessed measures would impact different stakeholders: biomethane producers, consumers, network operators, NRAs etc.:

- Measure 2.1 (access to the VTP) would empower biomethane producers to sell their biomethane via the VTP. On the other hand, network operators would have to physically enable the trades cleared on the market. Thus, from a network operator perspective, Measure 2.1 cannot not be fully dissociated from the Measure 2.2.
- Measure 2.2 (enable reverse flows) would mainly impact network operators. The measure would require enhanced coordination between TSOs and DSOs.
- Measure 2.3 (facilitation of renewable energy communities) engages citizens as both consumers and producers. This allows for greater social implication as citizens have an influence on energy investment, as well as increased social innovation, and a new form of citizen education, especially regarding energy saving issues[147]. It also supports local employment, and enhances competence building in sustainable sectors.
- Measure 3.1 (connection obligation with firm capacity) would provide enhanced certainty to the biomethane producers while putting an additional burden on network operators (notably to guarantee firm capacity). NRAs might be entrusted with the control of the connection obligation fulfilment from the network operators.
- Measure 3.2 would basically imply a reallocation of costs from gas consumers to other energy consumers or tax payers. However, according to the volumes at stake, this effect may be considered as marginal.
- Measure 3.3 would mainly affect TSOs and LSOs which would face increased uncertainty due to the removal of derogations for third-party access. Gas producers and suppliers would be affected as they would not be able to sign long term contracts beyond the year 2049. Yet, cost-wise it is ultimately the gas consumer who might face increasing costs (if increased uncertainty and more short-term contracts drive up the gas price) or benefit from decreasing costs and reduced environmental externalities (if the measure effectively reduces overinvestments in gas infrastructure and creates space for renewable and low-carbon gases). The net effect could not be fully quantified.
- Measure 3.4 would affect TSOs that would have to create a methodology to be able to separate the tariffs applied to natural gas in contrast to biomethane, which could lead to additional monitoring efforts.

[146] (bridge Horizon 2020, 2019)

[147] (JRC, 2020)

Box 4-6: Impacts related to hydrogen-blended gas and synthetic methane.

Impacts related to hydrogen-blended gas

In the MIX H2 scenario, the blending of hydrogen in gas networks is not expected to develop significantly before 2030. Blending may occur at the distribution and the transmission grid level, depending on the points of hydrogen injection.

If hydrogen-blending develops at the distribution grid level[148] relying on decentralised hydrogen injection, it could face similar market barriers than biomethane: no access to the VTP and barriers for grid connection. In this regard, Measures 2.1, 3.1 and 3.2 could also be beneficial for hydrogen injection into blended networks. At the same time, it is more likely that (renewable) hydrogen is generated in centralised large-scale units and injected into gas transmission grids or dedicated hydrogen networks. In the latter case, the actual blending in distribution grids would take place at the interface between gas/hydrogen transmission grids and the (hydrogen-blended) distribution grid.

Similarly, reverse flows are considered less relevant for distribution networks as the injection of hydrogen-blended gas into gas transmission networks would entail a contamination of the latter in the absence of a full harmonisation of hydrogen-blending in all networks.

Impacts related to synthetic methane

Like hydrogen-blended gas, synthetic methane is not expected to develop before 2030.

In contrast to biomethane, synthetic methane production is expected to materialise in more centralised, large-scale plants. Thus, all policy measures related to the access to distribution grids or from distribution to transmission grids (Measures 2.1 – 2.3) would have no significant impacts in the deployment of synthetic methane. However, policy measures 3.2 – 3.3 could provide a comparative advantage for synthetic methane compared to fossil natural gas, by granting grid connection, reducing grid connection costs and injection tariffs and ultimately by benefitting from the potential gas supply gap emerging under Measure 3.3

Nonetheless, in light of the projected deployment by 2030, these measures are likely to tackle only secondary barriers compared to other hurdles for a major deployment (notably in terms of competitiveness).

4.1.5 Comparison of measures

Biomethane is assumed not to be economically competitive with natural gas by 2030. Thus, **public support would still be required**.

The effectiveness of **Measure 1** depends on the level of bindingness and precision of the actual provisions. If DSOs and TSOs effectively pledge for enhanced coordination, **benefits might exceed the related efforts** however they are subject to high uncertainty.

Measure 2.1 (entry-exit zone to include DSOs) is already implemented in most of the MSs (covering 79% of the biomethane production). In the other MSs, the access to the VTP would allow biomethane producers to market their gas more efficiently, and could thereby **save about 10 M€ of public support costs** (assuming that the liquidity brought

[148] See Section 4.3 for the potential impacts and costs (in terms of gas quality and network adaptation requirements) related to hydrogen-blending at the distribution and transmission grid level.

by the access to the VTP grants producers a price for biomethane 1 €/MWh higher than under the bilateral agreement). Under support scheme, the measure **would not have any environmental impact**, as the development of biomethane would be determined via the public support scheme (quota). Otherwise, one might expect a marginal increase in installation volumes.

Measure 2.2 (enabling physical reverse flows) is only implemented in France so far. The issue of reverse-flow is not yet a major issue and should remain limited by 2030 if biomethane production stays in the range indicated under the MIX H2 scenario. Yet, when assuming that 10% of all biomethane production would require reverse flow compressors, this policy measure would trigger additional **investments in revere flow compressors of 70 M€** (or 4.6 M€/year) and operational costs of 3 M€/year. On the other hand, reverse flow compressors would **avoid about 2.2 TWh of biomethane curtailment**, which is equivalent to **390 ktCO_2** and **45 M€/year** of purchase costs for replacement with natural gas **plus 18 M€/year of CO_2 costs** (if the curtailed biomethane may not be used otherwise). Generally speaking, a lack of reverse flow compressors could complicate biomethane injection in distribution grids facing biomethane saturation during specific periods of the year, **but may not be a main barrier** to the general development of biomethane.

Under Measure 2.3 (facilitating energy communities), major provisions available for CECs under the Electricity Market Directive (which are not included for RECs) could be transferred to some kind of gas energy communities. These provisions might be in particular facilitate grid access by providing the opportunity to gas energy communities to own and manage distribution grids.

Measure 3.1 (connection obligation with firm capacity) is already implemented (or under implementation) in 16 MSs, covering 89% of the biomethane production by 2030. Connection obligation with firm capacity would **reduce the development risk** carried by biomethane producers. Assuming that this lowers capital costs (WACC of 5% instead if 6%), Measure 3.1 would enable **11 M€/year of cost savings for public support** in the 11 MSs concerned. Policy measure may further provide **certainty for investors**, thus facilitate investments. Similar to Measure 2.1, Measure 3.1 **would not have any environmental impact** under support scheme, as the development of biomethane would be determined via the public support scheme (quota). Otherwise, one might expect a marginal increase in installation volumes. On the other side, the measure could also trigger additional grid connection investments and increase the cost burden on gas consumers or tax payers.

Measure 3.2 (reducing costs/tariffs of injection for renewable and low-carbon gases) is expected to have **marginal impact**, as injection tariffs play a very minor role in the LCOE (less than 0.5%).

Measure 3.3 (removals of privileges and constrained duration for LTCs) is likely to disincentivize new gas investments. However, the impact on renewable and low-carbon gases is expected to be minor.

Measure 3.4 (removal of the intra-EU cross-border tariffs for biomethane only) is expected to support slightly the exploitation of least-cost biomethane potentials, but its impacts should remain marginal, and its concrete application may be complex.

Table 4-3: Comparison of the impacts of measures related to the market and grid integration of renewable and low-carbon gases.

Measure	Economic	Environmental	Social	Efficiency	Effectiveness
Measure 1	+	0	0	+	0
Measure 2.1	+	0	+	++	++
Measure 2.2	++	++	0	+	++
Measure 2.3	0	+	++	+	+
Measure 3.1	+	0	0	+	++
Measure 3.2	0	0	0	-	0
Measure 3.3	0	0	-	-	+
Measure 3.4	0	0	0	-	0
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)					

4.2 GTM++: Reform of the current entry/exit tariffication system

4.2.1 Methodology

This section aims at evaluating the impacts of the two GTM++ sub-measures introduced in Section 3.3.2 as a subset of the measures 3.1-3.3 that shall facilitate the market and grid access of renewable and low-carbon gases and enhance the efficiency of the internal EU gas market. Both sub-measures are described in Table 4-4. They will be analysed with the METIS model. The METIS model used in the present analysis represents the European gas market including all flows between European MSs and from third country exporters[149] towards the EU through the gas transmission network and via LNG terminals. The gas system is modelled for 365 daily time steps of a single year. The focus is set on the year 2030. METIS is used to determine the least-cost gas supply mix by optimising the mix of domestic production and imports from the different gas sources outside the EU. The framing scenario data builds upon the European Commission's MIX H2 scenario. Box 4-7 provides an overview of the general set of assumptions applied for the modelling with METIS, and Section 8.2 in the Annex provides insights on the model and how KPIs are computed. The entry/exit tariffs are configured in the model in compliance with the GTM++ sub-measures.

The following terms are applied in the remainder of this section with respect to the tariffs:

- **Internal entry/exit tariffs** refer to the tariffs paid for gas withdrawals from the transmission grid (towards the distribution grid or directly to the consumer) or for gas injected into the national transmission grid by domestic producers of natural gas, biomethane or other renewable or low-carbon fuels.
- **Intra-EU cross-border tariffs** refer to tariffs charged at the intra-EU IPs, i.e. between two MSs.

[149] Algeria, Azerbaijan, Eastern countries (Russia, Belarus, Ukraine), Libya, Norway, Turkey, United Kingdom, LNG (Northern Africa, Australia, Middle East, Norway, Peru, Sub-Sahara, Trinidad and Tobago, United States)

- **External entry/exit tariffs** refer to the tariffs that are charged at IPs between EU MSs and third countries. This term also includes tariffs that are charged at LNG terminals.

Box 4-7: Main assumptions for the METIS modelling of the GTM++ measures.

Perfect market: All market participants (consumers and suppliers) have equal access to information and behave in an economically rational way. In reality, more complex behaviours may impact the bidding strategies of the different market participants, and strategies may take time to adapt to the commissioning of infrastructure projects.

Inelastic gas demand: For the purpose of simplicity and because public data is scarce for this matter, the gas demand was considered inelastic. Gas demand by MS is assumed to be the same in modelled cases and does not depend on the gas wholesale prices.

Fixed cost curves: Following the methodology used by ENTSOG for the TYNDP2020, the price of gas offered by the different supply sources is increasing with the volume of gas sold. It is assumed that changes in network tariffs do not provoke any feedback effects of on the prices of the cost curves. In particular, the suppliers do not change their strategy when the tariff configuration changes but always compete with the same cost curves. However, the volumes sold by the individual exporting countries (and thus the prices) are subject to the change in tariffs and their surplus changes accordingly.

Indigenous gas & biomethane production constraints: The EU 27 and the UK are modelled considering the domestic gas and biomethane production. To reflect the fact that a country consumes its indigenous production first rather than imported gas, these domestic assets are constrained to produce at their maximal capacity at each time step.

Constant imports from third countries: The imports from third countries were considered to feature a constant profile, to ensure that seasonal flexibility is provided by the European storages. However, the import volumes are subject to the cost optimisation with METIS.

Both GTM++ sub-measures are compared to a baseline model run representing the gas market in 2030 with the measures of Option 2 activated (cf. Section 3.2.2 for more details on Option 2), especially for the LNG terminals that have the same tariffs and a 100% availability. The modelling specifications of the Baseline and of both sub-measures are listed in Table 4-4.

Table 4-4: Modelling specifications for the baseline model run and the two GTM++ measures.

Baseline	GTM++ Sub-measure 3	GTM++ Sub-measure 3+
In the baseline scenario, no measures related to the GTM are activated. Hence, in this situation: - Similar to the current situation, there are intra-EU entry and exit tariffs and entry tariffs between the MSs and third countries; these tariffs are approximated as commodity tariffs in €/MWh with values corresponding to the tariffs found in the TYNDP 2020[150] - The LNG entry points are charged with tariffs values corresponding to the current LNG tariffs in place - The storage injection and withdrawal are charged with tariff values corresponding to the current storage tariffs in place - Internal exit tariffs (applied to domestic consumption) and internal entry tariffs (applied to biomethane and indigenous production) tariffs are not modelled explicitly and set to 0 in the model, which does not influence the results as demand is inelastic	Compared to the current situation, this measure consists in: - Abolishing tariffs at intra-EU cross-border entry and exit points both for long- and short-term capacity bookings - LNG entry tariffs are fully discounted (*i.e.,* zero tariffs at TSO entry point); - Tariffs at pipeline entry/exit points between the EU and third countries are based on their distance to a virtual point in the middle of Europe[151] - The storage injection and withdrawal are charged with tariff values corresponding to the current storage tariffs in place - Internal exit tariffs (applied to domestic consumption) and internal entry tariffs (applied to biomethane and indigenous production) tariffs are not modelled explicitly and set to 0 in the model, which does not influence the results as demand is inelastic	Compared to the current situation, this measure consists in: - Abolishing tariffs on intra-EU cross-border entry and exit points both for long- and short-term capacity bookings - Tariffs at pipeline *and LNG* entry/exit points based on their distance to a virtual point in the middle of Europe - The storage injection and withdrawal are charged with tariff values corresponding to the current storage tariffs in place - Internal exit tariffs (applied to domestic consumption) and internal entry tariffs (applied to biomethane and indigenous production) tariffs are not modelled explicitly and set to 0 in the model, which does not influence the results as demand is inelastic

Note that these tariff modifications only apply to the European side of the pipelines connecting Europe to third countries. For instance, at the IP between Belgium and the UK, only the cross-border exit tariff for gas flows towards the UK and the cross-border entry-

[150] https://www.entsog.eu/sites/default/files/2020-11/ENTSOG_TYNDP_2020_Annex_D_Tariff_Values.xlsx

[151] Based on a distance provided by DG ENER, or estimated at 125% of the bird eye distance when no data was available. See the Annex, Section 8.3 for details of the computation.

tariffs for gas flows towards Belgium would be modified in the GTM++ model runs, while the tariffs on the Great-Britain side would not change.

In the Baseline and the two sub-measures, **no inter-compensation (ITC) mechanism between the TSOs was studied**. This kind of mechanism allows to reallocate the external revenues of the TSOs among each other that may ensure a revenue distribution which is close to the current situation (for instance from TSOs which have a border with a third country to TSOs which are only linked to European countries, such as Austria). It can influence the level of adaptation of internal exit tariffs needed by the TSOs to fully recover their costs. The reasoning presented in the following may be considered as a first step for the establishment of an ITC: it determines the global impact of the different GTM++ measures, and quantifies the change of revenue for each EU TSO, hence indicating the order of magnitude of a required ITC mechanism.

In addition to the Baseline model run (used to obtain TSO revenues under current rules), two iterations are performed in the present analysis:

- **First iteration - Model run without intra-EU cross-border tariffs:**

A first run is performed based on the assumptions of the two GTM++ sub-measures as described in Table 4-4 and with tariffs based on the distance of the entry and/or exit cross-border point to a virtual point placed in centre of Europe (Tillenberg, CZ) as described in Section 8.3.1.

- **Second iteration - Model run with adapted external entry/exit tariffs:**

As the distance-based tariffs of the first iteration are not necessarily similar to the current tariffs, the total revenues generated via the external entry/exit tariffs and congestion rent are expected to be substantially different in the first iteration compared to the Baseline. An adjustment of the distance-based tariffs is performed in a second iteration to align the TSO revenues with the Baseline level. This adjustment is based on the revenue results of the first iteration and further described in Section 8.3.1. Such a method could also be applied if the need for an ITC would appear in order to identify the share of TSO revenues that are to be recovered through internal or external tariffs, and the need for redistribution of revenues between the national TSOs.

All the results reported in the following rely on a set of KPIs that capture the dynamics, costs and benefits related to the European gas system, distinguishing EU27 MSs and third countries if relevant. An exhaustive description of the KPIs is available in the Annex, cf. Section 8.3.2.

Sensitivity analysis on Nord Stream 2

To evaluate the influence of the absence of the Nord Stream 2 (NS2) pipeline connecting Russia to Germany on the assessment results, the second iteration of the Sub-measure 3[152] is repeated but with the capacity of NS2 being removed. This implies that the interconnection capacity between Russia and Germany would drop from 147 GWh/h in the reference case with NS2, to 75 GWh/h in the sensitivity without NS2.

Note that for the Nord Stream pipelines, the distance considered to derive the new tariff in both GTM++ sub-measures is based on the distance between the virtual centre of Europe and the German entry point rather than any point further on the pipeline in between Russia and Germany. If the entry point was farther away, Nord Stream may be less used in the model.

Figure 4-18 displays an overview of the different model runs assessed and realised:

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[152] Sub-measure 3 with second iteration being both a model where EU consumers are benefiting from the measure and where the measure has a strong impact on tariffs.

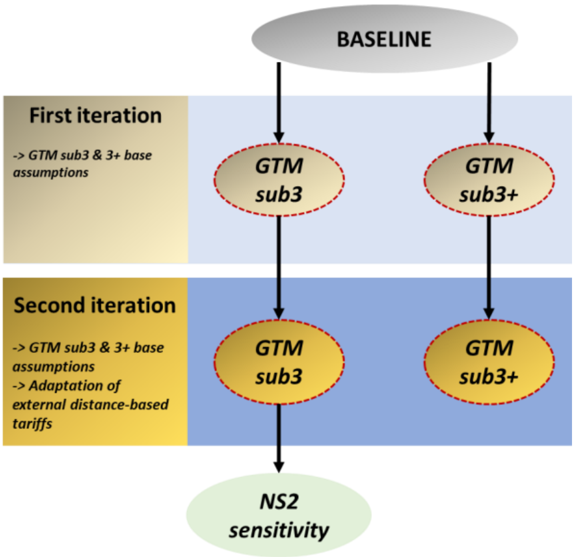


Figure 4-18: GTM++ measures assessment model runs simulated with METIS.

Additional analysis of the impacts on the power system merit order

In order to estimate the impacts of the GTM++ sub-measures on the power system that are not captured by the model runs explicitly (as all the gas demand is inelastic), the reference power merit order in each country is assessed through a post processing analysis under the Baseline model run for the gas-to-power plants and an estimation of the cost of marginal power generation costs for coal and lignite power plants in 2030. For each MS, the power producers are classified by ascending order of their marginal costs, which include the variable cost, the fuel price and the CO_2 emission costs. This analysis is repeated for both GTM++ measures and iterations (four model runs in total being compared to the Baseline model run), taking into account the change in gas prices due to the modification of tariffs. It reveals to what extent the change in tariffs implies a shift in the merit order, enhancing or deteriorating the competitiveness of gas-fuelled power plants compared to other plants.

In the model runs used to assess the GTM++ measures, the following power generation technologies are in competition with gas-fuelled CCGTs and OCGTs: young and old[153] coal and lignite power plants and oil power plants. This merit order is schematically represented in Figure 4-19.

[153] *Young* power plants are assumed to be built after 2015 and featuring a higher conversion efficiency than *old* power plants.

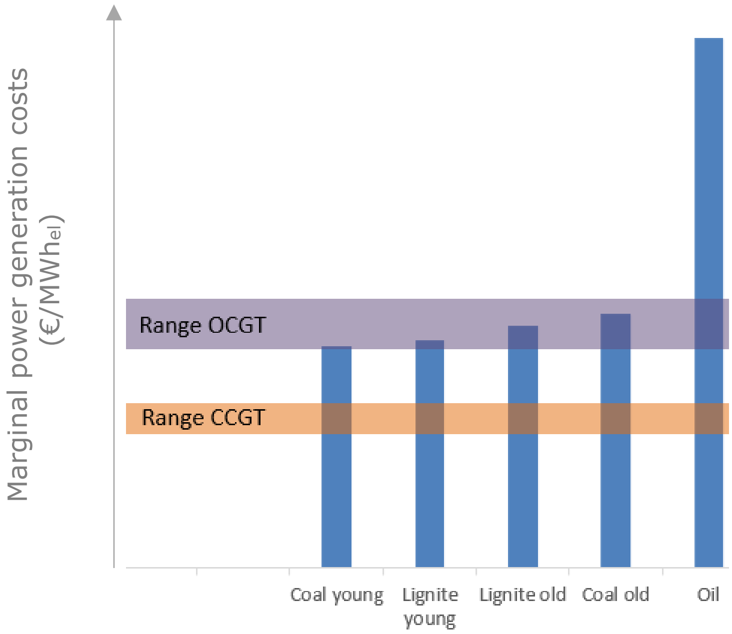


Figure 4-19: Power merit order for fossil fuelled power plant types[154]. Source: own calculations.

Box 4-8 provides an overview of the main limitations of the METIS-based modelling approach with respect to the GTM++ measures. An evaluation of the general assessment approach and its limitations is available in Box 4-9.

[154] The price range indicated for OCGTs and CCGTs is primarily linked to the change in end-consumer gas prices due to the GTM++ measures.

Box 4-8: Main limitations of the METIS modelling approach with respect to the GTM++ measures

Main limitations of the METIS modelling approach with respect to the GTM++ measures
The assumptions applied for the METIS modelling may include simplifications which need to be taken into account when analysing the results presented below. In the case of the GTM++ options, the main assumptions to be considered are the following: - Each national natural gas supply source is represented by a supply curve from the TYNDP 2020 (with a modification for the LNG curve), which is used to estimate the supply gas price in 2030. The change in gas supply computed for the different policy measures strongly depends on the shape of these supply curves. - The tariffs are modelled only as commodity-equivalent tariffs which implies the assumption that 100% of the capacity booked are used. In reality, not all these bookings are used, and the TSOs revenues are more important than the amounts presented below. - The model optimises the use of gas infrastructure from the point of view of an omniscient operator, hence all the infrastructures are used in a cost-optimal manner, whereas in reality the infrastructures are used more extensively and TSO/LSO/SSO revenues are likely to be higher. For instance, in reality gas storages are used to cope with the uncertainties of the future, while in the METIS model they are used only to the extent effectively needed, as the model applies a perfect foresight approach.

4.2.2 Economic impacts

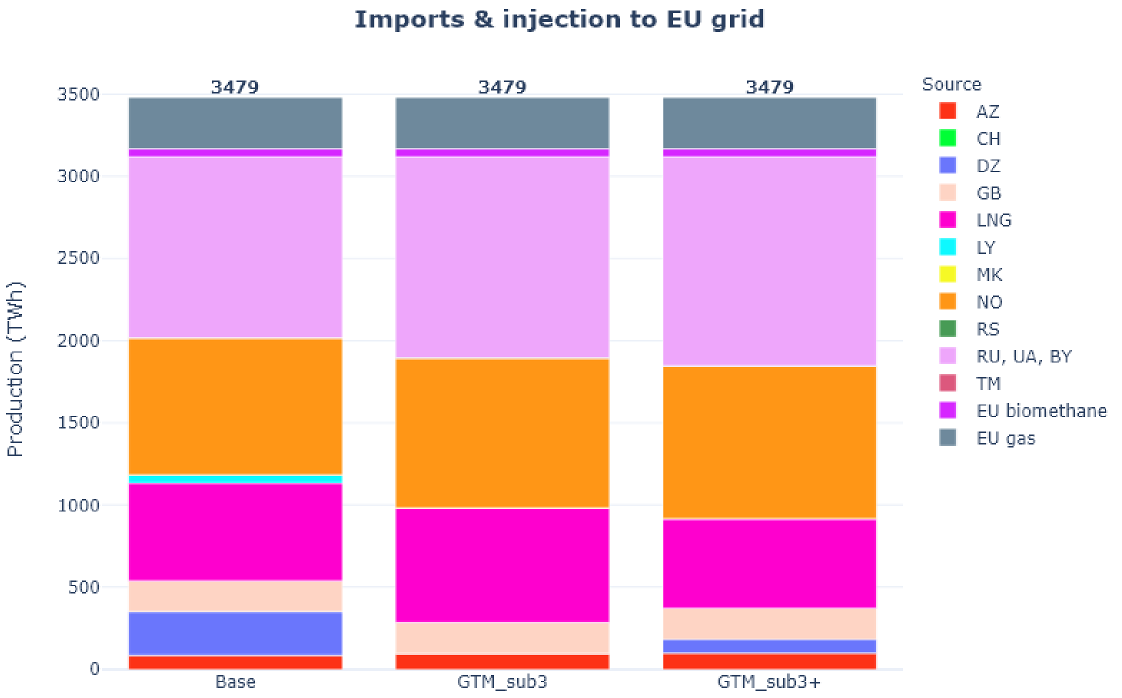
4.2.2.1 Economic impacts – 1st iteration: removal of intra-EU cross-border entry/exit tariffs

4.2.2.1.1 Changes in the EU gas supply mix

Since the EU gas demand (3479 TWh) and the domestic EU gas supply of biomethane and natural gas are assumed to be constant across all measures, the total volume of imports is constant among all model runs, too. However, as the tariffs paid between the different supply routes differ, the import mix differs. The difference of supply for each gas source is illustrated in Figure 4-20.

In Sub-measure 3, the removal of intra-EU cross-border entry and exit tariffs and the 100% discount on LNG terminal entry tariffs increase the imports of Russian gas, Norwegian gas and LNG to the detriment of Northern African gas. This is due to the new tariff calculation methodology with respect to the distance from the EU centre that incentivizes the use of the Nord Stream pipelines in comparison with gas from Northern Africa, and the 100% discount on entry tariff of LNG terminals that increases the competitiveness of LNG.

In Sub-measure 3+, adding an entry tariff at the LNG terminals increases the imports of Russian and Norwegian gas to the detriment of Northern African gas (-73%) and LNG (-8%), compared to the Baseline. However, the reduction in gas imports from Northern Africa is less pronounced than in the case with LNG discounts.



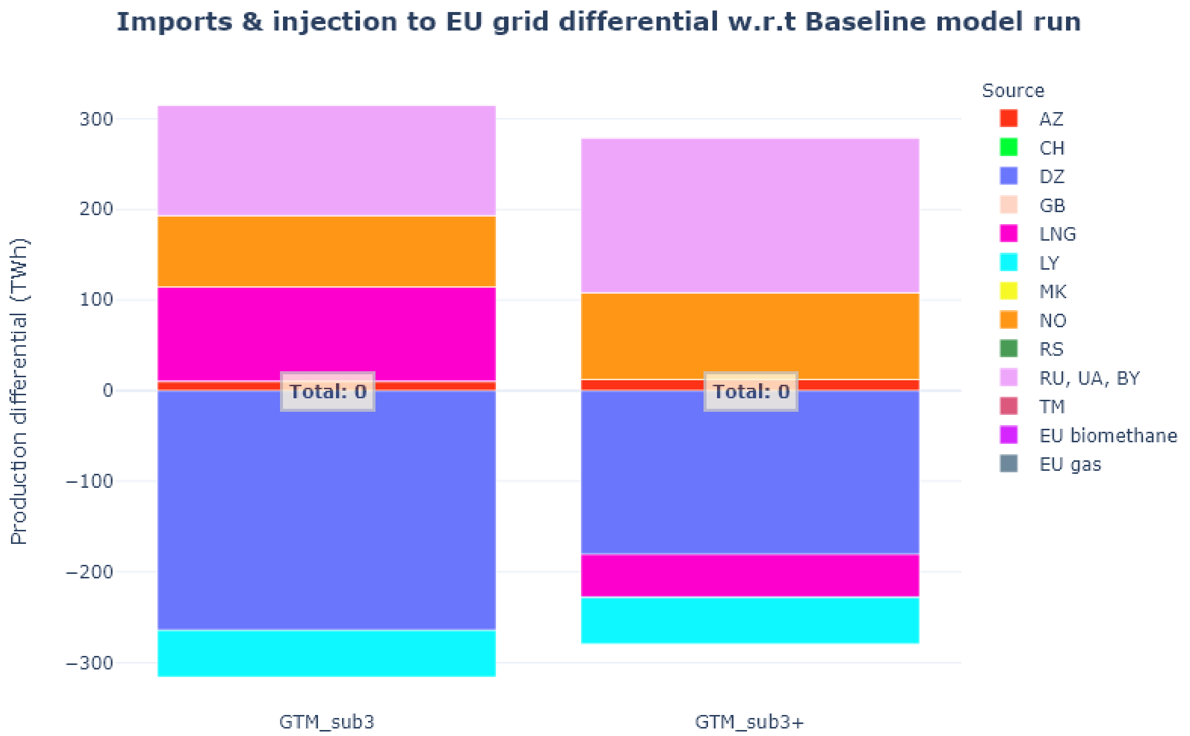


Figure 4-20: The EU gas supply mix and changes compared to the Baseline. Source: own calculations with METIS[155].

4.2.2.1.2 Impacts on cross-border exchanges

In addition to the supply mix, the GTM++ sub-measures affect the cross-border gas exchanges, cf. Figure 4-21. The arrows displayed in the figure represent the difference between the annual net exchange (which is the difference between the annual flows in

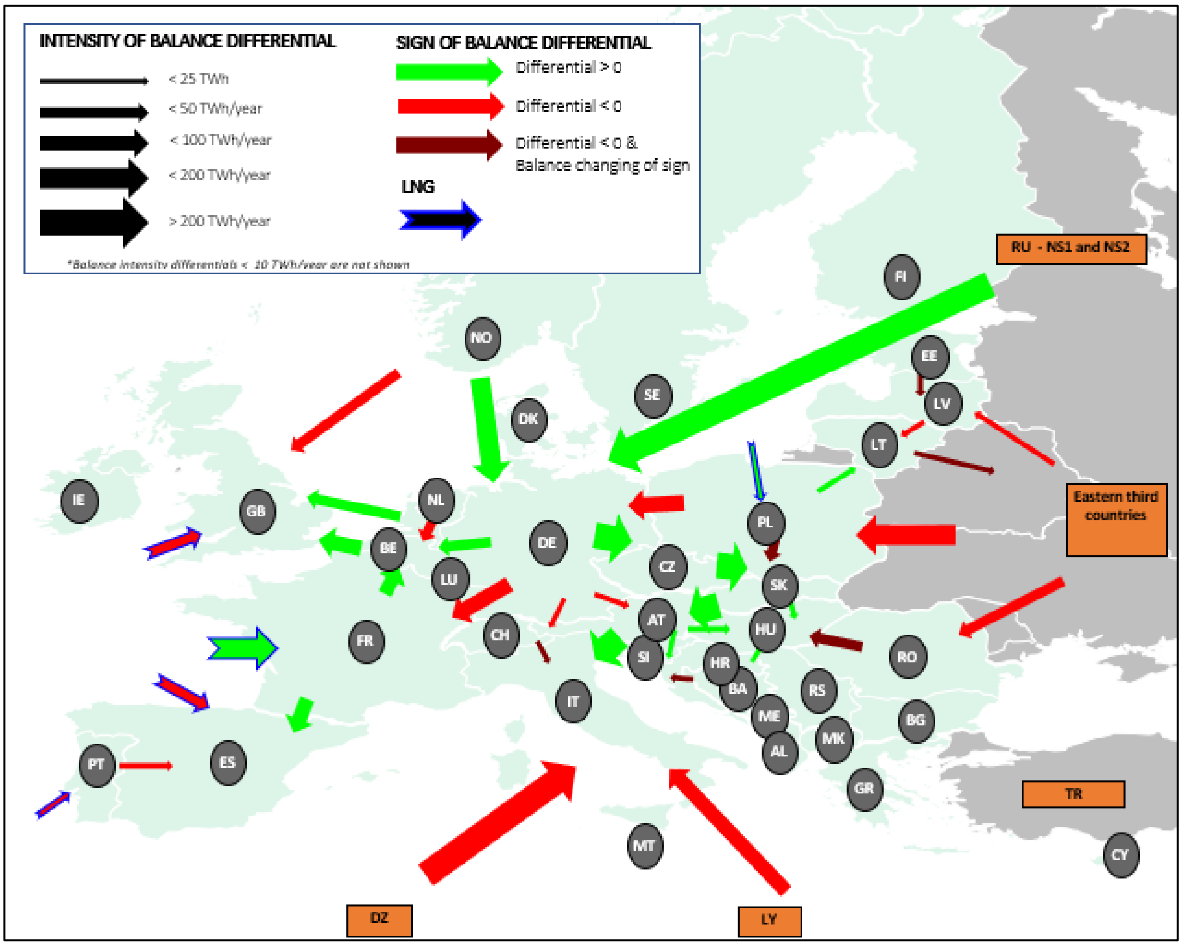
[155] A list of country abbreviations is available at the beginning of the report.

both directions) in the sub-measures analysed and the Baseline. The width of the arrow indicates the magnitude of the difference in net exchanges. The direction of the arrow indicates the direction of the net gas flow in the baseline model run. Only one arrow is represented per cross-border interconnection, hence some arrows may represent the flows of several gas pipelines combined.

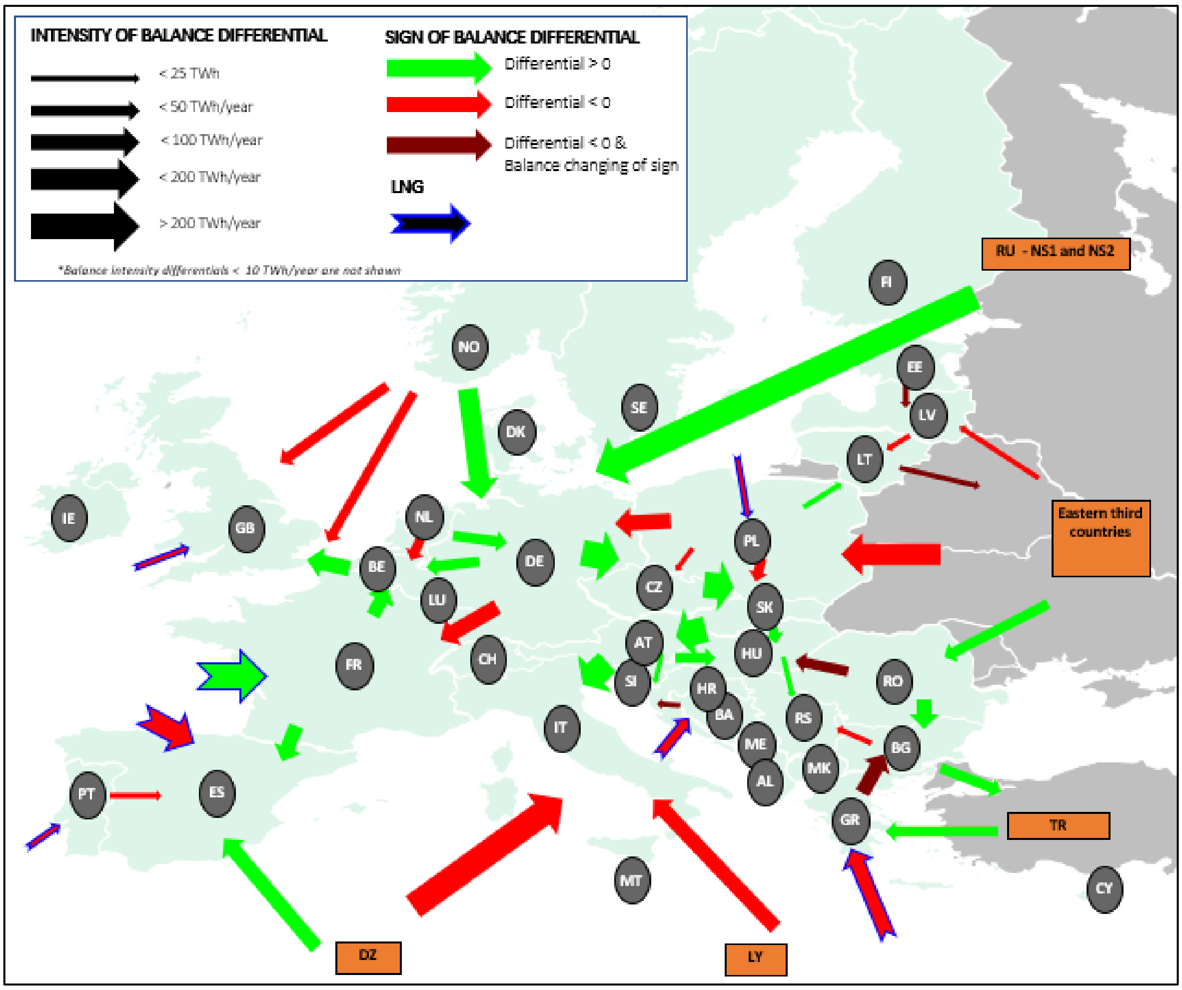
For instance, the change in gas flows between Estonia (EE) and Latvia (LV) in the GTM++ Sub-measure 3 represents a red arrow from EE to LV because of the logic presented in Table 4-5. In the Baseline, the net exchanges are 10 TWh/year from EE to LV hence the arrow direction is set from EE to LV. In the GTM++ Sub-measure 3 model run, the net exchanges are -14 TWh/year from EE to LV, hence the net exchange differential is -24 TWh/year from EE to LV. In the map, a red arrow is displayed between EE and LV, its size being sized accordingly to this value of -24 TWh/year. In such cases, the reverse flow is indicated with a "dark red" colour in the flow maps presented hereafter while the indicated direction of the arrow still reflects the one from the Baseline.

Table 4-5: Example of representation of the change in gas flows between Estonia (EE) and Latvia (LV). Source: own calculations.

Model run	EE exports to LV	LV exports to EE	Net exchange | Direction of the arrow displayed	Change in net exchanges
Baseline	75 TWh/y	65 TWh/y	10 TWh/y EE => LV	/
GTM++ Sub-measure 3	26 TWh/y	40 TWh/y	-14 TWh/y Same as ref, but dark red colour	-24 TWh/y



GTM++ Sub-measure 3 (compared to Baseline)



GTM++ Sub-measure 3+ (compared to Baseline)

Figure 4-21: Change in cross-border exchanges compared to Baseline. Source: own calculations with METIS.

In the case of both GTM++ sub-measures, the imports from the South (e.g., Libya and Algeria) are drastically reduced (as identified in the EU gas supply mix). This is offset by an increase of imports from Nord Stream 1 and 2 (due to the low entry tariff as the entry point considered was positioned in Germany). At the same time, the imports from other Eastern third countries to Eastern-European MSs are reduced, and the gas imported by Germany is redistributed to the Eastern MSs.

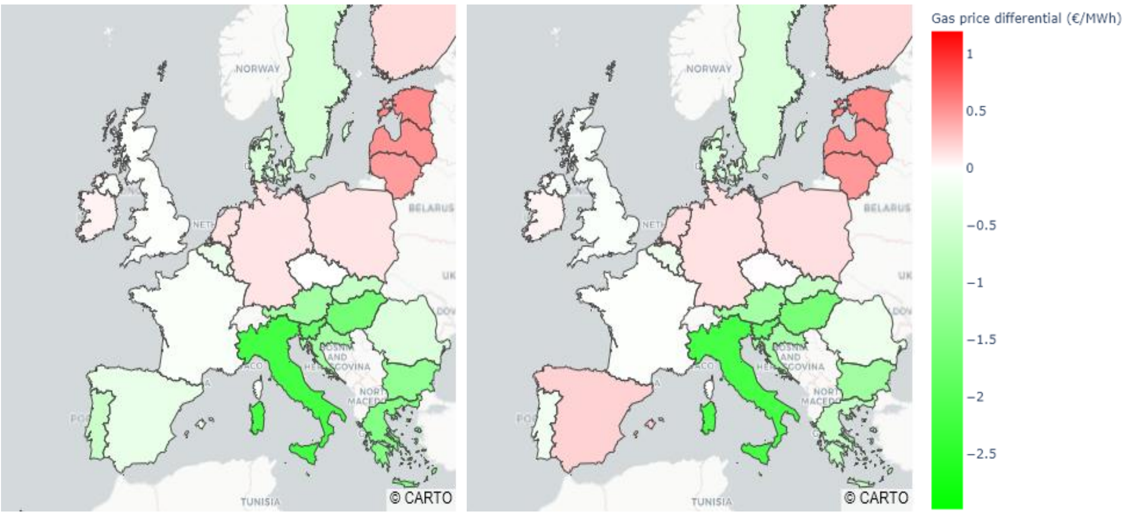
French LNG terminals benefit from both sub-measures, while LNG imports by the UK decline. This is linked to the fact that the cumulative costs for the entry tariff at French LNG terminals (which is relatively low even in the Sub-measure 3+ as France is closely located to the centre of Europe) and pipeline entry and exit tariffs to the UK are lower than the relatively high entry tariffs at the UK LNG terminals which are not impacted by the sub-measures.

The main difference between the Sub-measure 3 and the Sub-measure 3+ is that in the latter the LNG flows decrease at all LNG terminals (except for France which benefits of a low entry tariff since it is close to the centre of Europe), whereas pipeline gas imports mostly increase.

4.2.2.1.3 Changes in wholesale gas prices

For every model run, the average gas wholesale prices (demand-weighted over the year and excluding the internal exit tariffs) are computed. The detailed results are given in the

Annex, Section 8.3.4. The changes in gas prices in the GTM++ sub-measures compared to the Baseline are shown in Figure 4-22



GTM++ Sub-measure 3 *GTM++ Sub-measure 3+*

Figure 4-22: Changes in wholesale gas prices compared to the Baseline. Source: own calculations with METIS

Compared to the Baseline, wholesale gas prices decrease mostly in Southern Europe (benefiting from the 100% discount on LNG tariffs for Sub-measure 3 and the access to cheaper gas for both measures) and increase in Northern Europe and especially in the Baltic countries where external entry tariffs are increased.
As depicted in Figure 4-21, Southern Europe mainly benefits from the cheap gas coming from Norway and Nord Stream which is transiting through most of the countries concerned and ultimately is consumed in Italy where the price variation is the highest thanks to the removal of cross-border tariffs that benefit mostly to the countries far away of the supply sources. The gas price in Germany increases slightly as the cheap gas from Norway and Nord Stream is now competitive for the other European countries.
The main difference between the Sub-measure 3+ compared to Sub-measure 3 appears in Spain and Greece which face higher wholesale gas prices under Sub-measure 3+ due to the additional LNG entry tariffs.

4.2.2.1.4 TSO revenues and need for adaptation of internal exit tariffs

For every model run, the total TSO revenue components (excluding revenues from internal exit tariffs) are determined and presented in Figure 4-23. These components are the TSO entry revenues (stemming for external entry tariffs), TSO exit revenues (stemming for external exit tariffs) and TSO congestion rent[156] here totally allocated to the TSOs. These KPIs are further described in the Annex, Section 8.3.2.

The decrease in TSO revenues under the sub-measures is mainly due to the lowered profits from modified cross-border entry and exit revenues rather than to the difference in revenues from congestion rent, which are roughly at the same level for the Baseline and the two GTM policy measures.

[156] The congestion rent is computed as the difference in the gas wholesale price at a given border multiplied by the flows of one interconnection, minus the TSO revenues from tariffs. As long as the interconnection is not subject to congestion, the congestion rent is null.

The congestion rent is seen to be rather stable between the model runs. This is due to the fact that even if the flows are modified, with the same level of demand the gas infrastructure is not expected to be more stressed with the GTM++ measures hence the total congestion volume and associated congestion rent is not modified.

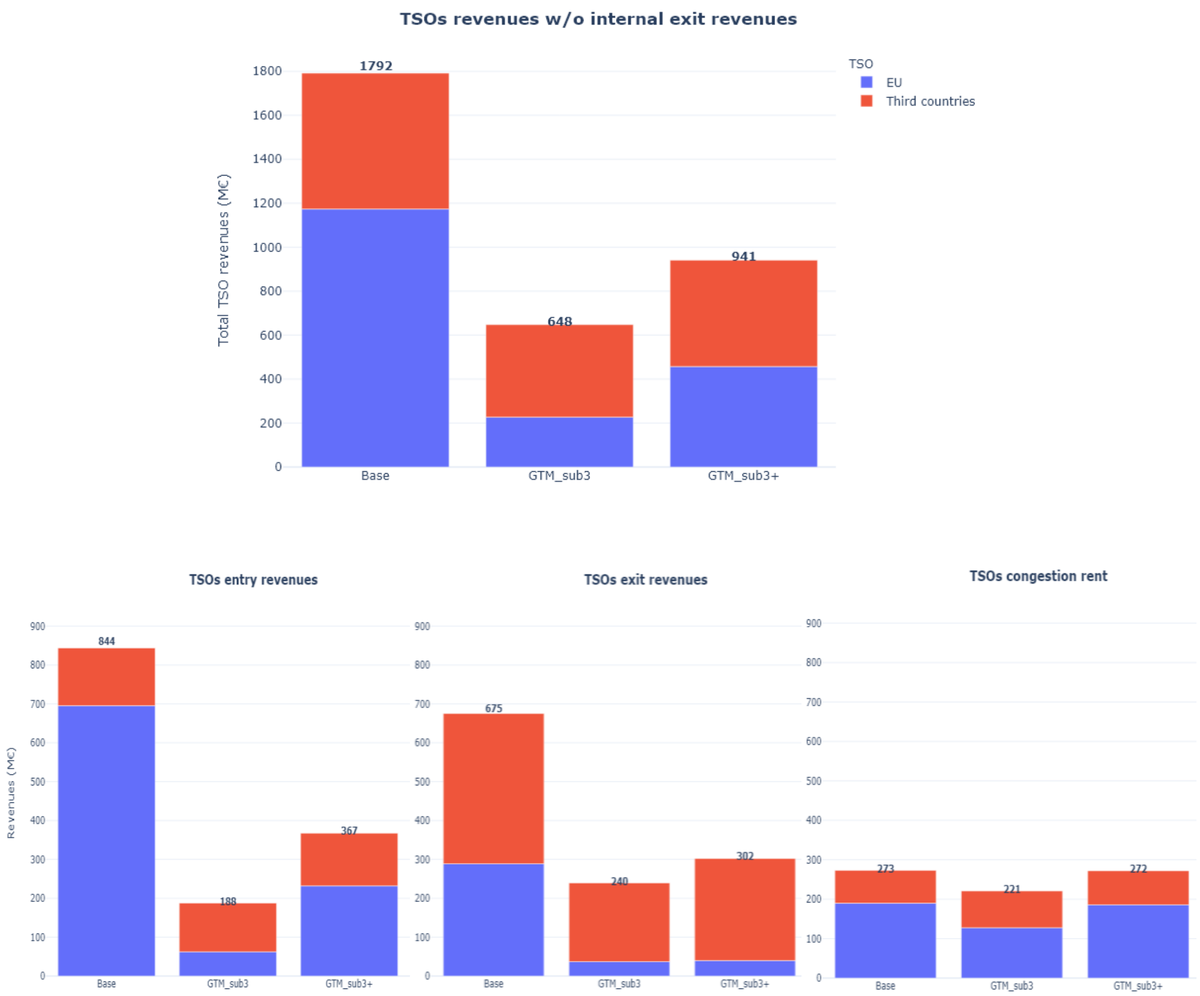
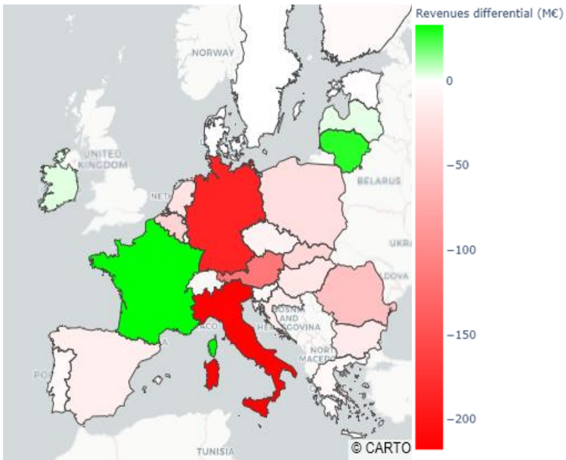


Figure 4-23: TSOs revenues (total revenues above, distinguished by components below). Source: own calculations with METIS.

For Sub-measure 3, the difference in total TSO revenues is negative for most of the MSs since all the intra-EU cross-border entry and exit tariffs disappear. The TSOs with the strongest decrease in revenues are Italy and Germany. The few countries observing an increase in TSO revenues are the countries with a border to a third entry point (typically Ireland), cf. Figure 4-24.

In the case of Sub-measure 3+, TSOs in France and Lithuania benefit from the additional entry tariff of their LNG terminal and also see their TSO revenues increase.

GTM++ Sub-measure 3



GTM++ Sub-measure 3+

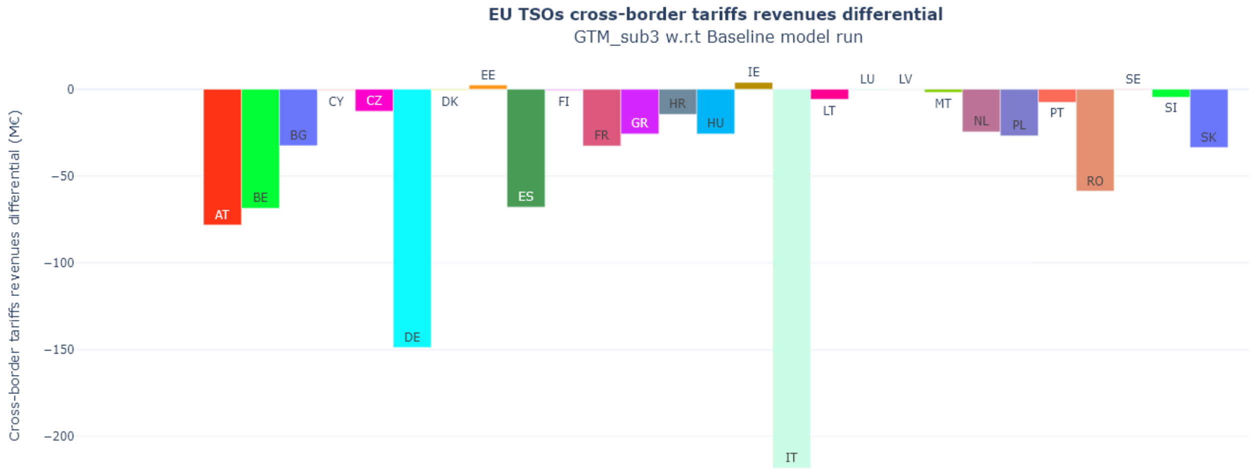
Figure 4-24: Changes in total revenues of TSOs (cross-border tariffs and congestion rent). Source: own calculations with METIS.

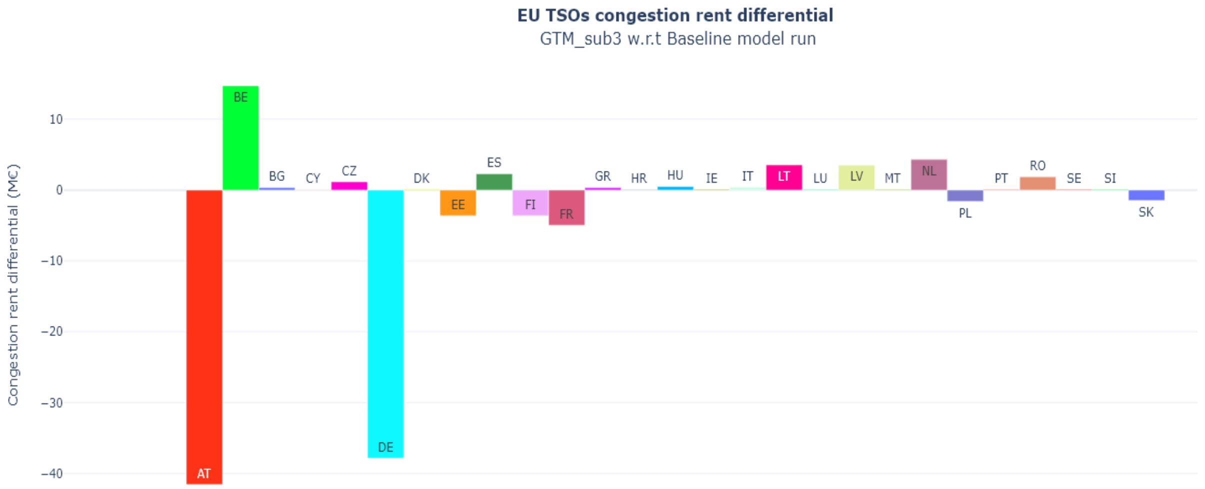
First solution: Adaptation of internal exit tariffs

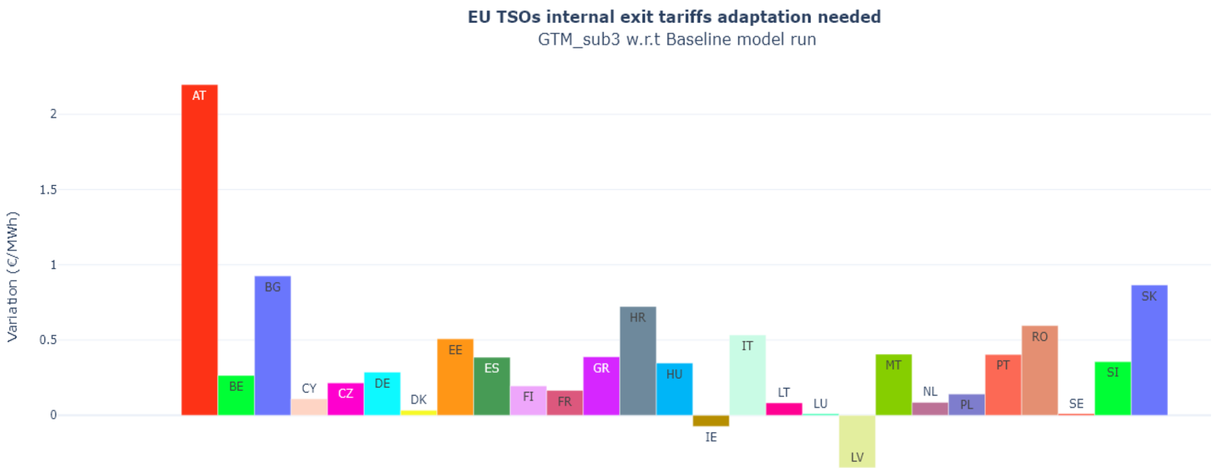
To retrieve the missing TSO revenues lost under the sub-measures, a first solution would be to modify the internal exit tariffs accordingly. This modification is estimated as the difference of TSO revenues between the Baseline and the sub-measure, divided by the national demand. For computation details see the corresponding KPI description in the Annex, Section 8.3.2.

The internal exit tariffs would need to be increased for almost all MSs to cope with the missing revenues, with the exception of those MSs that are located in direct neighbourhood to third countries. Figure 4-25 illustrates the change in TSO revenues (from cross-border entry/exit tariffs and from congestion rents) compared to the Baseline and the derived change in internal exit tariffs.

The change in cross-border tariff revenues is directly triggered by the change in cross-border gas flows, as illustrated in Figure 4-21. This change in revenues is due to the change in flows, tariffs but also congestion rents, as some interconnections are more or less used with the new tariffs, leading to the removal or the apparition of congestions. The most significant changes in congestion rent appear in Austria, Belgium and Germany. In particular, the Austrian-German interconnection which is congested in the Baseline model run is less used in both GTM++ model runs leading to a decrease of 83 M€ in congestion rent, split half-half between German and Austrian TSOs. The change in the congestion rent of the Belgian TSO is due to the increase in exports towards the United Kingdom, with a congestion rent of 43 M€ and 37 M€ in the sub-measures 3 and 3+, respectively compared to no congestion under the Baseline. Still the net increase in the Belgian congestion rent is dampened in both GTM++ runs by the decrease of 30 M€ in congestion rent from the Norway-Belgium pipeline.







GTM++ Sub-measure 3

GTM++ Sub-measure 3+

Figure 4-25: Changes in TSO revenues compared to the Baseline and adaptation of internal exit tariffs. Source: own calculations with METIS.

Second solution: Adaptation of external entry/exit tariffs

Another method to compensate for the loss in revenues is to modify only the third country entry point tariffs, by multiplying them by a corrective factor which is derived by comparing the EU TSO revenues under the Baseline with the revenues under the two sub-measures. These corrective factors are determined for the entirety of the third country entry point tariffs and equal **5.2 in case of Sub-measure 3 and 2.6 in case of Sub-measure 3+.**

This factor is more important in the Sub-measure 3 than in the Sub-measure 3+ as in the latter LNG imports contribute to TSO revenues, so the need to increase the third country entry/exit tariffs is less important.

A detailed overview of the adaptation of tariffs at external EU entry and exit points needed to retrieve the same level of revenue is given in Figure 4-26. For the adaptation of the LNG entry points tariffs, only the Sub-measure 3+ model run is presented as these tariffs are null in case of Sub-measure 3.

TSO_entry	TSO_exit	GTM_sub3 Entry tariff	GTM_sub3+ Entry tariff	GTM_sub3 Entry tariff adjusted	GTM_sub3+ Entry tariff adjusted
BE	GB	0.05	0.05	0.26	0.13
BE	NO	0.07	0.07	0.35	0.18
BG	RS	2.65	2.65	13.71	6.81
BG	TR	0.11	0.11	0.58	0.29
DE	CH	0.09	0.09	0.48	0.24
DE	NO	0.02	0.02	0.13	0.06
DE	RU	0.01	0.01	0.04	0.02
EE	RU	0.36	0.36	1.86	0.92
ES	DZ	0.13	0.13	0.66	0.33
FI	RU	0.39	0.39	2.04	1.01
FR	CH	0.24	0.24	1.23	0.61
FR	NO	0.06	0.06	0.32	0.16
GR	TR	0.20	0.20	1.04	0.52
HR	RS	0.63	0.63	3.26	1.62
IE	GB	0.17	0.17	0.90	0.45
IT	CH	0.04	0.04	0.19	0.10
IT	DZ	0.07	0.07	0.38	0.19
IT	LY	0.17	0.17	0.85	0.42
LT	BY	0.16	0.16	0.83	0.41
NL	NO	0.03	0.03	0.17	0.08
PL	BY	0.04	0.04	0.18	0.09
PL	UA	0.23	0.23	1.20	0.60
RO	RS	0.91	0.91	4.72	2.35
RO	UA	0.04	0.04	0.19	0.09
SK	UA	0.02	0.02	0.08	0.04

Adapted tariff levels (€/MWh) for external entry points

TSO_entry	TSO_exit	GTM_sub3 Exit tariff	GTM_sub3+ Exit tariff	GTM_sub3 Exit tariff adjusted	GTM_sub3+ Exit tariff adjusted
BA	HR	0.10	0.10	0.50	0.25
CH	DE	0.07	0.07	0.35	0.17
CH	FR	0.09	0.09	0.47	0.23
CH	IT	0.05	0.05	0.28	0.14
GB	BE	0.05	0.05	0.27	0.14
GB	IE	0.48	0.48	2.49	1.24
GB	NL	0.09	0.09	0.46	0.23
ME	HR	2.61	2.61	13.48	6.70
MK	BG	2.77	2.77	14.29	7.10
MK	GR	0.81	0.81	4.19	2.08
RS	BG	0.12	0.12	0.64	0.32
RS	HR	0.82	0.82	4.21	2.09
RS	HU	0.24	0.24	1.24	0.61
RS	RO	0.91	0.91	4.72	2.35
RU	EE	0.93	0.93	4.78	2.37
RU	LT	0.59	0.59	3.04	1.51
TR	BG	0.13	0.13	0.67	0.33
TR	GR	0.22	0.22	1.15	0.57
UA	PL	0.23	0.23	1.20	0.60
UA	RO	1.41	1.41	7.26	3.61
UA	SK	0.08	0.08	0.43	0.21

Adapted tariff levels (€/MWh) for external exit points

	GTM_sub3+	
TSO_entry	Entry tariff	Entry tariff adjusted
BE	0.23	0.59
CY	5.94	15.25
DE	0.18	0.47
EE	0.99	2.53
ES	0.67	1.73
FR	0.25	0.63
GB	0.19	0.19
GR	1.53	3.92
HR	0.72	1.84
IE	0.50	1.28
IT	0.52	1.34
LT	0.70	1.80
LV	0.33	0.85
NL	0.16	0.42
PL	0.38	0.98
PT	1.07	2.76
SE	3.30	8.46

Adapted tariff levels (€/MWh) for LNG entry points (only for Sub-measure 3+)

Figure 4-26: TSOs cross-border tariffs adaptation needs. Source: own calculations with METIS.

4.2.2.1.5 Changes in welfare and specific cost components

The study of the welfare of the different stakeholder types (consumers, producers, TSOs, LSOs, SSOs, shippers) allows to understand which gas market participant is benefiting or not from the GTM++ measures. Figure 4-27 illustrates the difference in welfare under the two sub-measures compared to the Baseline for each of these stakeholders. Further, the presentation of the welfare is decomposed in two ways. First, the welfare of EU countries is shown separately from the welfare of third countries. Secondly, the revenues/surplus of national stakeholders (consumers, TSOs, LSOs, SSOs summed up in the "welfare's component" chart) are shown separately from the revenues of international stakeholders (producers, shippers summed up in the "other system costs" chart). This later distinction is done as the revenues/surplus of national stakeholders are necessarily impacting the consumers' welfare of the same country, whereas the revenues/surplus of producers and shippers are not explicitly linked to consumers of a specific country.

The sum over all these elements is null in every model run as the consumer surplus is equivalent to the full systems costs, rents and producer surplus (as in the end the consumers are paying for everything), as explained by the overall equation in the Annex, Section 8.3.2. For instance, for the Sub-measure 3, the sum of the total EU welfare (475 M€/year), non-EU welfare (-123 M€/year), EU other system's costs (-190 M€/year) and non-EU other system's costs (-162 M€/year) is zero. Further details on the welfares distinguished by country may be found in Section 8.3.5.

Figure 4-27: Changes in EU countries' and third countries' welfare and specific cost components. Source: own calculations with METIS.

As the missing TSO (and presumably SSO and LSO) revenues are compensated by an increase in internal exit tariffs and paid anyway by the consumers, the actual consumer surplus shall be rather read as the sum of the consumer surplus, TSO, SSO and LSO revenues computed in METIS. For instance, in the results for Sub-measure 3, the consumer surplus and SSO revenues increase by nearly 1.5 B€/year, but the TSOs revenues decrease by about 1 B€/year. As this missing revenue will be charged to the consumers, the real EU consumer benefit from the measure equals the difference between the two values, that is 475 M€/year.

That means that both sub-measures are beneficial to the EU consumers, even when taking into account the increase of internal exit tariffs to retrieve the missing TSO revenues, as the increase in consumer surplus exceeds the decrease in TSO revenues. This is possible at the detriment of third country consumers and producers:

- In the case of the Sub-measure 3, the EU consumers gain 475 M€/year. This may be explained by a reduction in the EU producer surplus by 190 M€/year, a net reduction in non-EU TSO revenues (exceeding the increase in non-EU consumer surplus) of 123 M€/year and a net reduction in non-EU production costs (exceeding the increase in non-EU LNG shipping costs and non-EU producer surplus) of 162 M€/year.

- In the case of the Sub-measure 3+, the EU consumers gain 179 M€/year, notably driven by a reduction in EU producer surplus (154 M€/year).

Under the given entry/exit tariffs, both GTM++ sub-measures seem to reduce production costs, which means that in the end the sub-measures facilitate the accessibility to cheaper gas sources.

4.2.2.2 Economic impacts – 2nd iteration: with adapted external entry/exit tariffs

For this second iteration, the external entry and exit tariffs were increased as described in Section 8.3.2, both for sub-measures 3 and 3+[157], by a factor of **5.2 in case of Sub-measure 3 and 2.6 in case of Sub-measure 3+** as computed in 4.2.2.1.

4.2.2.2.1 Changes in the EU gas supply mix

The identified effects in terms of changes in the EU gas supply mix under the second iteration are quite similar to those of the first iteration with two major differences (cf. Figure 4-20 and Figure 4-28):

- In Sub-measure 3, the higher level of LNG imports is emphasized at the detriment of Norwegian and Eastern third countries imports. This is due to higher pipelines entry/exit tariffs at the EU borders while the LNG entry tariffs are still not charged;
- In Sub-measure 3+, the reduction in LNG imports is more pronounced than in the first iteration, as the difference between the LNG entry tariffs compared to the Baseline is more important than in the first iteration.

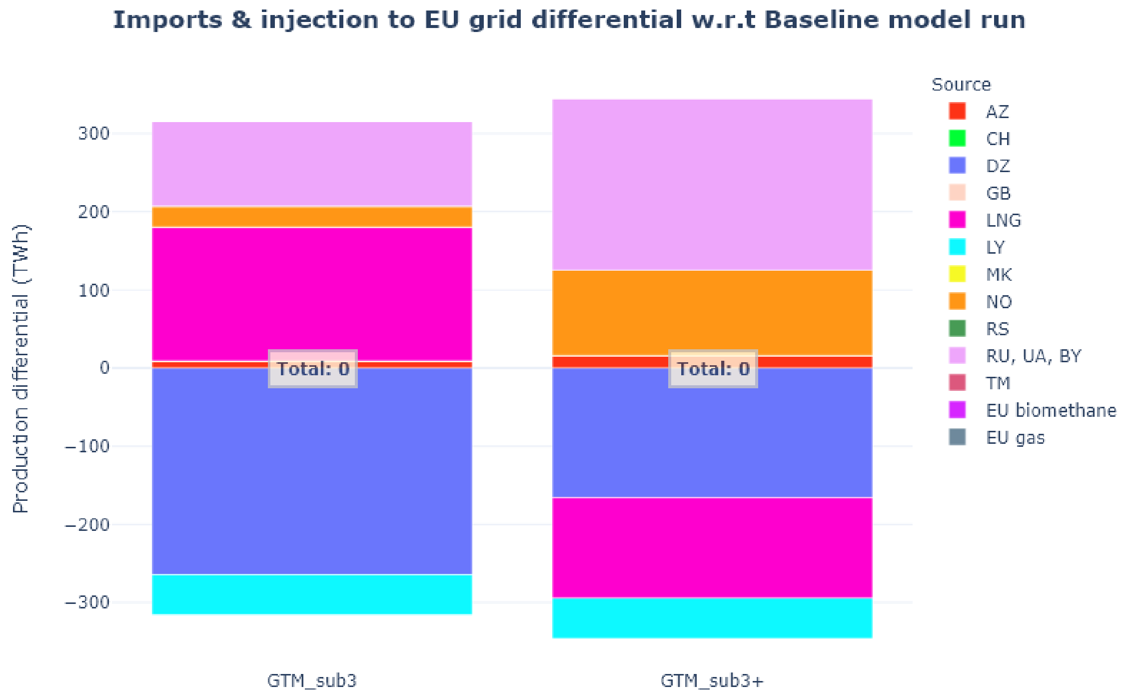


Figure 4-28: Changes in the EU gas supply mix compared to the Baseline. Source: own calculations with METIS.

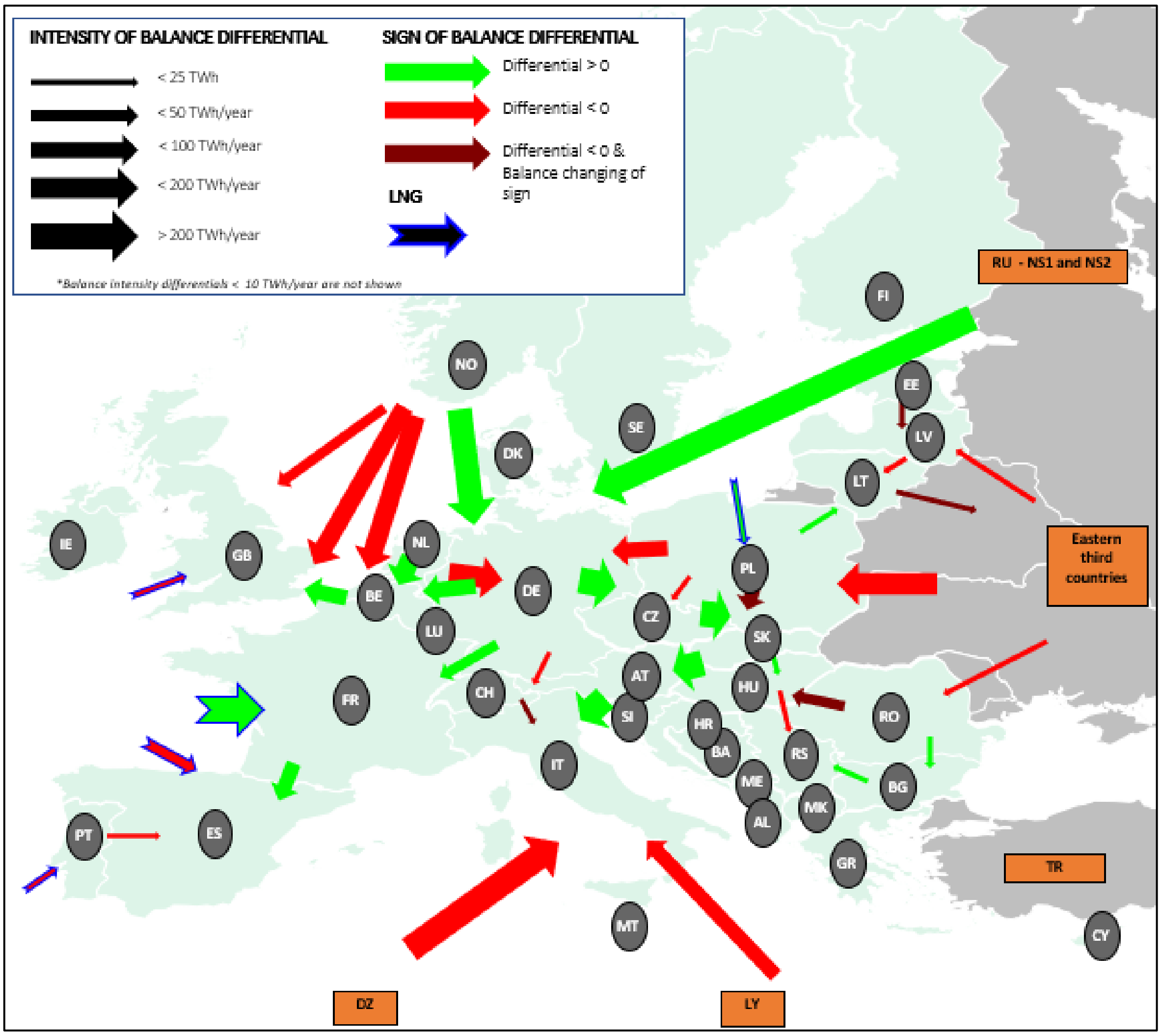
[157] In Sub-measure 3 the LNG entry tariffs are still zero while in Sub-measure 3+ they build upon the same methodology as for the cross-border pipeline.

4.2.2.2.2 Impacts on cross-border exchanges

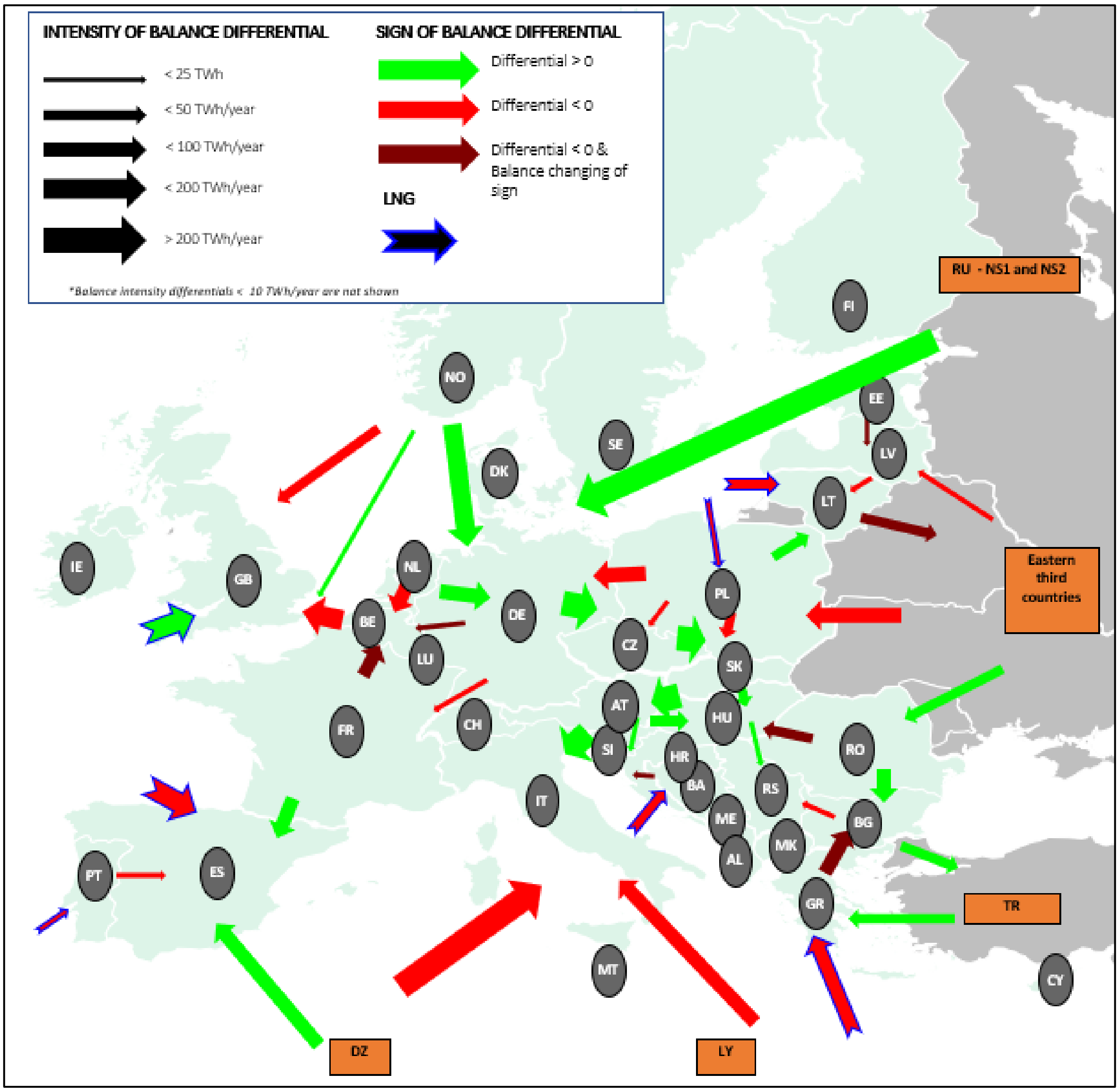
As in the previous iteration, both GTM++ sub-measures imply lower imports from Northern Africa (*e.g.,* Libya and Algeria) due to the higher level of imports from Nord Stream 1 and 2 (cf. Figure 4-29).

Generally speaking, the effects are the same in the second as in the first iteration, but they are mostly amplified in the second iteration.

Another difference between the two iterations can be identified with respect to Sub-measure 3+ where French LNG imports are not increased compared to the Baseline while UK LNG imports are strongly increased. This is due to the fact that with the increase of external entry/exit tariffs, it becomes more cost-efficient for consumers to directly import LNG from the UK LNG terminals rather than from the continent and then transferring it to the UK. Thus, the UK takes advantage of the low-cost LNG made available by comparatively low LNG entry tariffs compared to the rest of Europe.



GTM++ Sub-measure 3 (compared to Baseline)

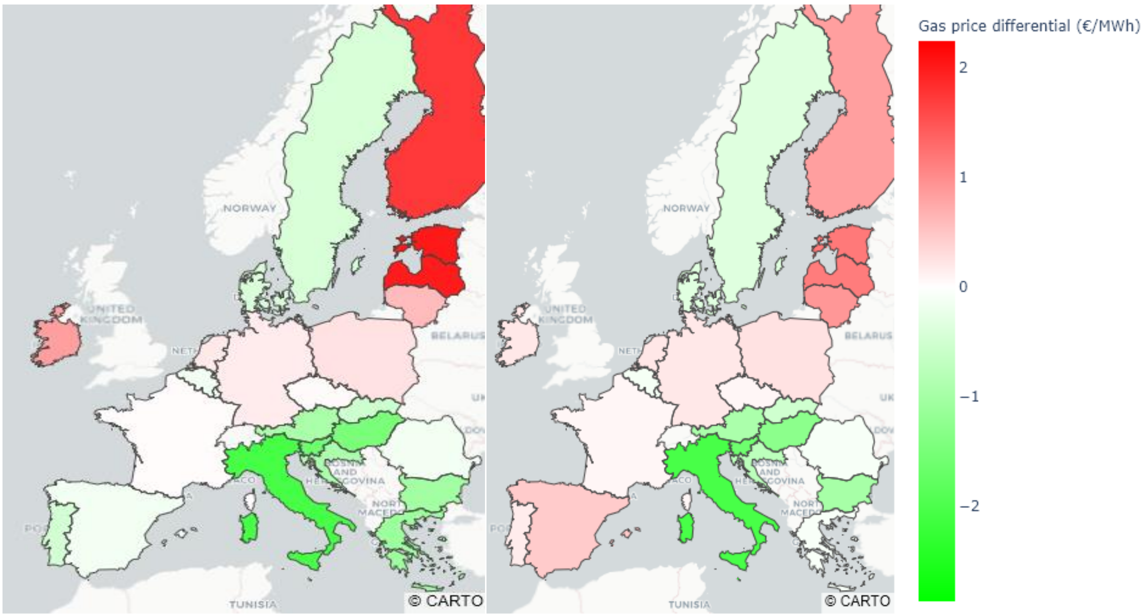


GTM++ Sub-measure 3+ (compared to Baseline)

Figure 4-29: Changes in cross-border exchanges compared to Baseline. Source: own calculations with METIS.

4.2.2.2.3 Changes in wholesale gas prices

As in the first iteration, the average gas wholesale prices (demand-weighted over the year and excluding the internal exit tariffs) are computed. The detailed results are given in the Annex, Section 8.3.4. The changes in gas prices in the GTM++ sub-measures compared to the Baseline are shown in Figure 4-30.



GTM++ Sub-measure 3 *GTM++ Sub-measure 3+*

Figure 4-30: Changes in wholesale gas prices compared to the Baseline. Source: own calculations with METIS.

Compared to the first iteration, the effect on wholesale gas prices is similar with a decrease mostly in the Southern countries opposed to a slight increase in several Central and Northern European MSs and especially in the Baltic countries where external entry tariffs are increased.

The raise in wholesale gas prices is more extreme than in the first iteration, with a maximal raise of about +2 €/MWh against +1 €/MWh previously observed in the Baltic region. This is directly due to the surge of entry points tariffs compared to the first iteration with the multiplicative factor of 5.2 and 2.6 applied in GTM sub-measures 3 and 3+ respectively.

4.2.2.2.4 TSO revenues and need for adaptation of internal exit tariffs

The TSO revenues (for EU and non-EU TSOs) in sub-measures 3 and 3+ rise by 61% and 18%, respectively, compared to the first iteration. However, TSO revenues still differ from the Baseline revenues despite the increase in tariffs. This is due to the fact that (a) the gas flows are modified by the new tariffs, hence the change of TSO revenues from tariffs is not proportional to the adaptation of tariffs and (b) that congestion rents are also part of the TSO revenues and are not proportional to the adaptation of tariffs neither.

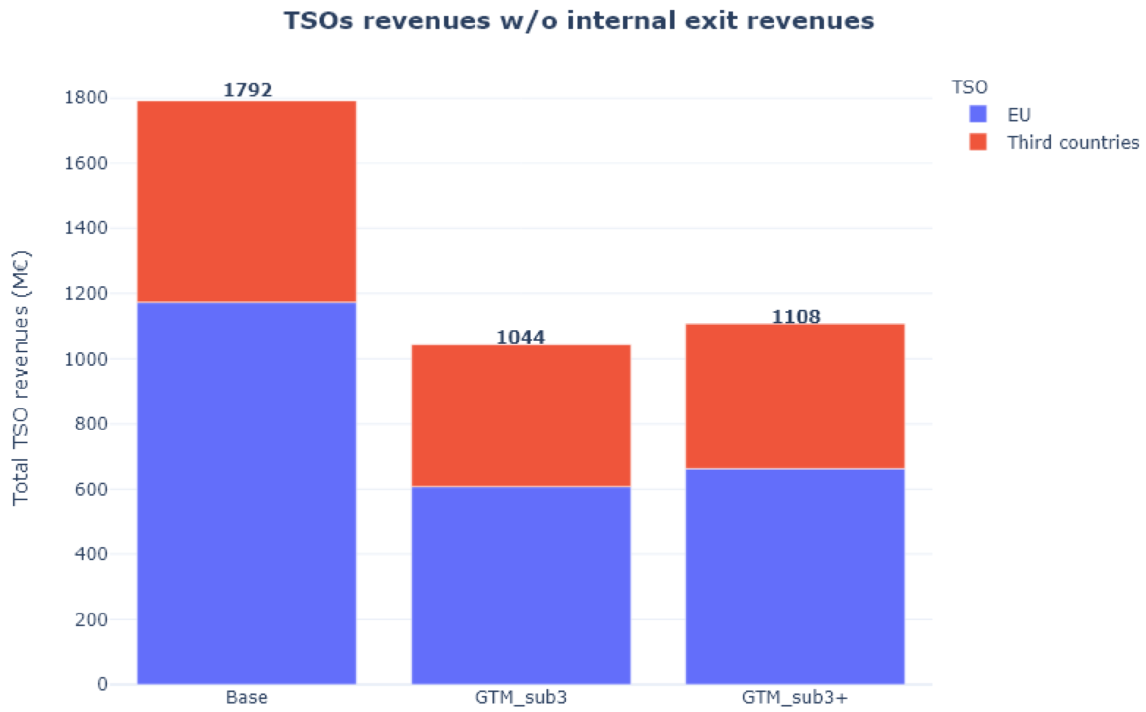


Figure 4-31: TSOs' total revenues. Source: own calculations with METIS.

The change in revenue compared to the Baseline and the resulting need for adaptation of the internal exit tariffs are illustrated in Figure 4-32 by MS for the sub-measure 3. Overall, the adaptation needs for lower internal exit tariffs decline compared to the first iteration, with mean EU[158] tariff adaptation needs of **+0.17 €/MWh** against **+0.27 €/MWh** in the former iteration. This is directly due to the additional revenue from external entry/exit tariffs compared to the previous iteration, hence the mean tariff adaptation is less important.

[158] The EU average is weighted by the demand of the MSs.

Figure 4-32: Changes in TSO revenues compared to the Baseline and adaptation of internal exit tariffs under Sub-measure 3. Source: own calculations with METIS.

As for the Sub-measure 3, a lower internal exit tariff adaption is needed for Sub-measure 3+, with an EU-mean (with the same weight for each MS) tariff adaptation needed of **+0.16 €/MWh** against **+0.21 €/MWh** in the former iteration (cf. Figure 4-33). This is directly due to the additional revenue from external entry/exit tariffs compared to the previous iteration, hence the mean tariff adaptation is less important.

In any case, the differences are very different between the different EU countries, raising the need for an ITC mechanism to equilibrate the losses and gains (and redistribute the overall benefits) among the MSs.

Figure 4-33: Changes in TSO revenues compared to the Baseline and adaptation of internal exit tariffs under Sub-measure 3+. Source: own calculations with METIS.

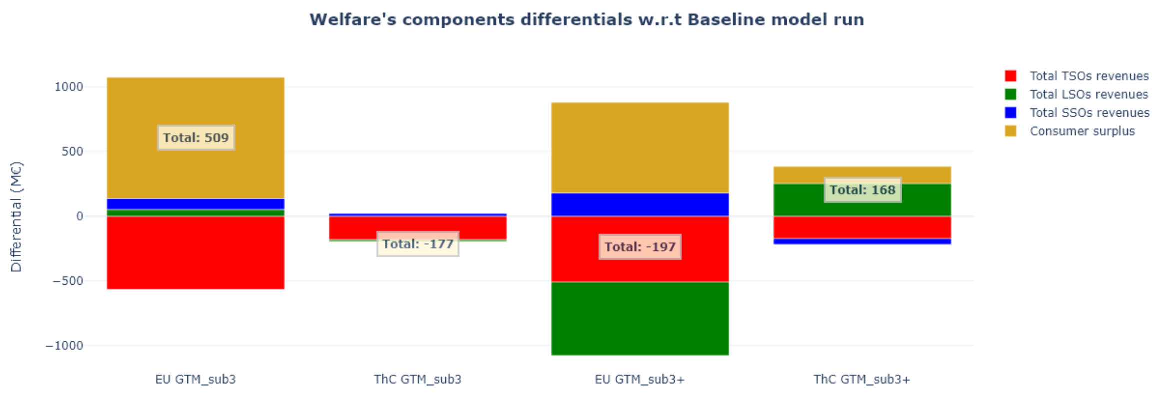
4.2.2.2.5 Changes in welfare and specific cost components

Details on the welfares distinguished by country may be found in the Annex, Section 8.3.5.

In terms of welfare the outcomes are quite different between the two sub-measures, cf. Figure 4-34:

- In the case of Sub-measure 3, the results are similar to the first iteration with a net benefit for EU consumers. Indeed, even when taking into account the compensation of TSO, LSO and SSO losses on the consumer surplus, the EU consumers gain 509 M€/year compared to the Baseline. On the other hand, non-EU consumers lose 177 M€/year. From a producer perspective, the EU producers lose 132 M€/year in producer surplus and the non-EU producers'/shippers' surplus drops by 200 M€/year;

- In the case of Sub-measure 3+, the results have shifted from both the consumer and the producer perspectives. Taking into account the compensation of TSO, LSO and SSO losses on the consumer surplus, the EU consumers lose 197 M€/year compared to the Baseline. This opposite trend compared to the previous iteration is mainly due to higher LSO losses incurred by lower LNG imports into the EU. At the same time, the higher level of LSO revenues in third countries entails a net benefit of 168 M€/year for third country consumers. The producers located in the EU lose 116 M€/year in terms of surplus while it increases by 145 M€/year for non-EU producers/shippers.



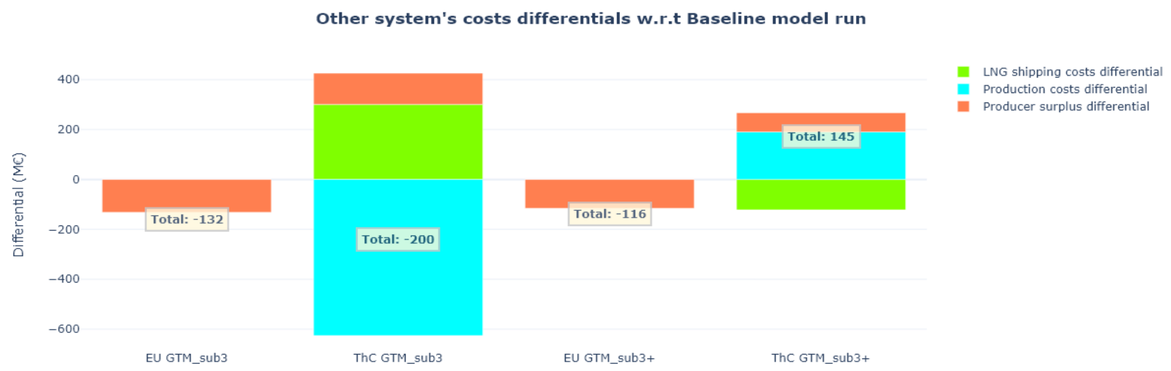


Figure 4-34: Changes in EU countries' and third countries' welfares and specific cost components. Source: own calculations with METIS.

This second iteration thus leads to the conclusion that **raising the external entry/exit tariffs** is beneficial to EU consumers to the detriment of non-EU consumers and non-EU producers in the case of **Sub-measure 3 only (with a 100% discount on the entry tariffs for LNG terminals)**.

However, for **Sub-measure 3+ (with an entry tariff on LNG terminals)** it seems that the raise of tariffs is too important as the EU consumers lose money as opposed to non-EU consumers and producers. Moreover, the production costs increase in this configuration, meaning that these high entry tariffs reduce the accessibility of cheaper gas.

The comparison of the two iterations advocates for a careful design of the GTM. The analysis shows that a raise of entry tariffs can be beneficial or negative for EU consumers depending on (a) the amplitude of tariffs and (b) where they are applied. In particular, no general conclusion on the EU consumer welfare can be derived from this analysis.

4.2.2.3 Economic impacts - Sensitivity analysis on Nord Stream 2

To evaluate the influence of the Nord Stream 2 (NS2) pipeline connecting Russia to Germany, the same tariff configuration as in the second iteration of Sub-measure 3 is considered. This second iteration serves as the reference, which is complemented by a sensitivity where the pipeline capacity of Nord Stream 2 is removed.

4.2.2.3.1 Changes in the EU gas supply mix

Removing the Nord Stream 2 pipeline capacity reduces the Eastern third countries' gas exports to the EU by nearly 200 TWh/year (-15%) and 67 TWh (–6%) compared to the second iteration of Sub-measure 3 and the baseline model run, respectively. This reduction is mainly offset by Norwegian gas and LNG imports (approx. +100 TWh/year each).

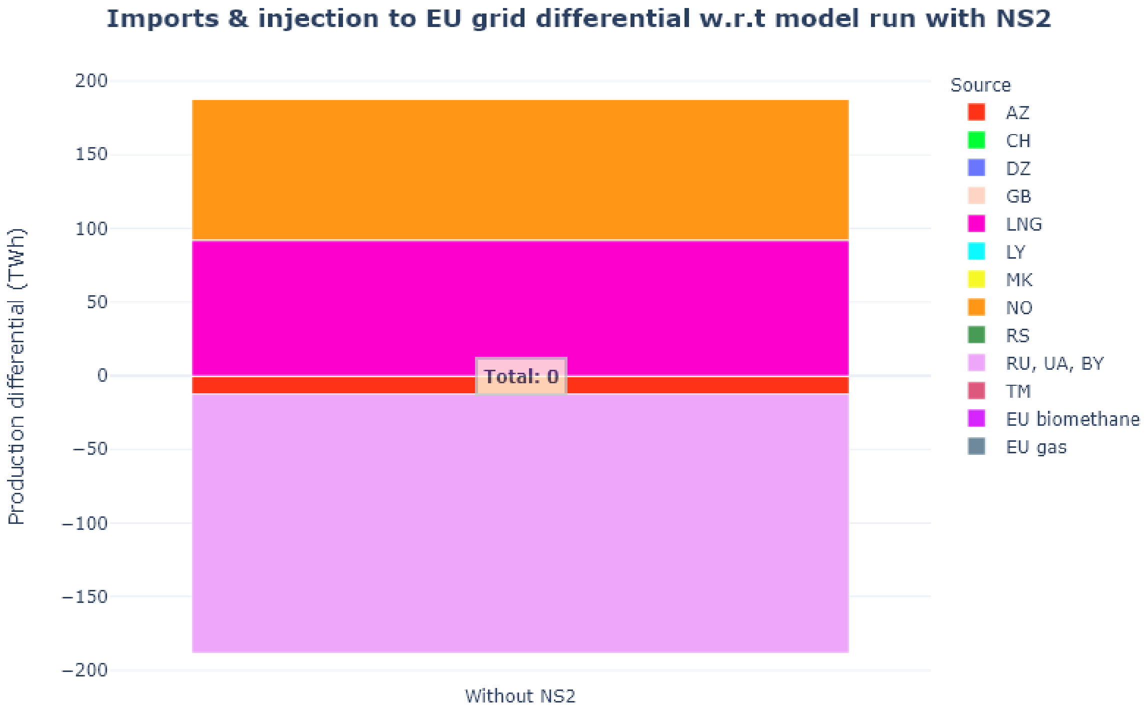


Figure 4-35: Changes in EU gas supply mix. Source: own calculations with METIS.

4.2.2.3.2 Changes in wholesale gas prices

The demand-weighted average gas prices (before applying the internal exit tariffs) are computed with the METIS model. The detailed results are given in the Annex, Section 8.3.4. Figure 4-36 illustrates the changes in average gas prices compared to the second iteration of Sub-measure 3. Wholesale gas prices decrease slightly in Eastern European MSs sharing a border with the Russian region as more cheap Russian gas is available for direct imports in the absence of Nord Stream 2. In contrast, Western countries encounter a slight raise of wholesale gas price as their access to cheaper Russian gas is reduced. The demand-weighted EU average gas price features a net increase in the absence of Nord Stream 2.

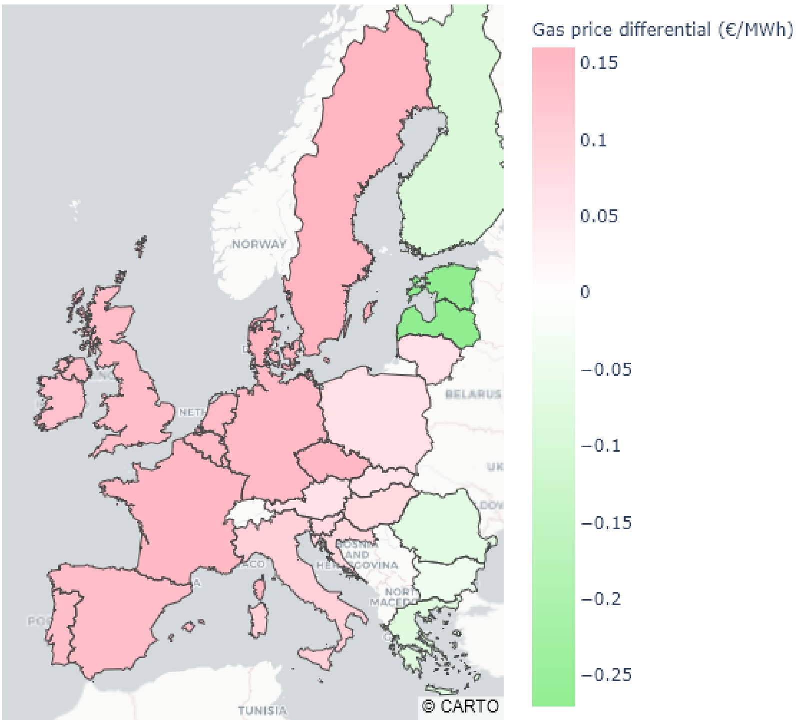


Figure 4-36: Changes in wholesale gas prices. Source: own calculations with METIS.

4.2.2.3.3 TSO revenues and internal exit tariffs

Since the reference case including Nord Stream 2 is identical to the second iteration of the analysis of Sub-measure 3, revenues are the same (cf. left-hand side of Figure 4-37). The TSO revenues (for EU and non-EU TSOs) in the case without Nord Stream 2 increase by 25% w.r.t the second iteration of Sub-measure 3.

Figure 4-37: Total TSO revenues. Source: own calculations with METIS.

Figure 4-38 reveals the change in TSO revenues by MS, disentangling revenues from external entry tariffs and revenues from the congestion rent.

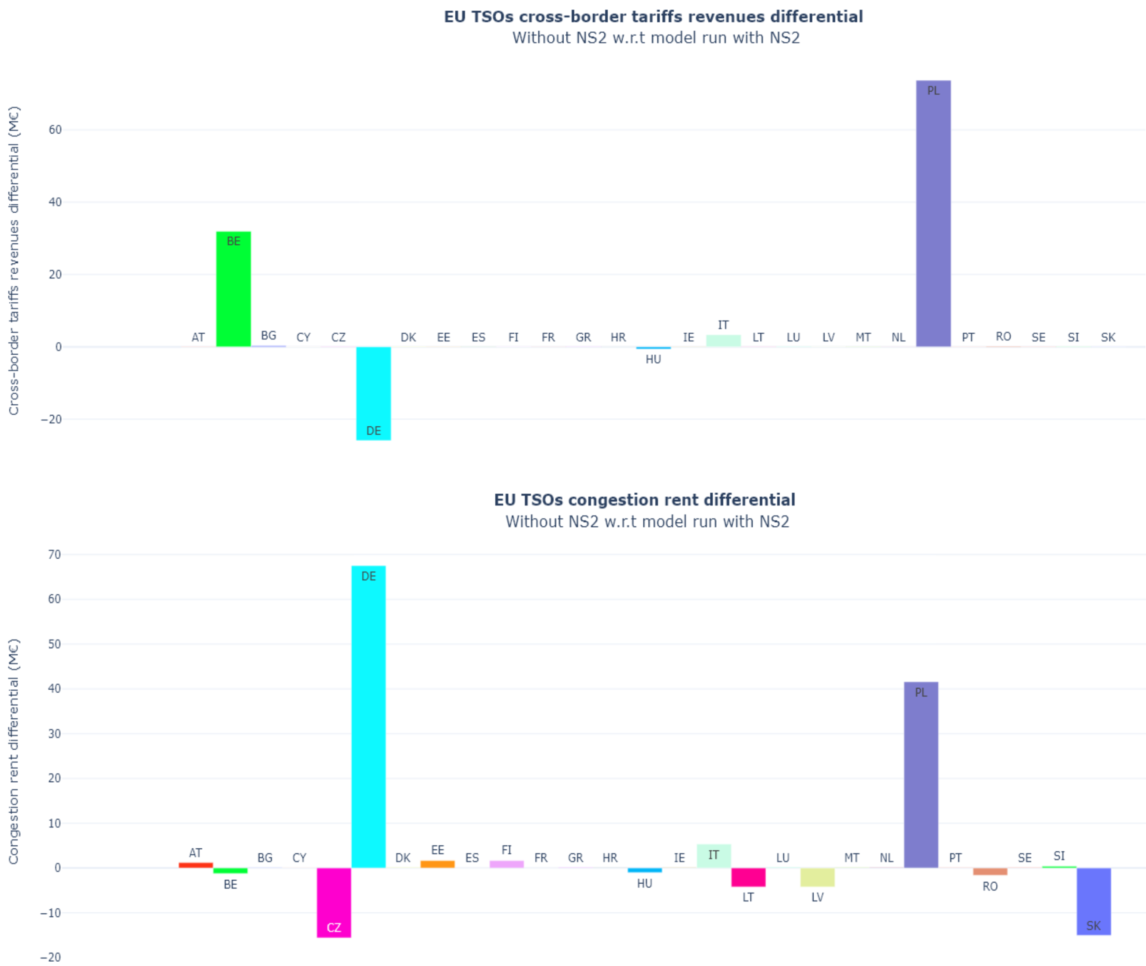


Figure 4-38: Changes in TSO revenues by country. Source: own calculations with METIS.

As the direct pipeline interconnection capacity between Germany and Russia is reduced by roughly 50%, several TSOs benefit from new transit flows, for instance Poland, with a significant increase in revenues from external tariffs. In the Polish case, this effect is combined with a high congestion rent on the Belarusian-Polish pipeline[159]. This congestion rent equals up to 90 M€ and is split half-half between Belarus and Poland. In addition, the reduced interconnection capacity between Russia and Germany is used at full capacity and thus triggers a high level of congestion rent (218 M€/year compared to the 68 M€/year in the baseline). The detailed congestion rents are presented in Figure 4-39.

[159] Belarus is part of the cluster of "Eastern third countries" in the METIS modelling.

Context	With NS2	Without NS2
Pipe		
AT-HU	0.0	0.7
AT-IT	0.1	10.7
AT-SI	0.0	0.5
BE-GB	20.4	18.0
BG-GR	1.9	1.9
BY-PL	0.0	90.1
CZ-PL	0.7	0.0
CZ-SK	30.5	0.0
DE-AT	9.3	0.0
DE-PL	6.0	0.0
DK-DE	0.1	0.1
EE-FI	9.7	13.1
FR-ES	4.6	4.4
HU-RO	8.2	4.9
LT-LV	40.4	32.0
NO-DE	15.7	15.7
NO-NL	68.1	68.1
PL-LT	0.2	0.2
RU-DE	68.1	218.4
SI-IT	0.0	0.1
SK-HU	0.0	0.6
SK-PL	0.2	0.0

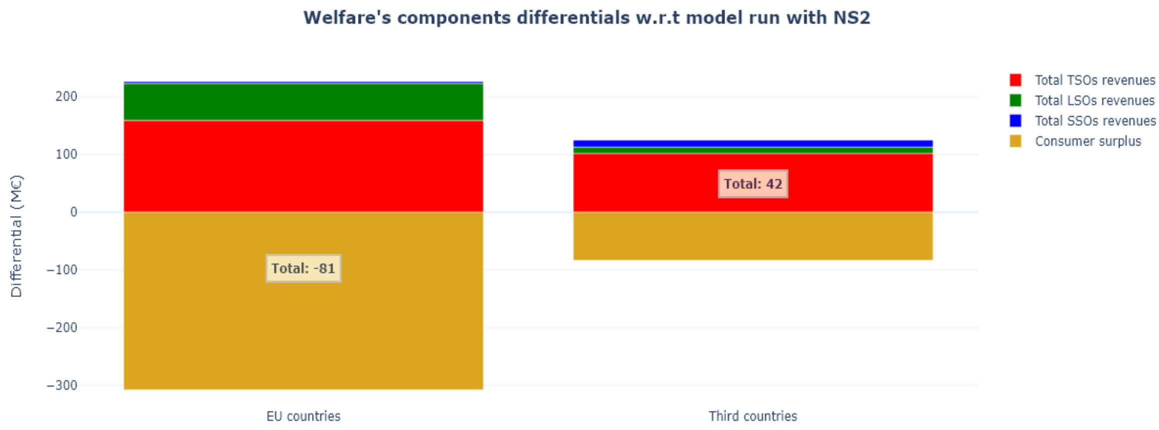
Figure 4-39: Comparison of congestion rents (in M€) in the case with and without Nord Stream 2. Source: own calculations with METIS.

Note: A pipeline's terminology is "Origin-Destination".

4.2.2.3.4 Changes in welfare and specific cost components

Figure 4-40 depicts the change in welfare and cost components compared to the reference case including Nord Stream 2. Details on the welfares distinguished by country may be found in the Annex, Section 8.3.5.

The EU consumers' net loss in surplus of 81 M€/year is mainly due to a higher gas price (consumer surplus reduction), which is partly balanced by higher TSO and LSO revenues. Non-EU consumers are the beneficiaries of the removal of Nord Stream 2, thanks to higher TSO revenues entailed by the new transit towards the EU.



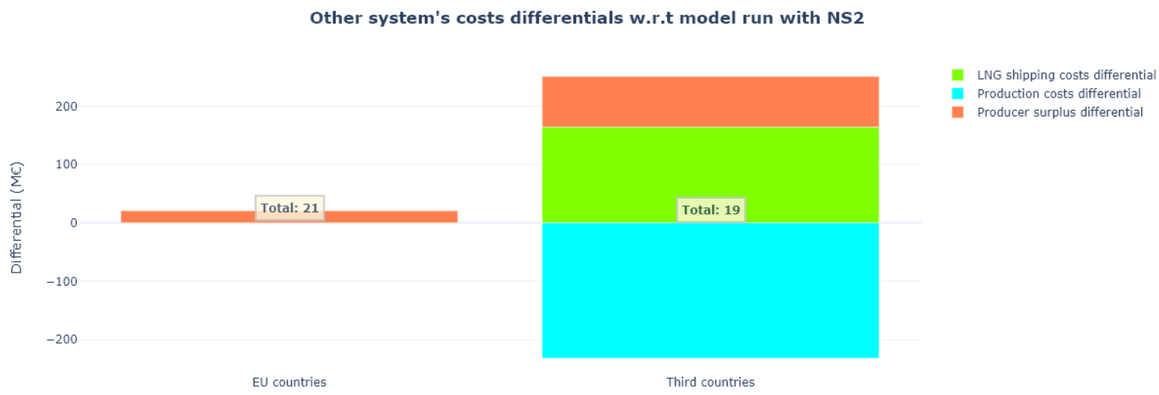


Figure 4-40: Changes in EU countries' and third countries' welfares and specific cost components. Source: own calculations with METIS.

4.2.2.4 Economic impacts - Impacts on the power sector

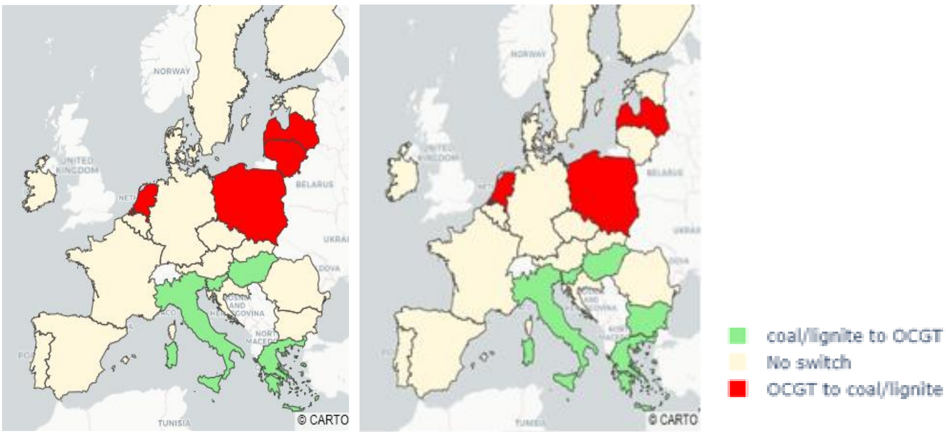
This section analyses how the change in gas prices under the two sub-measures and the two iterations affects the merit order of power producers. As only the gas price varies between the different sub-measures and iterations, only the Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT) power plants are subject to a shift in the merit order.

The national wholesale gas prices that are considered to determine the marginal cost of electricity generation for OCGTs and CCGTs are determined as average annual gas prices weighted by the countries' gas demand at each time-step. Adapted internal exit tariffs (from solution 1 in follow-up to iteration 1) are added to the gas price in every MS to reflect the sub-measures' impact at the MS level. Table 4-6 provides an overview of the number of MSs subject to a change in the merit order compared to the Baseline.

Table 4-6: Number of Member States that is confronted to a switch in the power sector compared to the Baseline. Source: own calculations.

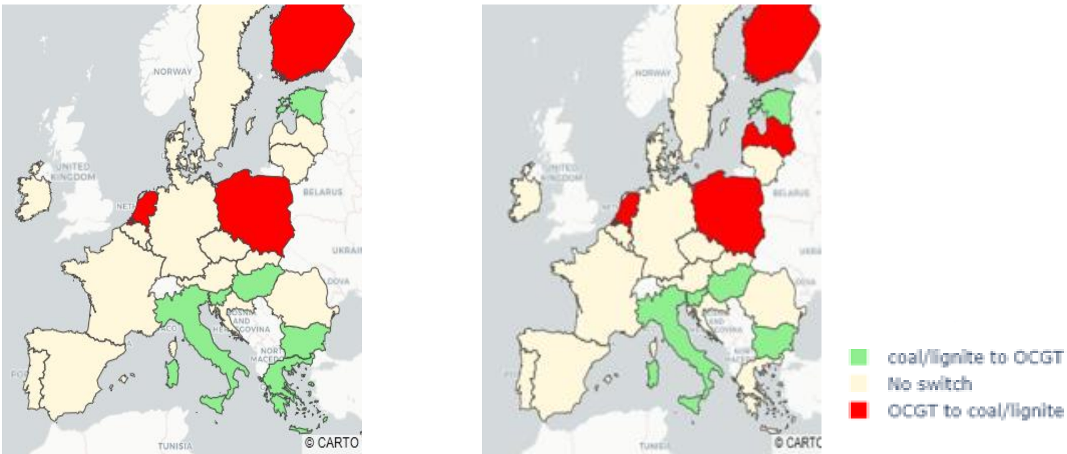
		First iteration		Second iteration	
		GTM_sub3	GTM_sub3+	GTM_sub3	GTM_sub3+
Switch towards OCGT	Young coal & young lignite & old lignite displaced by OCGT			1	
	Old coal displaced by OCGT	5	6	6	5
	Old lignite displaced by OCGT				1
No switch in merit order		18	18	17	16
Switch from OCGT to coal/lignite	OCGT displaced by old lignite	4	3	2	3
	OCGT displaced by old coal			1	2

First iteration:



GTM++ Sub-measure 3 *GTM++ Sub-measure 3+*

Second iteration:



GTM++ Sub-measure 3 *GTM++ Sub-measure 3+*

Figure 4-41: Merit order switches in the power sector for EU MSs, compared to the Baseline. Source: own calculations.

Note for MT and CY: MT is in green (switch of coal/lignite to OCGT) on every map, CY is in red (switch of OCGT to coal/lignite) for the GTM++ Sub-measure 3+ - second iteration map.

The impacts of the GTM++ sub-measures in 2030 for the MIX H2 scenario on the power sector merit order are the following:

- A change in tariffs due to GTM++ does not affect the position of CCGTs in the merit order as CCGTs feature substantially lower marginal generation costs than coal and lignite plants (cf. Section 4.2.1).

- The GTM++ sub-measures could change the merit order between the OCGT and the different coal/lignite technologies, depending on the country. Yet, for most EU MSs there would be no change.

    - The effects appear to be relatively similar for the four cases considered. At least 5 countries present a switch from coal to OCGT plants, as a consequence of the sufficient decrease of the gas prices in these MSs (upper part of Table 4-6).

  - In up to 5 countries, one may observe a switch from gas to coal or lignite (lower part of Table 4-6).

This analysis was carried out without considering an ITC mechanism. With a perfect ITC mechanism, the gas price for consumers is expected to equal or even decreases for each EU MS, compared to the baseline. In such a situation, it would be probable that the OCGT production would become more competitive in some EU MSs, and that OCGTs would notably become more competitive compared to coal power plants.

In addition, no DSO entry tariff was considered on top of the gas prices for OCGT and CCGT power plants as they are partly directly connected to the TSO. Such a tariff would increase the overall marginal costs of these plants, moving the range further up and potentially dampening the identified effect of coal/lignite power plants being displaced by OCGTs in some countries.

Note that the effects identified with regard to the merit order are very sensitive to the gas price signal. For instance, in case of the Netherlands switching from OCGTs to old lignite is triggered by a change in the difference of marginal generation costs (OCGT – old lignite) from +1 €/MWh in the Baseline to -0.4 €/MWh in Sub-measure 3 (first iteration).

Box 4-9: Limitations of the GTM++ assessment and complementary considerations.

Limitations of the GTM++ assessment and complementary considerations

Three main limitations can be associated to this analysis:

- **Market imperfections and strategic behaviour are not modelled**: The modelling of the European gas market with METIS relies on the assumption that the market functions in a perfect way. In reality, gas market participants may exhibit strategic behaviour. Asymmetric information may imply that particular consumers or producers can capture rents beyond the societal economic optimum. Thus, it is likely that the impacts identified for the application of the GTM++ sub-measures in the present analysis must be interpreted under the assumptions taken. It should be further noted that the sub-measures under consideration may trigger other, unexpected impacts due to unforeseen strategies that could endanger the gain of welfare for the EU consumers.
- **Historical contracts are not taken into account**: In reality, in 2030 a certain share of gas supply sources and capacity reservation will be constrained by long term contracts. The KPIs presented in this analysis do not take into account such contracts. Hence the benefits of the GTM++ sub-measures may be not directly obtained in 2030 as not all gas exchanges will be only market-based.
- **Operational implementation of the measures can be costly**: The transition towards the GTM++ sub-measures is a major challenge as the removal of intra-EU tariffs and increase of external tariffs with third countries would represent a change of tariffication never seen before. Many stakeholders (TSOs, LSOs, NRAs) may doubt they benefit from the measures and be reluctant to endanger their current situation, thus opposing or delaying the application of the measures. Practically, the adoption of the new routine of capacity reservation including the new management of congestion may be long and costly in terms of design of governance, IT conception, etc. Thus, the operational application of the measures is expected to be quite extensive and to necessitate significant efforts from the different gas stakeholders being part of the process. The analysis presented here does not take into account these considerations.

4.2.3 Environmental impacts

The removal of intra-EU entry/exit tariffs implies higher tariffs for imports with increasing distance from the EU's virtual centre. As domestic biomethane production is typically localised within the MS, this distance is expected to be lower on average than for natural gas being imported from third countries. Thus, GTM++ sub-measures would imply a comparative advantage for (local) biomethane compared to natural gas imports from outside the EU. However, assuming that biomethane production still largely relies on public support by 2030, biomethane injection are likely to depend on public support instead of economic competitivity (cf. Section 4.1.2). Hence, the related environmental impacts may be considered to be close to null. Further, the comparative tariff advantage for domestic biomethane production would also apply to domestic natural gas production, which could ultimately favour a net increase in emissions if domestic natural gas production was in competition with biomethane imports.

Apart from the impact on the competitivity of domestic biomethane and natural gas production compared to natural gas imports, GTM++ sub-measures are not expected to provide some direct increase or reduction of CO_2 emissions as the volume of natural gas and CO_2 content are expected to be the same in all the situations studied.

4.2.4 Social impacts

The key figures to understand the social impacts of the two sub-measures on European consumers are the welfare balances of the first and second iteration:

- **First iteration**: From a consumer perspective, the EU consumers benefit from both GTM++ sub-measures to the detriment of third country consumers. From a producer perspective the EU producers' surplus decrease, but the non-EU producers' surplus increase.
- **Second iteration**: In this iteration the welfare balances are more pronounced for each region. From a consumer perspective, EU consumers benefit from the GTM Sub-measure 3 at the expense of non-EU consumers. The situation is reversed in GTM Sub-measure 3+. From a producer perspective the same dynamics as in the first iteration appear: the EU producers' surplus decreases, but the non-EU producers' surplus increases.

The GTM++ sub-measures are also strongly impacting non-EU countries as the choice of (a) the value of the distance-based factor to determine the external entry/exit tariff and (b) the choice of putting a 100% discount on the entry tariffs of the LNG terminals or applying the same methodology as for external entry tariffs are largely impacting both the non-EU suppliers and consumers. In some GTM++ configurations, some sources will be preferred while others may be discarded.

Without a strong political will and a sophisticated and well-coordinated tariff calculation methodology, the GTM++ sub-measures have to be complemented by an ITC mechanism, otherwise the impact of the sub-measures on MSs is too disparate to be accepted as such. The establishment of the ITC would be expected to raise many discussions among the MSs' NRAs and TSOs, and an important level of negotiations and coordination will be needed to reach a well-balanced mechanism. Nonetheless, it is unlikely to find an ITC mechanism that benefits strictly all the MSs to a similar extent.

4.2.5 Comparison of measures

The GTM++ sub-measures were found to have major impacts on gas flows, the EU gas supply mix and the distribution of gas market revenues among the different stakeholders. Based on an analysis with two iterations and building upon a comprehensive modelling of the 2030 EU gas market with the METIS model (relying on the 2030 MIX H2 scenario), the Sub-measure 3+ was seen to be less beneficial to the EU consumers than the Sub-measure 3. For one configuration studied (Sub-measure 3+, high third country and LNG entry points tariffs), the economic impact was found to be negative for EU consumers, highlighting the fact that the GTM++ sub-measures are not necessarily beneficial and could harm the EU consumers.

Moreover, the implementation of the GTM++ sub-measures is considered to represent a major challenge and an ITC mechanism is likely to be needed to ensure a balanced impact on all MSs. The efforts to design GTM rules and an ITC in a well-balanced and concerted manner is expected to represent a significant and time-consuming task for different stakeholders across all MSs. As the results are subject to high uncertainty and strongly driven by the assumptions (cf. Box 4-9). Thus, the overall efficiency cannot be considered as definitely positive.

Thus, the GTM is a powerful tool that will certainly bring major changes to the gas market in Europe, but as such it should be carefully developed and applied to ensure well-balanced impacts.

Table 4-7: Comparison of the impacts of sub-measures related to GTM++.

Measure	Economic	Environmental	Social	Efficiency	Effectiveness
Sub-measure 3 (low third country entry tariffs, 100% LNG entry tariff discount, without ITC)	++	0	++	-	+
Sub-measure 3 (high third country entry tariffs, 100% LNG entry tariff discount, without ITC)	++	0	++	-	+
Sub-measure 3+ (low third country & LNG entry tariffs, without ITC)	+	0	+	-	+
Sub-measure 3+ (high third country & LNG entry tariffs, without ITC)	-	0	-	-	-
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)					

4.3 Regulatory framework for the quality of gases (incl. hydrogen blend)

In a context of increased injection of hydrogen and biomethane and consequent decentralisation of gas supply (while in the past only few non-EU and EU sources injected gas in the system), EU-level coordination of gas quality standards is one way to improve the management of gas quality and provide clarity to network users, from producers to storage operators and end-users. Currently, European standards for gas quality exist but are not binding, with Member States setting the actual mandatory gas quality specifications (possibly referring to European standards).

EU-level gas quality standards might stay **voluntary or can become mandatory.** Voluntary standards can lead to an alignment of gas quality specifications between Member States, if national authorities or network operators adopt them. For example, several connected Member States with high current or future ambitions for hydrogen or biomethane injection have an incentive to align their gas quality standards in order to ensure unhindered gas cross-border flows. Mandatory standards on the other hand will ensure that standards are aligned within the EU but might not reflect the national contexts and lead to unreasonable costs for adapting gas infrastructure and end-user equipment, appliances and processes.

There are several other aspects that must be considered when establishing gas quality standards that take into account hydrogen and/or biomethane, of which the main ones are introduced next.

The **difference between the Wobbe index classes for entry and exit points** influences where responsibility for complying with gas quality standards lies. Larger differences between entry and exit point bandwidths will lead to challenges for the grid operators in order to ensure specific gas quality characteristics downstream. A narrower gas quality range at entry points may restrict the capacity of gas producers to inject and potentially require the use of measures such as gas enrichment in order to keep the injected gas within the specified gas quality range, while facilitating the gas quality management by network operators. Future EU gas quality standards should strike a balance between end-user application safety and minimal modification costs for infrastructure and end-user equipment, appliances and processes, while delivering maximal flexibility for producers.

Another aspect is whether binding EU-level gas quality standards would in the future set **specifications for the whole EU gas system or solely for cross-border flows**. In the former case, it might also apply to national **transmission and distribution networks** (especially if there is a higher penetration of renewable and low-carbon gases at the distribution level).

The following assessment focusses in particular on the impacts of increased harmonisation of standards with respect to hydrogen-blending in gas transmission networks and at cross-border IPs.

4.3.1 Introduction

4.3.1.1 Methodology

According to the ACER Report on NRAs Survey[160], most European NRAs agree on the relevance of defining H_2 blending limits at the EU level. The aim of this study is to assess the **impact of regulation on H_2 blending rates at the EU gas transmission system level**. The impact of regulation of hydrogen blending at the transmission level on the EU gas distribution networks is not studied in this analysis.

The impacts of four situations are assessed: **no measure taken**, reinforced **coordination** between the MSs on gas quality management and transparency on national hydrogen blending levels (Measure 1), implementation of a **minimum acceptance level** at cross-border points (Measure 2), and implementation of a **maximum level in addition to the minimum acceptance level** (Measure 3.1).

The following **methodology** was used for this analysis:

1. Estimation of national limits for hydrogen blending in transmission networks, in the case of nationally chosen blending limits.
2. Estimation of clusters of cooperating MSs, based on the previously expected individual blending limits.
3. Construction of different "cluster configurations" depending on the policy measures chosen and their associated minimum and maximum acceptance levels. The minimum acceptance level and the maximum levels considered in this

[160] (ACER, 2020a)

analysis are 5%, 10%, 20% and 30%[161]. The three first thresholds were chosen as each of them implies the adaptation of additional equipment and thus additional adaptation costs. The minimum acceptance level and the maximum level for H2 blending are chosen at the EU level, while national blending limits depend on the MS. These national blending limits must be higher than the EU-wide minimum acceptance level, and lower than the EU-wide maximum level.[162]

4. Assessment of economic, environmental and social impacts for the different cluster configurations.

The blending volumes estimated with this methodology go beyond the blending volumes projected by the MIX H2 scenario. Hence, the assessment on gas quality differs in this regard from the assessments of the other policy topics.

In the following paragraphs, the methodology for the determination of the cluster configuration is described in more detail. It is important to note that the blending levels (in%) are expressed in volumetric terms and represent the H_2 blending rates at the transmission grid level. 10% of blending rate means in this analysis that 10% of the volume is constituted by H_2, which represent approximately 3% of the energy content of the gas mixture (HHV).

The clusters were determined according to the following rules:

- If a country cooperates with another, they coordinate regarding the establishment of a joint minimum acceptance level at the TSO level. In this analysis, the highest national blending limit of the cluster was chosen as the joint minimum acceptance level for each cluster. The gas flows between countries cooperating together are not constrained.
- Gas systems are supposed to be able to cope with dynamic blending levels between 0% and the minimum acceptance level at any point in time.
- Gas flows from a country with a low blending level to a country with a higher blending level are feasible.[163]
- Gas flows from a country with a high blending level to a country with a lower blending level are not feasible. It would be technically possible thanks to deblending stations at the IPs, but the associated costs would be important, thus this solution was discarded in the analysis.

4.3.1.2 No measure taken

In a situation where no measure is taken, the blending limit of each MS (at the transmission grid level) was estimated considering the current national legislation (if available) or other indications, disregarding the blending limit in neighbouring countries.

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[161] This 30% blending rate was chosen as an upper limit of blending at the TSO level where new adaptation after the threshold of 20% would be needed, in order to calculate associated blended volumes and avoided emissions.

[162] One example to illustrate this: assuming a 5% EU-wide minimum acceptance level and a 10% EU-wide maximum level, TSOs have to accept blending levels at interconnection points between 0 and 5% (i.e. they cannot reject flows with a blend under and at 5%). TSOs/MS can voluntarily agree on national blending limits between 5-10%, but no blends can go beyond 10%, even on a voluntary basis.

[163] This analysis assumes that non-EU gas exporting countries opt for a lower blending level than EU importing countries; they can thus export gas to MSs without any constraint.

The level of blending considered in this configuration relies on the following sources, by order of used source:

- ACER Report on NRAs Survey[164]
    - Blending levels for Belgium and Portugal are chosen equal to those of France and Spain, respectively, as ACER mentions their regulatory framework is under revision
- FCH Observatory's data on National Policy[165]
- Hydrogen blending projections from the MIX H2 scenario for the year 2035[166], when no explicit limit is defined in the current national regulation
- IEA's overview of current limits on hydrogen blending[167]

As mentioned before, these estimated blending limits differ from the ones projected by the MIX H2 scenario. They are indeed partly assessed according to national regulatory frameworks. The estimated rates are shown in Table 4-8. They represent the maximum hydrogen blending levels accepted by the national gas network operators.

[164] (ACER, 2020a)

[165] (FCH Observatory, 2020)

[166] The volumes of blended hydrogen projected by the MIX H2 scenario are almost null in 2030. Blending projections for 2035 are used in this analysis: it is assumed that the regulatory blending limits are set earlier than the introduction of blending in the MIX H2 scenarios. Except from this assumption on blended hydrogen volumes, the present analysis relies on 2030 data from the MIX H2 scenario.

[167] (IEA, 2019)

Table 4-8: Estimated national blending limits and corresponding source.

Country	Blending Rate	Source
Germany	10%	ACER
Belgium	6%	French level
France	6%	ACER
Portugal	5%	Spanish level
Spain	5%	ACER
Austria	4%	ACER
Switzerland	2%	IEA
Lithuania	1.95%	ACER
Estonia	1.93%	MIX H2 value for 2035
Sweden	1.59%	MIX H2 value for 2035
Latvia	1.54%	MIX H2 value for 2035
Romania	1.4%	MIX H2 value for 2035
Slovakia	1.26%	MIX H2 value for 2035
United Kingdom	1.11%	MIX H2 value for 2035
Finland	1%	FCH Observatory
Italy	1%	ACER
Croatia	0.76%	MIX H2 value for 2035
Greece	0.73%	MIX H2 value for 2035
Poland	0.7%	MIX H2 value for 2035
Luxembourg	0.68%	MIX H2 value for 2035
Slovenia	0.53%	MIX H2 value for 2035
Hungary	0.43%	MIX H2 value for 2035
Bulgaria	0.41%	MIX H2 value for 2035
Cyprus	0.1%	MIX H2 value for 2035
Ireland	0.1%	ACER
Netherlands	0.02%	FCH Observatory
Malta	0.01%	MIX H2 value for 2035
Czechia	0%	FCH Observatory
Denmark	0%	ACER

These individual levels lead to 23 different zones or clusters:

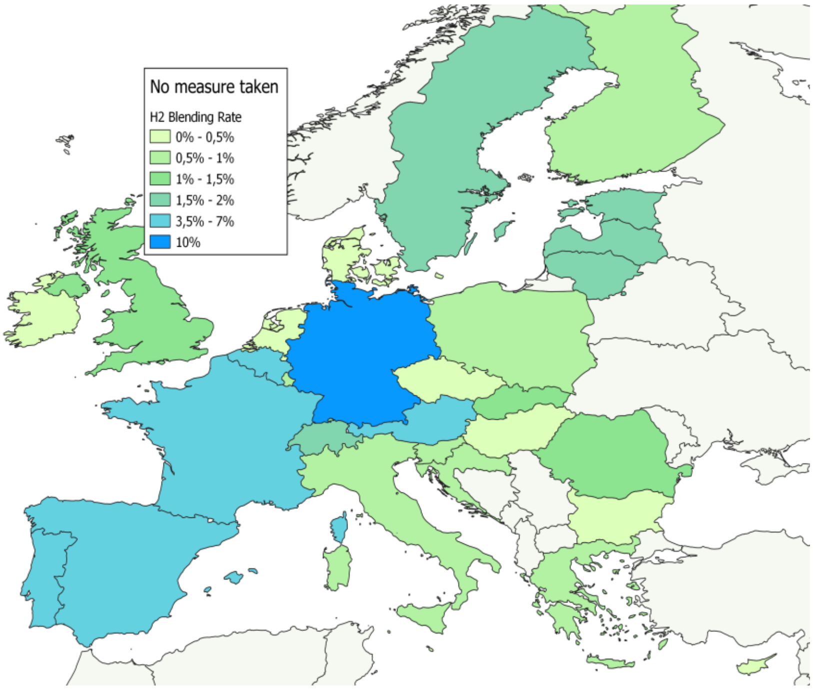

Figure 4-42: Estimated national hydrogen blending limits in the configuration where no measure is taken. Source: own calculations.

The highest estimated blending limit is identified in Germany. Though in this analysis this limit was applied to the whole transmission network, in reality this limit (10%) should be applicable only in some sections of the transmission network, where no sensitive customers are connected. For the parts of the network where sensitive customers are connected (including CNG refuelling stations, storage facilities, gas turbines), the threshold could drop to 2% or 1% (or 0.2% if no calibrated H_2 content measuring system is installed)[168].

4.3.1.3 Measure 1: Cross-border coordination

Cross-border coordination and transparency on blending level could lead to coordination in the implementation of blending thresholds. With this measure, a stronger cooperation is expected. Based on the previously estimated national blending levels, three clusters of cooperating countries are identified (cf. Figure 4-43):

- A **Western-European cluster**, demonstrating strong ambition on hydrogen blending, composed of Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Portugal, Spain and Switzerland. The German blending level, i.e., 10%, was chosen as the joint minimum acceptance level for the Western-European cluster. Luxembourg, Belgium, Portugal and the Netherlands do not feature such high blending integration ambitions, but the analysis considers these countries would line up with cross-border states. Except for Luxembourg and Belgium, the MSs of this cluster have all published a hydrogen strategy, which highlights their ambition regarding the development of a distinct hydrogen sector[169].
- An **Eastern-European cluster**, opting for lower hydrogen integration. It consists of 16 Member States. It is assumed that these countries would align themselves with the MS with the most ambitious unilateral choice of blending limit in the absence of any measure, which is Estonia (1.9%, value based on MIX H2 scenario projections for 2035). For Measure 1, this cluster's blending limit is thus set up at 1.9%.
- A third cluster composed of **UK and Ireland**. Ireland is largely dependent on UK gas exports. Thus, it is assumed that the country aligns with the UK's national blending level of 1.1% to assure cross-border gas flows.

The clustering suggested is to be understood as an exemplary configuration in order to assess the impacts of Measure 1. Of course, cluster configurations are manifold and may differ from the setting chosen.

[168] (HyLAW, 2021)

[169] (ACER, 2020a)

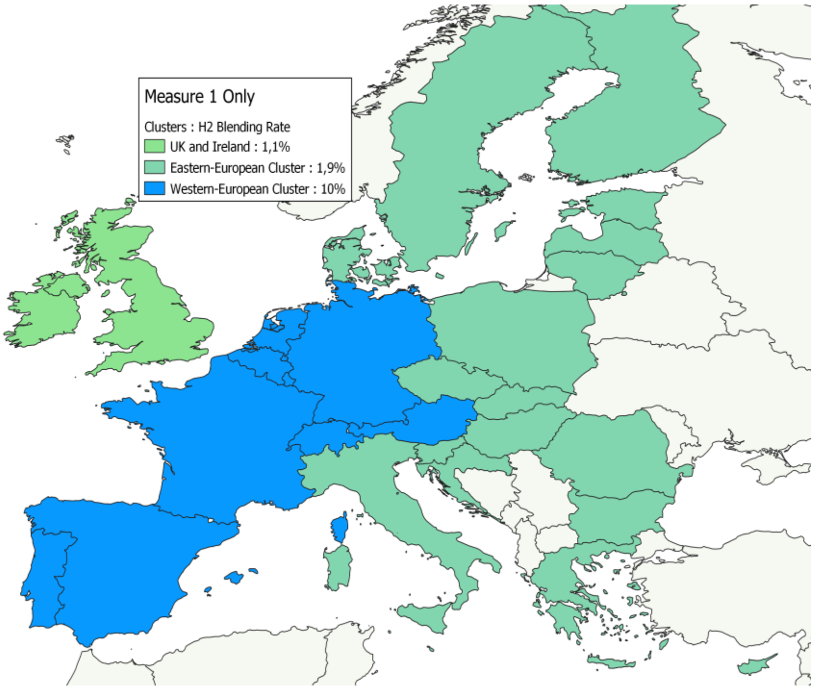

Figure 4-43: Estimated national hydrogen blending limits in the configuration where only Measure 1 is taken. Source: own calculations.

4.3.1.4 Measure 2 (EU-wide minimum acceptance level) and Measure 3.1 (EU-wide minimum acceptance and EU-wide maximum levels)

The impact of Measures 2 and 3.1 depends on the levels chosen at EU-level, especially for the minimum acceptance level:

- If the EU-wide minimum acceptance level is lower than 1.9% (blending limit of the Eastern European cluster under Measure 1), the cluster configuration stays the same as the one depicted for Measure 1, i.e., three distinct clusters as it is assumed that countries would go anyway for a blending rate of at least 1.9% if MSs coordinate.
- If the EU-wide minimum acceptance level is higher than 1.9% and lower than 10%, two blending clusters are formed where Ireland and the Eastern-European cluster feature the same blending limit (though they are not connected) and Western Europe represents still one cluster. Figure 4-44 displays a configuration with a 5% minimum acceptance level.

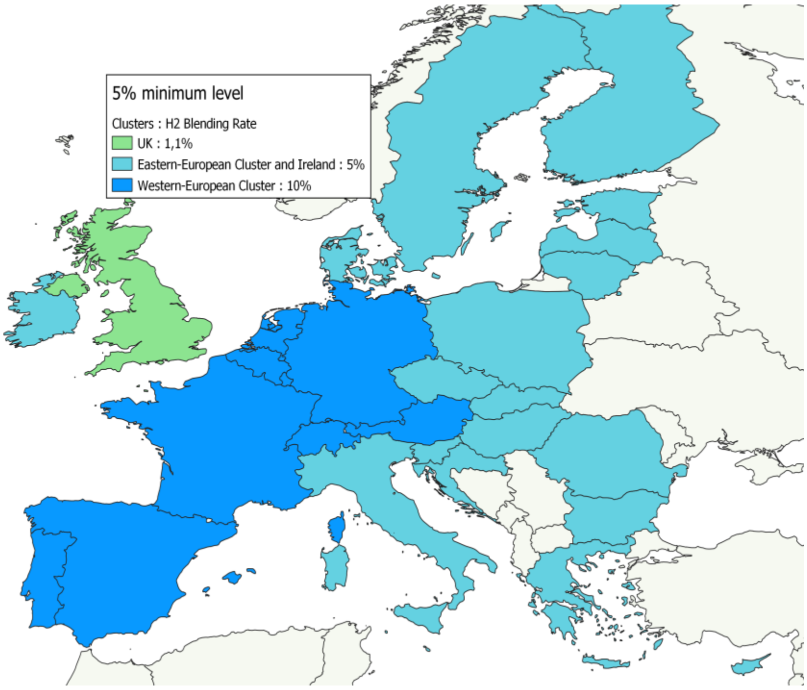

Figure 4-44: Estimated national hydrogen blending limits in the case of an EU-wide minimum acceptance level of 5%. Source: own calculations.

- If the minimum acceptance level is higher than 10%, only one EU cluster would appear as shown in Figure 4-45, as all MSs would need to comply with a minimum acceptance level of 10% which must not be exceeded either. This could also occur if Measure 3.1 is applied with a minimum acceptance level and a maximum level both equal to the same rate (5% in this analysis).

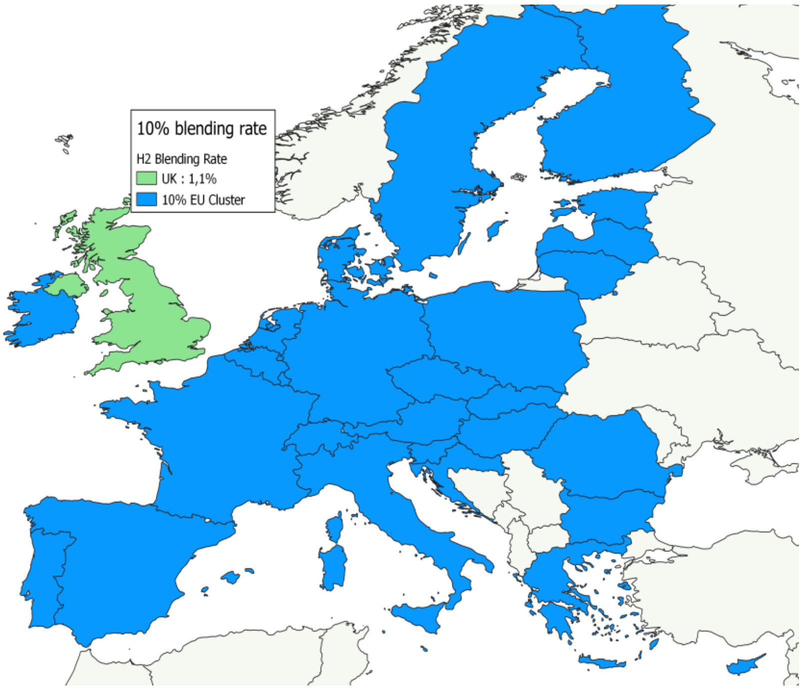

Figure 4-45: Map of national hydrogen blending limits in the case of homogenous blending limits over the EU. Source: own calculations.

The behaviour of the modelled third countries was assumed to be the following for Measures 1, 2 and 3.1: Switzerland applies the rate of its neighbours from the Western-European cluster, and the UK opts for its own blending rate since it relies on alternative supply sources than continental Europe and is thus less obliged to coordinate with the EU MSs.

The implementation of Measures 1, 2 and 3.1 and the case with no measure thus lead to seven possible configurations, described in Table 4-9. The impact assessment of the measures on gas quality will rely on these seven configurations, and key results will be presented for these configurations.

Table 4-9: Overview of the seven configurations under the different policy measures.

Configuration Name	Measures that lead to this configuration	Nb. of Clusters	Clusters	Chosen hydrogen blending rate
No measure taken	- No measure	23	Individually chosen blending rates	
Measure 1 only	- Measure 1 with cross-border coordination	3	Western European Cluster	10%
			Eastern European Cluster	1.9%
			UK + Ireland	1.1%
5% minimum level	- Measure 2.1/2.2 with 5% minimum level - Measure 3.1 with 5% min and 10, 20 or 30% max level	2	Western European Cluster	10%
			Eastern European Cluster + Ireland	5%
5% blending rate	- Measure 3.1 with 5% minimum and maximum level	1	EU Cluster	5%
10% blending rate	- Measure 2.1/2.2 with 10% minimum level - Measure 3.1 with 10% min and 10, 20 or 30% max level	1	EU Cluster	10%
20% blending rate	- Measure 2.1/2.2 with 20% minimum level - Measure 3.1 with 20% min and 20 or 30% max level	1	EU Cluster	20%
30% blending rate	- Measure 2.1/2.2 with 30% minimum level - Measure 3.1 with 30% min and 30% max level	1	EU Cluster	30%

4.3.2 Economic impacts

The economic impacts of a more coordinated European approach for the establishment of blending rates relate on the one hand to the positive economic repercussions of the **increased production of H_2**, and on the other hand to the **adaptation costs** of the gas chain, to the increased **administrative costs**, and to the possible negative impacts of a **change in gas flows and supplies**. These economic impacts were estimated for each configuration previously introduced.

4.3.2.1 Development of the hydrogen sector

Figure 4-46 illustrates the theoretical evolution of blended hydrogen volumes across the seven configurations. The volume of blended hydrogen increases with the ambition of the policy measures.

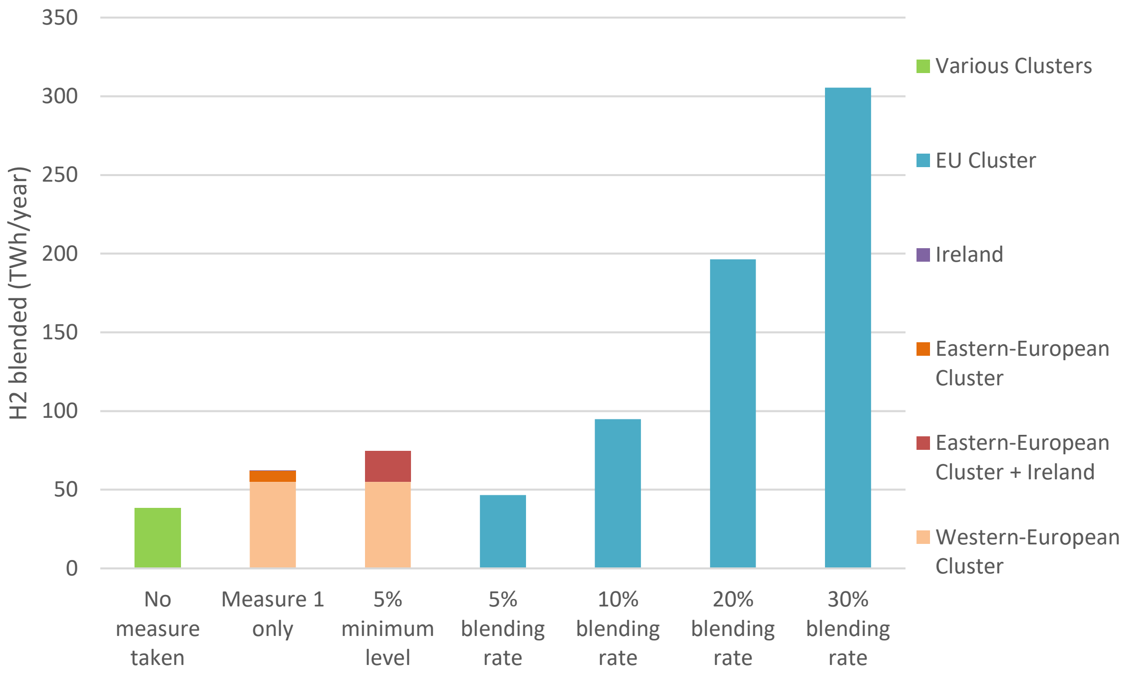

Figure 4-46: Volume of hydrogen blended into gas networks depending on the cluster configuration. Source: own calculations.

The figures represent an upper estimate of what the volumes of blended H_2 could be. Indeed, the levels estimated correspond to the maximum levels that could be accepted on the national networks. The actual blending level on the network will range between 0 and this maximum accepted level. To achieve the H_2 volumes shown in Figure 4-46, blending would need to be at its maximum rate all the time. In practice, fluctuations in blending rates within national networks may result in lower volumes of blended H_2.

Measure 3.1 with 5% minimum acceptance and maximum levels ("5% blending rate" configuration, with a homogenous EU 5% blending limit) leads to a reduction in H_2 integration for the Western Cluster compared to the Measures 2 and 3.1 with 5% minimum acceptance level and a maximum level higher than 10% ("5% minimum level"). Indeed, if a maximum level is implemented, the countries demonstrating strong ambitions on H_2 integration must reduce their blending rate at cross-border points. The reduction in H_2 injection compared to the situation where selected national networks are not capped by a maximum blending rate equals 27 TWh or 36% of hydrogen injection in the "5% minimum level" configuration. Figure 4-47 shows the distribution of this reduction in H_2 injection across MSs.

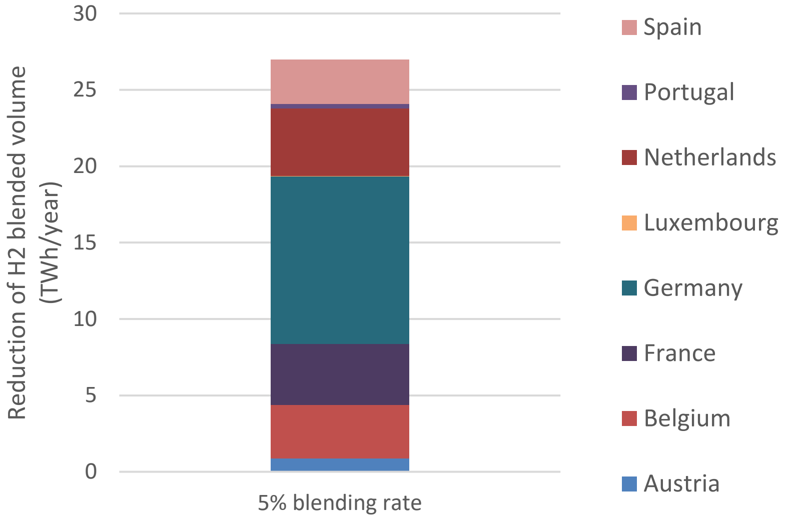

Figure 4-47: Reduction in H_2 integration for the "5% blending rate configuration compared to the "5% minimum level configuration". Source: own calculations.

4.3.2.2 Adaptation Costs

The adaptation costs estimate builds on blending adaptation cost curves that were generated for each individual MS.[170]

The analysis assesses the adaptation costs of the integration of hydrogen blended into transmission networks, impacting both the transmission and distribution network equipment. The adaptations required are divided into five categories: industry, end-use, storage, transmission, and distribution. The detail of the required adaptations is shown in Table 4-10 and further detailed in Section 8.4 of the Annex.

[170] The analysis of adaptation costs was primarily realised by Fraunhofer IEE. See the Annex, Section 8.4 for further details on the methodology.

Table 4-10: Major adaptations required to make the equipment H_2 blending ready. Source: own calculations[171].

Category	Adaptation needed at the transmission level	Adaptation needed at the distribution level
Industry	Deblending for the chemical industry using gas as feedstock and for the glass industry Calorific value adjustment for industrial high temperature application (>500°C)	
End-Use	Deblending for gas turbines for power generation connected to the transmission network	Deblending for gas turbines for power generation connected to the distribution network Deblending for CHP plants for power generation Investment in new heating boilers
Storage	Desulfurization and drying for porous storage (from blending levels below 5%) Deblending for gas turbines that power compressors for gas grid (storage) Component exchange of the compressor for storage (this investment concerns both cavern and porous storage)	
Transmission	Deblending for gas turbines that power compressors for gas grid (transport) Installation of higher gas turbine capacities for compressors (both for transit and storage) Component exchange of the compressors for gas grid Adaptation of the gas chromatographs	
Distribution		Exchange of the gas pressure regulator Additional process chromatographs analysers for calorific value reconstruction system of the gas chromatographs Deblending for gas turbines for grid and storage

The need for adaptation also depends on the actual blending level. The main adaptation needs are summarised in Table 4-11.

Table 4-11: Need for adaptation depending on the blending level[172].

Equipment to adapt	Blending level			
	0 - 5%	5 - 10%	10 - 20%	20 - 30%
Chemical industry (feedstock), including glass	x	x	x	x
Porous storage	x	x	x	x
Industrial high temperature application		x	x	x
Gas turbines (power generation, grid, storage, compressors)		x	x	x
Chromatographs		x	x	x
Combined Heat Plant for power generation			x	x
Compressors (for compressors on grid and storage)			x	x
Gas pressure regulators			x	x
Boilers				x

Deblending facilities are required when a certain equipment may not cope with a specific blending rate or a temporally varying blending rate. The ranges at which deblending processes might be required are[173]:

- To reach **5% blending rate**: equipment of the glass industry and of the chemical industry using natural gas feedstocks needs deblending membranes.
- For a **10% blending rate**: gas turbines for power generation, and for compressors in gas grid and storage require deblending.
- To get **from 10% blending to 20%**: CHPs for power generation require deblending.

For this analysis, it is estimated that H_2 obtained from the purification process can be sold at one third of the H_2 market price. The H_2 price in 2030 is estimated to equal 50 €/MWh[174], thus the H_2 resale price for H_2 obtained from the deblending process is set at one third, that is 17 €/MWh.[172]

[171] The underlying information is further detailed in the Annex, Section 8.4.

[172] The underlying information is further detailed in the Annex, Section 8.4.

[173] These ranges are further detailed in the Annex, Section 8.4.

[174] Estimation of the hydrogen production costs from electrolysis in the MIX H2 scenario. The sensitivity of total EU adaptation costs to this hypothesis is discussed in the Annex, Section 8.4.

For the impact analysis of the measures, the adaptation costs between 0–5%, 5–10%, 10-20% and above 20% up to 30% were considered to be set at the upper threshold level (i.e. if one country has a 2% blending limit, its adaptation cost will be computed as if it would have a limit of 5%).

A first illustration of adaptation costs is done for all EU27 MSs together: they are estimated to reach 5%, then 10%, 20%, and finally the adaptation costs beyond 20% blending are estimated. These costs are annualised and include both capital and operational expenditures.

Figure 4-48 depicts in detail the adaptation costs for the considered levels of blending distinguished by the different types of end-users and TSO/DSO competences. As presented in Table 4-11, for the lower blending rates only a few adaptations are needed implying limited adaptation costs, while for higher blending limits the adaptation costs increase with the number of end-users being concerned by the adaptation needed.

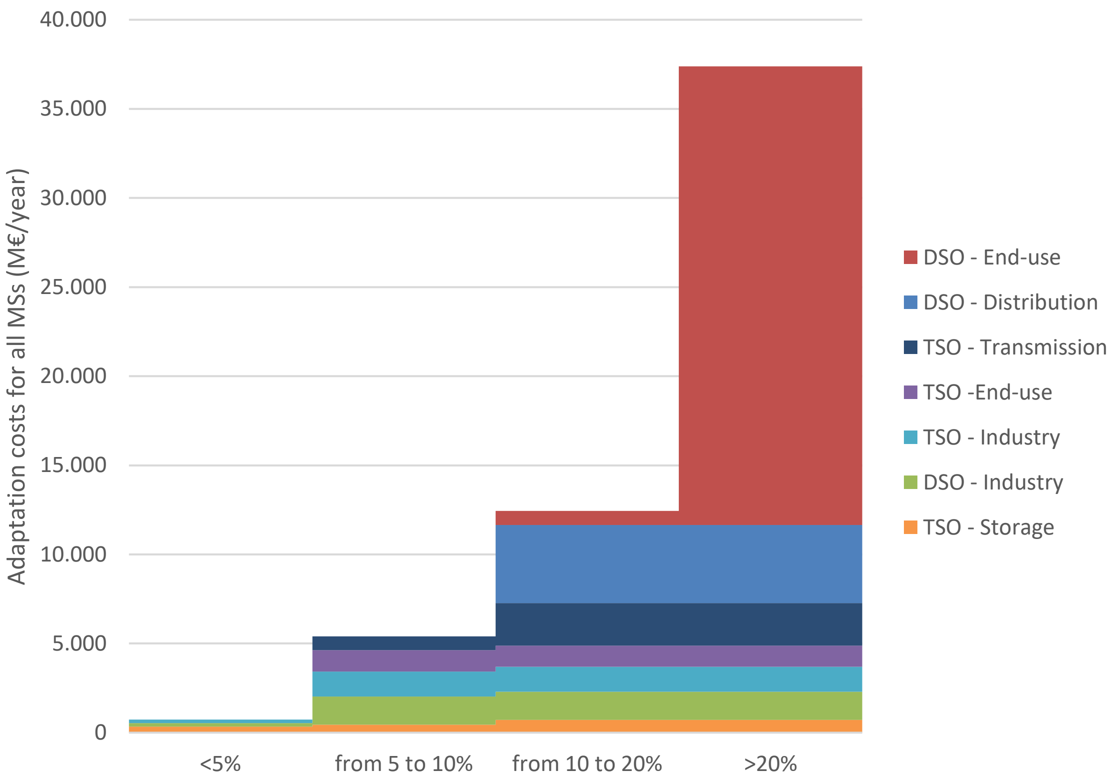

Figure 4-48: Total adaptation costs needed to make EU equipment suitable for a certain level of blending. Source: own calculations.

Figure 4-49 shows the adaptation costs for the considered levels of blending, this time distinguished by the equipment that needs to be adapted. It has to be noted that beyond a 20% blending rate, the major identified source of adaptation costs is the replacement of heating boilers, which represents a very significant cost item. This is the only source of cost increase considered in the present analysis when making the system ready for blending rates above 20% blending rate. In particular, valve replacement costs are not taken into account, thus the costs above 20% are likely to be higher than indicated[175].

[175] Details on costs assumptions can be found in the Annex, Section 8.4.

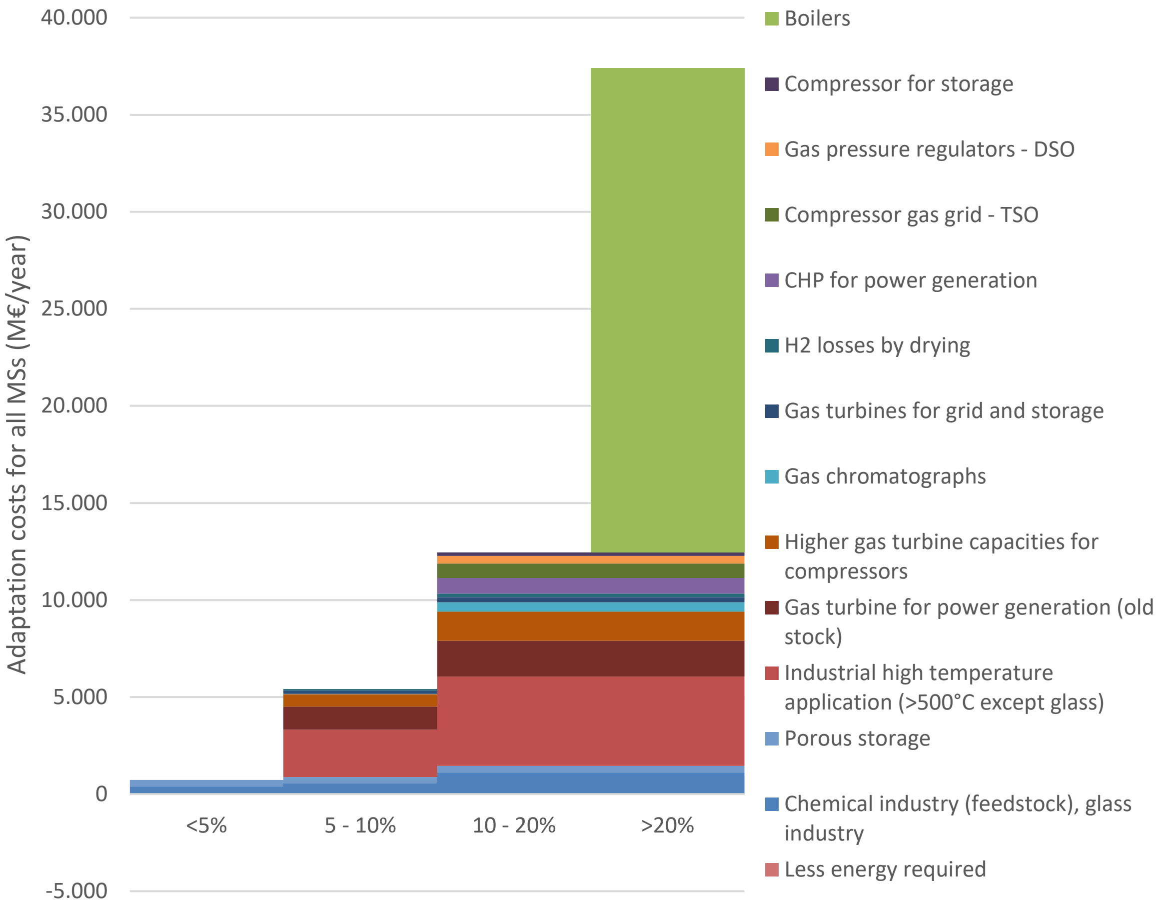

Figure 4-49: Distribution of total EU costs, by category of required adaptation. Source: own calculations[176].

To evaluate the adaptation costs for each blending configuration, the adaptation costs associated with each configuration are cumulated for all MSs. For instance, if in a cluster configuration FR is at 5% and DE at 10%, the adaptation costs of 5% for FR are added to the adaptation costs of 10% for DE. Figure 4-50 indicates the resulting adaptation costs distinguished by measure and cluster configuration.

[176] This distribution and the costs assumptions are further detailed in Annex 8.4.

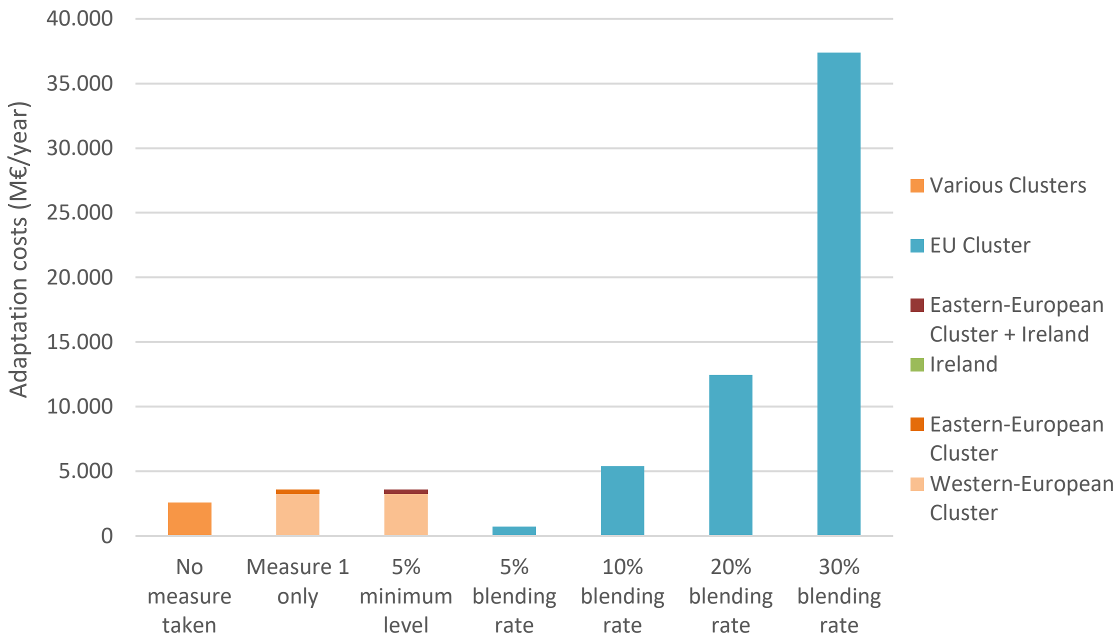

Figure 4-50: Total adaptation costs over the seven possible configurations. Source: own calculations.

4.3.2.3 Administrative costs

In addition to the adaptation costs, the measures reinforcing the regulation of blending would lead to increased administrative costs, most notably for:

- **NRAs**, as they need to ensure the implementation of the new regulatory framework
- **ACER and ENTSOG** to monitor the implementation at the European level. However, Indicator 2.6 (cf. Section 10.3.6) estimates the associated costs to be limited.
- **TSOs**, regarding both additional information publication, and real-time monitoring of gas quality. TSOs may need to **publish additional information** on gas quality, due to the increase in blending in the networks, in order to inform sensitive users that may adapt the behaviour of their equipment to the gas quality. Hydrogen concentration notably affects the Wobbe-index and gross calorific value. But this will cause very limited additional administrative costs as provisions already exist regarding data publication of the Wobbe-index and gross calorific value on an hourly basis[177]. Indicator 2.6 (cf. Section 10.3.6) evaluates the costs related to **real-time monitoring and forecasting** of gas quality at 6.9 M€, considering that this real-time management requires 1.5 full-time equivalent per TSO.
- **Gas-consuming equipment manufacturers (resp. certification agencies)**, may have to produce (resp. check) additional certification documents to ensure that equipment are blending-ready up to the limits given by the measures. However, these costs strongly depend on the legislation that will be adopted for the gas-consuming equipment, and on the quantity of equipment that are concerned.

[177] TSOs must already publish the Wobbe-index and gross calorific value for gas entering their transmission networks at interconnection points on an hourly basis. (European Commission, 2015)

- **Hydrogen producers connected to the natural gas networks**, will have to monitor (in collaboration with the TSOs/DSOs) the blending levels of the local network before injecting hydrogen, to respect the limits given by the measures. The contracts between them and the TSOs (that should be able to stop the hydrogen injection at will if the blending rate is too high) may lead to additional administrative costs.

4.3.2.4 Gas supply sources

As the flows from MSs featuring high blending rates to MSs featuring low blending rates are constrained, the gas flows are likely to change depending on the cluster configuration. This section highlights the **change in the gas supply mix and gas flows** depending on the blending configuration, computed with the METIS model representing the gas market for the 2030 MIX H2 scenario. The analysis focuses more specifically on the impacts of different levels of EU blending coordination/harmonisation on cross-border gas flows and the potential risk of a gas market fragmentation.[178]

The **gas flows** in the different configurations are compared to the gas flows in a reference situation without blending (i.e., the configuration where gas flows are not restricted, similar to the current situation). The next paragraphs exhibit maps indicating the changes in gas flow balances across EU MSs. The maps depict the difference between the flow balance in the different blending configurations compared to the flow balance of the reference case without blending.

In the following maps, green arrows reveal an increase in gas flows and red arrows indicate a diminution of the flows. Dark-red arrows indicate a diminution of gas flows which results in a reverse flow compared to the initial flow direction (which is still indicated by the shape of the arrow). The blue-framed arrows represent changes in LNG imports. The width of the arrow is proportional to the volumetric change in gas flows. When no arrow is drawn, this means that the flow is either not changed or that the change in flow is less than 15 TWh/year. The country group "Eastern third countries" combines the following gas-exporting countries: Azerbaijan, Belarus, Georgia, Moldova, Russia, Turkmenistan and Ukraine.

In the configuration "No measure taken" (cf. Figure 4-51) no coordination takes place. This changes considerably the flows compared to a situation without blending and even implies relevant volumes of energy not served in selected MSs. In practice, such a situation is unlikely to occur, as coordination between MSs would arise before taking the risk of a serious gas market fragmentation. Still, this map displays what would be the impact of a large disparity of the blending levels. The following impacts can be noticed:

- ***Impact on Germany***: the German estimated blending limit is the highest one in the EU. Thus, gas flows from Germany to its neighbouring countries drop from 326 TWh/year to 0 TWh/year. Germany is thus no longer a transit country, which leads to a 268 TWh/year drop in German imports from Eastern third countries[179], and the initial imports from Norway of 58 TWh/year fully disappear.

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[178] Blending is not modelled here explicitly as the purpose of the analysis is to properly reflect the gas flow dynamics and identify the related impacts by different blending measures in this regard. To this end, cross-border gas flows are supposed to be cut-off from countries with high blending levels to countries with lower blending levels which reflects an implicit estimation of the impacts of blending in terms of a potential fragmentation of the European internal gas market.

[179] The flow from Eastern third countries to Germany equals 905 TWh/year in the reference situation.

- ***Impact on Italy***: flows from Austria and Switzerland drop to 0 TWh/year as the blending limits assumed for Austria and Switzerland are higher than the one for Italy. This leads to increased LNG imports (15-fold increase in LNG imports compared to the reference situation without blending), and increased imports from Algeria (10% increase).
- ***Impact on UK***: as its estimated blending rate is lower than the ones for France and Belgium, gas flows from France and Belgium are not feasible anymore: the initial flow of more than 200 TWh/year disappears completely. To compensate for this drop in supply to the UK, the flows from the Netherlands and Norway to the UK increase, by 133 TWh/year and 35 TWh/year, respectively.
- ***Impact on Belgium***: as Belgian exports to the UK disappear, its imports decrease significantly, too, with imports from France and the Netherlands basically vanishing.
- ***Impact on Ireland***: the only gas flow supplying Ireland (i.e., from the UK) is not feasible as Ireland has a lower blending rate. As it will be shown afterwards, this results in a substantial amount of energy not served, namely 85% of national gas consumption, which is equal to the annual supply from the UK to Ireland in the reference case.
- ***Impact on Luxembourg***: The relatively low blending rate in Luxembourg compared to neighbouring MSs implies an isolation of the Luxembourgian gas system, basically preventing from any gas imports leading to substantial volumes of energy not served (90% of national gas consumption).

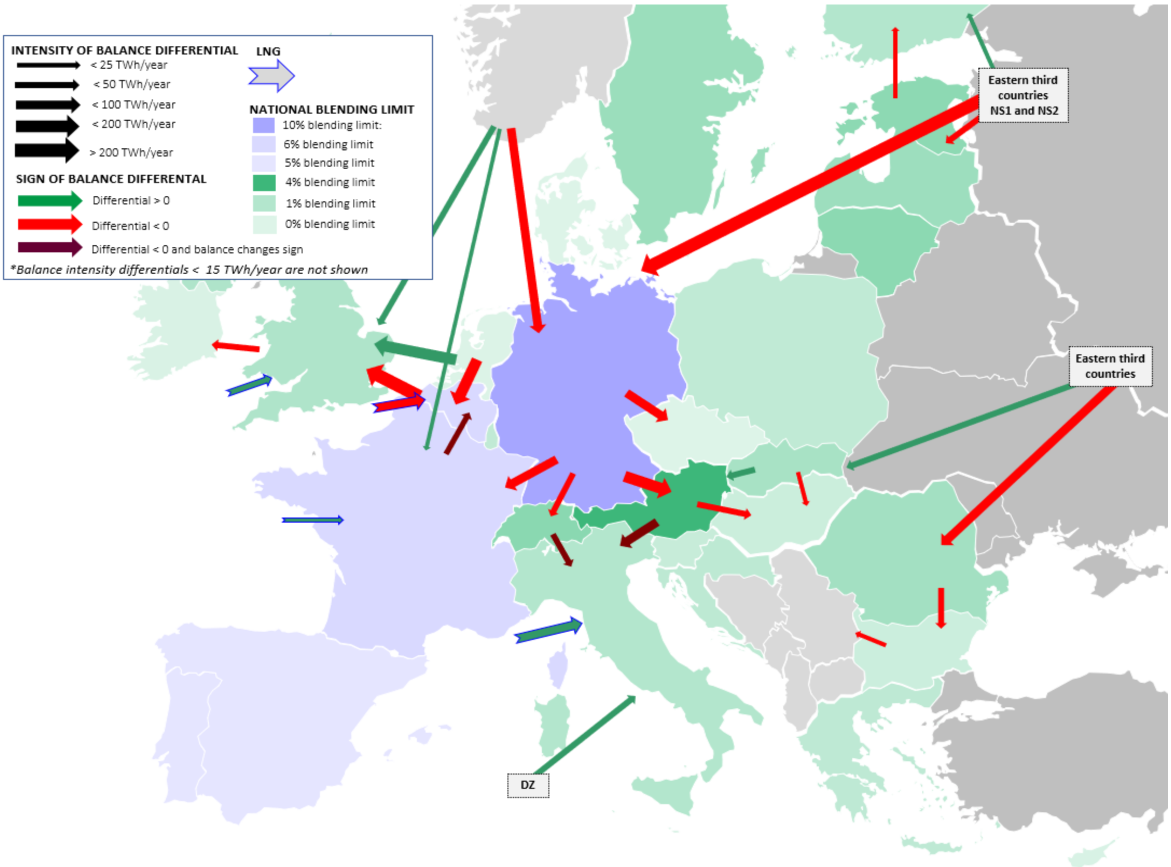

Figure 4-51: Changes in gas flows across Europe: difference between flow balances in the "no measures taken" configuration compared to the reference without blending. Source: own calculations with METIS.

In the configuration "Measure 1 only" (cf. Figure 4-52), flows from the Western-European cluster are no longer feasible, neither to Great-Britain, nor to the Eastern-European cluster:

- ***Flows towards the Eastern cluster***: exports from Germany and Austria are no longer feasible. The Eastern-European cluster therefore increases its LNG imports (in particular from Italy), as well as its imports from Algeria and the Eastern third countries.
- ***Flows towards the UK***: as in the previous configuration, there is a cut in the flows from Belgium to the UK in the "Measure 1 only" configuration. Contrary to the previous configuration, no MS can compensate for this decrease, so it is balanced by an increase in Norwegian and LNG imports.

This results in a decrease in the imports from the Western-European cluster. In particular, the flow from Norway to the Netherlands decreases by 38% (compared to a situation without blending), the imports from Eastern third countries decrease by 22%, and LNG imports into Belgium drop by 64%.

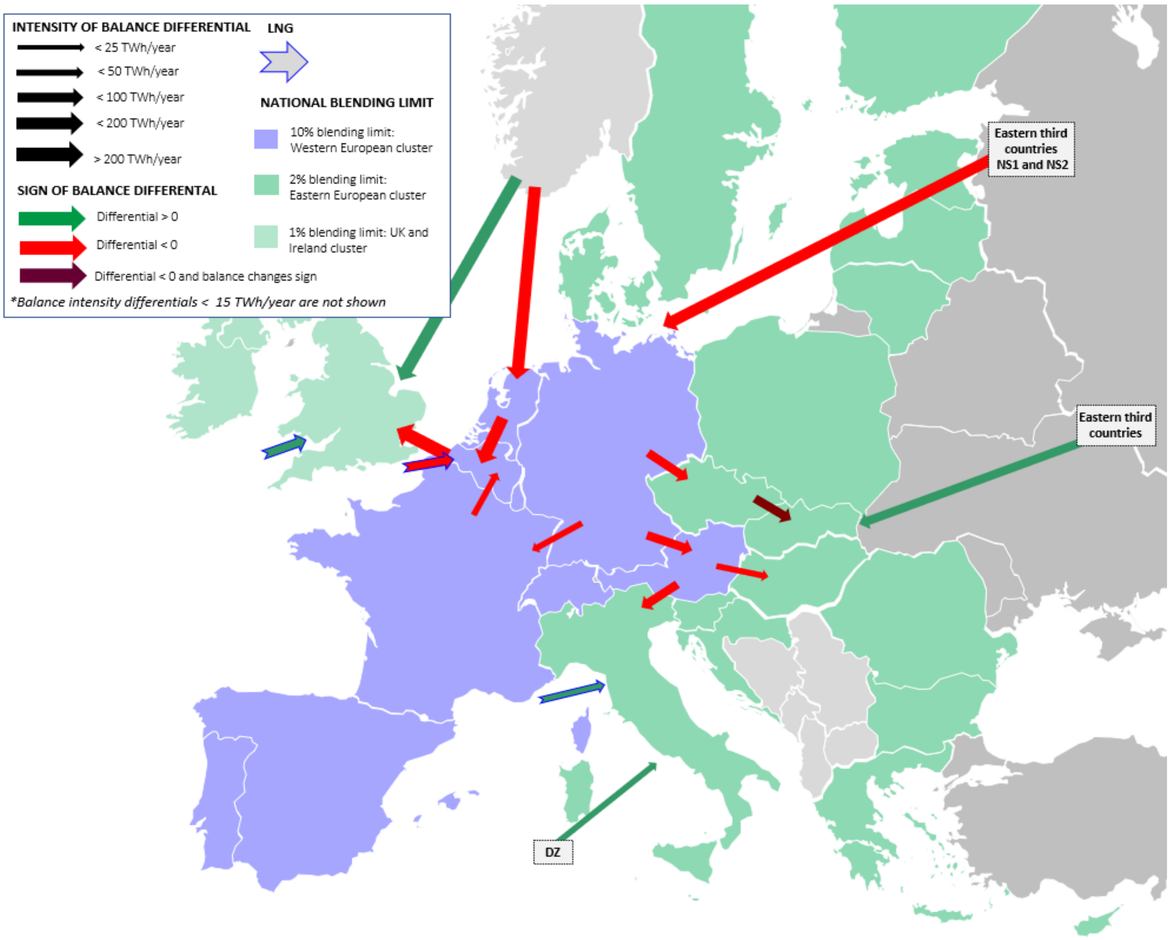

Figure 4-52: Changes in gas flows across Europe: difference between flow balances in the "Measure 1 only" configuration compared to the reference without blending. Source: own calculations with METIS.

The clusters of the "5% minimum blending" configuration (cf. Figure 4-53) are almost identical to those of the "Measure 1 only" configuration (cf. Figure 4-52). Only Ireland switches to another cluster: it adopts the same blending limit rate as the Eastern-European cluster. This does not change the flows compared to the "Measure 1 only" configuration: with a blending limit of 5%, flows from the UK to Ireland are still possible, and this is the only flow towards Ireland.

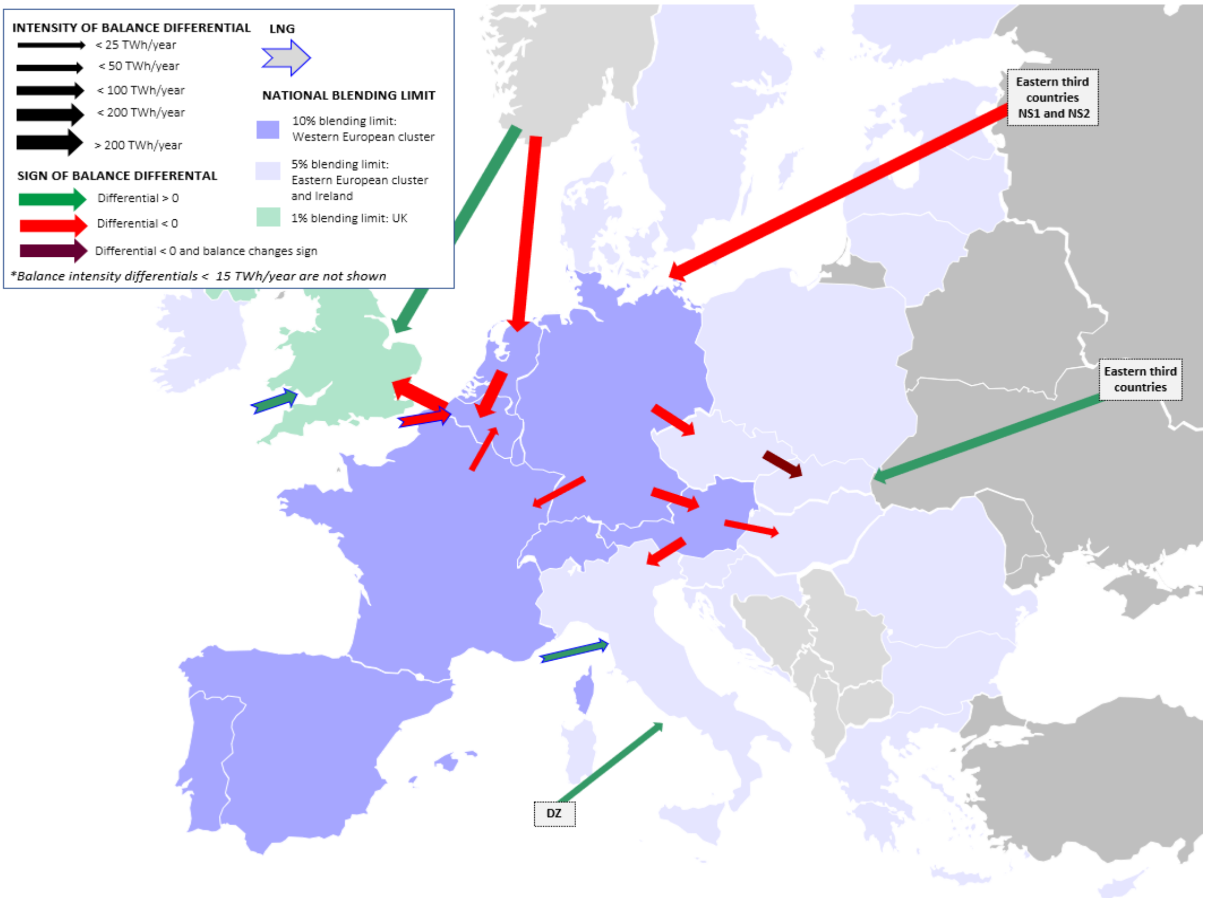

Figure 4-53: Changes in gas flows across Europe: difference between flow balances in the "5% minimum blending" configuration compared to the reference without blending. Source: own calculations with METIS.

The flows of the configuration shown in Figure 4-54 are representative for the flows of all the configurations where a homogenous blending limit is implemented in the EU (i.e., the "5% blending rate", "10% blending rate", "20% blending rate" and "30% blending rate" configurations).

In these configurations where a homogenous EU blending limit at cross-border points is implemented, the only constrained flows are the ones from MSs to the UK and to non-EU gas import countries. The EU gas import needs are reduced in this situation, as gas exports to the UK from the EU are no longer feasible. This situation will only arise if the UK does not adapt its blending limit to the EU blending rate.

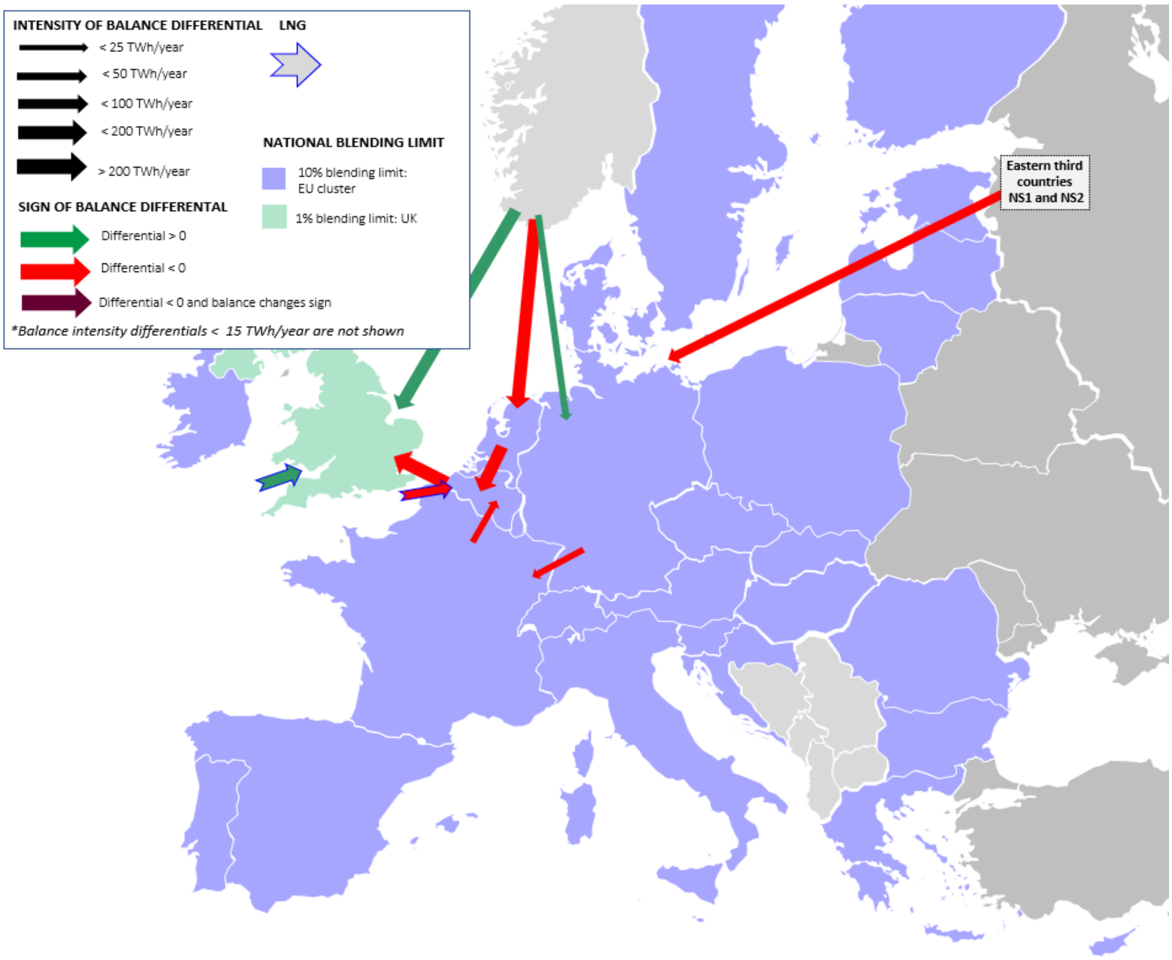

Figure 4-54: Changes in gas flows across Europe: difference between flow balances in the "homogenous EU-blending rate" configuration compared to the reference without blending. Source: own calculations with METIS.

Figure 4-55 shows the European gas supply mix for each of the configurations i.e. which gas producers are selling their gas to the European consumers (including CH, UK and the Balkans). The « Homogenous EU blending rate » configuration refers to all the configurations where there is only one EU cluster: the "5% blending rate", the "10% blending rate", the "20% blending rate" and the "30% blending rate" configurations. The 5% minimum level differs from the "Homogenous EU blending rate" as some countries have a higher blending rate than 5%, thus creating several clusters and changing the gas supply source.

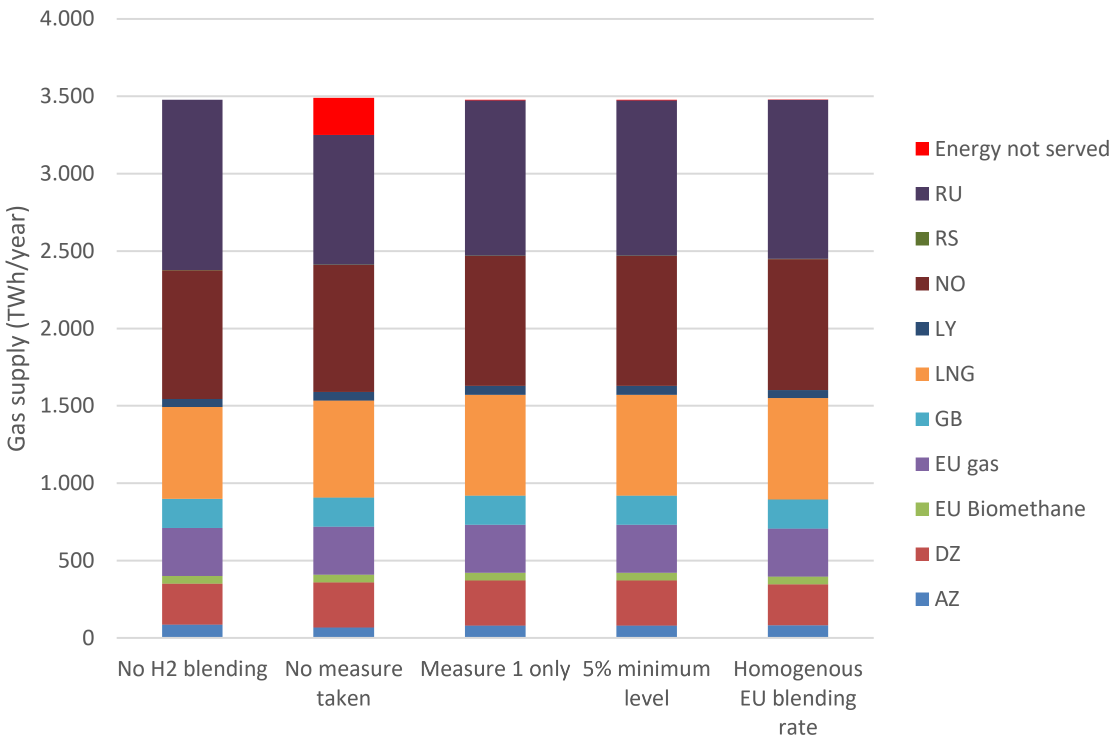

Figure 4-55: European gas supply mix (including CH, NO, UK and Balkans) depending on the configuration. Source: own calculations with METIS.

The distribution of supply sources between the "Measure 1 only", "5% minimum level" and "Homogenous blending rate" configurations is close. In the "No measure taken" configuration, the most notable impacts are the decrease in imports from Russia and the increase in the volumes of energy not served. This is mainly due to the impossibility for Germany to re-export the Russian gas received on its territory via the pipelines Nord Stream 1 and Nord Stream 2. As the gas market is supposed to be heavily fragmented in this situation, no alternative routes are possible for isolated or peripherical countries.

Figure 4-56 shows the changes in the European gas supply mix under four blending configurations in comparison to mix in the reference case without blending (i.e., in the case where all flows are possible). This figure highlights the increase in energy not served and the decrease in Russian exports in the "No measure taken" configuration.

An increase in LNG imports and in imports from Algeria cannot fully compensate the drop in Russian exports. This can be explained by the fact that Germany cannot re-export the gas imported into its territory to the whole of Europe in the "No measure taken" configuration, and to the Eastern European countries in the configurations "Measure 1 only" and "5% minimum level".

In the "Homogenous EU blending rate" configuration, the decrease in imports from Russia is the result of the infeasibility of EU gas exports to the UK. This leads to an increase in LNG imports to the UK. The impact of measures leading to a homogeneous EU blending limit on gas supply is largely dependent on whether the UK chooses to align with the EU blending limit.

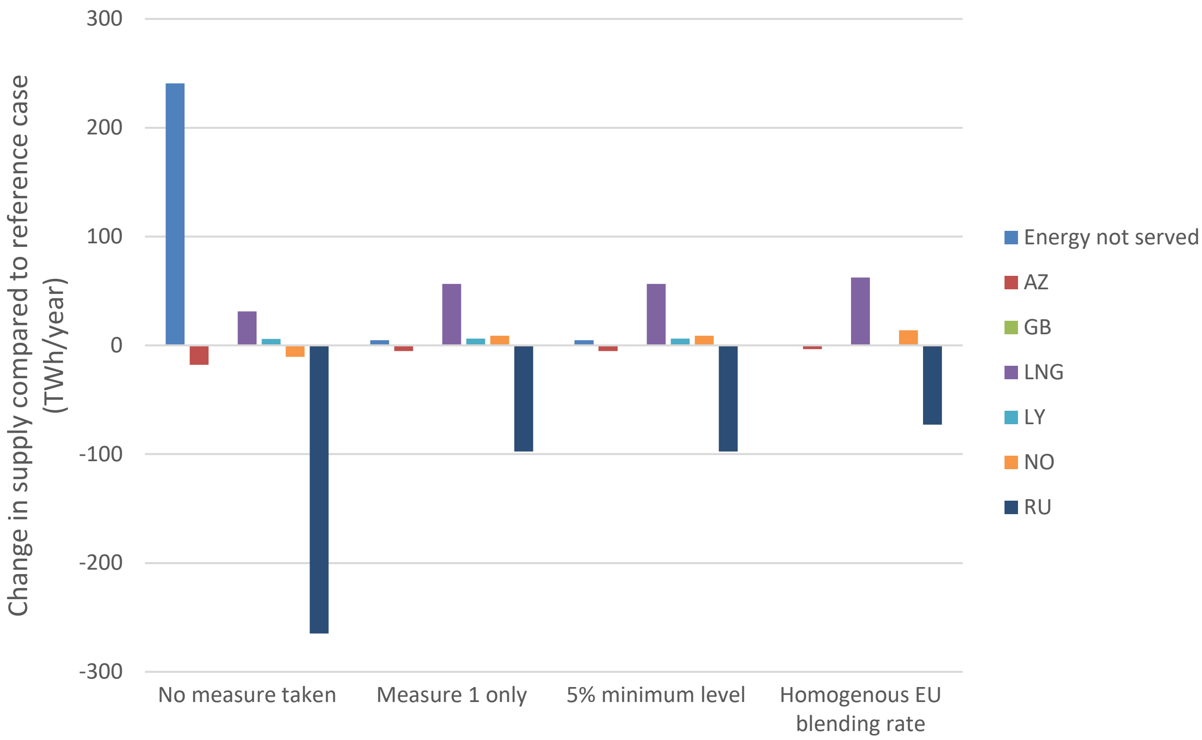

Figure 4-56: Change in the European gas supply mix compared to the reference case where all gas flows are feasible (configuration with no blending). Source: own calculations with METIS.

4.3.2.5 Security of supply

For the "No measure taken" configuration (full fragmentation of the market), the assumption that there is strictly no coordination implies that the volume of energy not served reaches 7% of the total natural gas demand (which is projected to equal 3500 TWh/year by 2030 under the MIX H2 scenario for the EU, plus CH, NO, UK and the Balkans, 2750 TWh for the EU27 only), cf. Figure 4-57. This is an upper estimate, as MSs would be inclined to coordinate (or refrain from blending) before such a serious issue would emerge.

The energy not served decreases significantly with the implementation of Measures 1 and 2, representing less than 0.2% of total EU gas consumption under the “Measure 1 only” and “5% minimum level” configurations, and less than 0.005% of total EU gas consumption under the homogenous cluster configuration[180].

[180] The remaining energy not served is due to the optimisation approach which may find a local optimum where it is better to keep a low level of energy not served. This is basically driven by the price assumed for energy not served.
This energy not supplied is a result of the infeasibility of EU gas exports to Turkey. In the baseline scenario without blending, Bulgaria exports 6.2 TWh/year to Turkey which re-exports 6.2 TWh/year to Greece. As the flow from Bulgaria to Turkey is no longer possible in a situation with H2 blending, it leads to a disequilibrium in the region, which entails the observed volume of energy not served.

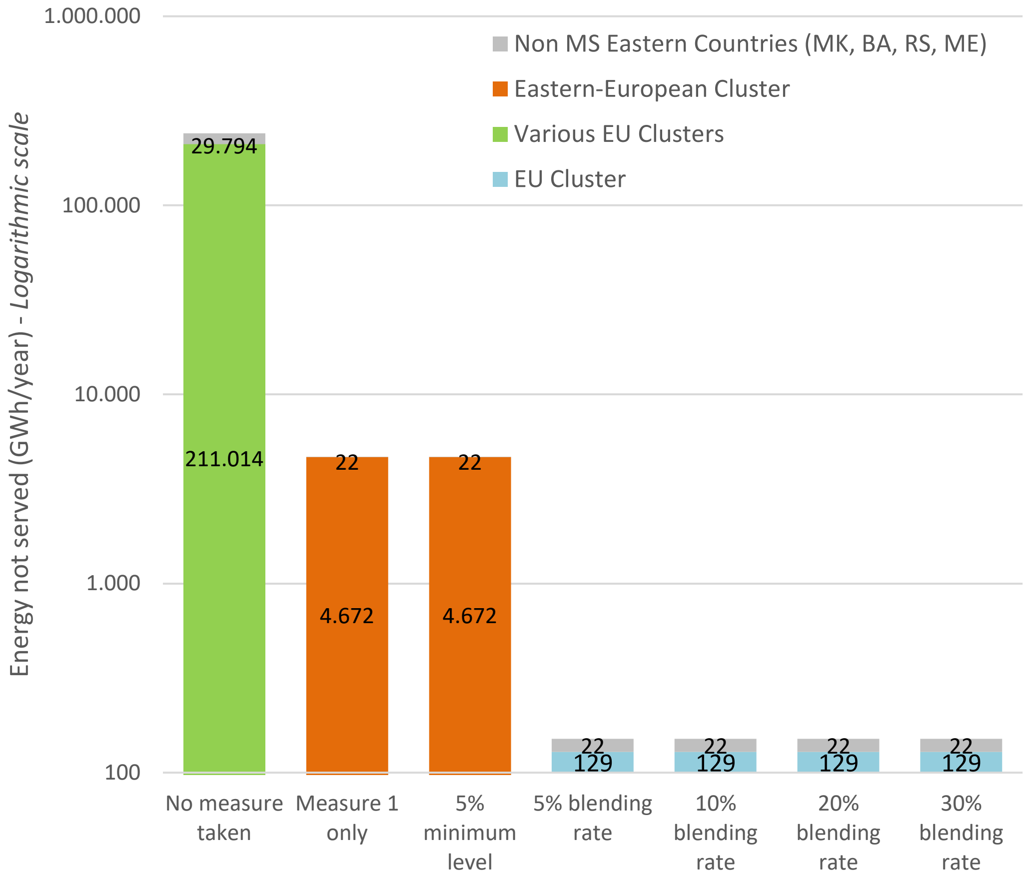

Figure 4-57: Energy not served across the different clusters, distinguished by configuration. Source: own calculation using METIS.

Box 4-10 provides an overview of the major limitations of the assessment approach which need to be taken into account when interpreting the modelling results with METIS.

Box 4-10: Limitations of the METIS model for the analysis of gas quality measures.

Limitations of the METIS model for the analysis of gas quality measures
In the METIS model, the flows were computed as if they were pure natural gas flows in terms of prices (which could be locally changed depending on the level of hydrogen blending) and volumes of energy. As the energy content of hydrogen is lower than the one for methane, hydrogen blending results in a lower energy content of the gas in the pipelines. This leads to a diminution of the pipelines' capacity (in terms of energy transport capability). This diminution was not taken into account for this analysis. In this regard, the resulting volumes of energy not served may be higher than the estimated ones. As deblending stations at IPs were supposed to be too expensive to see a significant deployment, cross-border gas flows were totally blocked from a country with a high blending limit to a country with a low blending limit in the model, which leads to extreme results, especially in terms of volumes of energy not served. In reality, bilateral or multilateral arrangements are likely to be found. Such arrangements were not modelled.

4.3.2.6 Measure 3.2: Biomethane-based gas quality standard

The MIX H2 scenario estimates that in 2030 biomethane will be meet around 1.8% of the total EU27 gas demand. Therefore, for most transmission and distribution grids, the blending rate for biomethane will in the near future still be limited and consequently its influence on gas quality as well, except for potential constraints related to underground gas storage or gas quality variations affecting sensitive industrial end-users. Currently there are no binding EU-wide standards for natural gas quality. Parameters to be addressed within gas quality standards can be divided in two groups, gas composition related parameters and calorific parameters.

Gas composition related parameters

In addition to methane as the main compound of natural gases and biomethane, gas quality parameters include trace gases in particular. Most relevant compounds or sum parameters are (related to biomethane from biogas): CO_2, O_2, N_2, H_2O, H_2S, H_2, other S-compounds such as thiols, COS, DMS, NMVOCs, NH_3, organic silicon compounds, halogens. Netbeheer Nederland[181] indicates that standards could also allow higher concentrations of hydrogen sulphide (H_2S) and carbon monoxide (CO), which currently need to be filtered so that the biomethane can meet gas standards.

Limiting the concentration of trace gases primarily serves to prevent disruptions and damage to infrastructure components in the gas network itself, but also to gas consumers. Therefore, a separate gas quality standard for biomethane should not include higher limiting values for such compounds which can cause problems compared to a common gas quality standard.

Non-upgraded biogas with a high CO_2 content of around 40% is not suitable for grid injection because it significantly lowers the Wobbe index and calorific value, and the CO_2 can corrode gas infrastructure and pose safety risks for end-users.[182] Therefore, biogas must be upgraded prior to injection and there is only a degree of freedom in the

[181] (Netbeheer Nederland, 2018a)

[182] (Angelidaki, et al., 2019)

purification stage. Note that depending on the upgrading technique, several trace components are already removed from the biogas during the upgrading stage. Specifically related to CO_2 and depending on accepted CO_2-concentrations in gas grids, a biomethane standard that takes into account the specificities of biomethane compared to natural gas could have advantages for the biomethane producer. Higher tolerable CO_2-concentrations in the gas network would open up the possibility of partial upgrading, which can lead to cost reductions in biogas upgrading.

The prerequisite for this is, however (a) that higher CO_2-quantities in the gas network do not lead to damages in the infrastructure, (b) that the influence on the calorific parameters does not lead to restrictions for gas consumers and (c) that this does not result in higher full costs in the overall system (e.g. by increased post-compression-costs that substitute the decreased costs in biogas upgrading).

Calorific parameters

The definition of nominal values and ranges for calorific parameters, or parameters that influence the combustion behaviour of a gas, is relevant to ensure a failure-free operation of gas consumption aggregates. Furthermore, relatively constant heating values are demanded to ensure a correct billing of gas customers as long as volumetric billing systems are applied.

According to the ENTSOG 2020 gas quality outlook[183], the system-wide average gas quality (Wobbe index and gross calorific value) would remain relatively stable up to 2030 in all regions, in both the Russian gas or LNG supply scenarios. Depending on the region, a higher upper limit for the Wobbe Index and gross calorific value can be observed due to LNG imports, or some widening of those indices occurs due to the injection of biomethane. However, in general gas quality in the regions assessed would be stable.

The main advantage of a separate biomethane standard would be that biomethane would become the base gas in a network section and no adjustment of the calorific parameters of biomethane to natural gas would have to take place, but vice versa. From an overall systemic point of view, however, this would only make sense if the (financial) efforts for adapting the calorific parameters of biomethane to natural gas were greater than adapting natural gas to biomethane.

Independent of a biomethane standard, however, there is also the possibility of implementing calorific value reconstruction systems. In particular, if other renewable gases such as H_2 are also fed into gas network sections, these systems have the advantage of determining calorific values for the respective end consumers of the gas.

Therefore, if a binding biomethane-based gas standard was applied in the EU, an important question would be accommodating LNG supplies, which on average have a higher gross calorific value and WI than most EU and non-EU pipeline sources (Algeria, UK and Danish gas in particular can have higher WI).[183]

If adaptation of standards is needed, a wider WI and gross calorific value range as well as eventually higher allowed oxygen concentrations could be more sensible than a biomethane-based standard. A biomethane-based binding standard would be feasible rather at most for specific distribution grids with high local biomethane injection, which is discussed next.

System costs for a biomethane-based gas quality standard

System costs for a biomethane-based standard have not been assessed yet. Allowing a lower and possibly wider Wobbe index range and higher concentrations for several components present in biomethane, especially oxygen, H_2S and carbon monoxide, can

[183] (ENTSOG, 2020e)

require the adaptation of both gas infrastructure as well as end-user equipment, appliances and processes. It is important to assess if resulting system adaptation costs weigh up against the avoided costs for biomethane production and resulting higher production volumes.[184] This also raises the question of how additional system costs will be allocated.

One potential cost saving of a biomethane-based gas quality standard would be the avoidance of some of the costs for purifying biomethane (as indicated above). Biomethane must be upgraded (CO_2 removal) and purified (removal of several other components, for more info on trace components see section above) to comply with most national gas quality standards.

No separate cost indications are available for the biogas purification stage of e.g. oxygen or sulphur which makes it difficult to quantitatively asses the production cost reductions that can be achieved with a biomethane-based standard allowing higher concentrations of e.g. oxygen. However, the standard EN 16723-1 already foresees the possibility of an oxygen concentration of up to 1%, in the absence of sensitive network users.

Currently many biomethane producers condition the biomethane with liquefied petroleum gas before grid injection in order to increase the calorific value of the gas. The costs for liquefied petroleum gas conditioning are a major operational cost component, amounting to up to 40% of operational costs when such gas enrichment is necessary. In case of a biomethane-based gas quality standard, this should not be necessary anymore and this could thus lead to significant savings.[185] However, it is difficult to quantify this impact in detail.

Biomethane-based gas quality standard in specific distribution grids

If a dedicated biomethane-based standard was applied for specific distribution networks, additional purification and/or enrichment may be needed at the TSO/DSO interface in case reverse flows were to take place. This could still lead to cost savings resulting from the economies of scale of centralized purification and enrichment, as well as lower volumes of gas to be conditioned as most gas will be used in the distribution grid.

Due to the larger range of possible calorific values of gas in the case of a biomethane-based standard, there could be additional costs for metering and billing within specified margins of error. A study of several Dutch DSOs mentions the metering and billing costs as a major potential cost driver, although a comparison has not been conducted on whether the avoided costs for biomethane producers would compensate the metering and billing costs.[186]

4.3.3 Environmental impacts

One of the main advantages of blending hydrogen into gas networks consists of lowering the CO_2 content of the transported gas. In this analysis, avoided CO_2 emissions were calculated by removing the emissions of natural gas and replacing it by the indirect emissions of the corresponding H_2 energy. The CO_2 content of natural gas used is the

[184] (Netbeheer Nederland, 2018a)

[185] (IRENA, 2018)

[186] (Netbeheer Nederland, 2018a)

one published by ADEME for combustion only and is equal to 185 gCO_2/kWh HHV[187]. The CO_2 content of H_2 used for the analysis comes from the EU Taxonomy (3 $kgCO_2/kgH_2$)[188], and is thus set at 76 gCO_2/kWh HHV.

Figure 4-58 shows the avoided CO_2 emissions for each configuration. The "5% minimum level" configuration leads to lower emissions than the "5% blending rate" configuration because in in the "5% minimum configuration" the Western-European country opts for a 10% minimum acceptance level, leading to higher blended volume than in the "5% blending rate" configuration, hence to lower emissions.

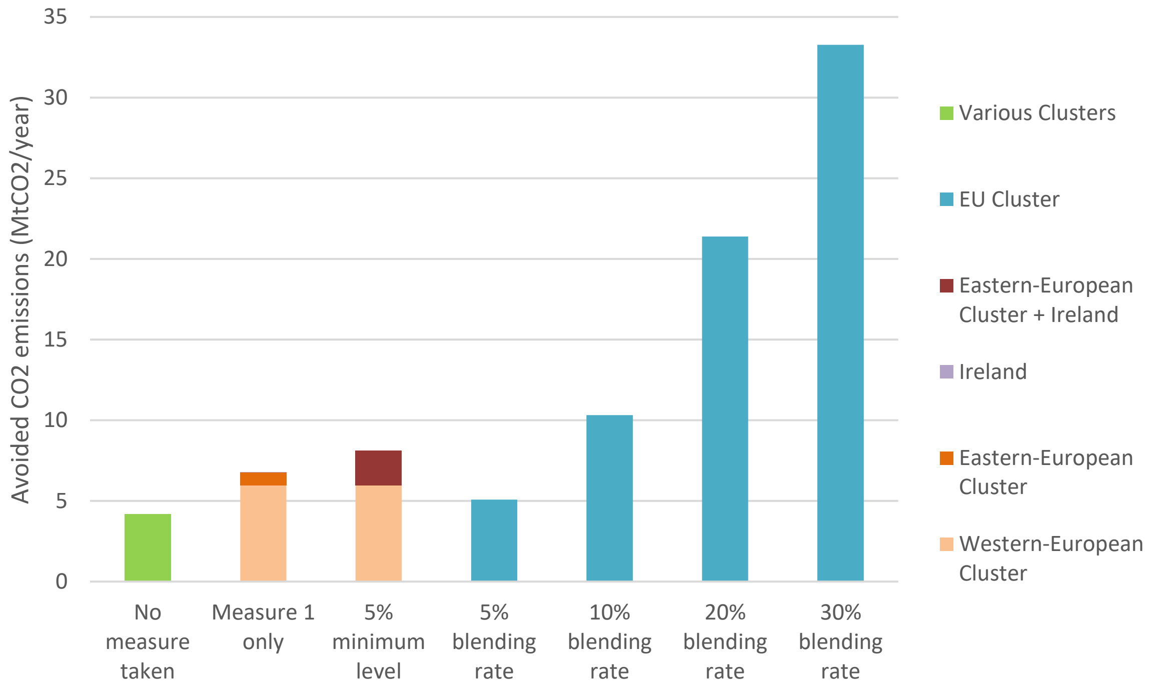

Figure 4-58: Avoided CO_2 emissions across the seven possible configurations. Source: own calculations.

CO_2 abatement costs correspond to the cost of adapting the equipment divided by the avoided emissions. They are useful to assess at which cost the measures are decreasing the European CO_2 emissions which can be linked to the efficiency of the measures. The calculated costs displayed in Figure 4-59 disregard any other costs.

[187] (ADEME, 2021)

[188] (European Commission, 2021b)

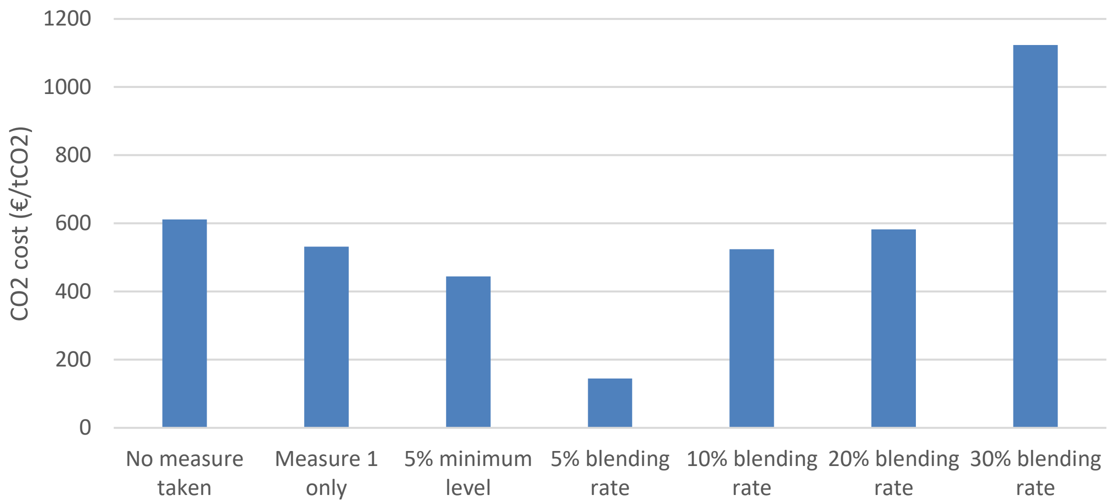

Figure 4-59: CO_2 abatement costs across the seven possible configurations. Source: own calculations.

The CO_2 abatement costs are lowest (144 €/t_{CO2}) in the situation where all MSs adopt a 5% blending threshold (Measure 3 with 5% minimum and maximum level). The CO_2 abatement costs exceed 1100 €/t_{CO2} for blending levels above 20% H_2. These values are three to more than twenty times higher than the carbon price under the MIX H2 scenario in 2030.

The CO_2 abatement costs shown in Figure 4-59 rely on the following hypotheses/approximations:

- They do not include the cost of H_2 production.
- They do not take into account the costs of the possible consequences of a change in supply (energy not served and increased import costs for example).
- Potential fluctuations in the H_2 blending rate over time are not considered: to achieve these calculated costs, the whole national gas networks would need to operate continuously at the maximum national blending limit.
- They were calculated considering the step-wise adaptation cost curve illustrated in Figure 4-48 (5%, 10%, 20% and above), even if for the "No measure taken" and "Measure 1 only" configurations some countries opt for a blending limit different from these thresholds.
- For the "30% blending rate", the costs are underestimated as the analysis only considers boiler replacement for the calculation of adaptation costs above 20% blending rate.

The biomethane-based gas quality standard is not expected to have direct environmental impact, but can have indirect positive impact as it facilitates the integration of biomethane in the gas markets.

4.3.4 Social impacts

4.3.4.1 Coordination between MSs

The measures facilitate to different degrees an unconstrained gas flow and regional coordination compared to a situation where all countries would establish their own blending rates. With the homogenisation of blending rates at the TSO level, the decrease in the number of clusters (cf. Table 4-12) leads to enhanced interoperability of networks and scale effects on equipment purchase[189].

Table 4-12 Number of clusters per cluster configuration.

Configuration name	Number of clusters
No measure taken	23
Measure 1 only	3
5% minimum level	2
Homogeneous blending rate (5%, 10%, 20%, 30%)	1

Measure 3.1 would have a positive impact as a maximum level set at the EU-level would avoid that a single MS's initiative on blending at the TSO level would harm its neighbours in terms of gas supply. At the same time, the establishment of EU-wide minimum acceptance and maximum levels imply a significant coordination and negotiation effort in order to define thresholds that comply with the plans and strategies of all individual MSs.

4.3.4.2 Impacts on gas consumers

The consumers and tax payers will be impacted as they have to pay for the adaptation costs directly or indirectly. The gas consumers are also directly impacted as they will need to adapt their equipment as shown in Table 4-11.

4.3.5 Comparison of measures

The main impacts of the different measures are summarised in Table 4-13. They strongly depend on the thresholds chosen in the different measures.

Table 4-13 Summary of the results.

Blending level	No measure	Measure 1 only	5% min & max	5% min. level	10%	20%	30%
Measures	No	1	3.1	2 or 3.1	2 or 3.1	2 or 3.1	2 or 3.1
Adaptation costs (Bn€/year)	2.6	3.6	0.7	3.6	5.4	12.5	37.4
Avoided emissions (Mt CO_2/year)	4	6	5	8	10	21	33
Abatement costs (€/t_{CO2})	612	532	144	445	524	582	1124

[189] (GRTgaz; GRDF; Teréga; Storengy France; Géométhane; Elengy; Réseau GDS; Régaz Bordeaux; SPEGNN, 2019)

That means, if increasing the blending rates at the TSO level increases the avoided CO_2 emissions, it also drastically increases the CO_2 abatement costs. The effectiveness of the measures is put into relation to the objective pursued in order to determine their efficiency (cf. Table 4-14). If CO_2 emissions have to be reduced "at any cost", Measure 2 with a high minimum acceptance level is sufficient but the costs of saved CO_2 will be very high. If these costs are to be mitigated, Measure 3.1 is needed to avoid unreasonable blending penetrations. Measure 3.1 with a 0% maximum blending rate can also be used to forbid hydrogen blending on the transmission network, in which case blending would only occur at the level of local distribution networks.

Table 4-14: Comparison of the impacts of measures related to a regulatory framework for gas quality.

Configuration name	Measure	Economic	Environmental	Social	Efficiency	Effectiveness
Measure 1 only	Measure 1	0	0	+	+	++
5% minimum level	Measure 2 or 3.1	--	+	--	--	+
5% blending rate	Measure 3.1	-	+	0	-	++
10% blending rate	Measure 2 or 3.1	--	+	--	--	+
20% blending rate	Measure 2 or 3.1	--	++	--	--	+
30% blending rate	Measure 2 or 3.1	---	+++	---	---	+
	Measure 3.2	-	+	0	+	+
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)						

4.4 Regulatory framework for LNG terminals

This section focuses on studying the impacts of potential regulatory measures on the LNG system in order to assess their efficiency to address the current market or regulatory shortcomings. A particular attention is paid to the economic impacts, i.e., costs and revenues for the various stakeholders, the environmental impacts and social impacts.

4.4.1 Economic impacts

4.4.1.1 Measure 1: Harmonised tariff setting methodology

The analysis of Measure 1 focuses on the impact of switching from the current tariff regime to negotiated tariffs for all EU LNG terminals. This would lead to LNG terminals competing between each other similar to gas storages under a negotiated access regime and bearing the full risk of commercial operations. The negotiated tariff for each EU LNG terminal associated with unloading, storage and regasification services is simulated by determining the tariff maximising the revenues of the terminal. The optimal tariff is calculated for each LNG terminal independently[190], while keeping the tariffs of all other EU LNG terminals unaltered. The methodology for determining these tariffs is explained in detail in the Annex, cf. Section 8.

Three scenarios are compared:

- « Base » scenario: No measure is considered. All EU LNG terminals are regulated with the exception of the currently exempted terminals, all of them having fixed predefined regasification and capacity tariffs[191].
- « Intermediate » scenario All EU LNG terminals are regulated, with the exception of the currently exempted terminals which have a negotiated regime (i.e. use of the tariff which optimises the corresponding LSO revenues). These terminals are highlighted in Figure 4-60.
- « Intervention » scenario: All EU LNG terminals are transferred to the negotiated regime (i.e. use of the tariff which optimises the corresponding LSO revenues).

The tariffs for all the considered LNG terminals for each scenario are available in Figure 4-60. It should be noted that UK LNG terminals are represented in the model but their tariffs are not optimised and remain equal in all model runs.

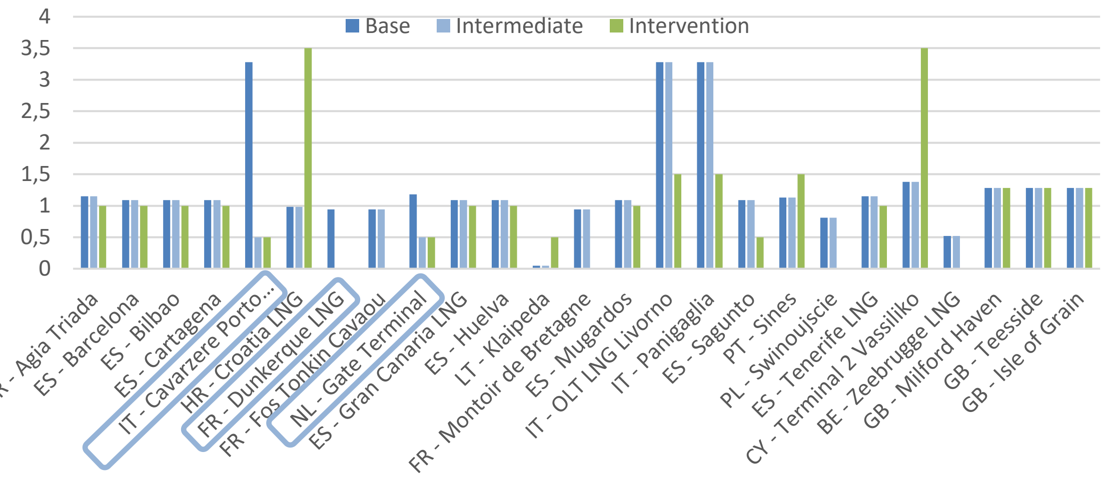

Figure 4-60: LNG tariffs (€/MWh) by scenario for all LNG terminals planned to be operational in 2030, used in Measure 1. Source: (Trinomics; REKK; enquidity, 2020) and own calculations with METIS.

Figure 4-60 shows that the negotiated tariffs applied in the Intervention scenario are mostly lower than in the other scenarios[192] except for Croatia, Lithuania and Cyprus. Lower tariffs may still imply higher revenues for LSOs as import volumes may increase. Tariffs can even be zero. In this case, the terminal has no revenue associated with its services but still earns the congestion rent through capacity auctions.

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[190] Note that the methodology to determine the negotiated tariff leads to an optimal revenue for each terminal's perspective. All LNG terminal's negotiated regimes together do not represent a macro-economic optimum.

[191] Taken from (Trinomics; REKK; enquidity, 2020).

[192] This is explained by the fact that cheaper terminals increase their attractiveness and their sales.

These scenarios are modelled with METIS and rely on the MIX H2 scenario, considering all LNG terminals that are planned to be operational in 2030 as fully available. For each scenario, an optimal dispatch is computed on the whole European model. The following results show the impact of introducing a negotiated tariff regime in the EU LNG terminals.

As seen in Figure 4-61, the **European gas supply** is impacted by these lower tariffs for LNG. To satisfy the gas demand in Europe, in the Intermediate scenario LNG imports are 25% higher than in the Base scenario. The increase reaches 55% in the Intervention scenario. LNG additional imports mostly replace natural gas pipeline imports from Russia, Algeria and Norway.

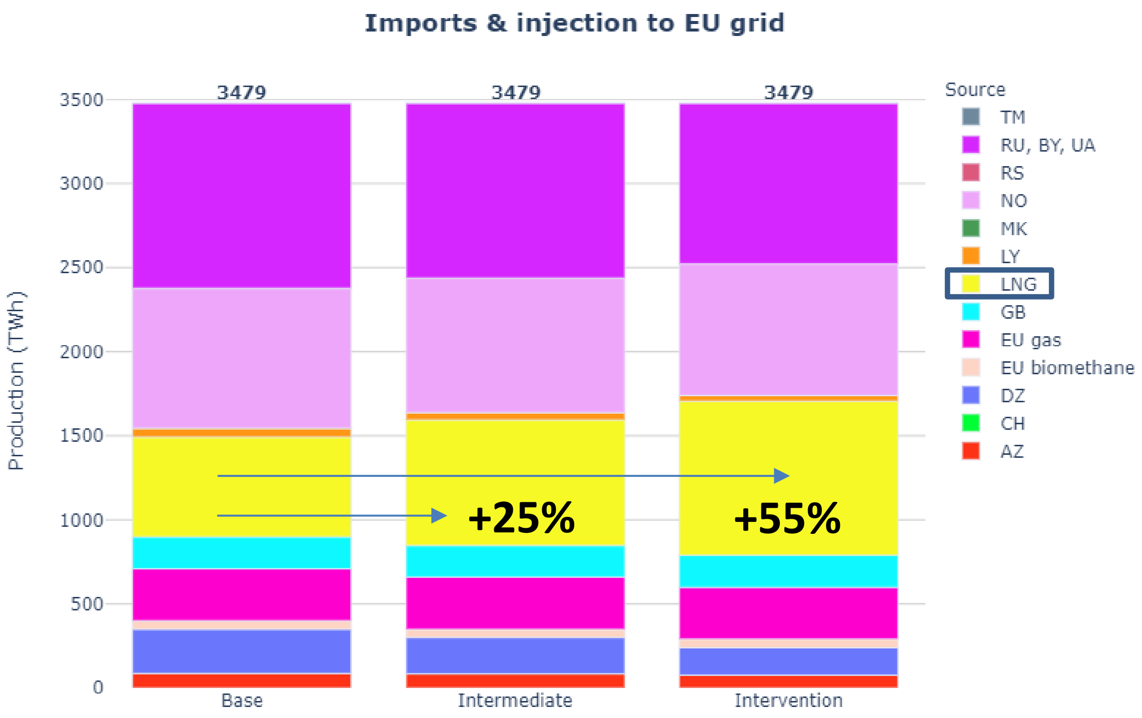

Figure 4-61: Annual Imports and injection to the European grid for Measure 1. Source: own calculations with METIS.

The drop in prices at most LNG terminals induces higher LNG volumes imported at a generally lower tariff as seen in Figure 4-61. **LSOs' total revenues** increase in both Intermediate and Intervention scenarios due to higher volumes (enough to compensate for lower tariffs) and congestion rents.

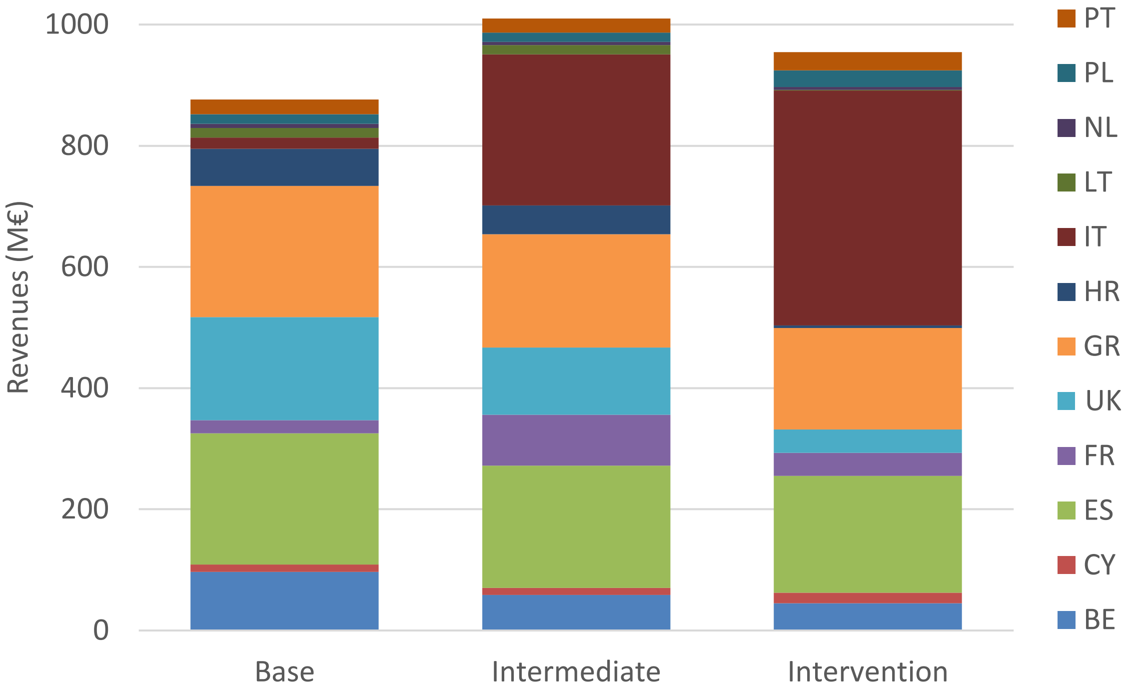

Figure 4-62: Annual LSO revenues per country for Measure 1. Source: own calculations with METIS.

In the Intermediate scenario, since the optimal tariffs of exempted LNG terminals are lower than the fixed predefined regasification and capacity tariffs used in the Base case, exempted LNG terminals see a decrease in their tariff and an increase in their attractiveness. Dunkerque (FR) and Cavarzere (IT) take advantage of their tariff reduction and benefit from a significant increase in their volumes and revenues. In the Intervention scenario, the majority of terminals see a decrease in their tariffs but few of them see a major increase. For example, Italia (Cavarzere, Livorno, Panigaglia) benefits a lot from its tariff reduction, while Croatia has a drop in LNG imports. Overall, the total revenues for LSOs are higher than in the Base scenario due to an increase of 55% of LNG total supply.

The Intermediate scenario leads to higher revenues for the LSOs compared to the Base and Intervention scenarios. However, as seen in Figure 4-63, if only the LSOs in the EU are considered, the revenues are higher in the Intervention scenario than in the Intermediate scenario.

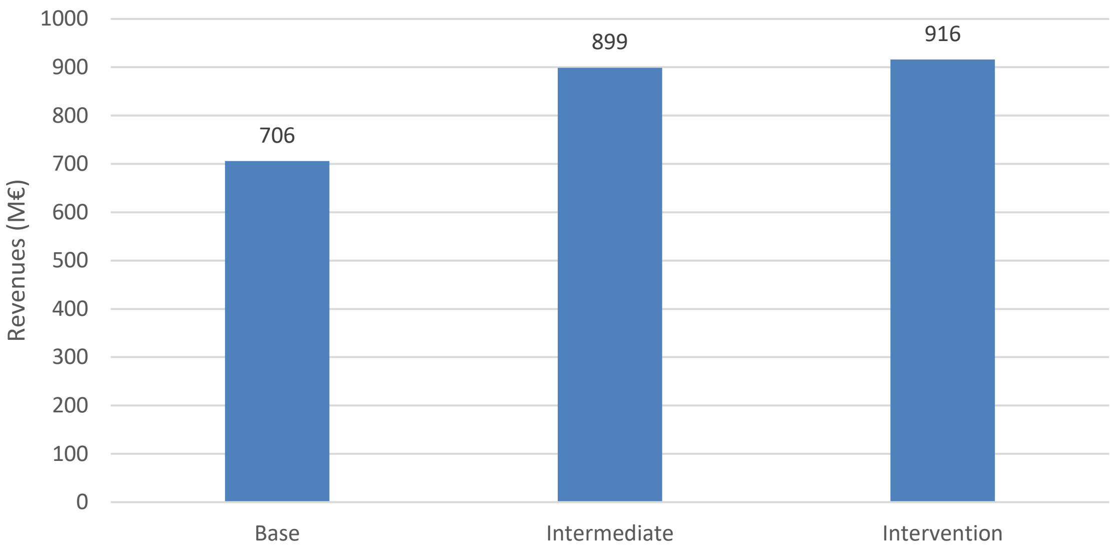

Figure 4-63: Annual LSO revenues for EU countries for Measure 1. Source: own calculations with METIS.

The LNG supply is higher in the two studied scenarios compared to the Base scenario, leading to increased **LNG shipping costs**. Figure 4-64 shows that Sub Sahara and the Middle East benefit the most from the increased LNG imports to Europe.

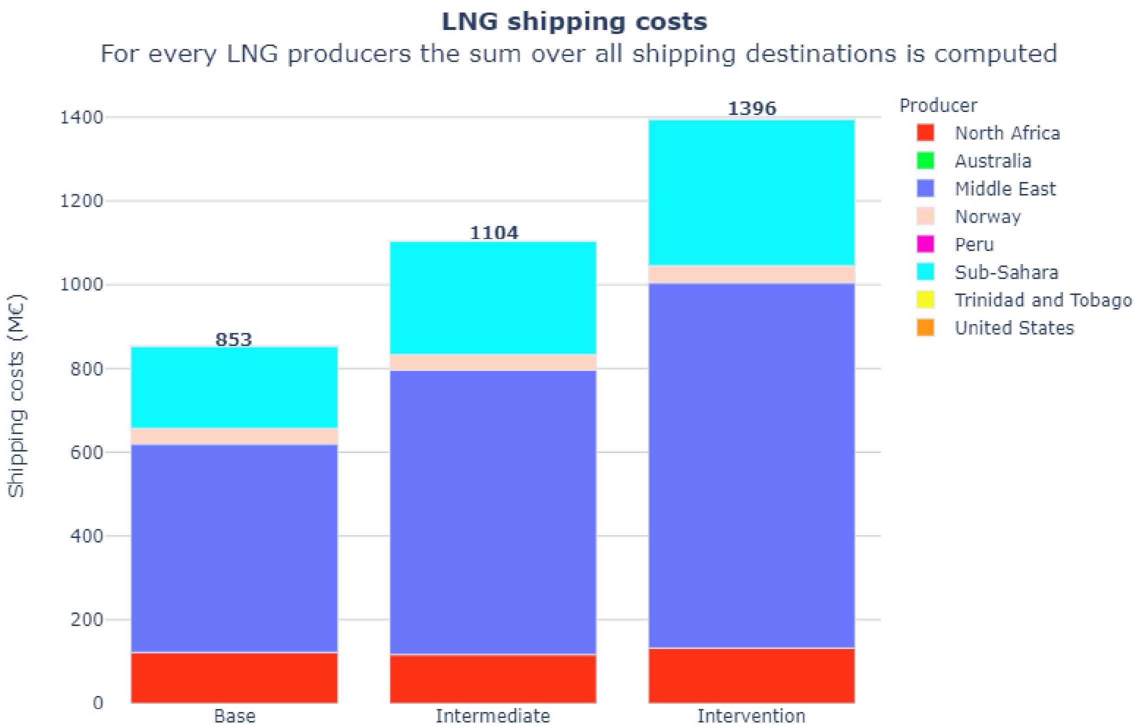

Figure 4-64: LNG shipping costs for LNG producers for Measure 1. Source: own calculations with METIS.

In terms of change in social **welfare**, Figure 4-65 shows that the EU countries benefit the most from the negotiated tariff regime. The LSOs revenues are higher due to higher LNG imports. The consumer surplus increases in both scenarios due to generally lower LNG and gas prices. The TSO revenues slightly decrease due to less pipeline imports, which is partly compensated by higher entry-fee revenues for LNG. The SSOs revenues decrease too, due to less storage usage and more flexible LNG supply. Finally, third-party countries (ThC) see a decrease in their revenues, mostly due to lower TSO and LSO revenues.

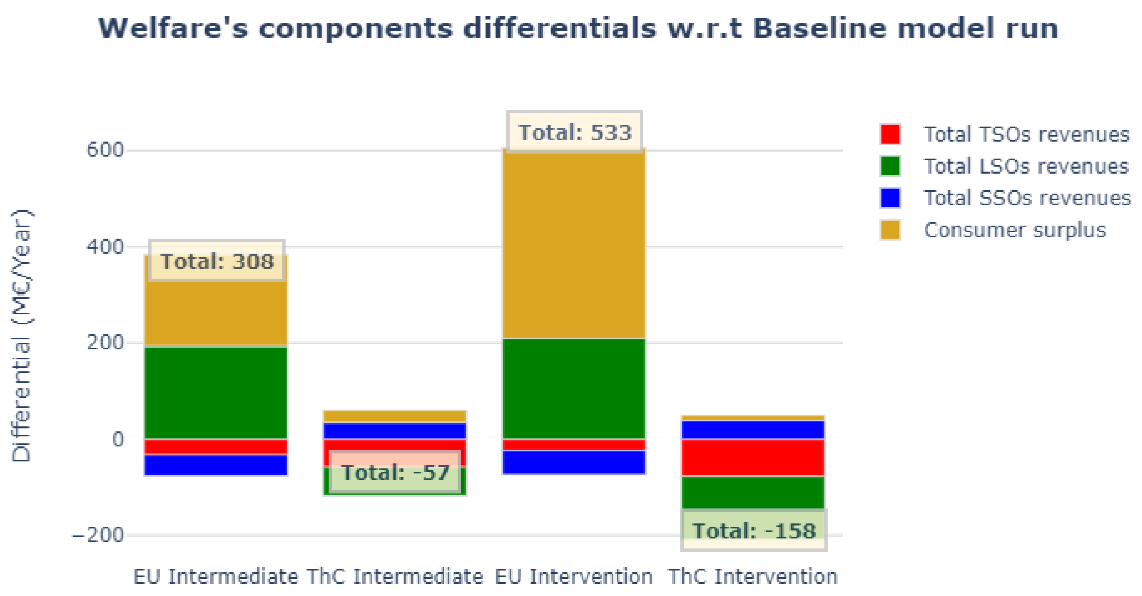

Figure 4-65: Changes in welfare components[193] of the EU and third countries for Measure 1 compared to the Base scenario. Source: own calculations with METIS.

4.4.1.2 Measure 2: Light intervention – Focus on optimal use of available capacity

One of the identified market or regulatory shortcomings concerns the potential sub-optimal usage of the LNG infrastructure. In order to analyse how this affects the system, the analysis of Measure 2 quantifies the impact of higher availability of LNG terminals on the gas market. The modelling consists in limiting the availability of European LNG terminals to historical levels (reflecting sub-optimal utilisation) and comparing it with a case of 100% availability.

The limited availabilities from Figure 4-66 are derived from historical data: for each LNG terminal is identified a historic period of 3 months during which the LNG prices were

[193] The welfare components displayed in this figure are the consumer surplus and the TSOs, LSOs and SSOs revenues that directly impact the welfare of national consumers. Producer surplus is not represented as it is not possible to associate it to national stakeholders, unlike consumers, TSOs, SSOs, LSOs.

lower than natural gas prices. The observed maximum utilization rate of the LNG terminals in this period is then considered as their maximal availability.

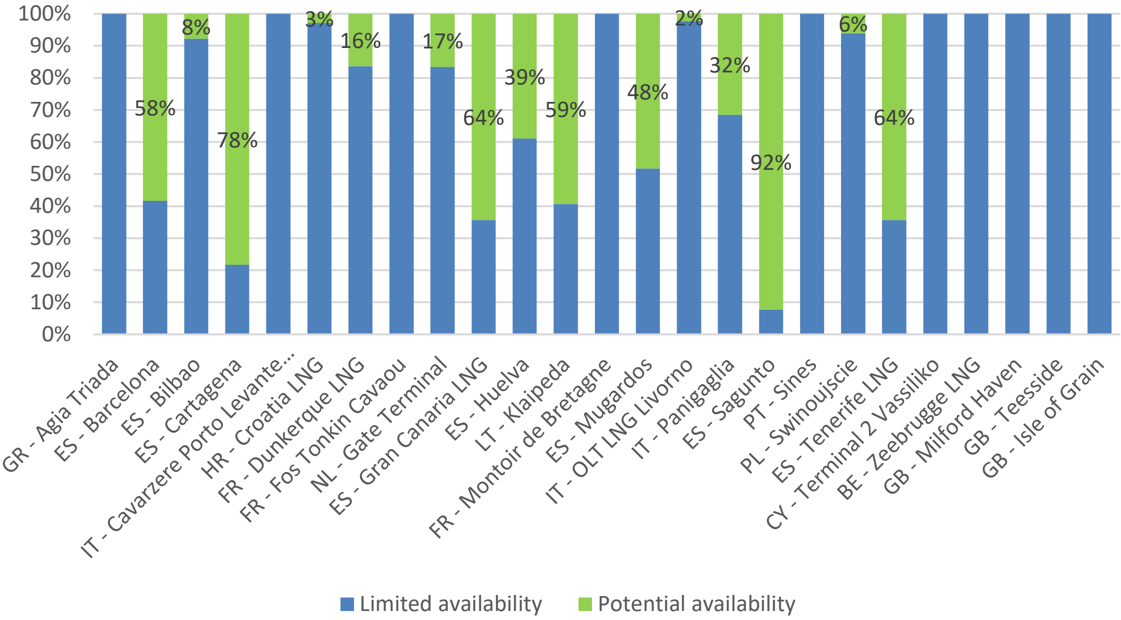

Figure 4-66: Maximal capacity factor of LNG terminals considered in Measure 2. Source: own calculations based on data from (GIE, 2021b). Details in Section 8.5 of the Annex.

Out of the 20 considered terminals (EU only), 15 terminals did not reach their maximal send-out capacity within the considered historical period of low LNG prices. The terminals with most limited availabilities are located in Spain and in Lithuania.

In order to assess the impact of removing these limitations and enable LNG terminals to be used at their full potential, 2 scenarios are simulated and compared: one with Limited availability (Base scenario) and one with 100% availability. For each scenario, an optimal dispatch is assumed in the whole European model, based on LNG terminals tariffs resulting from the Measure 1 Base scenario.

The following results show the impact of higher maximal capacities of EU LNG terminals. The results of Figure 4-67, indicating the mix of gas imports to the EU, are almost identical for the two model runs. In the model run with limited capacity (or Base scenario), it happens only during a few time steps that LNG terminals use their maximum send-out capacity. For the vast majority of the LNG terminals, the increase of their availability does not impact their volumes. Thereby, the total imports and injection of LNG in the natural gas market remain the same in the 100% model run.

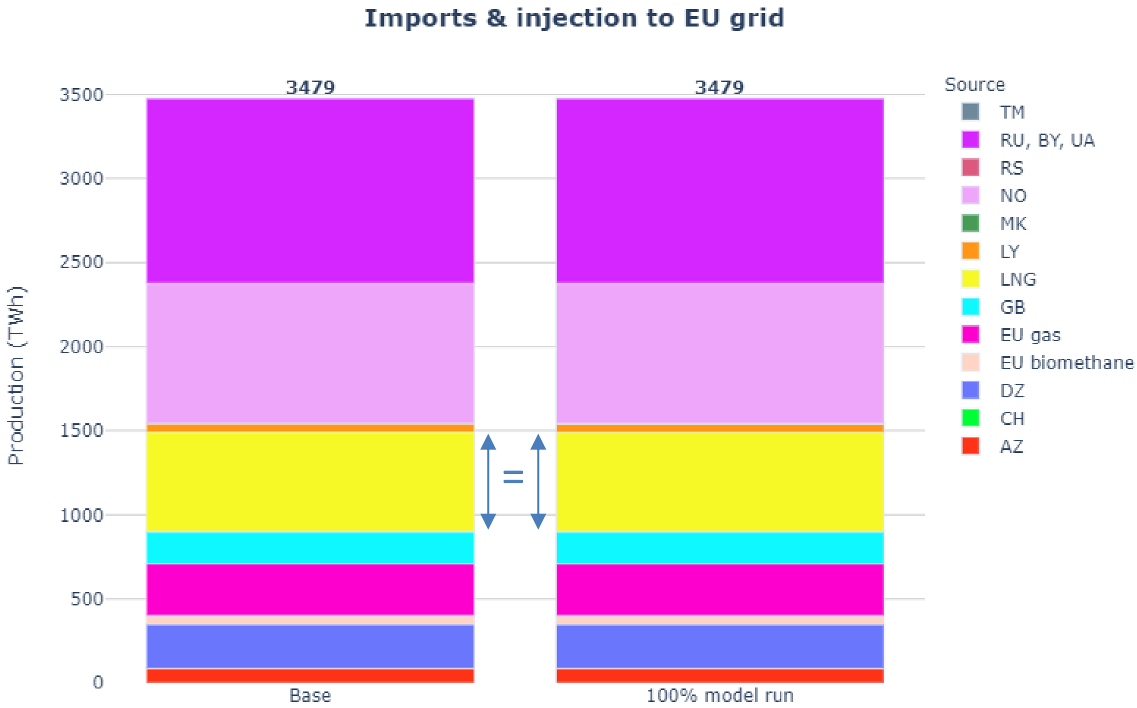

Figure 4-67: Annual imports and injection to the European grid for Measure 2. Source: own calculations with METIS.

Most of the terminals that show a limited availability are located in Spain. As there are several LNG terminals in Spain with a large overall capacity, they are rarely used at their maximal capacity at the same time in the model, and there is no congestion. Thus, as shown in Figure 4-68, the measure would only lead to a small difference in welfares of about 0.03% of consumer surplus.

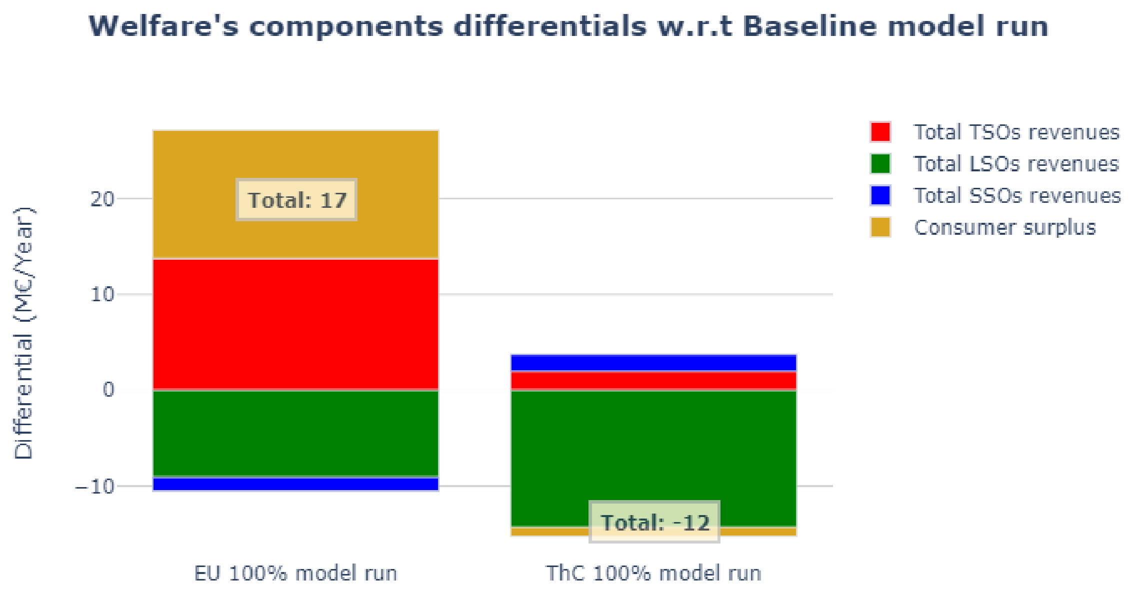

Figure 4-68: Changes in welfare components of the EU and third countries for Measure 2 compared to the Base scenario. Source: own calculations with METIS.

Unlike the consequences analysed in Measure 1, higher LNG terminal availability does not lead to a significant impact on the natural gas market according to the modelling results. Note that it is not possible to reflect the fact that under current "inefficient" LNG utilisation access to least cost LNG potentials might be restricted, i.e. even when having the same utilisation of LNG terminals, a facilitated access to LNG terminals (e.g. via a well-functioning tool to make unused capacity available) could make cheaper LNG arrive in Europe, having an impact on gas prices and welfare (that cannot be quantified).

4.4.1.3 Measure 3.1: Heavy intervention - Obligation on planning for LSOs/SSOs

LNG terminals could act as facilitators for the import of low-carbon gases into Europe. These imports could support the decarbonization of the European gas system if certain regions of the world were to produce large quantities of low-carbon gases at low cost. The goal of the analysis is to estimate the LNG Terminal's levers to stimulate the import of low-carbon gases.

The first part of the analysis qualitatively assesses the impact of importing liquefied renewable gases on the terminals. This analysis provides an overview of the implications of the measures to develop and make public plans to make LNG terminals/storages ready to receive hydrogen and biomethane (including if re-purposing is needed) and to coordinate developments plans for the adaptation of infrastructure to transport renewable and low carbon gases. It covers the import chains of biomethane, synthetic methane, H_2, methanol and ammonia, and the associated adaptations for LNG terminals.

Then, a case study on Dunkerque LNG Terminal is performed to assess whether the implementation of liquefied biomethane import targets can be economically viable, and to check whether the modification of LNG terminal tariff levels (for unloading, regasification, storage) could change the volume of biomethane imported.

Liquefied renewable gases supply chains and necessary adaptations

Several potential pathways towards a low-carbon gas supply chain involve LNG terminals:

- Import of liquefied biomethane or synthetic methane
- Import of liquefied pure H_2
- Import of liquefied methanol or ammonia

This section describes qualitatively the differences between the LNG import chain and those of the concerned renewable gases, and the adaptations needed to facilitate these import streams.

- Biomethane and synthetic methane:

Biomethane and synthetic methane's production and supply chain differs from that of natural gas for the production, and for the location of production and transport. No adaptations are required for liquefaction and shipping. New investments in liquefaction and gas transport may be necessary for the biomethane exporting countries if they are not already natural gas exporters.

The properties of biomethane or synthetic methane are similar to natural gas. Therefore, in case the biomethane or synthetic methane meets the gas quality specifications, no changes are needed in EU LNG terminals[194]. Administrative measures may be needed for shippers regarding the management of guarantees of origin / sustainability certificates as well as guaranteeing the gas meets technical specifications, but no investments or additional O&M are necessary[195].

Imported biomethane could find profitable markets in Europe. Marketing of the related guarantees of origin could value the low-carbon character of the gases, and enable gas suppliers to provide differentiated offers to their customers. Besides, the biomethane imported via LNG terminals could find direct outlets in industrial and port areas, especially as a substitute to fossil LNG for truck and marine transport.

- Pure Hydrogen:

H_2 produced from renewable sources by electrolysis of water can also be considered for import. LNG infrastructure can be converted to facilitate hydrogen carriers, and bunkering infrastructures can be used[196].

Importing H_2 makes it possible to take advantage of significant low-cost power-to-hydrogen potentials located outside the EU. Some nearby countries (Norway, Morocco, Saudi Arabia in particular) have been identified as potential exporters of power-to-gas[197].

The boiling temperature of H_2 is low (-253°Cat atmospheric pressure), compared to that of methane (-162°C). The cost of the liquefaction, transport, storage and regasification

[194] (Frontier Economics, 2020)

[195] (GIE; GLE, 2020)

[196] (Frontier Economics, 2020)

[197] (Frontier Economics, 2018; Fraunhofer IEE, 2021)

stages is therefore significant, and could be a barrier to the import of H_2. For the import to be relevant, a network supporting the integration of H_2 would have to be in place around the LNG terminals. In the future, H_2 could also be used directly as a fuel around the terminal[198] (for maritime or heavy transport demand in particular) without the need to be integrated into a gas transmission network.

- Ammonia and methanol:

The import of ammonia and methanol through LNG terminals is also a possibility. Both of these gases are produced by converting H_2. These energy carriers could be directly used in order to limit the transport costs involved in the import chain, but should be reconverted if they cannot be used at such in the vicinity of the ports (yet implying additional costs, potentially putting at risk their economic competitivity).

The boiling temperatures of ammonia and methanol (resp. -33°C and 65°C at atmospheric pressure) are much higher than those of H_2 and CH_4. The liquefaction, transport, storage and regasification stages can therefore be executed at higher temperatures or lower pressures. The associated costs could become competitive in the future. Synthesizing methanol and ammonia abroad make the import steps easier than importing H_2. However, the possibility to use or convert current LNG infrastructure to ammonia and methanol is limited[199].

Both gases are potential low-carbon fuels, although they are currently used mainly for industrial purposes. For imported ammonia and methanol to be used for industrial processes, a transmission network will have to be developed around the LNG terminals allowing their import. Their local use as fuel could avoid the need for network investment.

The pathways for importing liquefied renewable gases with an existing import chain are the most feasible in the short term. Importing biomethane and synthetic methane offers the advantage of requiring few adaptations compared to the LNG chain. The import of other low-carbon gases can also be considered: methanol and ammonia in particular, both produced from H_2. Their different physical characteristics require more adaptations compared to the LNG chain. Cost data are lacking for a complete analysis of H_2, ammonia and methanol imports; the second section will focus on the case of biomethane.

Case Study – Are there efficient and cost-effective levers for the Dunkerque LNG terminal to stimulate the import of biomethane?

This case study evaluates the impact of the measure proposing to "set their own targets" for the LNG terminals. The goal is to assess whether the imports of liquefied biomethane can be economically viable to understand if LNG terminals could influence the content of their imports by adapting their tariffs for biomethane shippers.

The objective of this case study is to assess whether the import of biomethane could be competitive for Dunkerque LNG Terminal by 2030. The section first details the costs of the liquefied biomethane import chain to Dunkerque. The total costs of the import are then compared to the purchase price (market price plus guarantee of origin) of

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[198] (Hydrogen Europe, 2021)

[199] (Frontier Economics, 2020)

biomethane in France. Sensitivity analyses are then performed on the key parameters: CO_2 price, guarantee of origin price and availability of resources.

The costs of imported liquefied biomethane are separated in different categories, shown in Figure 4-69.

Figure 4-69: Steps in the import chain of Liquefied Natural Gas.

Biomethane production costs are estimated for six non-EU regions (cf. Table 4-15). They are based on the supply costs in 2040 projected by the IEA[200]. Production potentials are assumed to be low relative to demand. It is thus considered that the cheapest sources will be sold locally. The costs chosen for the reference analysis are those related to the median production in each region. The table below includes the costs associated with the median production, and with the first and the ninth deciles of production.

Liquefaction costs are estimated at 8.5 €/GWh for the year 2030[201]. Shipping costs to Dunkerque are based on ENTSOG's Ten-Year Network Development Plan[202] (cf. Section 10.2.11)

Table 4-15 Production and shipping costs from region of production to Dunkerque LNG terminal (€/MWh HHV). Source: (IEA, 2020a) for the production costs, and (ENTSOG, 2020c) for the shipping costs.

Region of production	1st decile production costs	Median production costs	9th decile production costs	Shipping costs
North America	12.0	36.8	47.4	2.0
Central and South America	33.1	40.2	59.1	2.5
Asia Pacific	21.7	28.3	45.2	3.9
Eurasia	11.3	36.1	46.4	0.6
Africa	35.5	44.9	62.5	1.3
Middle East	25.5	32.2	50.7	2.5

Terminal tariffs at Dunkerque currently amount to 0.94€/MWh (ENTSOG, 2020d). These costs include unloading, storage and regasification. Transmission grid injection tariffs are assumed to be zero for biomethane[203].

The objective is to evaluate whether the implementation of an attractive terminal tariff for biomethane could be a lever for its import. In a free market, imported biomethane

[200] (IEA, 2020a)

[201] (CE Delft, 2020)

[202] (ENTSOG, 2020c)

[203] Cf. Indicator 1.34 in the Annex, Section 10.2.34.

is in competition with natural gas. For a market operator, buying biomethane is worthy when the price of biomethane is lower than the sum of the natural gas price (including CO_2-emission cost), the guarantee of origin price, and the TSO entry tariff (cf. Box 4-11).

Box 4-11: Calculation of the projected purchase price for biomethane.

Calculation of the projected purchase price for biomethane in France in 2030

The natural gas wholesale price projection for 2030 amounts to 19.2 €/MWh HHV without carbon price in the MIX H2 scenario. For the baseline scenario, the chosen CO_2 price is 44 €/t_{CO2}, which is the reference value of the Climate Target Plan 2030. The TSO entry tariff amounts to 0.3 €/MWh. The natural gas wholesale price projection for 2030 including CO_2 price and transport costs thus amounts to 27.6 €/MWh.

It is assumed that guarantees of origin in France are valued at around €5-10 per MWh. For the average value, a premium of 7.5 €/MWh was chosen. The impact of this choice is evaluated in the sensitivity test section.

The total estimated costs for liquefied biomethane import to Dunkerque LNG Terminal in 2030 are then compared to the projected purchase price for biomethane in France in 2030.

In Figure 4-70 it is shown that the import of biomethane is not economically viable for the Dunkerque LNG Terminal as the purchase price is for all sources significantly lower than the production cost.

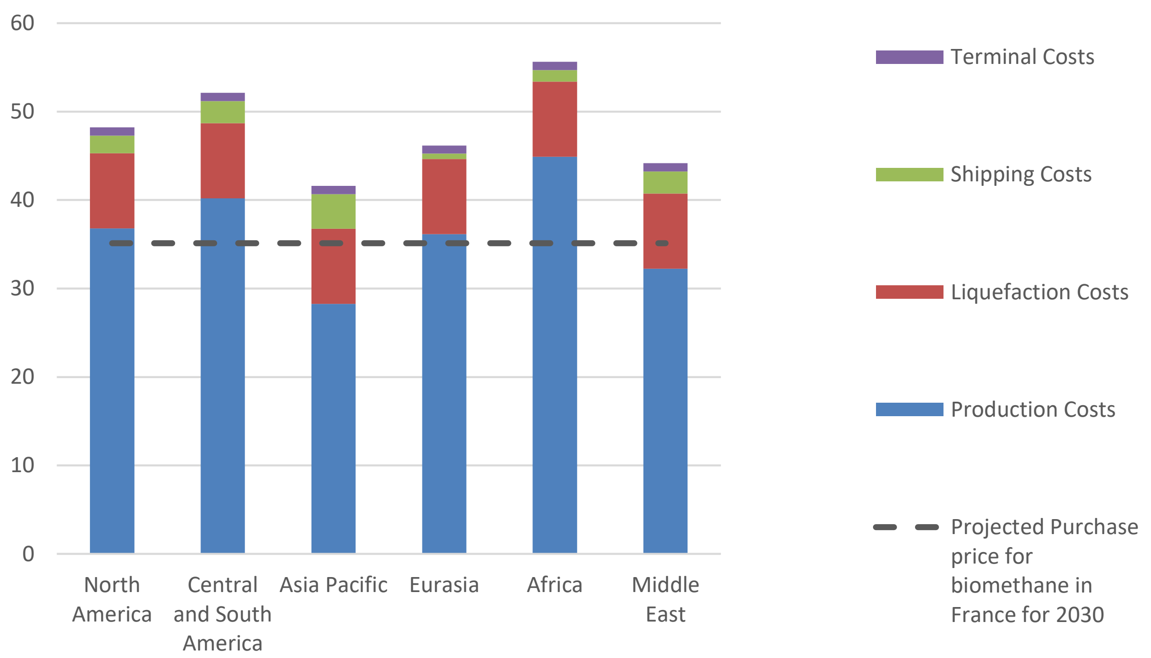

Figure 4-70: Comparison between the projected purchase price for biomethane in France in 2030 and the projected costs of imported liquefied biomethane in Dunkerque. Source: own calculations.

The cost reduction needed to make the import competitive being significantly higher than the terminal tariffs, the LNG terminal cannot support the transit of biomethane by itself as even if the terminal charges a zero tariff for unloading, storage and gasification, the overall import costs remain higher than the purchase price. With these assumptions, LNG terminals would not set their own biomethane import targets, as import is not competitive. The measure alone is therefore not likely to have any significant effect if there are no additional incentives.

This conclusion is highly dependent on the assumptions chosen. In particular, a higher price for CO_2 emissions or for guarantees of origin for biomethane could make the import of biomethane economically viable. Thus, three sensitivity tests have been performed. The objective is to estimate whether the variation of some inputs could make the import of biomethane competitive. It was estimated:

- The purchase price sensitivity to:
  - The price of CO_2-emissions (44€/t_{CO2} in the reference analysis)
  - The value of the biomethane premium (7.5€/MWh in the reference analysis)
- The costs sensitivity to the deciles of local production allocated to imports (median production in the reference analysis)

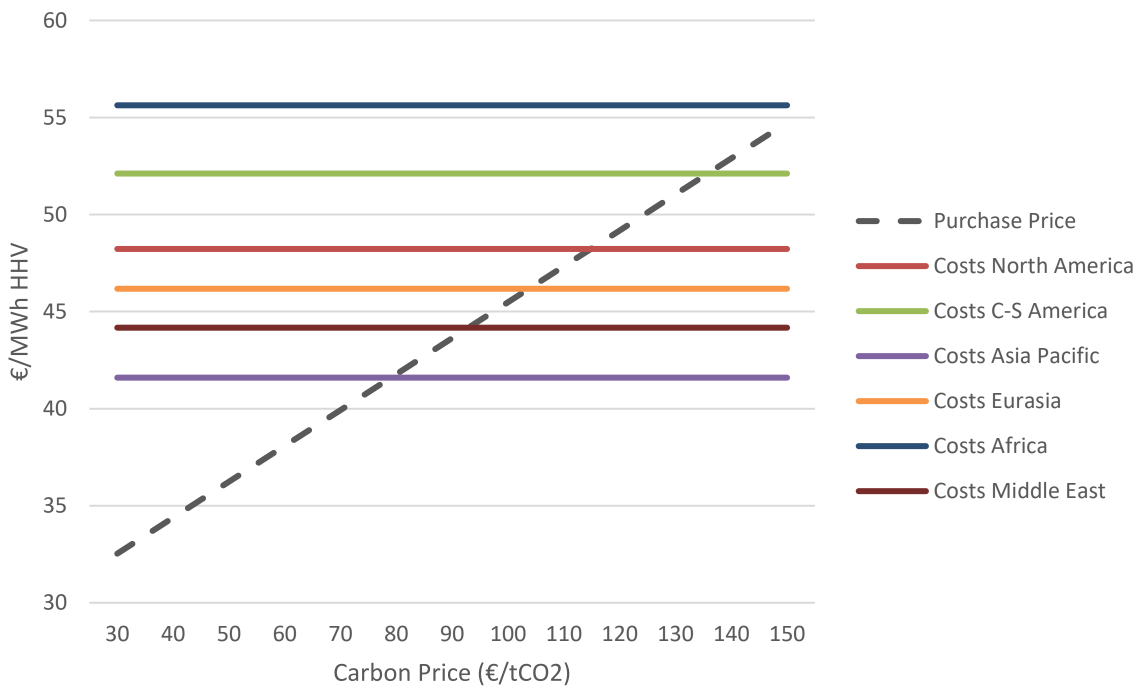

Figure 4-71: Purchase price sensitivity to carbon price. Source: own calculations.

The import of biomethane from Asia Pacific could become competitive if the price of CO_2 increases substantially (to around 80€/t_{CO2} with the hypothesis of this analysis).

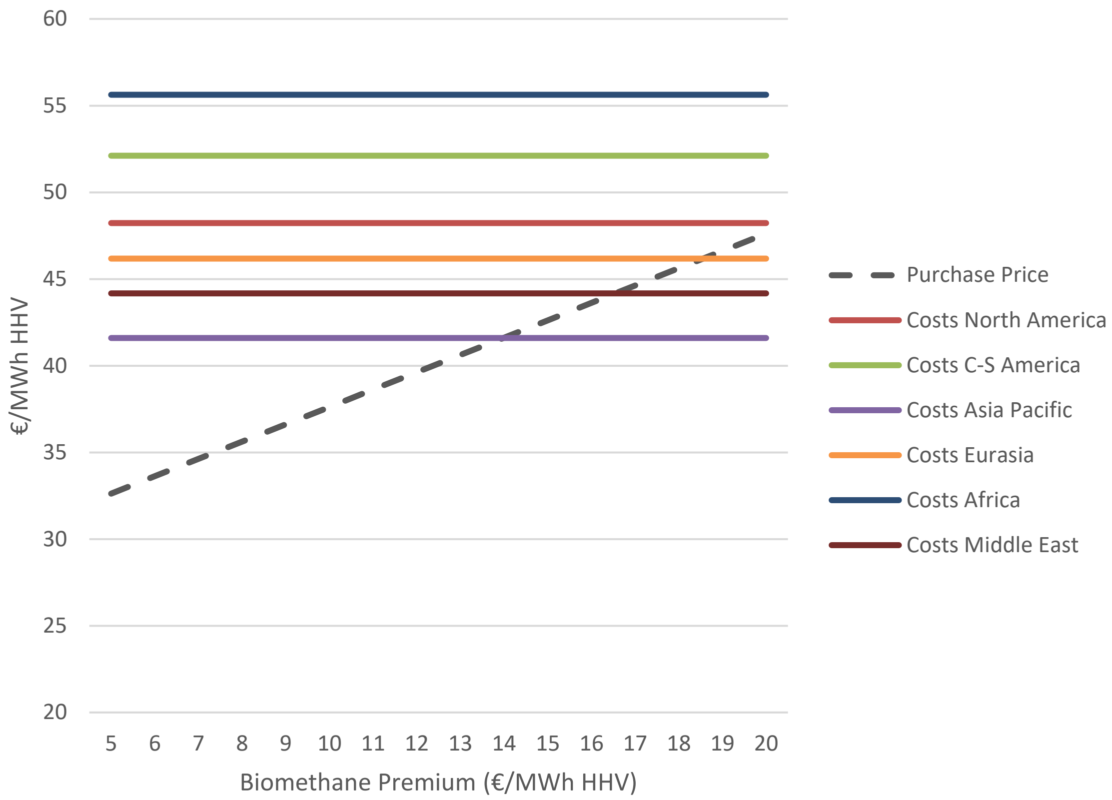

Figure 4-72: Purchase price sensitivity to biomethane premium. Source: own calculations.

Similarly, a tangible increase in the price of the guarantee of origin would allow a competitive import of biomethane (to around 14€/MWh HHV with the other variables of the reference analysis remaining constant).

The production cost of imported biomethane will depend on the demand for biomethane where it is produced. For the reference analysis, the production costs are those of the median local production. Costs could be underestimated if more production was to be consumed locally.

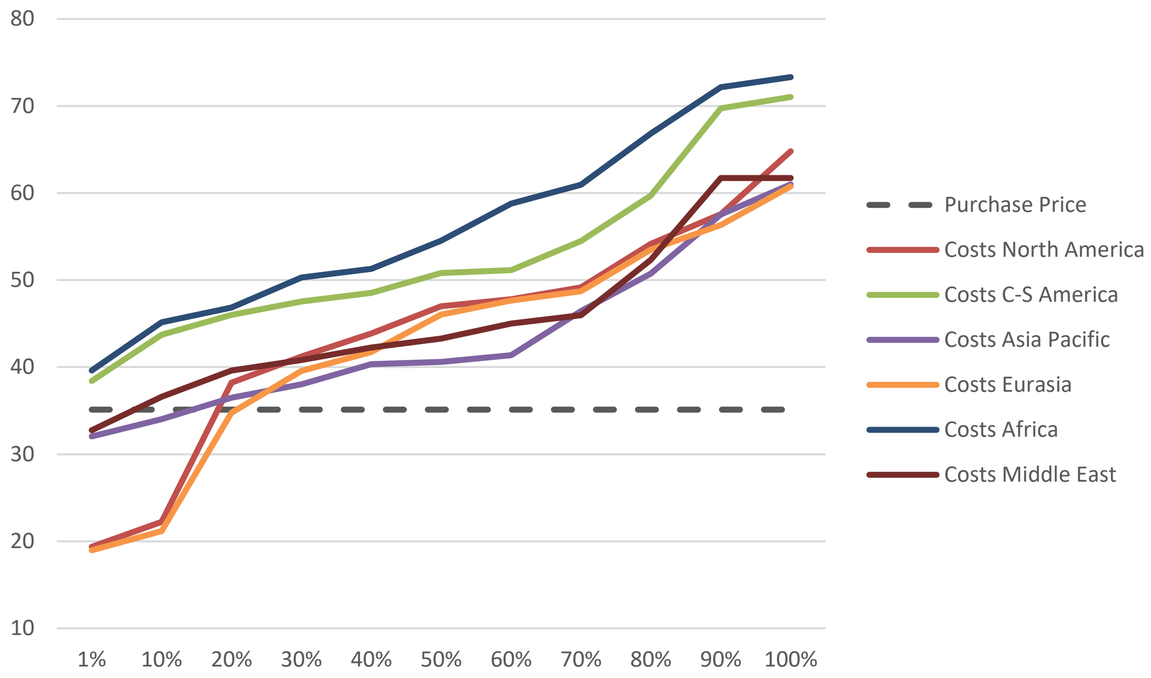

Figure 4-73: Cost sensitivity to the decile of production allocated to imports. Source: own calculations.

These sensitivity analyses show that if under standard hypothesis the measure alone is not sufficient for the terminals to stimulate the import of biomethane, this is not the case with other ones. Thus, if the price of the guarantee of origin or the price per tonne of CO_2 were to increase more than expected, or if cheaper biomethane in non-EU countries was accessible, the import could become competitive. However, higher CO_2 and GO prices will also make local biomethane more competitive, creating a possible competition between locally produced and imported biomethane.

4.4.1.4 Measure 3.2: Eliminate current entry tariff discounts for LNG terminals (variant)

In the EU, four countries apply at present a discount to their external entry tariff for LNG entering the system via terminals. The economic analysis consists in comparing two METIS models of the gas market with and without the currently applicable entry tariff discount for LNG to the TSO grid (tariff without discount derived from the TYNDP2020), cf. Table 4-16.

Table 4-16: Overview of modified LNG tariffs by country in Measure 3.2.

Country	Current LNG entry tariff (€/MWh) Discount ("Base")	Modified tariff (€/MWh) No discount ("Measure 3.2")
Greece	0.3 | 30% discount	0.5
Croatia	0.5 | 15% discount	0.6
Poland	0 | 100% discount	0.8
Lithuania	0.1 | 75% discount	0.4

The modelling reveals that the measure will in 2030 under the MIX H2 scenario result in a decrease of LNG imports of 10 TWh/year, compensated by an increase of Norway and Libyan imports of the same amount. Country by country: GR, PL, HR and LT are importing less LNG and UK is taking advantage of the cheap LNG available by increasing its own LNG imports.

In total, this would result in a decrease of 5% of the LSOs total revenues modelled, from 876 M€/year to 860 M€/year, with the total change in LSO revenues being depicted in Figure 4-74.

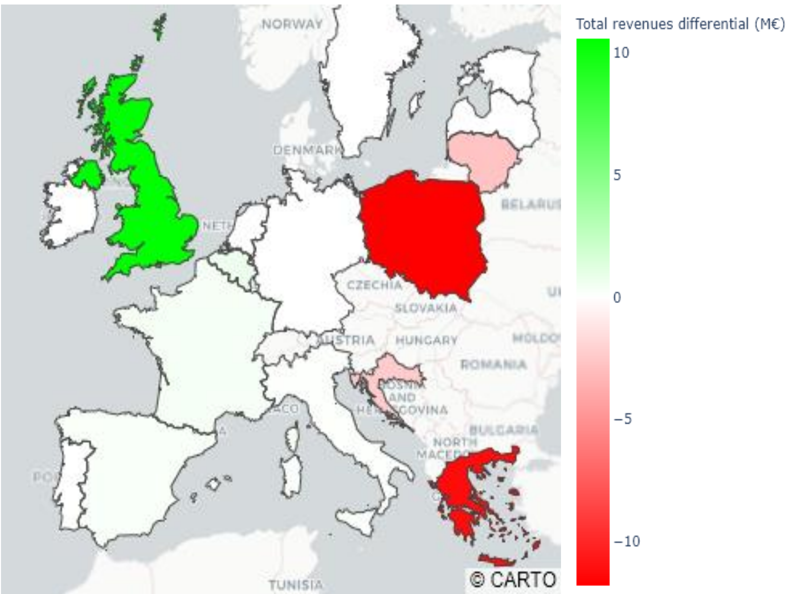

Figure 4-74: Changes in LSO revenues (M€/year) resulting from the implementation of Measure 3.2 and Measure 2 in comparison to a situation with Measure 2 only. Source: own calculations with METIS.

EU TSOs are the main beneficiaries of this measure (+20 M€/year). However, disparities appear among them with specific TSOs (e.g., Greece and Estonia, cf. Figure 4-75) collecting more entry revenues with the removal of the discount and taking advantage of this measure at the detriment of e.g. France and Belgium which export less gas to UK and thus collect less external tariff revenues.

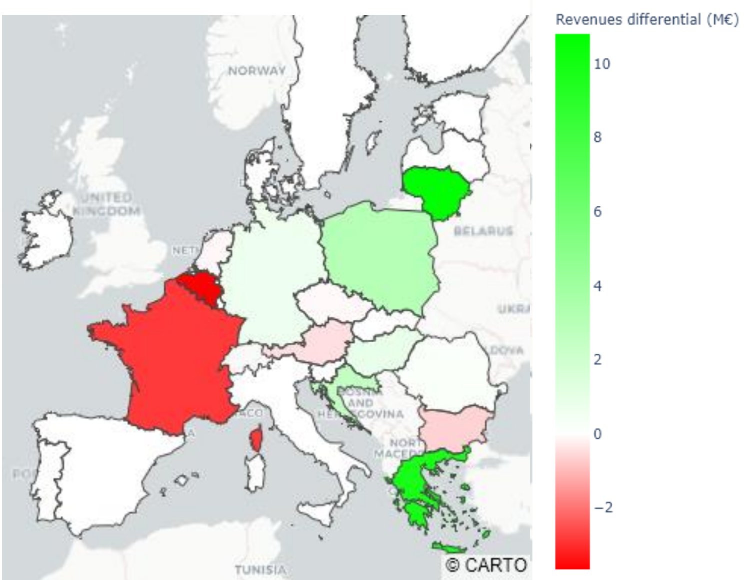

Figure 4-75: Changes in TSO revenues (M€/year) resulting from the implementation of Measure 3.2 and Measure 2 in comparison to a situation with Measure 2 only. Source: own calculations with METIS.

At the European level, non-EU countries appear to be the main beneficiaries of this measure and MSs are losing from it. This outcome is driven by higher low-cost LNG inflows to non-EU LNG entry points (mostly UK). In comparison with the natural gas market size (70-100 B€/year in the MIX H2 scenario), this measure is not expected to have a strong economic impact on the EU gas market, though.

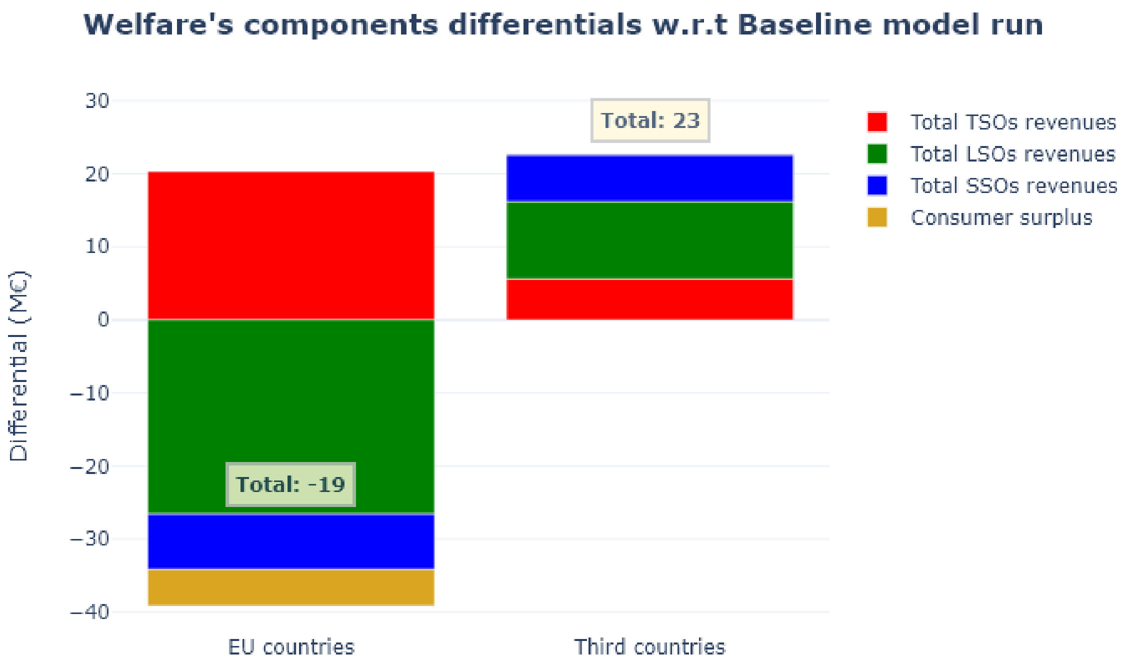

Figure 4-76: Changes in welfare components of the EU and third countries for Measure 3.2 compared to the Base scenario. Source: own calculations with METIS.

Still, this measure would ensure a homogeneity of LNG entry tariffs in Europe, and equal treatment between the different LNG terminals, decreasing the distortion of competition between European LNG terminals. This could result in beneficial economic welfare for the European consumers, which is not quantified in this report.

4.4.2 Environmental impacts

Measures 1 and 2 regard a better utilisation of LNG facilities. They focus on tariffs setting and on capacity use optimisation and result in more LNG imports to the EU (mostly with Measure 1). If they are not combined with specific environment related measures (i.e. like explored in Measure 3), they will mostly facilitate import of LNG from cheaper sources of fossil gas. So, the Measures 1 and 2 alone do not bring environmental benefits and could even have negative environmental impacts, assuming that shipping LNG has higher environmental impacts (energy consumption...) than transporting gas via pipeline. However, they contribute to optimising the LNG system and facilitating additional LNG imports that, combined with additional measures could contribute to decarbonisation.

While Measure 3.1 is dedicated to the environmental impacts of the gas supply, biomethane imports are found to be too expensive and will not enter into the EU gas market without additional support (whether by direct support, higher carbon tax or increased prices for guarantees of origin). Thus, this measure is not expected to have substantial environmental impacts within the MIX H2 scenario.

Measure 3.2 impacts the LNG market, and similarly to Measures 1 and 2, does not bring environmental benefit at the EU scale.

4.4.3 Social impacts

Most social impacts of Measures 1 to 3 regard the sources of natural gas supply, the impacts on security of supply for the EU and the welfare impacts for EU and non-EU countries. Measure 1 leads to higher imports from LNG sources substituting pipeline imports from neighbouring regions. The EU balance of natural gas is not impacted thus not affecting security of supply. In the welfare distribution though, Figure 4-65 shows that the measure mostly benefits EU stakeholders, which results in a positive social impact for EU countries. Measure 2 shows similar conclusions but to a lesser extent.

Measure 3.1 is not expected to have social impacts whether in the EU or in non-EU countries assuming there will not be biomethane exchanges at the LNG terminals.

Measure 3.2 could have a small negative social impact for consumers as it can slightly increase the gas price for European consumers (assuming that LSOs' missing revenues are recovered through internal exit tariffs). Even though this measure could reduce the incitation of importing LNG, it is not endangering the gas security of supply of Europe, as the gas infrastructures will in 2030 have an overcapacity compared to the gas demand modelled in the MIX H2 scenario.

4.4.4 Comparison of measures

Measure 1 shows that introducing negotiated tariffs at all EU terminals would make LNG imports more competitive compared with natural gas imports through pipelines. The measure is effective and benefits EU countries, but has no direct positive environmental effect, and could even lead to negative environmental impacts.

Measure 2 on the other hand has a very limited impact since the terminal infrastructures have in general already a rather high load factor, except in a few Member States, e.g. in Spain.

Measure 3.1 is not expected to have a positive or negative impact within the MIX H2 scenario. The impacts of this measure strongly depend on externalities such as carbon price, guarantee of origin market or biomethane resource availability. If these externalities do not change significantly from nowadays the impacts in 2030 are negative (useless efforts from the LSOs) but if they change the impacts will be positive (the LSOs will be ready for these new gases). However, this measure has no impact on these externalities.

Measure 3.2 is expected to have a limited but negative impact on the EU consumers, but can be considered as efficient as it allows homogenisation of EU entry tariffs at a limited cost.

Table 4-17: Comparison of the impacts of measures related to a regulatory framework for LNG.

Measure	Economic	Environmental	Social	Efficiency	Effectiveness
Measure 1	++	-	+	0	++
Measure 2	0	0	0	--	0
Measure 3.1	0	0	0	0	0
Measure 3.2	-	0	0	+	+
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)					

4.5 Network planning in light of energy system integration

The objective of this section is to provide an assessment of the economic, social and environmental impacts of a set of options related to potential new requirements for the planning of the evolution of gas networks.

The considered options are shortly described in Box 4-12 for convenience. See Section 3.4 for the precise definition of the options and their building blocks.

Box 4-12: Overview of the options for network planning.

Measures common to all options

- Information on decommissioning of methane pipelines
- Inclusion of one or several indicators dedicated to measuring the sustainability impacts of candidate infrastructure projects
- Transparency and stakeholder consultation

Option 1 – National Planning

Under this option, all MSs would have to publish **a single integrated gas NDP** every second year, covering transmission, storage, LNG terminals and supply. This NDP would have to comply with the measures that are common to all options listed above.

Option 2 – National Planning based on European Scenarios

Under this option, the assessment of gas infrastructure projects will have to be based on **scenarios that are jointly built by gas and electricity TSOs**, with the involvement of LSOs, SSOs, DSOs. NRAs will be in charge of establishing the framework for the involvement of these parties e.g. via de minimis rules.

The scenarios will be required to **cover the electricity, methane, hydrogen systems**, taking into account **CO_2 and district heating networks**. The planning of the development of the gas infrastructure will be based on these integrated scenarios, with NRAs having the competence of requiring that a market test on the actual need of hydrogen infrastructure is performed. At least one of the scenarios should be aligned with one of the most recent TYNDP scenarios developed by the ENTSOs, which are to be **in line with EU climate goals**.

Finally, the NDPs produced by gas and electricity TSOs have to undergo a set of **"sanity checks"** to ensure they are as consistent as possible with one another (without requiring joint planning). NRAs will be responsible for the definition of sanity checks and the associated procedure to implement these checks and to adapt NDPs.

Note that several governance options are compatible with Option 2. They range from the production of a consolidated and integrated network planning document (as is the case in Denmark) to the publication of sectorial NDPs produced using a concerted process (via sanity checks).

Option 3 – European Planning

Under this option, a **European-level system-wide network development plan**, based on integrated scenarios, would have to be drawn up.

A qualitative discussion of the potential impacts of each of the options is provided in the following paragraphs. The economic impacts are addressed first, then the environmental impacts are presented, and finally the social impacts are discussed.

4.5.1 *Economic impacts*

4.5.1.1 Measures common to all options

4.5.1.1.1 Information on decommissioning of methane infrastructure

Conducting a mapping exercise between the gas infrastructure and gas supply and demand projections is at the core of the NDP process. Reporting on underutilised infrastructure elements[204] that are candidates for decommissioning would entail **minimal additional efforts**[205].

However, there are **benefits** associated to this measure as its implementation would result in more clarity being available to developers of hydrogen infrastructure, especially in the case where hydrogen is not included into scenarios or into the NDPs themselves. This measure may therefore result in an **easier detection of candidate infrastructure elements for repurposing**, and may thereby save investments costs, as the repurposing of gas infrastructure projects is a considerably cheaper option compared to building a new hydrogen infrastructure[206].

The **risks** of such an indicator would be that decisions for the decommissioning of pipelines or storage assets are **locked-in too early and must be retracted**. On the other hand, such a risk might prompt TSOs to delay decision on the decommissioning of pipelines or storage assets and consequently potentially delaying their repurposing. This risk seems to be moderate compared to a situation where the information on decommissioning is not available.

4.5.1.1.2 Sustainability indicator

The inclusion of a sustainability indicator into gas NDPs comes at **virtually no costs**. Indeed, a recent study commissioned by the European Commission[207] provides actionable recommendations on the way the sustainability impacts of infrastructure projects can be defined and measured. The implementation of the measure can lead to **important economic benefits** (as well as sustainability benefits, see Section 4.5.2.1.2) since it can help detect projects that are not compatible with the long-term evolution of the European energy system, and thereby avoid that such projects are selected and either become stranded or put the transition at risk (lock-in effect).

4.5.1.1.3 Transparency and stakeholder consultation

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[204] Infrastructure elements includes pipelines, but also compressors, storages and other network-related equipment.

[205] The level of efforts can depend on the required underlying methodology to establish the information, and on the nature of the information (e.g. reporting for information purposes only, or decommissioning decisions). As a similar approach in all Member States should be adopted to avoid distortions, one should also keep in mind that that the costs of implementing additional cost benefit assessment in general are proportionally higher for smaller Member States. This could potentially be overcome by pooling resources at the regional level and/or by building on existing processes.

[206] See e.g. (European Commission, 2021a)

[207] (Trinomics; Artelys, 2020)

Ensuring that the framework under which infrastructure planning is organised is transparent and lets stakeholders provide feedback is of **crucial importance**. For NDPs where there is currently limited public consultation, costs may be associated with this measure. A distinguishing feature of the consultation process is the fact that TSOs and NRAs have different roles in setting and following up the process and also their interaction in these regards. In general, ACER's Opinion No. 09/2020[208] reveals that quite some heterogeneity is still existing as regards the specific types of stakeholders consulted in each Member State. Here the proposed regulation could possibly lead to a further harmonisation by introducing requirements on the categories of stakeholders to consults.

The implementation of this measure can lead to **economic benefits** as a higher level of buy-in can be achieved thanks to a more inclusive consultation process. Projects could see the level of opposition decrease if stakeholders and the population are made aware of the stakes and can provide feedback that is structurally feeding into the process leading to the establishment of NDPs.

Potential improvements could be based on further specification (and potential strengthening) of the roles of NRAs in the stakeholder consultation process and in the general definition of minimum requirement laying out aspects such as procedural aspects and mandatory stakeholders to be consulted. The anticipated benefits of such measures could be the **strengthening of a level playing field among markets participants and an increased predictability for market participants** on the ways they can feed into the process resulting in overall more coherent planning decisions. It should however be noted that the potential for **additional benefits can be considered relatively modest** as such conditions already are broadly in place despite the heterogeneity of approaches. Nevertheless, the identification and promotion of best practices in stakeholder consultation processes across Member States could be beneficial.

4.5.1.2 Option 1 – National Planning

Option 1 builds on top of the measures common to all options discussed above. The latter would be supplemented by the requirement that a single gas NDP is produced in each of the Member States every second year, irrespective of the unbundling model that has been chosen by TSOs, or the number of TSOs active in each of the Member States.

A number of Member States have multiple gas TSOs. In particular, Germany, Spain and Italy have three or more TSOs, while Austria and France have two. In the case of Germany, a single NDP is established via a collaboration amongst TSOs[209]. For Italy, a formal obligation to publish a coordinated document co-authored by the various TSOs is enforced. This includes inter-alia the coordination on the methods for the evaluation of investment options via cost benefits, with a common methodology, selection of input parameters, and reference values to be used. For France, the two TSOs collaborate to establish common scenarios for the total gas demand, but there is no obligation to publish a common NDP.

The assessment of the economic impacts (costs and benefits) of the implementation of Option 1 can only be of a qualitative nature, as a quantitative exercise would involve obtaining indications related to the potential behaviour of TSOs, and thus would strongly depend on the way the counterfactual is defined. The following paragraphs identify categories of benefits and characterise them. First, if two (or more) TSOs are planning

[208] (ACER, 2020b)

[209] (FNB Gas, 2021)

reinforcements within a Member State in an uncoordinated way, **infrastructure redundancies** may appear if the TSOs aim at solving congestions or at increasing import capacity without investigating if the sum of the projects considered by each TSO could result in over-capacities. Furthermore, the establishment of a single NDP per country also reinforces the **consistency of the national approach related to the injection of biomethane** or other renewable or low-carbon gases (e.g. via a coordinated approach to investments in reverse flow technologies) and of the development of the hydrogen infrastructure (including via the selection of pipelines that could be repurposed).

The implementation of Option 1 would consequently **reduce the infrastructure cost by enabling synergies** and identify interdependencies to be acted upon.

Second, all the processes mentioned above (information on decommissioning, sustainability indicator, stakeholder consultation) could be streamlined, resulting in an **overall more efficient process**.

ACER observes in Opinion No 09/2020 that all MSs with multiple gas TSOs have already procedures in place to assess the compatibility of plans by different TSOs (e.g. Italy) or establish a consolidated NDP, with the exception of France. The burdens in terms of regulatory and impl**ementation efforts of this option are likely to be lower than the benefits**.

Finally, in the case Member States choose to collaborate to establish **regional network development plans** instead of national ones, the same categories of synergies and cost savings can be expected to emerge, with additional benefits compared to a situation where NDPs are established at the national level. First, by establishing NDPs at the regional level, TSOs would ensure that there is a higher overall level consistency across investments foreseen by the regional NDP, since the vision of the future for the region is more likely to be consistent compared to a situation with national-level NDPs. Second, a regional approach can ensure investments are consistent across borders, e.g. in terms of expected evolution of gas quality and the required adaptations, the development of biomethane injection levels, or the repurposing of methane infrastructure to enable the exchange of hydrogen (for example by storing hydrogen produced in one Member State in another Member State).

4.5.1.3 Option 2 – National Planning based on European Scenarios

Option 2 builds on a number of measures (see Box 4-12 for an overview) which are discussed one by one in the next paragraphs.

4.5.1.3.1 Joint electricity and gas scenario building

Scenario building is an integral part of the process leading to the establishment of NDPs. It is on the basis of scenarios that infrastructure projects are assessed (e.g. via a cost-benefit analysis) and, then, based on the results of the assessment, selected or rejected.

Currently, the establishment of NDPs for gas and electricity are only loosely coordinated, if at all. Indeed, even if the majority of gas TSOs consider assumptions related to the electricity system within their scenario-building process, this does not guarantee that these assumptions are consistent with the assumptions used by electricity TSOs in their own NDPs.

The only exception mentioned by ACER in Opinion No 09/2020 is Denmark where a single NDP, based on scenarios covering gas and electricity, is published[210].

The implementation of this measure would bring economic benefits by recognising the impacts of interlinkages between the electricity, hydrogen, and methane systems, taking into account CO_2 networks and district heating. Interlinkages between the electricity, hydrogen and methane systems can be divided into two categories:

- **Direct interlinkages** are enabled by technologies that physically link the two energy carriers: gas-fired electricity generation (methane-to-power or hydrogen-to-power via CCGTs, OCGTs, CHPs), power-to-gas (electrolysis, potentially coupled with methanation), hybrid consumption technologies (e.g. heat-pumps with a gas back-up boiler),
- **Indirect interlinkages** are cases where power and gas are independently fuelling different technologies both capable of providing the same energy services. Under this condition, power and gas are substitutes, so that their competition is the linkage taking indirectly place via the end use sector. For example, the mobility sector is a source of indirect interlinkage, as trucks and buses could be electrified or could be using fuel cells. Another source of indirect interaction can be found on the supply side via the competition for the supply of methane between biomethane and synthetic methane.

Building joint electricity and gas scenarios would **ensure that indirect interlinkages are treated in a consistent way** in subsequent processes by gas and electricity TSOs, and that investment decisions are taken with a common vision of the future. In other words, without joint electricity and gas scenarios, there is a risk that gas infrastructure projects and electricity infrastructure projects are selected based on incompatible visions of the future. For example, in the scenario underpinning the gas NDP, biomethane could be envisioned as a means of decarbonising a given end-use, while in the scenario used to produce the electricity NDP, an indirect electrification route for that same end-use could be considered. In such a case, there is a risk that, put together, the gas and electricity scenarios meet part of the demand multiple times, resulting in an **over-dimensioning of the overall energy infrastructure**.

The ongoing trend towards a much deeper energy sector integration will significantly increase the level of interlinkage between the electricity, hydrogen and methane sectors. Therefore, the benefits associated with a joint scenario building exercise will only become more important in the future.

Establishing joint scenarios at the Member State level would **mirror the EU-level situation** where ENTSO-E and ENTSOG are, since the TYNDP 2018 cycle, jointly developing TYNDP scenarios. The implementation of this policy measure would be associated with a **moderate cost**, as joint scenario building does not require to establish a common simulation model encompassing the electricity, hydrogen and methane systems, as well as district heating and CO_2 networks, but rather to coordinate on a set of core assumptions.

To be precise, a joint scenario building exercise is defined as a process that leads to the definition of a consistent set of assumptions related to the decarbonisation pathways by end-use, the evolution of installed generation capacities in the electricity sector, the evolution of commodity prices, the availability of biomethane, the production/import potentials of gaseous fuels (natural gas supply sources, hydrogen imports, etc.). This process may be facilitated by the establishment of a common model (interlinked model

[210] See e.g. (Energinet.dk, 2018)

allowing to jointly dimension and simulate the gas and electricity systems, see METIS[211] for example), but such a model is not a prerequisite to the establishment of joint scenarios.

The coordination process amongst stakeholders in the gas and electricity sectors could lead to savings (on top of the other economic savings discussed above) in the mid- to long-term, as the pooling of resources involved in scenario building exercises leads to a more efficient process.

Finally, it is to be noted that this measure would also impact the process leading to the establishment of the electricity NDPs, therefore requiring that **provisions related to electricity NDPs need to be updated to reflect this measure**.

Integration of hydrogen, CO_2 and district heating into scenarios

Hydrogen has emerged as a promising energy carrier to support the decarbonisation of hard-to-abate sectors of the European economy. However, it is only recently that hydrogen has become one of the key points of focus in scenario building exercises, mainly due to the fact that **electrolysis, being considered as the most promising option to produce hydrogen, has strong impacts on both the electricity and gas systems**.

Currently, some plans provide indicative investment plans or future concepts or refer to hydrogen infrastructure delineated in external studies. According to the Annexes of ACER Opinion No 09/2020[212], hydrogen is covered in the NDPs of Belgium, Croatia, France, Denmark, Ireland, Latvia, Malta and Slovenia. However, the degree of sophistication when accounting for hydrogen varies significantly from one country to the next.

Extending the scope of NDP scenarios to cover hydrogen may be associated with additional efforts as the scope of scenario building increases. As such the **overall efforts to also include hydrogen into scenarios appear modest** (this measure only requires coordination between entities to align on key assumptions, and not to develop joint simulation models, even if the latter can facilitate scenario building exercises). These implementation costs can be expected to be much smaller than the benefits associated to this policy measure.

Indeed, it has already been underlined above that having a common vision of the future is essential to avoid over-investments and to capture synergies between sectors. When establishing such visions, it is crucial to include the hydrogen dimension given the role hydrogen is expected to play in the decarbonisation of the European economy, even in scenarios with relatively low hydrogen demands. Indeed, **without including hydrogen in joint plans, one risks over-investing in gas and hydrogen infrastructure** (and potentially electricity) due to the use of inconsistent assumptions related to e.g. the competition between biomethane, electrolytic hydrogen (potentially converted into other molecules) and electricity in the decarbonisation of end-uses.

A few plans (e.g., DE, IT, NL) refer to heat demand or district heating networks and their integration into the study / planning assumptions. Similarly, another subset of plans (e.g., BE, FR, IE) refer to future CO_2 networks. The efforts and costs associated with including these aspects into scenarios are similar to the ones discussed above in the case of integrating hydrogen into scenarios. In short, Table 8-37 (cf. Annex, Section 8.6) presents a visual representation of a review that has been carried out for a selection

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[211] METIS is a mathematical model developed on behalf of the European Commission to support their evidence-based policy making activities, see (European Commission, 2021d)

[212] (ACER, 2020b)

of NDPs. It provides an assessment of the status of each of the considered policy measures mentioned above (including measures common to all options, Option 1 and Option 2).

4.5.1.3.2 Sanity checks

Direct interlinkages between the gas and electricity systems are often linked with sources of flexibility at the operational level. For example, typical direct interlinkages include:

- **Gas-to-power plants**, which, except for CHP configurations where heat delivery is the primary driver, are highly flexible
- **Power-to-gas assets**, which can also be operated in a flexible way
- **Hybrid consumption technologies**, which can switch from using gas or electricity depending on real-time information (e.g. price-responsive hybrid heat pumps)

Therefore, the way direct interlinkages are considered in the models used to assess projects and establish NDPs can have an impact on the results of the project assessment. Since these assets are at the interface between the electricity and gas sector, it may be that **some models do not represent the full potential of flexibility services that could be delivered by such assets** (e.g. in a gas model, the consumption of gas by gas-to-power plants may be considered as being inflexible). If models are not taking into account or only partially taking into account the flexibility of interlinkages, it is likely that they will recommend investments in flexibility solutions that could have been avoided, had the impacts of these interlinkages been considered.

To summarise, **joint scenario building**, while being a precondition for joint planning (see Option 3), **only captures part of the potential benefits of a more integrated planning approach**.

In order to tackle this challenge, Option 2 focuses on the introduction of sanity checks to be carried out by electricity and gas TSOs when establishing their NDPs, without requiring the establishment of joint NDP, which is introduced in Option 3 (via requiring the establishment of a multi-energy EU NDP). Sanity checks are to be defined by gas and electricity TSOs, potentially with minimum requirement to be set out by NRAs.

In practice, these sanity checks can be operationalised by the gas and electricity TSOs by organising working sessions involving TSOs and NRA(s) based on draft NDPs. The key points of attention should be linked with the drivers of the investments in the various projects TSOs are foreseeing in their respective NDPs. In case the drivers are connected to direct interlinkages (e.g. reinforcement of networks due to expected power-to-gas installations), TSOs should assess whether there is consistency between their plans (e.g. that areas where the development of electrolysis is foreseen by each of the TSOs are well aligned; or that cross-sectoral flexibility of gas-fired electricity generation, power-to-gas and hybrid consumption technologies is satisfactorily taken into account). If relevant, TSOs may decide to carry out a joint assessment of a subset of their respective projects.

The **economic benefits of carrying out sanity checks outweigh their costs**, as there are not additional fora to be set up, since electricity and gas TSOs already collaborate to jointly establish scenarios feeding their respective NDPs. The two-year cycle foreseen in all options for the establishment of NDPs is considered as being adequate to enable TSOs to perform these sanity checks.

The economic benefits of the introduction of sanity checks emerge from the **higher level of consistency between the gas and electricity NDPs**, notably in terms of the identification of best suited areas for electrolysers, leading to consistent interventions on electricity, methane (e.g. via repurposing) and hydrogen networks at the local level. The economic benefits would however not be as high as the ones associated with jointly establishing multi-energy NDPs, covering the entire electricity, hydrogen and methane infrastructure, as such NDPs would structurally capture the synergies and interdependencies associated with direct and indirect interlinkages.

4.5.1.3.3 DSO participation in scenario building

DSO direct participation in future scenario-building is explicitly foreseen in Denmark, France, Ireland and the Netherlands. In Germany the applicable national law states DSOs shall cooperate and provide information on all relevant matters to the NDP creation process. For most of the other TSOs some exchange or consultation are organised, but no dedicated role for the DSOs is explicitly mentioned in NDPs.

Cooperation between gas TSOs and DSOs is already happening at operational and planning level. Therefore, in both types of entities, resources to carry out such work can be commonly assumed to be already existent and may only require some re-allocation to carry out the joint task (scenario building). Hence, additional cost impacts, if at all, can be expected to be small.

The transition of the energy system may entail integrating and managing reverse flows from substantial amounts of distributed resources which are typically connected at the distribution grid level (biomethane, electrolysers). As for the activities related to joint scenario building, the participation of DSOs in scenario building activities holds the **prospect of better coordination of investments, allowing distributed resources to play their role**. The underlying drivers leading to economic benefits associated with this measure include:

- Consistent vision on the potential of distributed energy resources
- Consistent view on the decentralised system flexibility
- Subsequently, optimisation of investments in grid infrastructure

4.5.1.3.4 LSO and SSO participation in scenario building

Benefits associated with the participation of LSOs and SSOs in scenario building are similar in nature to all other coordination efforts described above. Namely, the participation of LSOs and SSOs in scenario building activities would ensure a common vision is at the core of subsequent investment decisions, and that conflicting or redundant investments are avoided.

In some of the Member States for which NDPs have been analysed, this requirement is already met, either because LNG terminals and storages are operated by the TSO or via a subsidiary (e.g. Latvia) or via an interlinkage between the NDPs developed by UGS and/or LNG operators with the one developed by the TSO (e.g. Romania).

Regarding the possible efforts and costs of implementation, the same logic applies as for the DSO participation in scenario building. Moreover, LSO and SSO functions in cases still are carried out by TSOs through separate subsidiaries which facilitates coordination even further.

4.5.1.3.5 Market tests on the actual need for hydrogen infrastructure by NRAs

This measure foresees that NRAs may trigger market tests aiming at establishing the actual need for hydrogen infrastructure. This measure is introduced to assess whether investments into new hydrogen infrastructure and/or repurposing of existing methane assets that are being considered are well aligned with the actual appetite of consumers for hydrogen, which could be different from the one foreseen in scenarios should the accompanying measures to incentivise hydrogen demand (e.g. quotas in some sectors, carbon contracts for difference, etc.) not be put in place or not be as effective as foreseen, or should alternatives have emerged (e.g. direct electrification of end-uses that are considered as hard-to-abate).

The **economic benefits of this measure include potential savings in investments**. However, NRAs should carefully consider the potential impacts of delaying investments in the hydrogen infrastructure based on no-regret considerations. This is to ensure that investments in the hydrogen infrastructure does not become the bottleneck of the transition towards a net zero economy.

4.5.1.3.6 Alignment of at least one NDP scenario with EU targets, via the ENTSOs' TYNDP

To assess the impacts of infrastructure projects, one requires scenarios describing several plausible pathways of evolution of the energy system. Once a scenario is provided, infrastructure project can be assessed by evaluating how the presence of that infrastructure project impacts the operations of the considered system. The value attached to an infrastructure project therefore not only depends on its techno-economic characteristics but also and foremost on the scenario underpinning the analysis. **Important economic benefits can be generated by avoiding selecting infrastructure projects that are not compatible with long-term EU targets** (i.e. projects that are at risk of becoming stranded assets) or infrastructure projects that put the transition at risk (via a lock-in effect). The implementation of this measure would enable these benefits to materialise, provided that investment decisions are based on the outcomes of this scenario.

Currently, the scenario frameworks used in a selection of reviewed NDPs provide some linkage to the NECPs and/or Long-Term Strategies. Commonly the scenarios are set-up in the context of the energy transition in Europe and national energy policy priorities. Most NDPs also foresee an (explicit) linkage to the TYNDP scenario framework which also ensures an implicit linkage to EU policy goals. However, in a narrower perspective, deviation from the latest energy policy targets is found to be happening in NDPs. For instance, stakeholders have mentioned that the assumptions regarding gas consumption could be outdated and could thereby overestimate the future gas consumption in light of the more recent energy policy developments.

The definition of the scenario framework is a core part of the NDP creation process. Therefore, specifications regarding the use of a specific scenario framework should entail minimal or no costs.

4.5.1.4 Option 3 – European Planning

Option 3 requires to develop a multi-energy electricity-hydrogen-methane network development plan at the European level, encompassing all corresponding infrastructure assets, including unregulated ones.

Whilst joint scenario building between gas and electricity (considered in Option 2) ensures indirect interlinkages are treated consistently in scenarios underpinning the assessment of candidate projects, there are further benefits that materialise in case of joint planning (i.e., by using a methodology to assess projects that recognises the flexibility of technologies involved in direct interlinkages). Part of these additional benefits may be captured by the sanity checks introduced in Option 2.

Indeed, at present, most gas and electricity project assessment methodologies are not properly representing:

- **The flexibility of the electricity generation**: this can lead to identifying needs in terms of gas infrastructure to supply gas-fired power plants, whereas gas-fired generation could be modulated, and other plants be dispatched, to (partially) accommodate gas constraints
- **The flexibility of power-to-gas units** when connected to the electricity grid: this can lead to identifying needs for gas reinforcements to evacuate hydrogen or for electricity reinforcement to feed electrolysers, whereas the operations of electrolysers could be adjusted to (partially) accommodate gas and electricity constraints.
- **The flexibility of hybrid consumption technologies**: this can lead to identifying needs for electricity reinforcements to meet the peak electricity demand from e.g. hybrid heat pumps, whereas in reality, the gas back-up could kick in and reduce the peak residual load, so as to avoid (part of) the identified electricity network reinforcement needs. This could have an impact on the value attached to the gas infrastructure (mainly a capacity value).

To capture these benefits, coordination efforts among the development of electricity and gas investment plans are necessary, and **integration in planning may generate benefits that depend on the degree at which the electricity, hydrogen and methane systems interact** as explained above. It should however be noted that the level of interlinkage between the gas and electricity sectors is expected to grow in the future, with the development of electrolytic hydrogen and questions related to the repurposing of the gas infrastructure. The level of expected benefits from integrated network planning can be assumed to be highest for countries whose systems are characterised by a high degree of interlinkages between electricity and gas in their current and future systems.

Box 4-13: Cluster analysis of EU Member States regarding the interlinkage of the power and gas sectors.

Where would benefits materialise?

In the context of this assignment, the JRC has carried out a standard cluster analysis that groups countries looking at multiple variables available from the dataset of the scenario underpinning the impact assessment (MIX H2). Similarity and distances are among countries and are used to group MSs according to their potential level of interlinkage. The methodology is driven by a 'let the data speak' logic.

One of the key limitations of this approach is the rather low level of available data on hybrid consumption technologies (e.g. details on the deployment of hybrid heat pumps are not available) and power-to-gas conversion technologies in the MIX H2 scenario. The key direct interlinkage that is considered is therefore gas-to-power.

The key result of the analysis is that a large set of countries display important interlinkages due to the share of gas-to-power in the final electricity demand. While the value of this indicator is likely to reduce in most countries as natural gas is gradually phased-out, the value of the other indicators (not considered in this study as datasets were not available) will likely increase, leading to more and more benefits emerging from a joint planning exercise.

Based on the recommendations established in a study carried out on their behalf by Artelys[213], ENTSOG and ENTSO-E have also recently tested a set of criteria to determine where interlinked approaches should be primarily put in place when assessing infrastructure projects[214].

The ENTSOs have calculated several indicators based on TYNDP 2020 scenarios. From a methodological point of view, the ENTSOs approach establishes that a system has a relevant level of interlinkage when a set of conditions is met. These are identified comparing values of indicators with predefined thresholds that have been estimated in the study conducted by Artelys.

The ENTSOs methodology assesses, one indicator at a time, a checklist of conditions and additionally assesses the impacts of the interlinkages, by testing how the interlinkages impact the use/value of infrastructure. This is carried out based on the modelling of reference and stress cases with 35 climate years.

Option 3 represents the requirement to develop a European-level system-wide network development plan, covering the gas (methane and hydrogen energy vectors) and electricity sectors, and encompassing all infrastructure assets, including unregulated ones.

The option would go significantly beyond the requirement that joint scenario building exercises are carried out by TSOs (Option 2), in two major ways:

- The impacts of **sector integration** would be considered throughout the entire NDP process, including in the modelling work supporting the assessment of projects, and their inclusion in the network development plan.
- National/regional gas and electricity NDPs would be replaced by a **single European-level NDP**, effectively resulting in a significant upgrade of the TYNPD

[213] (Artelys, 2019)

[214] (ENTSOG and ENTSO-E, 2021)

process to also include national network elements that do not significantly impact cross-border capacities.

In what follows, the option is assessed against the baseline case where the development of NDPs would follow the current practices in most countries, i.e. NDPs are sectorial documents that do not take into account the interlinkages between sectors (or only in a limited way), and does not perform planning of the energy infrastructure adopting a holistic perspective, but rather a siloed approach.

4.5.1.4.1 Implementation costs

The **implementation costs of Option 3 would be important**, as it would involve very considerable efforts in terms of coordination amongst a large group of stakeholders (gas and electricity TSOs, gas and electricity DSOs, LSOs, SSOs, NRAs, and EU bodies such as the European Commission, ACER and the ENTSOs), and in terms of establishment of appropriate models to establish an EU-wide multi-energy network development plan. Indirectly these costs could also affect the end-consumers of electricity and gas via tariffs.

Furthermore, it should be noted that performing joint or multi-energy cost-benefit calculations **may require an update of the way modelling tools are used** to assess infrastructure projects. Indeed, in some Member States, techniques based on hydraulic modelling are used to assess the potential impacts of gas infrastructure projects. Performing an EU-wide NDP would require techniques to be harmonised across countries and a single gas transmission-level model to be developed (similarly to the Common Grid Model developed by electricity TSOs[215]), likely on the basis of hydraulic modelling techniques.

Finally, this option would not only require an EU-wide consistent approach to the modelling of the gas network, but also **interlinkages to be set up with the electricity sector** so as to enable the joint planning of electricity, hydrogen, and methane infrastructure elements. The extension of models based on hydraulic approach to cover all sectors (electricity, gas, hydrogen) is not strictly required to reap the benefits of joint planning. Indeed, one can already capture an important share of the benefits by **smartly coupling an integrated market model**[216] that provides injections and withdrawals that can then me downscaled and used as boundary conditions in a hydraulic model to finalise the assessment of the project (just as in the electricity sector a multi-energy market model can provide inputs to a grid model to simulate power flows more precisely and to assess the relevance of an infrastructure project).

This finding is consistent with the publication by the German energy agency (DENA, 2020) regarding the establishment of a system development plan, in which they note that the integrated scenario and modelling framework developed by the ENTSOs for the TYNDP can be a suitable way forward, albeit acknowledging that the higher granularity of the NDP processes sets limits to a one-to-one transferability of such an approach.

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[215] See https://www.entsoe.eu/publications/statistics-and-data/#entso-e-on-line-application-portal-for-network-datasets for the latest grid datasets.

[216] METIS, a multi-energy model developed on behalf of the EC, which is well adapted to play this role, especially thanks to features being currently developed to increase the spatial granularity of the representation of the European energy system.

4.5.1.4.2 Energy system synergies and benefits

There are multiple benefits to establishing an integrated EU-wide NDPs, as discussed below.

Detection of synergies to optimise investments

Energy system planning through network plans is geared at optimising the configuration of a system over a rather long time horizon, typically ten years or more, by anticipating the impacts of investment and operational decisions ex-ante. When the interlinkages across the energy vectors of electricity, methane and hydrogen are limited in nature, it is often reasonable for reasons of complexity reduction to limit the system boundaries of the planning approach to the specific energy vector under consideration.

The decarbonisation of the energy system involves tighter interactions between energy vectors. Taking advantage of synergies will become more and more important to achieve the decarbonisation objectives in a cost-effective and secure way. This however means that planning choices regarding one vector will increasingly affect the other interlinked vectors, which implies that optimal planning decisions can only be taken if all vectors are considered simultaneously in an integrated system plan.

Integrated planning across electricity, methane and hydrogen energy vectors would **enable the exploitation of synergies in decisions related to the level of investment, decommissioning, or repurposing of gas, electricity and hydrogen assets**. This is discussed in the following with a focus on the essential components along the (green) gas value chain, where benefits can be expected to arise in mostly two parts: On the one hand electrolysers would come in as a new component, linking the electricity and gas sectors and offering the opportunity for further complementarities and symbiosis across the two types of energy vectors (electrons and molecules). On the other hand, the stronger emergence of hydrogen as an energy vector provides potentials for a synergistic integration with the existing and yet to be developed methane gas infrastructure. The layers of integration would range from parallel methane and hydrogen networks, the repurposing of methane gas infrastructure into pure hydrogen networks, and potentially the admixture of hydrogen into methane networks.

Planning decisions regarding **electrolysers as a new link between the electricity and gas sectors** could benefit from a better consideration of the interlinkages that appear both on the hydrogen supply and demand sides. On the supply side, an integrated planning could help ensure the matching of electrolyser capacity with renewable energy supply and related electricity grid infrastructure. The selection of suitable electrolyser locations based integrated scenario and joint planning can anticipate gas and/or power system constraints and reduce the need for additional infrastructure investments. On the hydrogen off-take side, the adequate integration with the downstream gas infrastructure would be captured by an integrated planning process that holistically considers the different options to deliver the hydrogen to the end uses.

When fed into a network, both methane and hydrogen need to be compressed to the operating pressure of the network. Compressors that are driven by gas turbines derive their energy directly from the network and in case of repurposing of methane pipelines for use with hydrogen, compressors may have to be adapted according to the hydrogen admixture content[217] (see also Section 4.3.2.2 in this regard).

[217] According to Siemens' white paper "Hydrogen infrastructure – the pillar of energy transition" (Siemens, 2020), up to approximately 10% hydrogen content, the compressor can generally continue to be used without major changes. The compressor housing can be maintained up to approx. 40% hydrogen admixture, whereas impellers and feedback stages as well as gears must be adjusted. From approximately 40% hydrogen content, the compressor has to be replaced to achieve the compression needed to maintain

Gas infrastructure consisting of both methane and hydrogen pipelines exhibit competing, complementary as well as synergistic elements with the electricity infrastructure that jointly define a decision space for planning decisions, where an integrated approach is required to identify the options that lead to the highest level of system-wide benefits. Competition exists to the extent that hydrogen can be converted into methane and vice versa, electricity can be converted into hydrogen and vice versa, so that several transport and storage options (methane pipelines, hydrogen pipelines, electricity wires, etc.) could be used to connect supply and demand. However, conversion processes cause losses (and costs) that need to be accounted against the costs of enabling the transport via these different options. A methane pipeline infrastructure already exists across the EU, whereas dedicated hydrogen pipelines so far only have been erected to serve specific demands in industry or for demonstration project purposes.

An integrated approach can result in the detection of synergies where decisions on the level of blending (retrofitting the gas infrastructure), the repurposing of gas infrastructure into hydrogen infrastructure can be taken together with decisions on the locations of electrolysers and investments in electricity infrastructure.

Detecting the possibility to repurpose existing gas assets is especially interesting given the relatively minor cost of doing so, from the point of view of the infrastructure[218], compared to investing in new hydrogen pipelines, as emphasised in a recent EC ASSET study[219]. Savings could reach up to 85% of the cost of new build pipelines. Even if these numbers go along with some uncertainties, they provide a robust ground for significant savings potential, leading to high benefits being associated with a joint planning approach. In addition, time and cost intensive spatial planning and approval procedures could be avoided by utilising already existing methane gas infrastructure routes.

In an analogous manner to methane pipelines already **existing methane storage** facilities, subject to their technical and geological capability, could be retrofitted to store hydrogen. This would mostly apply to salt cavern storages which are considered as being the most promising forms of storage compatible with hydrogen compared to other technologies, even if R&D efforts are ongoing to assess the technical feasibility of repurposing depleted gas fields or aquifers.[220] At present, there is significant remaining potential in terms of available cavern for methane storage in the EU, although it is not uniformly distributed across countries. In addition, the role of methane is projected to decline with the transition towards a decarbonised economy. Thus, by following an integrated planning approach one could assess in which cases it would be more cost effective to convert these existing storage facilities rather than deploying new hydrogen storage infrastructure from the scratch.

transport capacities. In the case of repurposing a methane pipeline to pure hydrogen use, due to the comparatively lower energy density of hydrogen, approximately three times the drive power and therefore a correspondingly higher number of turbines and compressors is required to maintain a similar transport capacity as in the methane use case. This has to be accounted for through a cross-vectoral planning approach.

[218] From the point of view of the consumer, different options (electrification, use of hydrogen, use of methane) can lead to significantly different costs when taking into account the need to replace appliances or equipment. Any decision related to e.g., blending should take such costs into considerations, as the needs of different types of consumers may vary (stable gas quality is essential for the industry, but different levels of blends may be acceptable in some domestic settings).

[219] (European Commission, 2021a)

[220] (Guidehouse, 2021)

All assets also carry a time dimension given the lead times of their construction and the longevity of their technical lifetime. Therefore, network planning also needs to take into account that a hydrogen infrastructure will likely emerge through distinct stages ranging from initial admixtures of hydrogen into the methane network, via clusters adapting local/regional infrastructures of a pure hydrogen use, to integrated networks transporting pure hydrogen along long distances. This requires a coordinated trajectory of investing into, repurposing and decommission assets along the value chain. An integrated perspective is required in this regard to realise complementarities across energy sectors/vectors and mitigate path dependencies and stranded investments that might result from an isolated view on individual sectors/vectors. An integrated approach is also necessary to overcome the chicken-and-egg problem. This in particular regards yet to be constructed hydrogen infrastructure, where forward-looking planning decisions on regulated assets such as pipelines can provide enhanced predictability for the planning decisions of potential users of these assets such as electrolysers or end-uses of hydrogen.

The increasing need for such an integrated approach will only grow as energy vectors become more integrated and could be reflected in enhanced benefits for market participant such as higher reliability and predictability of planning decisions and reduced transaction costs to consider multiple (partially inconsistent) scenarios.

While all the effects described above can emerge with national-level network development plans, **benefits would be maximised in the case the plan is established at a European level**.

Harmonisation of planning practices across Europe

Besides identifying the synergistic potentials embodied in the cross-sectoral infrastructure of methane gas, hydrogen and power, setting-up an EU-level sector-integrated NDP process would also offer opportunities to harmonise planning practices in all Member States, mechanically ensuring that infrastructure planning is anchored to EU objectives as the scenarios established by the ENTSOs for the TYNDP exercise would likely constitute the basis of the EU-wide NDP.

However, the benefits of establishing integrated plans at the EU level compared to the publication of NDPs at national level could also be captured by ensuring that national NDPs are based a common vision of the future via the use of European scenarios (as is being proposed in Option 2, however without the requirement of publishing integrated plans, but to coordinate amongst TSOs).

4.5.2 Environmental impacts

4.5.2.1 Measures common to all options

4.5.2.1.1 Information on decommissioning of methane pipelines

A survey of a selection of NDPs has concluded that information on decommissioning of methane pipelines is not explicitly provided. However, several plans mention the potential to repurpose pipelines in the future. The plans for Belgium, Germany and the Netherlands discuss the impacts related to phasing out L-gas systems, due to the substantial decrease of gas supply from Groningen. This is however linked to a specific issue and does not follow a systematic assessment of decommissioning pipelines.

The main benefits of reporting on decommissioning of methane pipelines can be seen in an enhanced planning horizon for other market participants resulting in better investment decisions and the exploitation of cross-sectorial synergies. This measure has positive environmental impacts as it can lead to a better identification of repurposing potentials, and thereby avoid building a new infrastructure, resulting in a lower environmental footprint of the infrastructure, including the use of raw materials required for building the asset.

4.5.2.1.2 Sustainability indicator

A survey of a selection of NDPs has concluded that information on a dedicated sustainability indicator in project selection is unavailable in the considered NDPs.

In several cases, sustainability is treated at the scenario building phase, where climate/energy targets are used as a framework for the development of scenarios. However, this falls short of assessing the sustainability impacts of a given infrastructure project. In other cases, sustainability is implicitly considered by assessing the impacts of the project on the ability to inject biomethane into the system.

Sustainability indicators can have different levels of complexity depending on their objective. Simple indicators could simply assess the impacts of a given project on the gas supply mix, and assess whether the project allows to increase the use of low-carbon gases compared to the use of natural gas. More ambitious indicators can be developed to **assess the impacts of an infrastructure project on GHG emissions** driven by the switching of end-uses to gas (or hydrogen). As one of the key difficulties is to define a counterfactual (what is gas replacing?), indicators providing best- and worst-case scenarios could be developed (gas is replacing coal leading to lower emissions, gas is replacing coal, but electrification would be more climate-friendly, leading to higher emissions). Finally, one could use a fully integrated market model such as METIS[221] to assess sustainability indicators. The costs of deriving a sustainability indicator depends on the design of the indicator. However, the sustainability benefits would be clear.

If implemented in a rather light form as informative indicator it could contribute to market transparency. If implemented as a mandatory criterion, a sustainability indicator could be used to help select (societally) beneficial projects that otherwise might not be realised.

In a study for the European Commission[222], Artelys has defined and tested a comprehensive indicator for the sustainability impacts of gas infrastructure projects considering the TEN-E Regulation requirements of Art. 4.2 (b) (iv) and Annex IV.3 (chapters 1-3). The proposed indicator improves the consideration of the projects' sustainability impacts that feed in the gas PCI selection process. The proposed indicator addresses some of the weaknesses of the current sustainability indicator as defined in the gas cost-benefit analysis (CBA) methodology, such as possible misestimation/misallocation of sustainability impacts and increase the comparability of project-specific CBAs, and thus the ranking of PCIs in the regional groups. The proposed indicator can be implemented without introducing any additional complexity in ENTSOG's models. Furthermore, the study proposes a methodology to calculate sustainability benefits based on the use of an interlinked model that recognises the coupling of the gas and electricity systems. Such an indicator could be calculated using the METIS model. The considerations driving the proposals made in this study can be a starting point for the development of sustainability indicators in NDPs.

As a result, projects that are not future-proof (e.g. projects that are not compatible with the transition towards a decarbonised economy) can be avoided, leading to two types

[221] (European Commission, 2021d)

[222] (Trinomics; Artelys, 2020)

of environmental benefits: first risks of lock-in effects[223] and under-achievement of climate goals can be reduced, and second, over-investments can be avoided, leading to a small environmental footprint.

4.5.2.1.3 Transparency and stakeholder consultation

Implementing this measure can help achieve climate objectives, as stakeholder consultations can lead to informed discussions on the way projects are implemented, and on potentially available alternatives that have lower climate impacts and/or lower environmental impacts (e.g. via a reduced footprint).

4.5.2.2 Options 1, 2 and 3

The implementation of the policies included in the three options considered herein would result in sustainability benefits by (a) **reducing the level of risk of lock-in effects**, and by (b) **reducing the probability that stranded assets** materialise.

Indeed, in all three options, an implementation of the associated policies would result in **stakeholders better aligning their visions** of the future when establishing scenarios. As described in the section discussing economic impacts, basing investment decisions in several areas on common scenarios rather than on different ones can result in the avoidance of over-investments (including by building new hydrogen pipelines instead of repurposing existing ones), and risks of lock-in effects.

Furthermore, in Option 3, by going one step further and not only basing investment decisions on common scenarios (and a set of sanity checks across sectoral NDPs) but also by explicitly considering the synergies between sectors and the potential competition between infrastructure projects, one can further **reduce the risks of over-investments and of lock-in effects**.

Therefore, in all options the **footprint of the energy infrastructure would be lower**, including the use of raw materials required for building the asset, and the risk of not achieving climate targets would decrease (by avoiding lock-ins). The magnitude of the sustainability benefits to be highest for Option 3.

4.5.3 Social impacts

4.5.3.1 All options

The objective being pursued by all the options mentioned herein is to rationalise the way infrastructure projects are assessed and, ultimately, selected. By decreasing the probability that investments in stranded assets, lower financial resources are being used to provide the same energy services.

These expected savings must be traded-off against the costs of implementing the policy options, which have however been estimated to be small or even slightly negative in the longer term. The **net effect would translate into lower prices for energy** facilitating overall competitiveness.

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[223] Lock-in phenomena refer to the inertia that can be caused by fossil fuel-based energy systems that inhibits public and private efforts to transition towards a decarbonised energy system. Lock-in effects are causing GHG emissions to rise.

Lower prices for energy services also have a progressive social impact as energy prices tend to affect households with smaller budgets over-proportionally.

Finally, a more tightly integrated energy system reflected in a more integrated network approach to establishing NDPs offers more degrees of freedom to balance multi-criteria objectives. This could for instance facilitate more socially acceptable transformations of the energy system where significant assets are phased out as part of the transformation.

4.5.4 Comparison of options

The proposed options have various levels of impacts, on all the considered dimensions (economic, environmental and social).

All the considered options are expected to bring economic benefits that far outweigh their respective implementation costs. Indeed, by ensuring that planning decisions by different stakeholders are based on a common vision of the future (as in Option 1 and even more so in Option 2), one can ensure a more consistent set of investments will materialise, notably by avoiding over-investments that could emerge if investment decisions are taken based on incompatible visions of the evolution of the energy system. The economic benefits can be expected to be the most important for Option 3, but they are also associated with high compliance costs.

From the standpoint of environmental and social impacts, all options will have a positive impact by ensuring the same level of energy services can be delivered with a smaller set of investment projects, thereby avoiding potential lock-in risks (which could put climate targets at risk or increase the cost of the transition if some assets become stranded) and reducing the environmental footprint of the energy infrastructure.

Table 4-18: Comparison of the impacts of options related to network planning.

Option	Economic	Environmental	Social	Efficiency	Effectiveness
Option 1	+	+	+	+++	+
Option 2	++	++	++	+++	++
Option 3	+++	+++	+++	++	+++
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)					

5 COMPARATIVE ASSESSMENT OF OPTIONS RELATED TO PROBLEM 1

5.1 Methodological approach

5.1.1 Impacts assessed

The analysis of options builds upon the more detailed analysis of policy measures, presented in Section 4, along the dimensions of economic, environmental and social impacts.

The analysis pays special attention to the stakeholders potentially affected under the different options, including producers of renewable and low-carbon gases, operators of gas transmission and distribution grids, NRAs, consumers.

The focus is set on the year 2030.

5.1.2 Modelling

Different approaches were applied, depending on data availability and appropriateness. They range from dedicated, scenario-based modelling exercises with the EU energy system model METIS, over semi-quantitative estimations to qualitative analyses.

The methodology may differ between policy measures (depending on how heterogeneous they are).

The analysis relies on quantitative framework data from the MIX H2 scenario.

A more detailed description of the methodology applied for the analysis of individual policy measures is integrated in Section 4. A more detailed description of the methodology is available in Annex I – Methodology.

5.2 Impacts of Option 0 (business-as-usual)

5.2.1 Economic impacts

Under Option 0, barriers regarding the integration of renewable and low-carbon methane gases and blended hydrogen are not expected to be tackled at the EU level.

Market and grid access for renewable and low carbon gases might continue to be constrained in MSs where cooperation between DSOs and TSOs regarding new connection requests and an obligation of DSOs to install reverse flow compressors are not in place by 2030. This implies the risk that the biomethane production of 50 TWh assumed under the MIX H2 scenario might not be effectively integrated in the gas grid. Assuming that 10% of all biomethane plants would face difficulties to inject their biomethane (notably related to saturated distribution grids and a lack of reverse flow compressors), the missing biomethane injection would need to be replaced by natural gas and entail additional purchase costs of some 45 M€/year[224] (excluding CO_2 emission costs).[225]

[224] Assuming that the gas cannot be used locally.

[225] If investors/project developers would refrain from building the respective biomethane plants concerned by reverse flow needs, the related costs for natural gas purchase would be even twice as high. At the same time, overall system costs would be lower as the natural gas price is significantly lower than the LCOE for biomethane. This holds even true when considering the CO_2 costs for natural gas, as the CO_2 abatement costs for biomethane are significantly higher than the expected CO_2 price in 2030, cf. also Section 4.1.2.

If restricted access to wholesale markets (linked to the non-integration of distribution grids in entry-exit zones) as it exists today in up to 17 MSs representing 20% of the 2030 biomethane production persists by 2030 and if no additional national initiatives are undertaken for the introduction of a connection obligation with firm capacity for producers of renewable and low-carbon gases (currently existing in at least 16 MSs), biomethane producers may in some MSs face sub-optimal market conditions. This may have different effects. Biomethane producers risk to achieve prices for their biomethane below market prices on the VTP. If biomethane production benefits from public support, this may entail an increase in support costs of 10 M€/year for a price difference of 1 €/MWh. If the network operator is not obliged to provide grid connection and firm grid capacity, this may translate into higher uncertainty for biomethane producers (and project developers). Translating this risk in a 1% increase in the WACC implies additional production costs of about 11 M€/annually. As most of the biomethane production is expected to rely on public support, this increase in costs needs to be borne by gas consumers or tax payers.

Without specific EU provisions on the establishment of dedicated gas energy communities, biomethane production might face a limited deployment as fewer local actors would be interested to invest in local gas production. The specific effects under Option 0 are difficult to quantify.

Injection tariffs for renewable and low-carbon gases represent so far a minor share in total production costs. Thus, their removal or reduction is considered as a less relevant issue. However, in the long-run decreasing gas demand might increase the grid tariffs per MWh transported and hence require to reconsider such a measure.

For other low-carbon gases, such as H_2 blended into natural gas networks or synthetic methane, no specific impacts were identified under Option 0 as their volumes are expected to remain marginal.

Maintaining the intra-EU cross-border entry/exit tariffs would basically preserve the current situation. This implies that the gas flows (and imports) would remain mainly driven by the market prices of the different gas sources and intra-EU cross-border entry/exit tariffs (tariff pancaking).

In terms of **gas quality**, in the absence of a European coordination, cross-border management of gas quality and information sharing would rely on existing procedures. The definition of acceptable H_2 blending levels and other relevant aspects (such as acceptable variations of H_2 concentrations) at cross-border interconnection points and in national transmission or distribution networks would be left to Member States. By 2030, the impacts, including on market integration, are expected to remain marginal as H_2 blending would not be significant in Option 0 by 2030. However, if selected MSs would opt for higher blending shares going beyond the volumes of the MIX H2 scenario, Option 0 implies a risk of gas market fragmentation. As current legislation in Member States shows a large variety of maximum blending acceptance levels, gas flows might be restricted from countries with higher acceptance levels to countries with lower ones. Diverging blending rates at TSO level would represent a serious risk in terms of security of supply. It is estimated that if 23 different blending clusters would be created, this may result in some 200 TWh of gas energy not served (6% of total gas demand). Under Option 0, it is thus likely that blending will not be applied at the TSO level but remains restricted to the DSO level.

In terms of gas quality standards, the main gas quality issue related to biomethane is linked to oxygen concentrations, which might affect underground gas storages and a few sensitive industrial users if the concentrations exceed natural gas thresholds. However, such problems are considered to be very local, requiring tailored solutions at the national level or by individual actors. Hence, no major negative impacts are identified in this regard under Option 0.

With respect to **LNG** terminals, the identified barriers remain unaddressed at the EU-level (terminal capacity allocation, transparency, flexible services). However, as the LNG utilisation rate would on average only slightly increase under the policy measures, not addressing these issues would have a rather low impact. However, under Option 0 the possibility to provide network entry tariffs discounts to LNG terminals would remain, and thus existing discounts to terminals would in principle also remain. Yet, this implies that benefits from harmonised tariff setting (notably in terms of imports of low-cost LNG, decreasing gas prices, cf. Option 1, Section 5.3.1) cannot be harvested under Option 0.

The previous impacts identified assume that MS legislation would remain unaltered until 2030. Nonetheless, it is likely that **further developments will arise from the measures foreseen in the 3rd energy package** (full implementation of current network codes and development of new ones), from the process for developing or amending network codes and guidelines, legislative initiatives by Member States, and voluntary cooperation at the regional and national levels. Particularly the changes in the national regulatory frameworks and voluntary cooperation might address some of the barriers in the gas sector even under Option 0.

5.2.2 Environmental impacts

The major environmental impact of Option 0 consists of a potential risk of an incomplete integration in the gas grid and market of the biomethane production volumes projected under the MIX H2 scenario required to meet the 55% GHG emission reduction target. The major reason consists in the potential of reverse flow compressors. If 10% of all biomethane plants would be concerned by distribution grid saturation, replacing curtailed biomethane injection with natural gas would add some 0.4 MtCO2/year to the EU emission balance[226]. In contrast, under the 55% target, the EU's emissions are expected to drop to about 1720 MtCO2 by 2030 (compared to 1990 levels). That implies that the expected impact on target non-achievement may nonetheless be considered marginal.[227]

5.2.3 Who would be affected and how?

Producers of renewable and low-carbon gases are expected to still suffer from an unlevel playing field in comparison to natural gas suppliers in terms of market and grid access. This may create a more uncertain investment environment, raise the costs of market integration and hinder the actual grid access.

TSOs and DSOs are expected to pursue their activities in a similar manner as in the past[228] in the absence of additional provisions under the Gas Market Directive or Gas Regulation. If the EU refrains from the suppression of intra-EU cross-border entry-exit tariffs under the GTM++ measure, **TSOs and NRAs** would not be required to negotiate an ITC that reallocates revenues and is potentially subject to thorough and lengthy negotiation processes. Finally, in the absence of an EU framework, TSOs and NRAs would need to coordinate on their own initiative to facilitate the introduction of hydrogen

[226] Unless the non-injected biomethane is locally used (e.g. for transport or in CHP installations).

[227] For the purpose of comparison, it should be noted that the overall volume of 50 TWh of biomethane in 2030 reduces the total EU emissions by some 9 MtCO2/year. This represents less than 0.5% of the required annual emission reduction between 1990 and 2030.

[228] This disregards potential changes related to the full implementation of the third energy package, e.g. with respect to ownership unbundling.

blending and ensure unrestricted cross-border gas exchange via bilateral or multilateral agreements.

Consumers and tax payers are expected to bear the bulk of costs related to barriers and market imperfections. Restricted market and grid access for producers of renewable and low-carbon gases raise the costs for biomethane production and thus ultimately the overall support costs. Inefficiencies in the utilisation of LNG terminals and sub-optimal gas imports due to non-harmonised LNG tariffs and intra-EU cross-border entry/exit tariffs lead in the end to higher gas prices to be borne by gas end-users. Finally, in case of a fragmentation of the EU gas market related to a non-coordinated introduction of hydrogen blending in EU transmission grids, it would be gas consumers that would have to face supply disruptions and significant additional costs related to occasional and regional gas shortcomings

5.2.4 Administrative impact on businesses and public authorities

Option 0 is expected to have no additional administrative impacts on businesses, public authorities or other stakeholders as it does not contain any additional policy measure.

5.3 Impacts of Option 1

Option 1 includes policy measures that maintain the existing gas market model, with some improvements to provide a level playing field to renewable and low-carbon gases injected at the distribution or transmission level (compared to natural gas), and to reinforce cross-border cooperation.

Additional policy measures considered under Option 1 in comparison to Option 0 include:

- Integration of distribution grids in entry/exit zones to grant decentralised gas producers access to wholesale markets (VTP)
- Enabling physical reverse flows
- Reinforced cross-border coordination and transparency on national blending levels
- Principles concerning transparency (about available LNG terminal capacities and tariffs), access rules and flexibility of products through initiatives led by the industry and supported by EU guidance.

5.3.1 Economic impacts

Option 1 ensures the effective integration of biomethane to meet the 55% GHG emission reduction target, at lower specific costs for public support, yet potentially at higher system costs than under Option 0 (due to the important LCOE of biomethane compared to natural gas). Coordination on gas quality facilitates the (at least regional) introduction of hydrogen blending at the TSO level, avoiding major risks of gas market fragmentation. Industry-led initiatives on transparency about available LNG terminal capacities and tariffs may lead to a marginal increase of LNG terminal use.

Option 1 allows for **full integration of the biomethane potential** as projected under the MIX H2 scenario in order to comply with the 55% GHG emission reduction target by 2030. Further, the policy measures under Option 1 may help to reduce support scheme costs and thus the cost impact on consumers.

On the basis of the sources chosen, the LCOE for biomethane is in 2030 still expected to substantially exceed the natural gas price (even under a high CO_2 price and considering additional revenues from GO sale). The development of biomethane will hence to a large extent depend on public support.[229]

The **access of locally produced renewable and low-carbon gases to the VTP** via the integration of distribution grids in entry/exit zones (which is so far only the case in 10 MSs, representing 79% of projected biomethane production in 2030) would provide enhanced market access to biomethane producers improving their marketing options. If the sales price is increased by 1 €/MWh, support costs are lowered by around 10 M€ annually in the respective MSs.

The impact of the obligation on DSOs to install, where necessary, **reverse flow compressors** is difficult to quantify. Today, there is limited need for reverse flow compression and high uncertainty remains whether this is likely to change by 2030, as biomethane volumes increase only to a limited extent (from 21 to 50 TWh under the MIX H2 scenario). Furthermore, other remedial measures exist (e.g. meshing of distribution grids). However, the lowering gas demand and a higher development of biomethane injection than projected under the MIX H2 scenario may create a need for reverse flow compressors, at least in selected grids.[230] Under the assumption that grid saturation and reverse flow compression concern about 10% of all biomethane installations by 2030, this would require some 6 M€ of annualised investment in reverse flow compressors plus 3 M€ of annual operational costs.[231] The concerned investments would allow to additionally integrate 2.2 TWh of biomethane[232]. The respective gas demand would otherwise be met by natural gas, implying costs for natural gas of 44 M€/y and CO_2 costs of 20 M€/y.[233] Under support scheme, these costs may come on top of the costs for biomethane production in case the producer is entitled to receive compensation payments. In a competitive market, the lower investment in biomethane deployment may result in a net decrease in overall energy system costs as this scenario would lead to a higher use of natural gas at lower price (and independent from public support), but at the expense of higher carbon emissions.

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[229] It is important to bear in mind that direct local use of biogas for electricity/heat production is in several cases (if there is local heat need) less costly than converting it into biomethane. Biomethane counts among one of the most expensive RES options (also compared to wind, solar etc.). Covering heat demand by heat pumps is in many cases a more cost-efficient solution than using expensive biomethane to generate heat. Hence, a system approach should be favoured compared to policies focusing on a specific vector. This remark does not only apply to the Gas Market Directive, but to energy legislation in general (incl. for instance the Renewable Energy Directive).

[230] In France (which is the only country where an obligation to install reverse flow compressors is already in place), in 2020 19 reverse flow compression projects were approved by the French NRA (GRDF; GRTgaz, 2020). The French gas TSO GRTgaz projected in 2017 biomethane production to raise to 90 TWh, with 2600 out of 3000 sites being connected to the distribution grid. The need for reverse flow compression was estimated at 135 installations for flows from the distribution to the transmission grid, entailing investment costs of more than 400 M€ (GRTgaz, 2017).

[231] These costs link primarily to reverse flow compression, disregarding costs for deodorisation which may be required in some MSs but reflects a much lower additional cost.

[232] The lower end of the range considers that biomethane production is curtailed when the distribution grid is saturated while the upper end assumes that the actual investment into the biomethane plant not even materialises.

[233] Costs for natural gas and CO_2 abatement costs are calculated via mean prices (cf. Section 4.1). If a lack of reverse flow compressors would make investors refrain from making the investment related cost savings would counterbalance the additional costs for natural gas (from a system perspective).

The **framework of coordination around gas quality** facilitates a large-scale introduction of hydrogen blending at the TSO level (which is not guaranteed under Option 0). Following the national plans and national thresholds for maximum hydrogen blending announced by several MS, blending clusters in Europe are expected to emerge. A blending cluster is an aggregate of countries that can accept specific levels of hydrogen-blended natural gas below a certain threshold. One typical situation could be the presence of 3 clusters:

- a "Western" cluster including most of western European countries with a high blending level (between 5% and 10% in volume)
- an "Eastern" cluster with a less ambitious blending level (less than 2% of blending in volume) at the TSO level aggregating the Eastern countries
- one "UK-IE" cluster which would have a specific blending level taking into account the specificities of this energy island.

This scenario would result in up to 50 TWh of hydrogen injected in the transmission network[234], at an adaptation cost of the gas system of up to 4 B€/year (if blending occurs at the transmission grid level, all connected equipment must be blending-compatible or dispose of deblending installations, whereas blending at the distribution level allows for local blending solutions). Some interconnections would be suppressed (from the Western to the Eastern cluster typically) which could trigger up to 5 TWh of energy not served in the eastern cluster because of the blending-related partial fragmentation of the internal gas market. The isolation of UK would change the European gas flows, with the UK counting more on Norway and LNG to cope with the missing gas coming from the continent.

The industry-led initiatives on transparency about available LNG terminal capacities and tariffs may lead to an increase of **LNG** terminal load factors for 15 terminals that were identified to have periods of inactivity despite LNG price being lower than the one of pipeline gas. This would only have a minor impact since the terminal infrastructures present have already a rather high load factor; the estimated increase of the European consumer surplus is around 15 M€/year, hence less than 0.03% of the total consumer surplus.

5.3.2 Environmental impacts

Option 1 ensures compliance with the 55% GHG emission reduction target, closing the potential gap that may occur under Option 0.

VTP access for producers of renewable and low-carbon gases and reverse flow obligations for DSOs ensure the integration of the biomethane production volumes projected under the MIX H2 scenario (which represent a minor share of <2% of overall gas demand in 2030).

Not having these options in place might put at risk the target achievement. Assuming that 10% of all EU biomethane injection was concerned by needs for reverse flows[235] would imply additional emissions of about 1 Mt CO_2 annually, if the energy demand

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[234] This estimate is independent from the MIX H2 scenario (which does not foresee any blending), but relies on national legislation in terms of blending acceptability and assumes that the required hydrogen quantities would be available.

[235] Excluding France which features a dedicated regulation on reverse flow compressors.

related to the "missing" biomethane production would be replaced by fossil natural gas.[236]

Negative secondary effects from the enhanced biomethane utilisation might occur if some of the biomethane production would not be compliant with the sustainability criteria defined under RED II.

The possibility of injection of hydrogen would decrease the CO_2 emissions of the gas system, saving up to 7 MtCO2/year, but at major abatement costs of 532 €/t_{CO2} as adaptation costs would be needed to support high level of blending.

5.3.3 Who would be affected and how?

Biomethane producers are expected to benefit from VTP access and the reverse flow compressor obligation for DSOs as it reduces uncertainty for grid injection and allows to achieve more favourable market prices.

Natural gas producers are only marginally impacted the option, as the triggered increase in biomethane injection remains marginal. LNG import volumes remain largely unaltered, too.

Hydrogen producers benefit from the reinforcement of cross-border coordination on gas quality content as it facilitates hydrogen blending into transport networks.

TSO/DSOs instead would face increasing administrative costs as they would be required to increasingly coordinate when distribution grids are integrated in the entry/exit zone, in particular with respect to balancing responsibilities.

If hydrogen blending clusters appear in Europe, TSO/DSOs would have to adapt most of their equipment (the magnitude of the adaptation depending on the blending level chosen for the cluster) to accept the hydrogen share present in the natural gas. TSOs would have to avoid flows between the countries with a higher acceptance blending rate to the ones with a lower acceptance rate.

Small and medium-sized network operators might be more strongly impacted by the additional administrative and adaptation costs than large companies.

LSOs would be encouraged to address terminal accessibility issues.

NRAs would be required to prepare the rulebook for integration of distribution grids in entry/exit zones and reverse flow compressor obligation (cf. next section).

They would be strongly implicated into the establishment of hydrogen blending clusters (choosing the local minimum acceptance levels, negotiating joint conditions with neighbouring countries) and the setting of exchange rules between countries with different blending levels. They would need to implement obligations to ensure that equipment connected to the gas system can cope with blending levels varying over time.

Gas consumers and/or tax payers benefit from a potential decrease in specific support scheme costs, yet a higher biomethane production would increase overall support scheme costs compared to Option 0. Also, investment costs for reverse flow compressors would ultimately be borne by the consumers (or tax payers).

An increase in biomethane production reduces the dependency on natural gas imports from outside the EU (increase in security of supply). However, given the low biomethane volumes, the latter effect is marginal.

[236] The estimate assumes that biomethane is replaced by natural gas. It can also be replaced by RES-based heat pumps and then the environmental and economic result might be positive.

Improved LNG access would decrease very slightly the gas price for European consumers.

Depending on the hydrogen blending levels of their countries, end users will need to adapt their equipment. They will most likely also bear some of the grid adaptation costs linked to the deployment of hydrogen blending.

5.3.4 Administrative impact on businesses and public authorities

The integration of distribution grids in entry/exit zones implies implementation costs for NRAs (and energy ministries) to set up the respective legislation. They might further be required to oversee the compliance of DSOs with the new regulation or delegate this responsibility to a third-party entity. Reverse flow obligation implies implementation costs for the NRA (definition of the actual rulebook for installation, including specific thresholds in case of excessive costs for reverse flow compressors compared to the integrated biomethane volumes) and increases transaction costs for DSOs as they need to evaluate the need for compressor installation (possibly realising a CBA to properly evaluate the impacts).

Mandatory hydrogen blending adaptation will increase the administrative costs for businesses that have to ensure their equipment can withstand the level of blending and to obtain adequate connection authorisation.

5.4 Impacts of Option 2

Option 2 goes beyond Option 1 as it integrates:

- A connection obligation with firm capacity for biomethane producers
- Zero or reduced level of injection tariffs for biomethane and hydrogen (blending)
- EU gas quality framework with minimum cross-border hydrogen acceptance level through specific rules
- For LNG terminals, a binding legal framework at EU level for transparency, congestion and access rules

5.4.1 Economic impacts

The integration of biomethane production may be realised at slightly lower total costs, whereas biomethane volumes are expected to remain unaltered compared to Option 1 (assuming biomethane continues to benefit from public support). Minimum acceptance levels for hydrogen blending facilitate the creation of an EU-wide blending cluster, significantly reducing the risks of gas market fragmentation.

The **connection obligation with firm capacity** is already implemented in 16 MSs (representing 89% of assumed biomethane production in 2030 under the MIX H2 scenario), however connection cost allocation varies widely across MSs. Depending on the injection level (DSO or TSO) and the distance from the concerned grid, connection costs may represent up to 15% of the LCOE. Connection obligation in combination with a firm capacity guarantee reduces investor uncertainty, thereby potentially lowering the cost of capital. Assuming a 1%-point decrease in WACC, that would translate into cost savings of 2% or about 10 M€/year in the countries concerned, which benefit the final consumers or tax payers if biomethane is benefitting from public support.

Without public support the reduction in cost might result in enhanced competitiveness of biomethane production. If increased investment certainty triggers additional installed capacity of for instance 10% in the countries without such an obligation, this would add 0.5 TWh of biomethane production, which is rather insignificant. This needs to be contrasted with the additional costs related to network connection, which are particularly high if the distance to the gas grid is high; in these cases, onsite utilisation of biogas (for the production of power and heat) might be a more cost-efficient option.

Connection cost allocation in favour of the biomethane producer might be a more relevant lever, significantly reducing the burden on the producer. On the other hand, it is important to incentivise a least-cost connection of biomethane plants (i.e. at the most cost-efficient pressure level, at reasonable distances). While GHG emission abatement costs for biomethane are already relatively high[237] (a 88 €/MWh LCOE for biomethane translates into roughly 360 €/t_{CO2} of abatement costs), connection costs may increase the abatement costs by some 15 to 30 €/t or even more.

The legal obligation on grid operators to guarantee firm capacity could lead to over-dimensioning of grid infrastructure as DSOs/TSOs may want to minimise the risk of non-compliance with this firm capacity requirement (or maximise their revenues thanks to additional installations which increase their Regulated Asset Base). An incremental increase in biomethane capacities may result in a less cost-efficient extension of the grid in comparison to an approach that anticipates a certain biomethane rollout.

Reduced injection tariffs for renewable and low-carbon gases are expected to have no major effect as these tariffs are marginal compared to the overall LCOE (<1%). Under support scheme, removal/reduction of injection tariffs would merely represent a reallocation of costs from gas consumers to tax payers. In the absence of a support scheme, the removal of injection tariffs would enhance competitiveness, yet to a marginal extent (<1€/MWh compared to an overall LCOE of 88 €/MWh on average).

The impact of an **EU-harmonised minimum acceptance level for hydrogen blending** will strongly depend on the actual blending level chosen. Below a value of 10% the minimum acceptance level will impact only the MSs in the Eastern cluster, and above a value of 10% it will impact all MSs, giving rise to one unique European cluster. The level of adaptation costs is expected to increase drastically with the minimum acceptance level, from 3.6 B€/year for 5% (with some countries being already at 10%), 5.4 B€/year for 10%, 12.5 B€/year for 20% and 37.4 B€/year for 30%, while the hydrogen injected would follow a proportional increase, from 70 TWh (5% with some countries being already at 10%)[238] to 300 TWh (30%). In the case that all EU countries adopt the same level of blending, the gas flows would only be impacted if United Kingdom (which does not need continental gas to ensure its security of supply) has a lower blending rate, which would hinder the transit flows to the UK in the European continent.

The impacts for **LNG** are the same as under Option 1, just more likely to materialise as the EU puts in place a binding legal framework instead of relying on industry-led initiatives.

[237] Of course, there are also other benefits of biomethane (such as local value creation, waste recovery etc.) that need to be factored in. Nonetheless, this remains a rather expensive option for decarbonisation.

[238] The 70 TWh of hydrogen/year were calculated the following way: A 5 vol% blending share translates into roughly 1.6% blending share in energy terms (cf. Section 8.4.3.6). The MS-specific gas demand (about 3500 TWh at the EU level) is multiplied with this 1.6% blending share for all countries featuring a 5% vol% blending share (3.2% for countries featuring a 10 vol% blending share).

5.4.2 Environmental impacts

Environmental impacts under Option 2 related to biomethane injection are expected to be marginal. Environmental impacts of hydrogen blending depend on the actual blending level chosen.

Additional investments due to connection obligation with firm capacity could reduce GHG emissions marginally, by 0.1 Mt CO_2 if exceeding the biomethane production volume assumed under Option 1.

Again, the impact of hydrogen blending at the TSO level would depend on the actual minimum acceptance level. The avoided CO_2 emissions could go from 8 MtCO2/year (for a minimum acceptance level of 5%) to 33 MtCO2/year (for a minimum acceptance level of 30%), however as equipment must be adapted for higher blending levels, the associated GHG abatement costs would also increase: 445 €/t_{CO2} (5% with some countries being already at 10%), 524 €/t_{CO2} (10%), 582 €/t_{CO2} (20%) and 1124 €/t_{CO2} (30%).

5.4.3 Who would be affected and how?

Producers of renewable and low-carbon gases benefit from reduced risks linked to grid connection and interruption of gas injection related to potential grid bottlenecks thanks to a firm capacity guarantee. This increases certainty for producers and potential investors. Removal of grid injection tariffs would only have a marginal effect on producers. Because of the minimum cross-border hydrogen acceptance level, hydrogen producers are especially solicited (at a level depending on the minimum rate chosen) to provide the necessary hydrogen production at the interconnection points.

Hydrogen producers would benefit from the minimum hydrogen blending acceptance level imposed by EU rules as it facilitates the EU wide marketing of hydrogen.

Natural gas producers will have to decrease their production because of the minimum level of hydrogen that replaces natural gas, at a level depending on the minimum rate chosen. Yet, the decrease remains limited as an exemplary hydrogen blending level of 10% in volumetric terms only replaces approximately 3% of the energy content (HHV).

TSOs/DSOs are likely to face a limited increase in efforts due to the connection obligation as system operators would in any case need to take care of grid connection; however, they may need to carry out a CBA in case they want to oppose grid connection; if connection costs are allocated to grid operators, this might increase grid-related levies for consumers. Guaranteed firm capacity requires grid operators to assess and anticipate connection requirements of biomethane plants and dimension the grid accordingly.

All TSOs/DSOs would need to comply with the imposed minimum hydrogen blending acceptance level imposed by EU rules that would represent important adaptation costs for any threshold chosen.

LSOs would be directly impacted by the obligation of improving their transparency and access to their terminal, which can increase their administrative costs, but at the same time increase their revenues thanks to a higher load factor.

NRAs need to prepare the legal ground for a rule book on connection obligation with firm capacity (cf. next section) and to specify the rules applying for the potential removal or reduction of injection tariffs.

NRAs would further have to ensure that TSOs and DSOs comply with the minimum blending acceptance level. Regulations will have to be developed to determine how to treat hydrogen volumes generated during deblending, as for high transport blending levels some equipment cannot adapt and will need to have dedicated deblending installations, and notably if operators have to reinject it on the network, can sell it or store it.

Finally, NRAs face higher administrative costs as the supervision of LSOs would increase in this option.

Consumers/society are likely to face an increase in overall costs as connection obligations bring about an increase in overall costs (also related to the connection of plants potentially further away from the grid). As residential and commercial consumers typically face higher network tariffs (also due to the connection to the distribution grid), they are expected to be more strongly affected than industrial consumers. Indirect effects in terms of job creation and additional domestic value added are considered to be marginal.

The minimum acceptance blending level would need to be applied for an increasing number of end-users with the blending rate. For blending levels beneath 5% mainly chemical use and glass industries would require adaptations. Blending shares between 5% and 10% require gas turbines and industrial high temperature applications to be adapted. Increasing the blending to 20% implies adaptations of combined heat and power plants. Blending beyond 20% requires the installation of new boilers. Some of these adaptations include deblending installations (e.g. for gas turbines and in part for the chemical industry), which may require a dedicated management of the separated hydrogen for the consumer (local utilisation, storage etc.).

5.4.4 Administrative impact on businesses and public authorities

Regarding connection obligation with firm capacity, NRAs need to define rules for CBAs, economic thresholds for non-obligation to connect and specificities of the firm capacity obligation (e.g. regarding the level of capacity to be guaranteed). Reduction/removal of injection tariffs requires NRAs to define the concrete exemption rules, the mechanism of cost reallocation and its inclusion in the calculation of grid tariffs.

Depending on the threshold, most of the equipment will need to be adapted and certified to demonstrate it complies with the minimum acceptance level, which would add a layer of certification for the EU gas system. The fact that the effective blending levels could vary over time will have to be taken into account into the billing and trade of natural gas, by specific mentions in contracts and bills, which will increase the administrative complexity of the trade and supply on this market.

Depending on the EU regulations needed to increase the transparency, congestion and access rules for LNG terminals, the administrative work of LSOs could increase to ensure their compliance with them.

5.5 Impacts of Option 3

Option 3 goes beyond Option 2 in the following respects:

- For LNG terminals (and gas storage) operators will be obliged to realise market tests/screening and development plans (every 2 years) on their suitability to accept renewable and low-carbon gases, including hydrogen.
- For long-term natural gas supply contracts (LTCs), derogations for new contracts from Art. 32 (as defined under Articles 35 and specified under Article 48 of the Gas market Directive) are removed and duration is limited to 2049 at the latest.
- Option 3 removes cross-border tariffs from interconnection points within EU for renewable and low-carbon gases, facilitates voluntary regional gas market mergers (Guidance by the Commission), and includes measures for transparency of allowed revenues of network operators and costs benchmarking.

5.5.1 Economic impacts

Impacts on the integration of renewable and low-carbon gases are expected to be marginal. Removing derogations from Article 32 and limited duration of long-term contracts is likely to increase gas prices by 2030.

A priori, the **promotion of renewable gases** would not result in a significant change of the load factor of LNG terminals or European biomethane import as biomethane is too expensive[239] in comparison to standard natural gas in 2030, unless the price for guarantees of origin or the carbon price reach high values (i.e., 15 €/MWh HHV or 80 €/t_{CO2}). Ammonia and methanol trade could increase, but it cannot be evaluated whether end-uses will develop for these energy vectors at a wide scale by 2030.

Removing derogations from Article 32 for take-or-pay contracts might increase competition in the gas market as it enhances access to transmission/distribution systems and LNG facilities for new market entrants supplying renewable and low-carbon gases. However, renewable and low-carbon gases feature by 2030 still more important supply costs compared to conventional natural gas suppliers which implies a limited market uptake of renewable and low-carbon gases. Derogation from Article 32 might further increase the volume risk of the LTC buyer (as he faces additional competition from new market entrants), potentially at risk the existence of take-or-pay contracts and thereby potentially increasing gas prices.

Limiting the duration of new long-term supply contracts would tend to increase the market price of natural gas, as the limited engagement of gas buyers (as long-term contracts cannot cover the same time scale) in the gas market will increase the risks of the gas contract and thus their cost. However, by 2030 this effect is expected to be marginal as major shares of gas supply are already covered via existing long-term contracts.

If MSs opt for regional cooperation when exploiting biomethane potentials, the **removal of cross-border tariffs from IPs within EU for renewable and low-carbon gases**, biomethane producers would be exonerated from paying the intra-EU cross-border tariffs of a total of 12.4 M€/year to the TSOs. However, this missing revenue would need to be recovered, e.g., by a rise of the internal exit tariffs by 0.005 €/MWh HHV (assuming an EU natural gas demand of 2674 TWh HHV in 2030).

5.5.2 Environmental impacts

In 2030, no additional environmental impacts are expected for this option compared to Option 2. Limiting the duration of natural gas LTCs might create an artificial gap in natural gas supply towards 2050, potentially creating room for renewable and low-carbon gases. However, as long as renewable and low-carbon gases are not economically competitive, the gap still risks to be filled by short-term natural gas contracts. Hence, there is a need to further foster the market integration of renewable and low-carbon gases by dedicated support policies or an effective carbon price signal.

5.5.3 Who would be affected and how?

Natural gas producers will potentially try to find new consumers (outside the EU) for their long-term production that would accept long term contracts past 2050 to hedge risks, even if the selling price is less interesting than in EU.

[239] Low-cost biomethane potentials exist outside the EU which are competitive with natural gas. However, it is considered rather unlikely that these potentials would be exported to the EU instead of being used locally.

TSOs would face additional transaction costs as the limitation of removed intra-EU cross-border tariffs to renewable and low carbon gases require them to create a methodology to separate the tariffs applied to natural gas in contrast to biomethane, which could lead to additional monitoring efforts.

The **shippers** of natural gas would need to avoid long term supply contracts and will find more flexible contracts with shorter duration.

The **LSOs** might face increased volume risks and uncertainty if derogations from Article 32 are removed. Alongside the **SSOs**, they will need to draft strategies to facilitate the import of renewable gases, but without additional financial incentives (direct aid, contract for difference for alternative energies) only R&D projects without market development perspectives are likely to emerge.

The **NRAs** will need to increase their surveillance on the new long-term contracts to ensure they comply with the new obligation.

The **gas consumers** would see a slight increase of their gas bill on a long term because of the increase in gas contract prices compared to a situation where long-term contracts would not be affected.

5.5.4 Administrative impact on businesses and public authorities

The administrative exchanges between NRAs and natural gas shippers should increase to ensure the correct application of the measures on long term contracts.

5.6 Impacts of Option 4

Option 4 goes beyond Option 3 in the following respects:

- GTM++: Elimination of intra-EU cross-border tariffs
- GTM++: No differentiation between LNG and 3rd country entry charges (variant)
- Combined minimum and maximum acceptance levels for hydrogen blending
- EU-level biomethane based harmonisation of gas quality standards (variant)
- Time limit for new long-term contracts already before 2050
- Elimination of current entry tariff discounts for LNG terminals (variant)

5.6.1 Economic impacts

The **elimination of intra-EU cross-border tariffs** will have a significant impact on the European gas market. Several parameters (namely the distance-factor to set the third countries entry tariffs, and the application or not of this method to LNG terminals) will need to be clarified, but some general effects can be identified. Removing internal tariffs implies that the natural gas from Northern Africa will be replaced by gas coming from Norway and Eastern Europe, while LNG imports will increase (if entry tariff for LNG is suppressed) or decrease (if the distance-based rule is applied for the entry tariff of LNG terminals). The wholesale gas prices are likely to increase slightly in the northern countries and to decrease in the southern countries.

As most TSOs will lose revenue from the application of this measure, as long as no inter-compensation mechanism among the TSOs is in place, the internal exit tariffs will need to increase in most MSs (e.g. up to 2 €/MWh for Austria), and will decrease in EU Member States near third countries, Switzerland & United Kingdom excluded (e.g. down to -4 €/MWh for Estonia).

These changes of gas wholesale prices and internal exit tariffs may trigger a shift in the merit order between gas fuelled power plants (notably open cycle gas turbines) and coal power plants in both directions (coal to gas or gas to coal) for a few EU Member states.

To readjust the impact among the MSs, an inter-compensation mechanism among the TSOs would be necessary[240].

The impact on welfare between the different gas stakeholders (consumers, producers, TSOs etc.) depends on the parameters of the measure: it seems to be beneficial to the EU gas consumers (mainly Italy) of up to about 500 M€/year to the detriment of non-EU consumers and natural gas producers in the option where the LNG terminals do not have entry tariffs, variants where the third country entry tariffs were increased or where entry tariffs were applied to LNG terminals have shown to reduce this gain, even shifting it to negative impact on the EU consumers if entry tariffs (on both LNG terminals and third countries) are too high.

Another variant of gas market adaptation through tariffs was studied where the internal tariffs were kept but the legal possibility for NRAs to grant a discount for LNG entry tariff was removed. This measure was shown to have only a small impact on the gas market: 10 TWh/year in 2030 of import shift between LNG and Norway, and to benefit mostly to third-countries rather than EU MSs.

As high **hydrogen blending levels** are unlikely to be implemented at the TSO level on a voluntary basis, the adoption of a maximum blending level is expected to play a role only in the case where both the maximum and minimum acceptance level are at 5%, which was seen to be a threshold above which adaptation costs become very high. In this particular case where all EU MSs are obliged to have a 5% blending level on their transmission network, the injection of blended hydrogen equals 50 TWh/year in 2030, the adaptation costs reaching around 733 M€/year. If MSs tend to hydrogen blending to a specific threshold blending on their transmission network to avoid too important adaptation costs, an EU-wide maximum level could ensure the homogenisation of blending rates and prevent isolated initiatives that could lead to unwanted increase of adaptation costs for several neighbouring countries.

5.6.2 Environmental impacts

The change in gas tariffication is not expected to have significant environmental impact apart from possible switches in the merit order between coal and gas, which are to be limited would an inter-compensation mechanism between TSO be adopted.

In the case where both the maximum blending levels and minimum acceptance level are set at 5%, the expected decrease in CO_2 emissions is 5 MtCO2/year, for an average abatement cost of 144 €/t_{CO2}, which is important but still significantly lower than for higher blending rates.

5.6.3 Who would be affected and how?

The **producers of natural gas** would be impacted strongly by the removal of inter-EU tariffs, as the gas supply sources are likely to strongly change (in the present analysis to the benefit of RU, NO, BY and UA gas suppliers and to the detriment of North African gas suppliers), and producer surplus would be reduced to the benefit of consumers. The removal of intra-EU tariffs would benefit to end-users as it would ease the management of their delivery of gas.

[240] No ITC mechanism was studied in this assessment. Thus, the results displayed here represent a situation where there is no financial transfer among the gas TSOs, even though they are not homogeneously affected by the measure.

In particular, **LNG producers** will be strongly impacted by the choice made on the tariff at the LNG terminal level as removing this tariff strongly increase the LNG imports whereas adding it strongly decreases them. In any case, LNG producers will be penalised by the elimination of current entry tariff discounts for LNG terminals.

Domestic producers of renewable and low-carbon gases might face increased competition with domestic natural gas producers as the latter do not need to pay for internal entry-exit tariffs (at least in a system without public support).

In general, **gas producers** would benefit from the removal of inter-EU tariffs that would ease gas trade for industrial consumers that buy their gas on the wholesale market. On the other hand, the time limit for new long-term contracts will increase the risk of their activities, which would increase their hedging costs.

TSOs and LSOs will be deeply impacted by the removal of inter-EU tariffs. They will lose their financial autonomy as they will not be able to control their revenues themselves, the tariffs being set at the EU level (e.g. by ACER). They will need to strongly increase their cooperation to agree on an ITC mechanism, and decision and governance over this mechanism will be a major issue for them. They will need to justify at the EU level their costs and allowed revenues, which would increase the homogenisation of investments and operation costs calculations. At last, they will need to re-think their management of congestion, for instance by adopting capacity auctions with a starting price at 0€/MWh for all interconnection capacity.

The TSOs may be impacted by the adoption of a maximum blending level, in the sense that (depending of this maximum level) they would need less investment to adapt their infrastructures to high blending levels.

The **NRAs** would lose some of their national competence (the setting and control of the TSO allowed revenues by the setting of external tariffs) that will be transferred to the EU level (e.g. to ACER). They will need to be also involved in the design of the ITC mechanism in order to control the change of internal exit tariff.

In this option, the adaptation/creation of an entity at EU level (ACER, ENTSOG, new entity) that would control the ITC parameters and ensure the correct application of the distance-based rule for entry tariffs would be likely.

Consumers will be impacted by this option as it might change the gas prices in Europe to their advantage (depending on the parameters of the measure and of the probable ITC). However, if this is true at the EU-scale, the benefits will not be homogeneously distributed among MSs, and there will be winners and losers among the consumers of the MSs. The time limit for new long-term contracts should slightly increase the gas bill of the consumers, but this effect would be marginal in 2030.

5.6.4 Administrative impact on businesses and public authorities

In this option, the removal of intra-EU tariffs, the adoption of a maximum hydrogen blending level and the removal of possible discounts on entry tariffs for LNG terminals should all reduce the administrative work for market operators in the gas system by increasing the homogenisation of European gas market characteristics and reduce the need for justification for exception and interaction with different TSOs.

However, the increase of coordination needs (for the management of ITC and congestions) between all the TSOs and NRAs may also increase the administrative efforts and related costs in comparison with a situation where coordination was only needed between one NRA and the national TSO(s). The probable creation/adaptation of an EU-entity (ACER, ENTSOG, new one) to manage the competences transferred by the national TSOs and NRAs will also increase the administration needs at an EU level.

5.7 Impacts of Option 5

Option 5 differs from Option 1 as it integrates:

- The focus on local supply of renewable gas injection (incl. connection obligation with firm capacity and removal of injection tariffs)
- Negotiated TPA for LNG terminal possible
- Specific provisions for gas energy communities

Option 5 (in comparison to Option 1) excludes:

- VTP access through integration of distribution grids in entry/exit zones
- Reverse flow compressor obligation

On all matters related to hydrogen blending and transparency of LNG terminals, the impacts will be similar to Option 1.

5.7.1 Economic impacts

Integrating specific provisions for renewable and low-carbon gas **energy communities** (notably with regard to the ownership, establishment, purchase or lease and autonomous management of distribution networks, following the current provisions for Citizen Energy Communities under Art. 16(2b) of the Electricity Market Directive[241]) may facilitate the deployment of biomethane (and other renewable or low-carbon gases). However, fostering local supply of renewable and decarbonised gases without integrating the production into wholesale markets (VTPs) and transmission grids risks to fall short of the amounts of biomethane projected under the MIX H2 scenario for two major reasons: 1) some distribution grids are likely to saturate in terms of biomethane injection[242] (in particular in summer time) and VTP access is still restricted in some countries, implying that local supply would need to be curtailed which reduces the economic viability of biomethane plants and 2) a relevant share of biomethane plants are directly connected to the transmission grid as they have a high installed capacity (notably using energy crops). Dedicated policy measures on energy communities may facilitate a wider deployment of biomethane plants. But if biomethane production is capped by local gas demand the risk of saturation may become a major constraint, notably in the light of further declining overall gas demand levels. When estimating the potential need for reverse flow by 2030 at some 10% of all biomethane plants, this would mean 2.2 TWh to 4.7 TWh of reduced biomethane production (see also the related benefits listed in Section 5.3.1 for Option 1).

Energy communities typically accept lower profit margins or work as non-profit undertaking, thus reducing the LCOE. At the same time, their smaller size compared to commercial large-scale developers implies a higher specific cost of capital which may offset the first effect.

[241] (European Commission, 2019c)

[242] The assessment at the NUTS1 level did not identify issues related to reverse flows, however, it may be observed already today that reverse flow compressors are added to certain networks. Even if this remains an exception, it may become an issue in areas with low local demand and high local potentials.

As under this option **LNG terminal operators can negotiate their tariffs**, most of them will adapt their tariffs to optimise their revenues, which will result in a major increase of LNG imports (between 25% and 55%), mainly from the Middle East replacing gas from Russia, Algeria and Norway. The LSO revenues will increase (up to 28%), as well as the EU consumer surplus for a total of 308 to 533 M€/year of gain to the detriment of third countries consumers and producers.

5.7.2 Environmental impacts

Option 5 risks to fall short of the biomethane production volumes required to comply with the 55% GHG emission reduction target by 2030.

Assuming that 10% of the biomethane production would need reverse flow investments and could not be integrated but would need to be replaced by natural gas, this could increase GHG emissions by up to 1 Mt CO_2 per year.

5.7.3 Who would be affected and how?

Biomethane producers will find local support from the energy communities which should trigger more investment efforts.

Natural gas producers will face more competition because of the increased support for biomethane through the energy communities, though the market share concerned should be low as natural gas remains in 2030 the most advantageous economic solution.

LNG producers should be strongly impacted by the change of tariff regime of the LNG terminals, as depending of the different strategies adopted by the terminals, the LNG imports merit order can be directly impacted, shifting the imports from one LNG source to another in 2030.

Grid operators are likely to face increased administrative costs as they might need to deal with a larger number of smaller producers. Transaction costs may also increase for conventional TSOs/DSOs in case of cooperation with energy communities that own/lease/manage the local distribution grid.

LSOs will find a new autonomy in setting their tariffs and will be able to optimise their revenues, thus entering into competition between each other. They will have to predict the gas market to be able to capture the possible congestion rent at their level, either by setting the tariffs accordingly, or by organising capacity auctions with a relevant starting price.

NRAs need to establish the legislative framework for energy communities.

Gas consumers will directly benefit from the facilitated access to more competitive LNG.

Supporting gas energy communities would stimulate local gas supply, and potentially also trigger higher local acceptance as well as the willingness to pay for support costs by making them become prosumers.

Yet, a lack of measures to create a level playing field for biomethane in comparison to natural gas, e.g. with respect to its integration in wholesale markets and transmission grids, may increase investment uncertainty and decrease the attractiveness of local biomethane projects.

5.7.4 Administrative impact on businesses and public authorities

Enabling energy communities to manage distribution grids would facilitate biomethane deployment but would bring about a significant administrative cost.

NRAs need to establish the legislative framework for energy communities, notably with respect to distribution grid ownership/purchase/lease/management

The removal of regulated tariffs for LNG terminals may result in a decrease of administrative exchanges between the LSOs and NRAs on matters related to these tariffs, however the surveillance put in place by the NRAs may still represent some administration work by LSOs to justify their tariffs.

5.8 Summary of results

- Option 1: In comparison to Option 0
    - Allows for full integration of the biomethane potential projected under the MIX H2 scenario, facilitating compliance with the 55% target; may help to reduce support scheme costs and thus the cost barrier on consumers
    - Apparition of several European blending clusters at the TSO level
- Option 2: In addition to the impacts of Option 1
    - Has only a marginal impact on the integration of renewable and low-carbon gases, namely biomethane; may potentially reduce the costs
    - Homogenisation of blending levels across EU at the TSO level, most likely at the pre-defined min. acceptance blending level
- Option 3: In addition to the impacts of Option 2
    - Increase of wholesale gas price
- Option 4: In addition to the impacts of Option 3
    - Creation/adaptation of one EU entity to manage the gas tariffs, and strong adaptation of gas internal exit tariffs
    - Transfer of national competence to the EU level
    - Strong change of gas flows, less North African gas imported
    - Reduction of the risk of high blending level taken as a local initiative
- Option 5: In comparison to Option 1
    - Puts at risk the compliance with the 55% target as not all of the required biomethane production might access the market, due to focus on local supply
    - Apparition of several European blending clusters at the TSO level
    - Strong increase of LNG imports, benefiting to European consumers

Table 5-1: Overview of impacts for the options under Problem 1 (in comparison to the next less ambitious option).

Option	Economic	Environmental	Social	Efficiency	Effectiveness
Option 1 (vs Option 0)	+	++	+	+	++
Option 2 (vs Option 1)	+	0	+	0	++
Option 3 (vs Option 2)	-	+	-	0	0
Option 4 (vs Option 3)	+	0	0	-	++
(Option 5) (vs Option 1)	+/-	-	+/-	-	+
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)					

6 COMPARATIVE ASSESSMENT OF OPTIONS RELATED TO PROBLEM 2

6.1 Impacts of Option 0: Business-as-usual – No intervention

6.1.1 Economic impacts

A large majority of Member States have currently a single gas NDP per country, there is still limited cooperation between electricity and gas TSOs in planning, and also limited participation of gas DSOs. In Option 0, this situation is likely to change only slowly by 2030, given the complexities in developing common scenario or common assessment methodologies, which may require iterations between TSOs based on different models. In the absence of additional provisions and assuming that MSs do not develop significantly their NDP methodologies, an infrastructure planning at the national level is expected to remain fragmented, between TSO and DSO levels, between energy carriers and regarding the involvement of LSOs, SSOs and network users, among others. Even if some Member States opt for specific measures at the national level, it is likely that national situations regarding integrated network planning will be diverse.

Similarly, other planning aspects such as the assessment of infrastructure decommissioning needs, the use of sustainability indicators to avoid investing in infrastructure projects that are not future-proof and the scenario alignment with EU objectives, e.g. via a link with the National Energy and Climate Plans (NECPs) and/or the Long-Term Strategy (LTS), would depend on national initiative.

The transition of national and the EU energy systems progress continuously. However, the various stakeholders (DSOs, TSOs, LSOs, SSOs, policy makers, energy producers, consumers etc.) are likely to anticipate different evolutions. If these visions are not aligned different risks arise in terms of network planning and build-out.

Non-harmonised scenario visions of **gas and power** network operators risk to lead to an overestimation of the need for additional gas and electricity infrastructure projects, disregarding potential synergies between the two sectors. Given the long lifetime of these assets of 50 years and more, this may lead to underutilised and/or stranded assets. Similar effects may occur with respect to the coordination between TSOs, LSOs and SSOs, as grids, LNG (as gas import facilities) and storage assets may provide system flexibility and thus provide similar service as the reinforcement of the network. A lack of coordination between TSOs and DSOs risks to act as a barrier to the exchange of information on and the investment in assets facilitating reverse flows from distribution to transmission grids but also within transmission grids and even between networks of different TSOs, which may affect all other existing and future upstream network components.

A decoupled planning of **gas and hydrogen** network assets potentially leads to an overinvestment in new hydrogen pipelines instead of an efficient repurposing of existing gas pipelines under the condition of decreasing utilisation rates for gas (e.g. due to lowering gas demand levels), freeing up certain pipeline segments. In this regard, the information to what extent and from what point in time certain methane pipelines are not required anymore can be very useful. Another aspect concerns the introduction of hydrogen blending in gas (distribution and transmission) networks, which may play a role to kick-start the hydrogen ecosystem at least in local networks by facilitating the deployment of hydrogen supply assets and which potentially requires major investments (cf. Section 4.3.2, too).

If **network planning is not aligned with the vision of policy makers** and national and/or European decarbonisation strategies (for instance as outlined in the NECPs), network infrastructure build-out risks to lag behind and potentially hinder the deployment of new energy carries (such as hydrogen) and may result in a sub-optimal infrastructure that ultimately jeopardises the entire transition strategy. This risk is potentially more limited for the year 2030, as renewable and low-carbon fuels are still expected to play only minor roles (according to the MIX H2 scenario). However, given the significant lead times for infrastructure planning and construction processes which may last more than 10 years and bearing in mind that the uptake of renewable and low-carbon gases is expected to gain significant momentum in the years following 2030 (according to the MIX H2 scenario), a lack in alignment of today's NDPs with national and EU decarbonisation scenarios may have consequences in 2030 and beyond. In the worst case, uncoordinated planning may lead to technology lock-ins that delay or block the implementation of effective decarbonisation strategies.

Similar effects may appear in the absence of sustainability indicator/criteria for national network development plans. There is a risk of selecting investments that are not compatible with a decarbonised energy system, and that could lead to lock-in situations.

All effects mentioned (over-dimensioning, stranded assets, technology lock-ins, delayed energy system transition) ultimately result in additional costs without providing additional benefits to the society. Given the dimension and financial volumes related to infrastructure projects, the resulting costs may be significant. In the end, it is the consumer or tax payer who has to bear these costs.

6.1.2 Who could be affected and how?

Producers of renewable and low-carbon gases face the risk that grid infrastructure planning and upgrade is not aligned with an increased deployment of new gases (which are typically produced in decentralised units and injected into the distribution grid), as for instance reverse flow needs are not identified or not communicated and appropriately considered in a joint planning between DSOs and TSOs. This may result in a constrained integration of these new gases.

TSOs and DSOs do not necessarily face additional costs under Option 0 as they may follow the current procedures. However, there is a risk that an uncoordinated approach between the different network operators and other infrastructure operators and stakeholders results in parallel and overlapping planning efforts. Merging and streamlining such activities might result in overall benefits and allow to reduce some of the related costs – which would not happen under Option 0.

In case of sub-optimal network planning and expansion, **consumers** are likely to bear the bulk of the extra-costs. Unnecessarily high network costs make energy less affordable, affecting notably low-income households but putting also an additional barrier on European businesses (and potentially weakening their competitivity if competing with non-EU competitors). Nowadays, unitary grid charges (in €/kWh) are typically increasing with lower annual gas consumption volumes, implying that residential consumers pay the highest charges, followed by commercial and ultimately by industrial consumers. Thus, extra-costs are likely to be redistributed in a similar manner, affecting in particular household consumers. Also, grid charges are typically elevated in areas with low total gas consumption (due to limited population density or industrial activity), as network costs are allocated to a limited amount of gas consumption volumes. Hence, gas consumers in the respective areas might be concerned by the extra-costs above the national average.

6.1.3 Administrative impact on businesses and public authorities

Option 0 is expected to have no additional administrative impacts on businesses, public authorities or other stakeholders in the short- to medium-erm as it does not contain any additional policy measures. However, in the long run, TSOs and NRAs might face an increased coordination and negotiation effort when it comes to the potential question on how to deal with stranded assets.

6.2 Impacts of Option 1: National Planning

Option 1 contains the following policy measures (compared to Option 0):

- TSOs of a country are required to prepare a single, consistent and consolidated NDP that includes storage, LNG terminals and production
  - The NDP needs to be drawn up every two years
- The preparation of NDPs shall
  - Ensure a transparent involvement and management of all relevant stakeholders
  - Identify pipelines that are not required any more
  - Include sustainability criteria focusing/preferring investment that allow gases with low or no carbon impact to be transported in the network

6.2.1 Economic impacts

A more holistic network planning may ensure a more efficient and cost-effective network planning that factors in additional framework conditions which may affect the need for gas infrastructure.

Requiring a single, consolidated NDP to be drawn ensures that potential inconsistencies between the visions of different gas TSOs operating in the same country (e.g. in France) are identified, discussed and eliminated, leading to a more coherent, cost-efficient network planning procedure, lowering the risks of over-dimensioning the system or stranded assets.

A transparent process bringing together all relevant stakeholders may allow to anticipate new (technological) trends (e.g., with respect to the deployment of synthetic methane production, the use of ammonia, etc.), enhance the anticipation of the evolution of gas production and demand (e.g. level of energy efficiency efforts, flexibility of the demand), thereby bringing the planning closer to reality and enabling better investment decisions. It may further raise the acceptability for gas infrastructure projects, thereby minimising the risk of opposition and lawsuits and related delays and costs. It should however be noted that the potential for additional benefits can be considered relatively modest as such conditions already are broadly in place despite the heterogeneity of current approaches. Nevertheless, the identification and promotion of best practices in stakeholder consultation processes across Member States could be beneficial.

Joint scenarios considering pipelines, storage assets and LNG terminals may reduce investment needs, as all these assets provide flexibility but are owned and operated by different stakeholders. A coherent approach to the establishment of NDP can save infrastructure costs that are typically socialised via grid tariffs.

The main benefit of reporting on decommissioning of methane pipelines is that it enables more efficient investment decisions, notably with respect to the repurposing of gas pipelines for hydrogen instead of constructing new ones (which features CAPEX savings of 70 to 90%[243]) and the exploitation of cross-synergies.

[243] CAPEX data based on (Guidehouse, 2021)

6.2.2 Who could be affected and how?

The suggested provisions would make **DSOs/TSOs** face higher planning costs (cf. next section), in particular related to higher coordination efforts with other TSOs of the same country and with stakeholders (yet most countries feature already significant stakeholder involvement), as well as with storage and LNG system operators (SSOs and LSOs). The identification of underutilised pipelines that are candidates for decommissioning would entail minimal additional efforts.[244]

For **NRAs**, the provisions imply in particular significant implementation costs to set up the distinct rules for NDP preparation (one-off effort).

Gas consumers would benefit from a more cost-efficient planning as infrastructure costs are typically socialised via tariffs. Better anticipated grid planning avoids stranded assets as much as delayed network expansion and resulting grid bottlenecks (e.g. for new energy carriers such as hydrogen) which comes ultimately at lower cost for the consumer. However, too much harmonisation could collide with the subsidiarity principle and risks neglecting Member State specific aspects in the stakeholder consultations.

6.2.3 Administrative impact on businesses and public authorities

DSOs and TSOs would face increased implementation costs related to the enlarged scope and effort of NDPs. A publication of the NDP every two years implies recurring increased efforts, hence relevant transaction costs.

6.3 Impacts of Option 2: National Planning based on European Scenarios

Option 2 defines specific requirements in addition to those common to all measures and those included in Option 1, in order to improve the scenario building, namely:

- Joint electricity, hydrogen and methane scenarios
- District heating and CO_2 integrated into scenarios
- DSO participation in scenario building
- LSO and SSO participation in scenario building
- Alignment with TYNDP scenarios, anchoring the NDP exercise to EU objectives

Furthermore, while investments in electricity, hydrogen and methane infrastructure would not be jointly considered in a single multi-energy NDP, additional measures are introduced to capture part of the benefits associated with such a requirement. First, NRA can require that a market test of hydrogen infrastructure be performed. Second, gas and electricity TSOs have to perform a series of sanity checks related to the compatibility of their respective NDPs.

6.3.1 Economic impacts

Building joint electricity and gas scenarios would ensure that indirect interlinkages are treated in a consistent way in subsequent processes by gas and electricity TSOs. This

[244] The efforts might however be elevated if the correct assessment requires the introduction of an extended framework for the cost-benefit analysis.

ensures that the planning exercises are carried out using a common vision of the future, thereby eliminating risks that electricity and gas TSOs plan the evolution of their systems based on incompatible assumptions (e.g. electricity TSOs assuming a strong deployment of heat pumps in the residential sector while the gas TSO assumes a deployment of gas boilers). The participation of DSOs, LSOs and SSOs in scenario building activities would ensure a common vision of the different stakeholders implying that investment decisions (which are still taken independently) are more aligned, avoiding conflicting or redundant investments, thereby savings in societal costs.

While this option does not foresee that NDPs should be jointly established by gas and electricity TSOs, it includes that NRA can require market tests of the appetite for hydrogen infrastructure, thereby ensuring that the associated infrastructure is developed based on robust grounds. Secondly, by performing sanity checks on the basis of their draft NDPs, electricity and gas TSOs will ensure that the key inconsistencies are identified and eliminated.

Integrating a TYNDP scenario in line with EU climate targets ensures that the network planning takes into account the decarbonisation strategies at the national and EU levels, reducing the risk of potential lock-ins or stranded assets. Linking the NDP scenario framework to NECPs and LTS would increase the coherence of energy system planning – both across sectors and across Member States.

6.3.2 Who could be affected and how?

Producers of renewable and low-carbon gases might benefit from a more comprehensive grid planning that integrates in particular the fact that gas flows might reverse compared to today, from distribution to transmission grid level (reverse flows), injections taking place from domestic sites and less from external imports.

TSOs would be required to substantially increase their coordination efforts with electricity TSOs, as well as with LSOs/SSOs and DSOs. It is important to note that a too strong integration could potentially oppose functional unbundling.

NRAs would need to outline which elements of the scenario building should actually be harmonised, which stakeholders need to be directly involved and how to treat hydrogen in the plans (one-off implementation costs).

In case that the harmonised scenario building effectively avoids redundant or conflicting capacity investments, **consumers** would benefit from reduced gas tariffs.

6.3.3 Administrative impact on businesses and public authorities

Gas and electricity TSOs will see the need for interaction increase in an important way, first to establish joint scenarios, second to perform sanity check of their respective NDPs.

DSOs/TSOs face a significantly higher coordination effort, notably TSOs, as DSO number is quite high in certain MSs (DE: above 700, IT: 250, CZ: above 70).

NRAs potentially need to decide on a framework for the involvement of DSOs (de-minimis rules, national DSO association).

6.4 Impacts of Option 3: European Planning

Option 3 requires that a single system-wide EU-level network development plan be established (i.e. going beyond joint scenario development by jointly planning the evolution of their infrastructure), including gas, hydrogen and electricity.

Unregulated infrastructure investments and investment plans are taken into account when elaborating the national network development plan.

6.4.1 Economic impacts

In the run-up to a fully decarbonised EU energy system, where natural gas will be replaced by a mix between renewable and low-carbon gases and alternative energy carriers (notably electricity) and bearing in mind that low-carbon gases (such as synthetic methane or hydrogen) will rely substantially on renewable electricity generation, a joint planning of power, gas and hydrogen may significantly reduce infrastructure investment needs by structurally accounting for synergies and interdependencies between systems, notably in the long-run. According to the European Commission's Climate Target Plan, hydrogen demand is projected to equal some 2 500 TWh in 2050. Today's natural gas demand is around 3 500 TWh but expected to drop to less than 1000 TWh by 2050. There are important benefits to jointly planning the evolution of the potential location of electrolysers, of electricity grids, and of methane (for e.g. synthetic methane, biomethane) and hydrogen grids. Given the long lifetime of infrastructure assets (typically around 50 years), the transition of infrastructure use from conventional natural gas to other renewable and low-carbon gases needs to be planned as early as possible in order to take comprehensive and robust investment decisions that imply minimal costs for society. Furthermore, a joint planning ensures that the efficiency of investments in the gas sector (incl. hydrogen) is compared to alternatives such as electricity networks, and that the most economically, environmentally sound and secure option is identified and selected.

Finally, by performing this planning exercise at a European level, the practices related to network planning would be harmonised between Member States.

6.4.2 Who could be affected and how?

Producers of biomethane and hydrogen producers would benefit from a system-wide NDP as TSOs are expected to consider specific production and consumption sites and perform a joint planning, optimising the least-cost infrastructure built-out.

TSOs/DSOs will be confronted with a significant coordination effort between TSOs and DSOs for gas, power and hydrogen. This implies relevant transaction costs for the actors involved in NDP development, typically the gas and electricity TSOs, DSOs, but also LSOs and SSOs and to a lesser extent the NRAs. It could be expected that the increase in transactional costs weighs more heavily on SMEs than on larger operators. European bodies such as ENTSOG, ENTSO-E, ACER and the European Commission could see their role increase.

A system-wide NDP requires the development of an appropriate modelling approach. Currently, a number of gas TSOs use planning approaches based on hydraulic modelling. Extending hydraulic models to a system-wide representation is not considered a viable option. New approaches based on the (soft) linking of hydraulic models to a joint (and simplified) power/gas/hydrogen (market) modelling approach that reveals the synergies between the three sectors can be implemented (i.e. replacement of the gas market model by an interlinked multi-energy market model). In such an approach, the market model would provide boundary conditions used in the hydraulic model (in a way similar to the situation in the electricity sector where the market model provides inputs for grid models). TSOs (for electricity and gas) may face costs related to the development of this joint market model.

NRAs would need to prepare the regulatory rulebook for joint power, gas and hydrogen planning and ensure that TSOs comply with the requirements.

Consumers need to pay for the costs related to the increased coordination between all system operators, but also benefit from the more efficient planning procedures. The second effect is estimated to outperform the first. The net effect would translate into lower prices for energy enhancing affordability of energy and positively influencing the competitivity of European businesses.

A more sector-integrated system reflected in a more sector-integrated network planning approach due to its inherent flexibilities offers more degrees of freedom to balance multi-criteria objectives and thus also increases system stability and security of supply.

6.4.3 Administrative impact on businesses and public authorities

System operators, NRAs and European bodies (ENTSOs, ACER, EC) may be impacted by enhanced administrative costs.

6.5 Environmental impacts

Under Option 0, an unnecessary expansion of network (but also storage or LNG) infrastructure may be possible due to uncoordinated planning. This implies an additional impact on local eco-systems and enhanced use of resources. But more importantly, an uncoordinated scenario building, planning and investment process puts at risk the realisation of long-term decarbonisation strategies, thereby contributing to climate change.

Implementing sustainability indicators in NDPs under Option 1 could contribute to selecting future-proof projects only. If implemented in a more binding nature, a sustainability indicator could be used to address market failures (representing some of the externalities such as impact on methane leakages), helping to select (societally) beneficial projects.

Joint power, gas and hydrogen network planning paves the way for a deep integration of renewable and low-carbon gases (notably hydrogen) with the electricity system, and is thus expected to feature significant emission reductions.

Finally, by reducing the risk of over-investments (by ensuring investments are based on a common vision of the future), all options have a positive environmental impact by reducing the footprint of the overall energy system.

6.6 Summary of results

The options under Problem 2 compare to each other as follows (see also Table 6-1):

- Option 1: enhances the current design of NDPs and ensures that all MSs submit a single plan per country, which allows already for a better integration into the TYNDP process.
- Option 2: increases the cost-efficiency of planning processes as
    - DSOs are more strongly involved in the NDP process (even though this is already the case in some MSs today), reflecting that production of renewable and low-carbon gases is more likely to be linked to distribution grids.
    - Joint power-gas scenario building facilitates a more concerted approach in network planning, notably with respect to the balance between direct electrification and decarbonised-gas strategies (incl. indirect electrification).
    - Sanity checks are introduced to capture part of the benefits of joint system planning

- Option 3: provides the full picture, incl. joint planning of hydrogen, methane and electricity infrastructure, enabling the identification of the most appropriate way to transport energy, taking into account the synergies and interdependencies between systems. This option is best suited when considering the expected development of the hydrogen ecosystem, which gains strong momentum post 2030. However, establishing a single European NDP is a complex endeavour that requires substantial coordination amongst stakeholders.

Table 6-1: Overview of impacts for the options under Problem 2 (in comparison to the next less ambitious option).

Option	Economic	Environmental	Social	Efficiency	Effectiveness
Option 1 (vs Option 0)	++	++	++	++	++
Option 2 (vs Option 1)	++	++	++	++	++
Option 3 (vs Option 2)	++	++	++	-	++
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)					

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8 ANNEX I – METHODOLOGY

This annex provides additional information about the methodology applied for the evaluation of policy measures outlined in Section 4. The annex is structured along the different policy topics. Sections 8.1 and 8.2 relate to the integration of renewable and low-carbon gases into the market. Section 8.3 links to GTM++, i.e., the reform of the current entry/exit tariffication system. Sections 8.4 and 8.5 reveal the methodology applied to evaluate the regulatory frameworks for the quality of gases and LNG terminals, respectively. Sections 8.6 and 8.7 relate to network planning.

8.1 Integrating renewable and low-carbon gases into the market

The following sections provide additional information about the methodologies developed and applied to estimate the potential need for biomethane reverse flows in distribution grids and the comparison between RECs and CECs.

An in-depth description of the methodology applied to determine biomethane potentials and related cost aspects is available in the dedicated Section 8.2.

8.1.1 Estimation of local gas oversupply due to biomethane at the distribution level

An assessment of the balance between biomethane injection and local gas consumption for distribution grids has been conducted for 2030 at the NUTS1 level, in order to estimate the **actual need for reverse flow compressors by 2030**.

First, projected **gas demand** for 2030 was decomposed by sector, usage, NUTS1 zone, type of annual demand profile (thermosensitive or not) and network (distribution or transmission). The projected gas demand for 2030 has been taken from the MIX H2 scenario, decomposed by sector and Member State.

The decomposition by usage being too aggregate in the MIX H2 scenario, demand disaggregation keys from the IDEES database[245] (from the year 2015) were applied, for instance for the gas demand split between cooking and water heating in the residential sector. Disaggregation keys have likewise been used to split the gas demand between NUTS1 zones in each Member State[246].

The decomposition by network (distribution or transmission) and type of profile (thermosensitive or not) was made based on specific allocation keys, cf. Table 8-1 and Table 8-2. Specific values have been used for some Member States, when data were available. [247,248]

[245] JRC (2020): JRC-IDEES. Retrieved from: https://ec.europa.eu/jrc/en/potencia/jrc-idees

[246] Fraunhofer ISI (2021): Gas demand regional disaggregation keys of the METS3 model

[247] Cf. CEDEC; eurogas; GD4S; GEODE (2020): Facilitating grid injection of renewable and low-carbon gases: DSO joint initiative regarding end-users. Presentation at the 34th Madrid Forum. Retrieved from https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/events/presentations/06.03_mf34_presentation-grid_injection_res_lc_gases_dso_joint_initiative-deblock.pdf

[248] Artelys (2018): METIS Technical Note T8 – METIS Demand and Heat Modules

Table 8-1: Network allocation of gas demand depending on the sector

Usage	Share of the demand on the distribution network	Share of the demand on the transmission network
Residential	100%	
Tertiary	100%	
Transport	100%	
Power Generation and large Combined Heat and Power		100%
District heating and small Combined Heat and Power	100%	
Industry	50%	50%

Table 8-2: Type of gas demand profile depending on the usage

Sector	Thermosensitive	Non thermosensitive
Space Heating	100%	
Cooking		100%
Water Heating		100%
Industry		100%
Agriculture		100%
Transport		100%
Electricity generation		100%
Combined Heat and Power	100%	
District heating	100%	

This analysis enabled the estimation of the minimum daily gas demand on distribution networks, projected in 2030 (cf. for example the demand profile for the NUTS1 zone DE8 in Figure 8-1).

A similar analysis has been conducted to estimate the daily **biomethane injection** by 2030, in each NUTS1 zone. Projected biomethane demand in each MS was taken from MIX H2 scenario.

Based on estimates of future biomethane generation costs and biomethane potentials determined in the framework of the present assessment (cf. Section 4.1 for high-level numbers as well as Section 8.2 for a detailed description of the methodology and more detailed data), cost potential curves have been built for each Member State (cf. Figure 4-6 and Figure 4-7). In these cost-curves, two factors influence the biomethane costs: the biomethane technology and the distance to the gas network. The distance to the gas network is approximated with a fixed value in each NUTS1 zone, depending on the gas network density.

Based on these cost-curves, least-cost potentials were matched with the biomethane production projected in the MIX H2 scenario in each Member State. In order to estimate an upper bound of the seasonal local oversupply, it has been assumed that 100% of the biomethane would be injected at the distribution level. In reality, the level of biomethane injection depends on the technology, the plant size and national framework conditions (e.g., legal framework; cf. Indicator 1.2, Section 10.2.2).

A flat injection profile has been assumed, considering constant operation of the biomethane plant and network injection and the absence of seasonal patterns in biomethane injection profiles (cf. Indicator 1.8, Section 10.2.8).

Matching the determined gas demand profile with the biomethane injection profile (projected by 2030 according to the MIX H2 scenario) for each NUTS1 zone may reveal an estimation of reverse flow needs. If biomethane production exceeds demand, there is a need for remedial measures. For instance, Figure 8-1 underlines the absence of need for reverse flow in the zone DE8, as biomethane injection stays below local gas demand on distribution networks during the whole year.

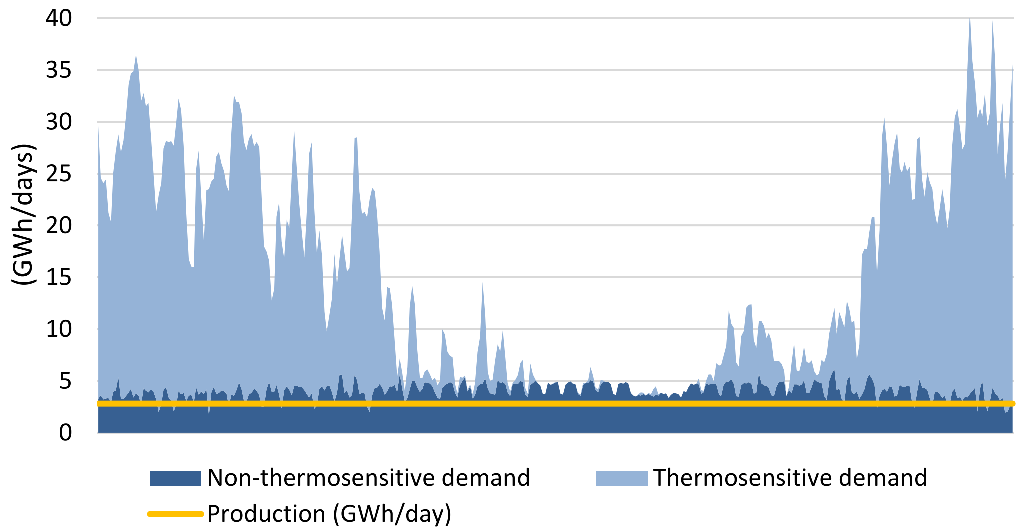
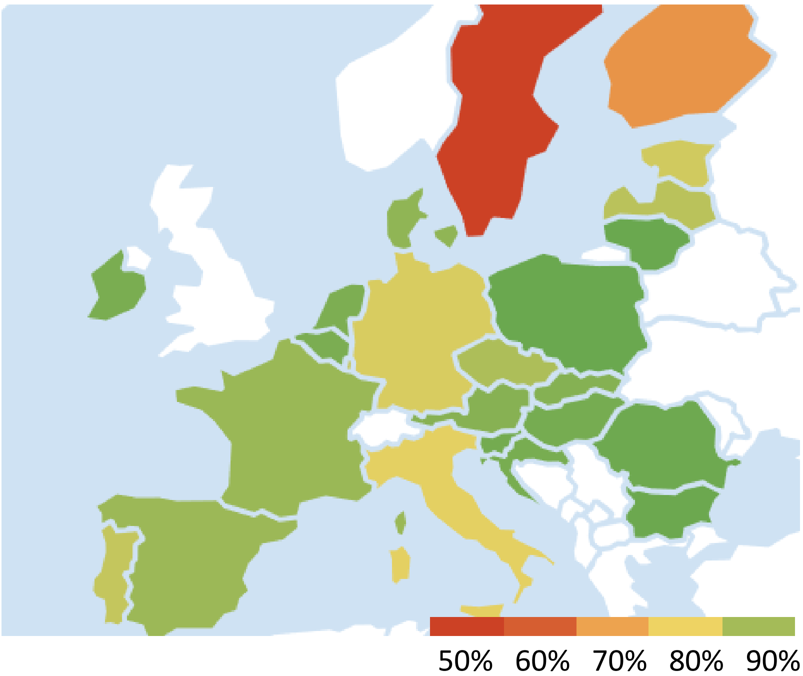


Figure 8-1: Daily demand and biomethane injection on distribution networks by 2030 in NUTS1 zone DE8

The injection margin, defined as $((demand) - Injection)/Min\ (demand)$, was calculated for each NUTS1 zone. An injection margin of 80% means that injection can be increased by 80% without identifying a need for reverse-flows (at the NUTS1 level and under the given assumptions). A negative injection margin indicates that reverse-flow or other remedial measures are required. For instance, in the NUTS1 zone DE8, the injection margin is 17%, which means that the daily biomethane injection reaches 83% of the minimum daily demand in the year. **Figure 8-2** illustrates the capacity margins aggregated at the MS level (average[249] of the margin of all national NUTS1 zones) and the capacity margin in the most critical NUTS1 zones (excluding Sweden and Malta[250]).

[249] Average weighted according to the production of each NUTS1 zone.

[250] Sweden and Malta have been excluded from the table due to very specific gas network structures and low gas demand on gas networks. In Sweden, an important share of gas is not distributed through the network but by truck and directly used in the transport sector.



NUTS1	Injection margin
DE8	17%
FI2	48%
DE4	61%
ITG	77%
ITF	79%
SE1	80%
DE9	80%
ITH	81%
DED	82%
DEE	83%
ITI	83%

Figure 8-2: Capacity margin at the MS level (average of the margin of all national NUTS1 zones) [left] and capacity margin in the most critical NUTS1 zones (excluding Sweden & Malta) [right]. Source: own calculations.

This assessment revealed no major need for reverse-flows by 2030. In all of the NUTS1 zones, the biomethane injection remains lower than the minimum gas demand.

However, this approach may underestimate the actual need for reverse flow due to the low geographical granularity used. Actually, NUTS1 zones may contain more than one distribution network. Thus, the assessment at the NUTS1 level tends to level out local oversupply in individual distribution grids (especially in rural areas). The result of the assessment is however in line with other recent studies[251].

8.1.2 Comparison of Renewable Energy Communities and Citizen Energy Communities

Table 8-3 gives an overview of the major differences between Renewable Energy Communities[252] and Citizen Energy Communities[253]. Provisions that highlight more restrictive aspects for RECs than for CECs are framed in red.

[251] See for instance (Trinomics, LBST, 2020)

[252] (European Commission, 2018b)

[253] (European Commission, 2019c)

Table 8-3: Major differences between RECs and CECs, and associated provisions' references

RECs		CECs	
Cover all renewable energy sources: entitled to "produce, consume, store and sell renewable energy", and to "access all suitable energy market"	22(2a) 22(2b)	Can operate both renewable and *fossil-fuel based* projects "including from renewable sources"	2(11c) 16(3a)
Restricted to *renewable* energy, may include renewable *gas*		Restricted to electricity: "access all electricity markets"	
"natural persons, SMEs or local authorities, including municipalities"	2(16b)	"natural persons, local authorities, including municipalities, or small enterprises"	2(11a)
"for private undertakings, their participation does not constitute their primary commercial or professional activity"	22(1)	[no restriction on private undertakings]	
"produce, consume, store and sell renewable energy"	22(2a)	"generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services"	2(11c)
"relevant distribution system operator cooperates with renewable energy communities"	22(4c)	"own, establish, purchase or lease distribution networks and to autonomously manage them" "are subject to the exemptions provided for in Article 38(2) [closed distribution systems]" "MSs may decide to grant CECs the right to manage distribution networks in their area of operation […]"	16(2b) 16(2c) 16(4)
[-]		"are financially responsible for the imbalances they cause in the electricity system"	16(3c)
"shall be part of the updates of the Member States' integrated national energy and climate plans and progress reports"	22(5)	[-]	
"located in the proximity of the renewable energy projects" "should be open to all potential local members"	2(16a) (71)	"Electricity sharing enables members or shareholders to be supplied with electricity from generating installations within the community without being in direct physical proximity to the generating installation and without being behind a single metering point."	(46)

8.2 Description of biomethane potentials and cost estimations

8.2.1 Quantification of long-term biomethane potentials

8.2.1.1 Methodology and assumptions

Availability of substrates at the country level

A sustainable residue-focused biomass potential is considered according to a European dataset on substrate-specific potentials available at Fraunhofer IEE and own assumptions on conversion pathways. The data are based on three studies from the JRC[254], BiomassFutures[255] and S2BIOM cost supply[256]. While these three studies represent a robust data basis for biomethane from anaerobic digestion with focus on residues, there is a larger uncertainty for the level of straw utilization, sequential cropping, and wood gasification. Due to the uncertainties, sensitivities were developed. These three sources may result in higher biomethane volumes being produced. The upper limit of the potential is aligned with the Navigant study[257] on behalf of the European natural gas industry.

The first study (JRC) is used for all manure potentials. The second study (Biomass Futures) is used for other substrates for anaerobic biomethane production. Used fats and oils are not considered for biogas or biomethane production as they are assumed to be used for biofuel production.

For straw, there is uncertainty as to how large the sustainable energetic potential is (see UBA-RESCUE study[258]) and it competes with biofuel use (ethanol). A sensitivity of the overall potential is calculated to consider a low or high straw potential. In the Navigant study, with reference to the work of the Italian Biogas Association, the use of sequential cropping as cultivated biomass is propagated (e.g. cereal-based whole-plant silage) with a focus on southern Europe. Here the question arises to what extent this potential is

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[254] Scarlat, Nicolae; Fahl, Fernando; Dallemand, Jean-François; Monforti, Fabio; Motola, Vicenzo (2018): A spatial analysis of biogas potential from manure in Europe. In: Renewable and Sustainable Energy Reviews 94, S. 915–930. DOI: 10.1016/j.rser.2018.06.035.

[255] Elbersen, B. S., Staritsky, I. G., Hengeveld, G. M., Schelhaas, M. J., Naeff, H. S. D., & Böttcher, H. (2012): Spatially detailed and quantified overview of EU biomass potential taking into account the main criteria determining biomass availability from different sources. Atlas of EU biomass potentials (IEE 08653 S12.529 241). Online available at https://research.wur.nl/en/publications/atlas-of-eu-biomass-potentials-spatially-detailed-and-quantified-, last approved 15-04-2021.

[256] Dees M., Höhl M., Datta P., Forsell N., Leduc S., Fitzgerald J., Verkerk H., Zudin S., Lindner M., Elbersen B., Staritsky I., Schrijver R., Lesschen J.-P., van Diepen K., Anttila P., Prinz R., Ramirez-Almeyda J., Monti A., Vis M., Garcia Galindo D., Glavonjic B. (2017): Delivery of sustainable supply of non-food biomass to support a "resource-efficient" Bioeconomy in Europe.

[257] Navigant (2019): Gas for Climate - The optimal role for gas in a net-zero emissions energy system.

[258] https://www.umweltbundesamt.de/sites/default/files/medien/376/publikationen/rescue_studie_cc_36-2019_wege_in_eine_ressourcenschonende_treibhausgasneutralitaet.pdf. Differences in straw potential may occur due to different crop shares, yield increases, the share of organic farming, or increased straw-based animal husbandry. Despite many years of research, it has not been conclusively clarified how straw removal affects soil biodiversity, so uncertainties remain. For example, excessive straw removal can lead to reduced humus content in the field, which is why the humus balance must be taken into account when calculating straw potential for energy use. It should be noted here that there are still uncertainties in the calculation of straw potentials with regard to regional factors, future humus build-up targets and soil fauna.

sustainable (additional soil tillage and chemical crop protection, impairment of the water balance). This uncertainty is also captured via sensitivity. In a simplified way, other data on rural biomethane potentials is used with a weighting between northern, central and southern countries to arrive at a relative distribution of the complementary sequential cropping potential among the countries. In total, with more straw or with sequential cropping, the total potential matches the pan-European potential from the Navigant study (as an average between with and without on-site electricity generation from manure and slurry since Navigant has not assumed any potential for on-site electricity generation at all).

The third study (S2Biom) is used for all lignocellulosic biomass potentials. This potential is by far the largest. These can be used either as materials or for heat production or can be gasified. For modelling purposes, this potential is only used proportionally for the relative country distribution of biomass potentials for thermal gasification and thus biomethane SNG production. The absolute amount of biomethane production in Europe is based on the study by Navigant.

The development of sewage gas and landfill gas builds on historical data from Eurostat[259]. Historical biogas production and biomethane production as starting points for interpolation to sustainable long-term potential.

Substrate allocation to biomethane and biogas technologies

All substrates mentioned above could be used to produce biogas and biomethane (as the first step of biomethane production is biogas production). In this assessment an allocation of substrates between biomethane and biogas technologies has been performed (cf. Table 8-4), based on the fact that biomethane plants are generally larger than biogas plants.

Thus, manure potentials are assumed to be directly converted into electricity and heat on-site in small plants, as this substrate not being worthy of transport. Methane emissions from digestate storage are avoided by covering.

Sewage and landfill gas plants are nowadays often on-site electricity generation plants and are considered functioning as biomethane plants in the long term.

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[259] Eurostat (2021): Renewables and waste supply, conversion and consumption; [NRG_CB_RW__custom_779400].

Table 8-4: Allocation of substrates to biomethane and biogas technologies.

Technology	Substrates
Biogas - on-site power and heat generation	- Manure; - Phasing out existing plants: o Corn; o Sewage gas, landfill gas.
Biomethane Anaerobic digestion - rural residues	- Straw; - Grass cuttings abandoned grassland; - Animal waste.
Biomethane Anaerobic digestion - rural cultivation	- Perennials: grassy; - Sequential cropping; - Phasing out existing plants: corn.
Biomethane Anaerobic digestion - urban	- Common sludge; - Sewage gas; - MSW (not landfill, composting, recycling); - Verge grass.
Biomethane – thermal gasification	- Stem wood from thinning and final fellings; - Logging residues from final fellings (tops and branches mainly); - Stumps from final fellings.

The allocation of substrates to different technologies represents a simplification of practice. In reality, manure that is attributed to on-site biogas production is also partly used in large plants that feed biomethane into the gas grid. On the other hand, it can be assumed that existing plants with cultivated biomass will also generate electricity and heat on-site in the long term due to existing rural heating networks. Sewage and landfill gas plants are nowadays often run as on-site electricity generation plants whereas they are assumed to operate as biomethane plants in the long term. Since these effects balance each other out, it is assumed that the allocation of substrates is robust and adequate for the long-term estimate of potentials. The identified potentials are considered to be sustainable, at least when applying the more conservative estimate on straw and sequential cropping. Box 8-1 gives a short overview of the sustainability criteria under RED II which also apply to biogas and biomethane.

Box 8-1: Classification of the sustainability criteria under RED II

Classification of the sustainability criteria under RED II

Criteria for biogas can be found in the Annex VI to RED II (Renewable Energy Directive). Annex VI regulates the calculation of biomass fuels and provides partial standard and standard values:

- Default values for biogas and biomethane from manure, bio-waste and manure, as well as mixed;
- Default values for biogas from corn & manure (mixing ratios manure/maize = 80/20, 70/30, 60/40);
- Credit for avoided methane emissions;
- Credit for fertiliser effect fermentation product.

As described earlier, the plants with on-site electricity generation have a focus on liquid manure and avoidance of methane emissions. For biomethane, the gas network and its seasonal storage capacity ensure very efficient the use in terms of both space and time. This also ensures a corresponding reduction in greenhouse gas emissions. In terms of substrates, the focus is set on residual materials and grass land (which becomes available for energy use by reducing meat consumption). Corn in transition or sequential cropping in the long-term only take up a small share of the substrate mix.

For the energetic use of wood, the focus of RED II is placed on residual wood that does not compete with material use. For stem wood, the focus is on the diameter. Our potential assumes only small-diameter stem wood for energy use. Nevertheless, the total potential of solid biomass in Europe is significantly higher than the demand for thermal gasification. Accordingly, there is a degree of freedom in the selection of substrates.

Disaggregation at NUTS1 level

CORINE land cover[260] and population projection data[261] are used to regionalise substrate-specific potentials from the country level to the NUTS1 level. The mapping between the type of potentials and the geographic layer used as disaggregation keys to regionalise potentials is shown in Table 8-5.

[260] https://www.eea.europa.eu/publications/COR0-landcover

[261] https://ec.europa.eu/eurostat/de/web/products-datasets/product?code=proj_19rp3

Table 8-5: Geographic layers used as disaggregation keys to regionalize biomethane and biogas potentials.

Type of potential	Geographic layer
- Biomethane - rural cultivation - Biomethane - rural residues - Biogas used on-site	- Non-irrigated arable land - Permanently irrigated land
- Thermal gasification	- Broad-leaved forest - Coniferous forest - Mixed forest
- Biomethane – urban	- Population projection[261]

8.2.1.2 Potentials at country level

Landfill gas

Landfill gas potentials are heterogeneous across Europe, as waste treatment techniques vary across Member States. There are countries without landfills, countries with proportionate incineration and proportionate landfill, countries with a high proportion of mechanical-biological plants for the pre-treatment of mixed waste (the aim is to reduce the biological activity of the organic fraction in household waste to such an extent that as little landfill gas as possible is produced). By 2035, landfilling of municipal waste generally is expected to be limited to 10% in Europe, and waste treatment will mainly rely on waste incineration and mechanical-biological waste treatment (biogas) but no more landfilling.

Based on historical data, gas volumes are extrapolated to 2050, assuming that landfill gas continues to decline and is therefore not available for biomethane production.

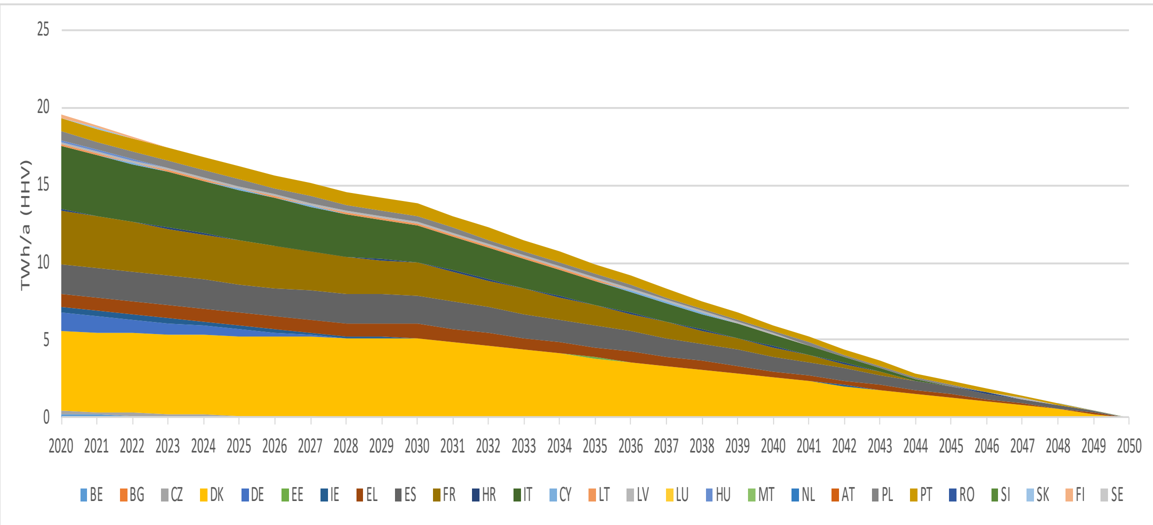

Figure 8-3: Development of landfill gas production in EU27, 2020-2050. Source: own calculations.

Sewage gas

Sewage gas production is currently implemented with varying intensity in Europe. Historical data was used and updated, assuming a comparable penetration in relation to population expectations in 2050, which will establish itself in the long term at the high level of countries that have already implemented sewage gas intensively today.

In 2020, sewage gas is part of biogas on-site electricity and heat generation. In the year 2050, sewage gas is assumed to be used at 100% for biomethane production. This builds upon the hypothesis that in the long term the incentives for generating electricity for on-site consumption will be lower and that the sewage treatment plants can therefore be supplied with electricity from external sources and the heat can be provided efficiently via heat pumps. A higher proportion of the plants are large plants and the gas infrastructure for the feed-in of biomethane is available. However, as described above, this is an approximation.

So, in 2020, sewage gas is entirely assigned to on-site electricity generation. In the years 2030/2040 a linear interpolation takes place. As already discussed, the separation of on-site electricity generation to substrates shows a certain fuzziness.

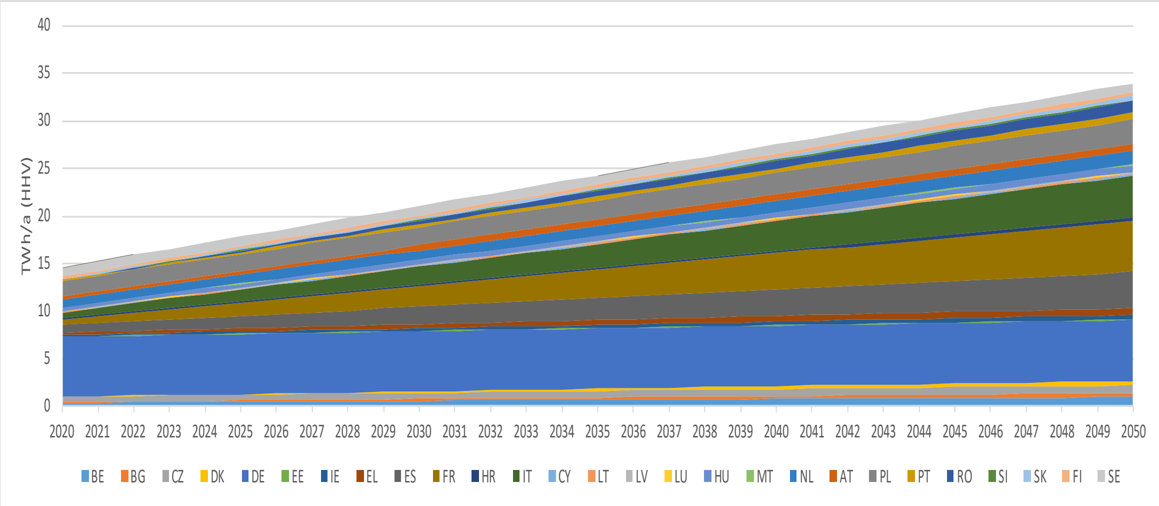

Figure 8-4: Development of sewage gas production in EU27, 2020-2050. Source: own calculation.

Total potentials

Figure 8-5 illustrates the resulting potential in 2050 with sewage gas of the maximum potential on a country level for the most sustainable scenario (no catch crops, less straw).

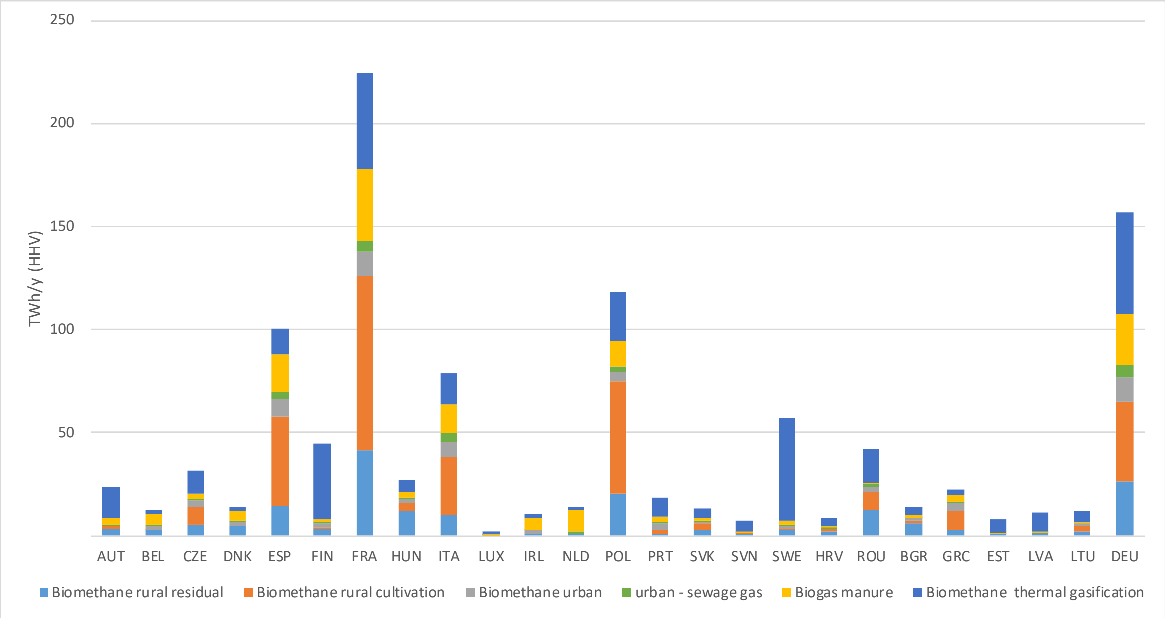

Figure 8-5: Potential 2050, EU27, without sequential cropping and less straw, with sewage gas. Source: own calculations.

8.2.1.3 Evolution of potentials at EU27 level

Figure 8-6 shows the aggregated development for Europe for the most sustainable scenario (no catch crops, less straw) incl. sewage and landfill gas. This leads to 1074 TWh/y (HHV) of biogas by 2050, including 919 TWh/y of biomethane. By 2030, however, potentials only equal 428 TWh/y (HHV) of biogas, including 259 TWh/y of biomethane.

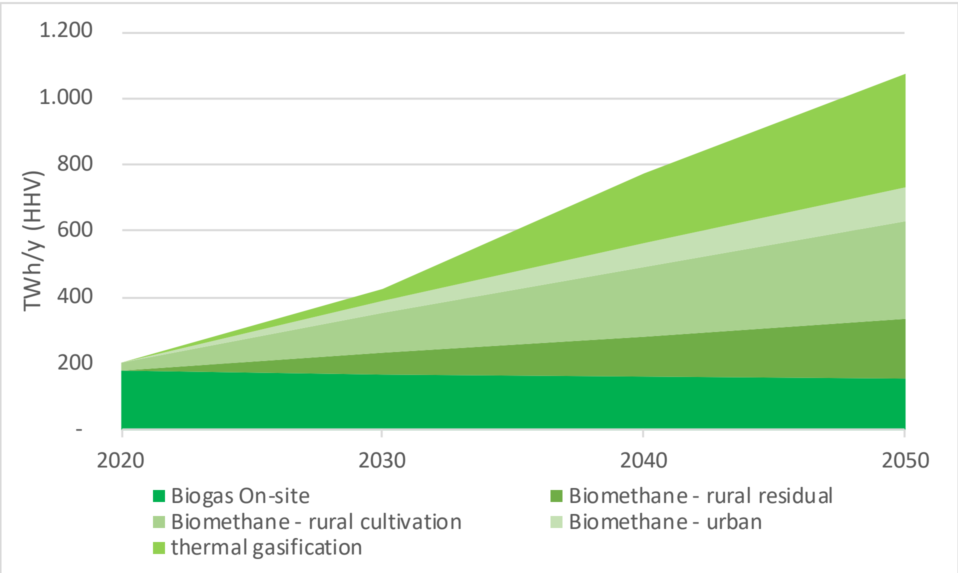

Figure 8-6: Path to 2050, EU27, without sequential cropping and less straw. Source: own calculations.

The assumptions on thermal gasification and biogas on-site electricity generation do not vary between sensitivities. Therefore, the difference in biomethane from anaerobic digestion is shown in Figure 8-7. The most sustainable scenario (no catch crops, less straw) leads to 577 TWh/y of biomethane from anaerobic digestion in 2050 and 220 TWh/y in 2030.

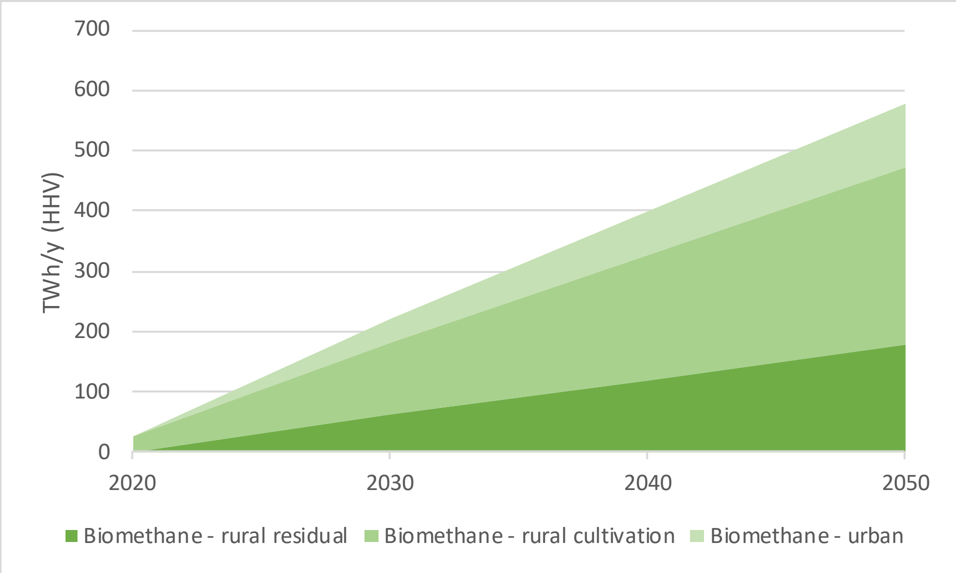

Figure 8-7: Path to 2050, EU27, only biomethane from anaerobic digestion, without sequential cropping and less straw. Source: own calculations.

With sequential cropping, potentials reach 671 TWh/y (+94 TWh/y) in 2050 biomethane from anaerobic digestion and 253 TWh/y (+33 TWh/y) in 2030 (cf. Figure 8-8).

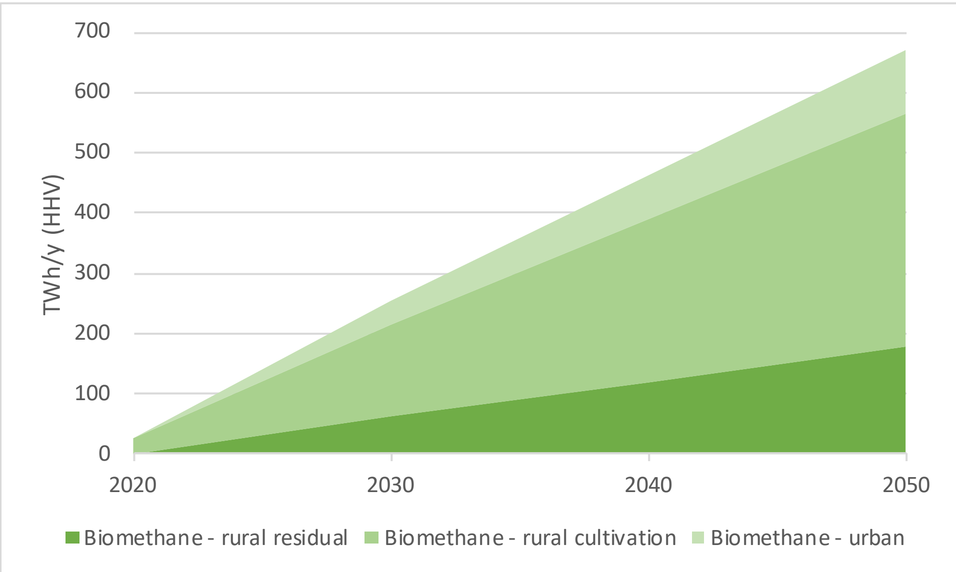

Figure 8-8: Path to 2050, EU27, only biomethane from anaerobic digestion, with sequential cropping and less straw. Source: own calculations.

With more straw instead but no sequential cropping, potentials reach 654 TWh (+77 TWh), but with a different distribution of residues and cultivated biomass and with a different distribution between countries. In 2030, potentials equal 252 TWh (+32 TWh) (cf. Figure 8-9).

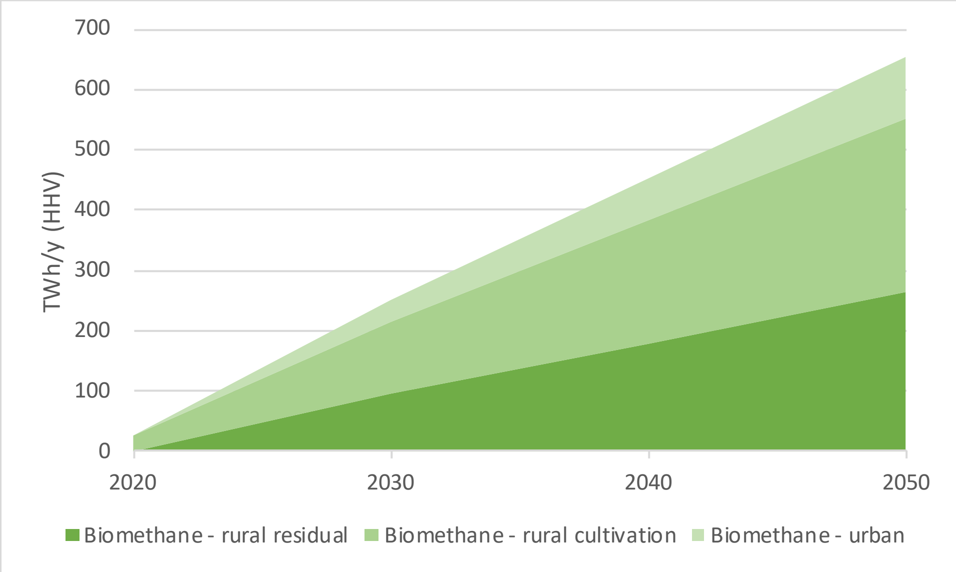

Figure 8-9: Path to 2050, EU27, only biomethane from anaerobic digestion, without sequential cropping and more straw. Source: own calculations.

8.2.2 Biomethane production costs

8.2.2.1 Methodology and assumptions

Specific assumptions for thermal gasification

Production costs of biomethane from thermal gasification rely on the Navigant study[262]: "Thermal gasification costs of €88/MWh represent the costs for the Gothenburg Biomass Gasification (GoBiGas) project, where a first-of-its-kind demonstration plant to produce 20 MW biomethane was commissioned in 2013. These are social costs calculated using a discount rate of 5%. The feedstock costs for today are estimated using the 2050 feedstock mix. The major difference in today's production costs and the costs from 2050 are increased energy conversion efficiency (from 65% to 75%), economies of scale benefits and deployment of multiple plants which result in increased plant reliability, better understanding of technology risks, and high operability. The production costs of €47/MWh for 2050 are estimated against a plant size of 200 MW_{th}."

For thermal gasification, the cost assumptions from Navigant are adopted. The market ramp-up is based on the same study. No major cost digression is expected until 2030, as the market ramp-up is not yet ready and further technological developments are necessary. It is thus assumed that the LCOE of biomethane from thermal gasification equals 80 €/MWh in 2030.

Assumptions on grid connection and injection

In Europe, the distance from rural biomethane plants (local substrate supply) to gas grids for injection is very heterogeneous. Accordingly, longer or shorter distances have to be bridged by building raw biogas pipelines.

For this additional transport cost, we refer to the Navigant study: "The raw biogas is transported to the upgrading unit via inexpensive PVC pipes (€200,000/km) at relatively

[262] Navigant (2019): Gas for Climate - The optimal role for gas in a net-zero emissions energy system.

low pressure (8 bar). The average distance between a digester and the upgrading facility is assumed to be 9 km." At locations further than 15 kilometres away from gas grids, the costs of connecting plant to existing gas grids increase significantly and it may become cost-efficient to produce bio-LNG onsite and transport this to either existing gas grids or to fuelling stations by truck. Navigant concludes that "on-farm liquefaction is possible at a cost of €12/MWh in addition to biomethane production costs of €57/MWh. This leads to a total bio-LNG cost of €69/MWh by 2050."

However, LNG plants also require the concentration of multiple biogas plants via raw biogas pipelines into one LNG plant. Here we assume an additional length of 8 km. This results in a cost of 7.3 €/MWh PVC pipe and 12 €/MWh LNG, which equals 19.3 €/MWh. (PCV lines have an annuity cost of 19,190 €/km/a.)

Using the ratio of length of gas transmission network and agricultural area at NUTS1 level, a connection cost proxy may be determined for all NUTS1 regions in Europe (cf. Table 8-6). Based on this ratio, the NUTS1 regions of Europe were assigned to 4 classes (linear between max. and min. values). Similarly, the costs between minimum (0 km distance of biogas plants) and maximum (LNG case) were approximately linearly divided into 2 other cases. Due to a lack of data, this is an approximate solution which allows a meaningful differentiation within Europe. This indicator allows a rough classification of the additional connection costs as a function of the connection length. We assume that the processing plants are always located in the immediate vicinity of the gas grid.

Table 8-6: Assumptions for connection length and costs.

Parameter	Probable distance	Connection cost
1 (dense gas network)	0 km raw biogas pipeline	0 €/MWh biomethane
2 (medium gas network)	8 km raw biogas pipeline	7 €/MWh biomethane
3 (low gas network)	14.5 km raw biogas pipeline	12 €/MWh biomethane
4 (no gas network at NUTS1 region)	21 km → Bio-LNG	19 €/MWh biomethane

Feedstock assumptions

For the quantification of biomethane LCOE, two scenarios following two feedstock-type-ratios for biogas plants using agricultural substrates are defined:

- No sequential cropping, less straw
- Sequential cropping, less straw

Table 8-7 shows the energetic feedstock ratios of these two archetypical agricultural biogas plant types.

Table 8-7: Energetic feedstock ratios of two archetypical agricultural biogas plant types.

	no sequentiel cropping, less straw	sequentiel cropping, less straw
maize silage	12%	10%
straw	29%	25%
grass silage	53%	45%
grain silage		15%
others	6%	5%
liquid manure (cattle)	3%	2.5%
manure (cattle)	3%	2.5%
Sum	100%	100%

Based on this, six different plant types are defined. Table 8-8 shows these six biogas plant types and their mass-related feedstock compositions.

Table 8-8: Mass related feedstock ratios of 6 biogas plant types. Source: own calculations.

	biogas plant raw gas capacity →	**250 m³/h**	**250 m³/h**	**500 m³/h**	**500 m³/h**	**250 m³/h**	**400 m³/h**
feedstock type ↓	**plant type →** **feedstock specification ↓**	**no sequentiel cropping, less straw**	**sequentiel cropping, less straw**	**no sequentiel cropping, less straw**	**sequentiel cropping, less straw**	**sewage sludge**	**bio-waste**
maize silage	maize silage, 35% DM	**10.1%**	**8.7%**	**10.1%**	**8.7%**		
straw	straw, finely chopped, 86% DM	**17.1%**	**15.1%**	**17.1%**	**15.1%**		
grass silage	grass silage, 35% DM	**50.3%**	**43.7%**	**50.3%**	**43.7%**		
grain silage	grain silage, 35% DM	**0.0%**	**13.4%**	**0.0%**	**13.4%**		
liquid manure (cattle)	liquid cattle manure with fodder rests, 10% DM	**17.0%**	**14.5%**	**17.0%**	**14.5%**		
manure (cattle)	cattle manure, 25% DM	**5.4%**	**4.6%**	**5.4%**	**4.6%**		
sewage sludge						100%	
bio-waste	40% DM						100%
Sum		100.0%	100.0%	100.0%	100.0%	100	

Costs for agricultural feedstocks for biogas production[263] are shown in Table 8-9.

[263] https://daten.ktbl.de/biogas/navigation.do?selectedAction=Startseite#start

Table 8-9: Costs for agricultural feedstocks.

Feedstock type	Plant type feedstock specification	Cost (€/t DM)
Maize silage	Maize silage, 35% DM	35
Straw	Straw, finely chopped, 86% DM	110
Grass silage	Grass silage, 35% DM	31
Grain silage	Grain silage, 35% DM	34
Others		
Liquid manure (cattle)	Liquid cattle manure with fodder rests, 10% DM	0
Manure (cattle)	Cattle manure, 25% DM	0

Related to the bio-waste feedstock costs, varying revenues between -20 €/t and 20 €/t have been considered.

Investment costs and technical parameters

Investment costs for all biogas plants are based on the cost calculator of KTBL[263]. Investment costs for BGUPs and BMIPs are based on Beil et al. (2019)[264] and additional data sets of Fraunhofer IEE.

With regard to the configuration of the BMIP, it must be emphasized that the technical configuration presented here is aligned with the system of separation of biogas upgrading and biomethane grid injection applied in Germany.

For the pressure level of the gas grid in which biomethane is injected directly, 16 bar had been chosen. On the one hand this is a typical pressure level for biomethane grid injection at least in Germany. On the other hand, this enables to avoid a post compression if using a membrane system for biogas upgrading.

The plant availability was assumed at 96%[265].

As reference biogas upgrading technology a membrane system was chosen. The methane loss from biogas upgrading was assumed to be 0.5% and specific electricity demand varies from 0.24-0.26 kWh/m³ of biogas depending on the plant capacity based on Beil et al. (2019) and additional IEE-data sets.

Process energy demands (for heat and electricity) for all biogas plants are based on KTBL[263]. The electricity demands for the BMIPs are based on Beil et al. (2019) and additional IEE-data sets.

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[264] Beil, M.; Beyrich, W.; Kasten, J.; Krautkremer, B.; Daniel-Gromke, J.; Denysenko, V.; Rensberg, N.; Schmalfuß, T.; Erdmann, G.; Jacobs, B.; Müller-Syring, G.; Erler, R.; Hüttenrauch, J.; Schumann, E.; König, J.; Jakob, S.; Edel, M. (2019): Schlussbericht zum Vorhaben „Effiziente Mikro-Biogasaufbereitungsanlagen (eMikroBGAA)".

[265] Assumption in line with the German Gas Grid Access Ordinance.

Moreover, no post-compression of biomethane is included in the typical plant assessed here, due to using membrane-BGUP (with an output pressure higher than the injection grid pressure). Conditioning is not included in the assessment either (LPG-addition).

For sewage gas, a biogas cost of 0 ct/kWh is assumed, as sewage gas itself is related to the wastewater treatment plant. Therefore, only the upgrading and connection costs are considered for biomethane produced from sewage gas.

Other assumptions

The annuity method used for following cost calculations is based on VDI information[266,267]. Other relevant parameter values are listed in Table 8-10.

Table 8-10: List of parameter description.

Parameter	Value	Unit	Comment
Related year start of operation	2020		fixed
Total returns to capital	5	%	default
Price increase (incl. Energy)	2%	%/y	assumption
Period	20	y	default
Maintenance factor	2	%/y x invest	assumption
Planning and permission	10	% x invest	assumption
Ancillary construction costs	5	% x invest	assumption
Overhead costs	1	%/variable costs	assumption
Service costs for biomethane upgrading plants	6	% x invest	assumption
Service costs for injection plants	4	% x invest	assumption[264]
Pressure level gas grid	16	bar	fixing
Costs electricity	8.2	ct/kWh	default
Costs heat	3.7	ct/kWh	default
Staff costs (average)	28	€/h	Destatis[268]
Staff costs BGP	21	€/h	assumption[269]
Staff costs BGUP/BMIP	35	€/h	assumption[269]
Activated carbon (impregnated)	5	€/kg	assumption
Activated carbon (non-impregnated)	2	€/kg	assumption
Diesel	0.8	€/l	KTBL[263]
Plant availability	96%		assumption
Methane loss BGUP	0.50%		assumption
RFCP operation time	3504	h/a	default

[266] VDI (2012): VDI 2067 Part 1 | Economic efficiency of building installations - Fundamentals and economic calculation.

[267] VDI (2012): VDI 6025 Economy calculation systems for capital goods and plants.

[268] https://www.destatis.de/DE/Presse/Pressemitteilungen/2021/05/PD21_203_624.html

[269] A discount of 25% was applied for personnel for the operation of the biogas plant (compared to the average) and a surcharge of 25% for the operation of GBUP and BMIP to reflect the different qualification level.

Pressure level upstream gas grid	40	bar	fixed

Land costs (building site) are not included, as the land is assumed to be already owned by the plant operator.

Expertise/certificate costs are not taken into account either due to country specific framework conditions and part of product sales outside system boundaries.

Finally, no reserves for deconstruction have been considered. In some MSs (e.g. in Germany), plants have to be deconstructed after operation. However, this may not be representative for all European MSs. Therefore, it is assumed that after the operation of the plant an alternative operation will be applied (e.g. for agricultural purposes).

8.2.2.2 Results

LCOE of combined biogas production, biogas upgrading and biomethane injection

Table 8-11 and Table 8-12 show the aggregated results of the cost calculation related to eight different plant types. Detailed results are shown in Table 8-13 to Table 8-18.

Table 8-11: LCOE biogas production, biogas upgrading and biomethane injection of 4 different plant types using agricultural feedstocks. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		250 m³/h		500 m³/h		500 m³/h	
BGP type →	no sequentiel cropping, less straw		sequentiel cropping, less straw		no sequentiel cropping, less straw		sequentiel cropping, less straw	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	322,064 €	2.6	319,157 €	2.6	483,585 €	2.0	477,605 €	**2.0**
annuity demand-related costs	689,860 €	5.6	672,555 €	5.5	1,331,039 €	5.4	1,298,309 €	**5.3**
annuity operation-related costs	270,538 €	2.2	269,535 €	2.2	372,086 €	1.5	370,033 €	**1.5**
annuity other costs	20,536 €	0.2	20,350 €	0.2	30,835 €	0.1	30,453 €	**0.1**
sum	**1,302,998 €**	**10.6**	**1,281,597 €**	**10.5**	**2,217,545 €**	**9.1**	**2,176,401 €**	**8.9**

Table 8-12: LCOE biogas production, biogas upgrading and biomethane injection of one sewage gas plant and one bio-waste plant with varying feedstock costs. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		400 m³/h		400 m³/h		400 m³/h	
BGP type →	sewage sludge		bio-waste -20 €/t_{FM}		bio-waste 0 €/t_{FM}		bio-waste 20 €/t_{FM}	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	180,454 €	**1.2**	449,190 €	**2.0**	449,190 €	**2.0**	449,190 €	**2.0**
annuity demand-related costs	79,371 €	**0.5**	-424,243 €	**-1.9**	247,940 €	**1.1**	920,122 €	**4.1**
annuity operation-related costs	182,345 €	**1.2**	357,085 €	**1.6**	357,085 €	**1.6**	357,085 €	**1.6**
annuity other costs	11,506 €	**0.1**	28,642 €	**0.1**	28,642 €	**0.1**	28,642 €	**0.1**
sum	**453,676 €**	**3.0**	**410,674 €**	**1.8**	**1,082,856 €**	**4.9**	**1,755,039 €**	**7.9**

Table 8-13: LCOE biogas production of 4 different plant types using agricultural feedstocks. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		250 m³/h		500 m³/h		500 m³/h	
BGP type →	no sequentiel cropping, less straw		sequentiel cropping, less straw		no sequentiel cropping, less straw		sequentiel cropping, less straw	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	141,610 €	1.2	138,703 €	1.1	267,216 €	1.1	261,236 €	**1.1**
annuity demand-related costs	611,614 €	5.0	594,309 €	4.9	1,194,391 €	4.9	1,161,662 €	**4.7**
annuity operation-related costs	88,194 €	0.7	87,190 €	0.7	153,101 €	0.6	151,048 €	**0.6**
annuity other costs	9,029 €	0.1	8,844 €	0.1	17,038 €	0.1	16,657 €	**0.1**
sum	**850,447 €**	**6.9**	**829,046 €**	**6.8**	**1,631,747 €**	**6.7**	**1,590,603 €**	**6.5**

Table 8-14: LCOE biogas upgrading of 4 different plant types using agricultural feedstocks. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		250 m³/h		500 m³/h		500 m³/h	
BGP type →	no sequentiel cropping, less straw		sequentiel cropping, less straw		no sequentiel cropping, less straw		sequentiel cropping, less straw	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	89,437 €	0.7	89,437 €	0.7	125,352 €	0.5	125,352 €	**0.5**
annuity demand-related costs	55,776 €	0.5	55,776 €	0.5	111,553 €	0.5	111,553 €	**0.5**
annuity operation-related costs	106,277 €	0.9	106,277 €	0.9	142,918 €	0.6	142,918 €	**0.6**
annuity other costs	5,703 €	0.0	5,703 €	0.0	7,993 €	0.0	7,993 €	**0.0**
sum	**257,194 €**	**2.1**	**257,194 €**	**2.1**	**387,816 €**	**1.6**	**387,816 €**	**1.6**

Table 8-15: LCOE biomethane injection of 4 different plant types using agricultural feedstocks. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		250 m³/h		500 m³/h		500 m³/h	
BGP type →	no sequentiel cropping, less straw		sequentiel cropping, less straw		no sequentiel cropping, less straw		sequentiel cropping, less straw	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	91,017 €	0.7	91,017 €	0.7	91,017 €	0.4	91,017 €	**0.4**
annuity demand-related costs	22,470 €	0.2	22,470 €	0.2	25,094 €	0.1	25,094 €	**0.1**
annuity operation-related costs	76,067 €	0.6	76,067 €	0.6	76,067 €	0.3	76,067 €	**0.3**
annuity other costs	5,803 €	0.0	5,803 €	0.0	5,803 €	0.0	5,803 €	**0.0**
sum	**195,358 €**	**1.6**	**195,358 €**	**1.6**	**197,982 €**	**0.8**	**197,982 €**	**0.8**

Table 8-16: LCOE biogas production of one bio-waste plant with varying feedstock costs. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		400 m³/h		400 m³/h		400 m³/h	
BGP type →	sewage sludge		bio-waste -20 €/t_{FM}		bio-waste 0 €/t_{FM}		bio-waste 20 €/t_{FM}	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs			246,797 €	**1.1**	246,797 €	**1.1**	246,797 €	**1.1**
annuity demand-related costs			-557,521 €	**-2.5**	114,661 €	**0.5**	786,844 €	**3.5**
annuity operation-related costs			152,358 €	**0.7**	152,358 €	**0.7**	152,358 €	**0.7**
annuity other costs			15,736 €	**0.1**	15,736 €	**0.1**	15,736 €	**0.1**
sum			**-142,629 €**	**-0.6**	**529,553 €**	**2.4**	**1,201,735 €**	**5.4**

Table 8-17: LCOE biogas upgrading of one sewage gas plant and one bio-waste plant with varying feedstock costs. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		400 m³/h		400 m³/h		400 m³/h	
BGP type →	sewage sludge		bio-waste -20 €/t_{FM}		bio-waste 0 €/t_{FM}		bio-waste 20 €/t_{FM}	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	89,437 €	**0.6**	111,376 €	**0.5**	111,376 €	**0.5**	111,376 €	**0.5**
annuity demand-related costs	56,901 €	**0.4**	109,234 €	**0.5**	109,234 €	**0.5**	109,234 €	**0.5**
annuity operation-related costs	106,277 €	**0.7**	128,659 €	**0.6**	128,659 €	**0.6**	128,659 €	**0.6**
annuity other costs	5,703 €	**0.0**	7,102 €	**0.0**	7,102 €	**0.0**	7,102 €	**0.0**
sum	**258,318 €**	**1.7**	**356,371 €**	**1.6**	**356,371 €**	**1.6**	**356,371 €**	**1.6**

Table 8-18: LCOE biomethane injection of one sewage gas plant and one bio-waste plant with varying feedstock costs. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		400 m³/h		400 m³/h		400 m³/h	
BGP type →	sewage sludge		bio-waste -20 €/t_{FM}		bio-waste 0 €/t_{FM}		bio-waste 20 €/t_{FM}	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	91,017 €	**0.6**	91,017 €	**0.4**	91,017 €	**0.4**	91,017 €	**0.4**
annuity demand-related costs	22,470 €	**0.1**	24,045 €	**0.1**	24,045 €	**0.1**	24,045 €	**0.1**
annuity operation-related costs	76,067 €	**0.5**	76,067 €	**0.3**	76,067 €	**0.3**	76,067 €	**0.3**
annuity other costs	5,803 €	**0.0**	5,803 €	**0.0**	5,803 €	**0.0**	5,803 €	**0.0**
sum	**195,358 €**	**1.3**	**196,932 €**	**0.9**	**196,932 €**	**0.9**	**196,932 €**	**0.9**

LCOE of centralized biogas upgrading and biomethane injection

For two different plant capacities for centralized BGUP and BMIP results of cost calculations are shown in Table 8-19.

Compared to the plant models above, following calculation shows two different kinds of centralized biogas upgrading and biomethane injection plants. Such plant constellations can be operated, if raw biogas is produced at several smaller biogas plants and collected and transported by biogas pipelines to one bigger centralized site for upgrading and grid injection. It decreases specific costs for upgrading and grid injection significantly. But, the economic feasibility depends mainly on the distance to the single decentralized biogas production plants.

Table 8-19: LCOE biogas upgrading and biomethane injection of two centralized biogas upgrading and biomethane injection plants [IEE 2021].

biogas plant raw gas capacity →	500 m³/h		1000 m³/h	
BGP type →	centralized upgrading biogas (agricultural feedstocks)		centralized upgrading biogas (agricultural feedstocks)	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	216,369 €	**0.9**	278,454 €	**0.6**
annuity demand-related costs	136,647 €	**0.6**	237,056 €	**0.5**
annuity operation-related costs	218,985 €	**0.9**	282,325 €	**0.6**
annuity other costs	13,796 €	**0.1**	17,755 €	**0.0**
sum	**585,798 €**	**2.4**	**815,590 €**	**1.7**

Valorisation of digestate as a fertilizer

For biomethane, Navigant (2019)[270] indicates a cost reduction due to the valorisation of biogas digestate as a fertilizer, leading to a weighted average reduction in the LCOE of €20/MWh.

In practice, however, the replacement of synthetic fertilizer (e.g. ammonia) with biogas slurry is more than compensated for by the additional costs of transport. It is true that with the future production of green ammonia (power-to-ammonia), higher fertilizer costs can be expected. On the other hand, biomethane plants are often larger than existing biogas plants, which increases the transport distance. Therefore, it is not considered justified to assume a cost credit here.

8.2.3 Cost aspects of reverse flow compression

8.2.3.1 Methodology and assumptions

For reverse flow compression, it has been assumed that it is integrated in an already available gas transfer station.

[270] Navigant (2019): Gas for Climate - The optimal role for gas in a net-zero emissions energy system.

Furthermore, the following costs do not include a potentially required deodorization, oxygen removal or post drying system. This approach avoids any redundancy.

All the general assumptions (financial assumption, electricity and personnel costs, planning and permission costs and ancillary construction costs, overhead costs, insurance costs etc.) are the same as described above

Investment costs rely on Mischner et al. (2013)[271] and are adapted to reflect a commissioning in 2020.

Maintenance costs are supposed to equal 2%/y of the investment, which should cover also potential replacements of investment. For service costs, a factor of 4%/y related to the investment was used.

For the related pressure level of the upstream gas grid, 40 bar was considered to be able to use a lower pressure level of a transmission system.

The operation time of the reverse flow compression station had been defined at 3504 h/y (cf. Section 4.1.2.4).

8.2.3.2 Results

The resulting specific costs shown in Table 8-20 are not related to the amount of gas that is recompressed inside the RFCP but to the overall biomethane amount that is produced at each specific biogas upgrading plant.

Table 8-20: LCOE biomethane reverse flow compression from a 16 bar to a 40 bar grid. Source: own calculations.

biogas plant raw gas capacity →	250 m³/h		250 m³/h		500 m³/h		500 m³/h	
BGP type →	no sequentiel cropping, less straw		sequentiel cropping, less straw		no sequentiel cropping, less straw		sequentiel cropping, less straw	
BGUP type →	Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure		Membrane separation 16 bar BM pressure	
BGIP type →	MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies		MOP 16 bar grid, odorization, no compression, no redundancies	
RFCP type →	post compression 16 to 40 bar (without deodorization, oxygen separation and additional drying)		post compression 16 to 40 bar (without deodorization, oxygen separation and additional drying)		post compression 16 to 40 bar (without deodorization, oxygen separation and additional		post compression 16 to 40 bar (without deodorization, oxygen separation and additional	
	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)	€	ct/kWh(Hs)
annuity capital-related costs	42,379 €	0.3	42,379 €	0.3	43,176 €	0.2	43,176 €	0.2
annuity demand-related costs	10,264 €	0.1	10,264 €	0.1	12,655 €	0.1	12,655 €	0.1
annuity operation-related costs	34,568 €	0.3	34,568 €	0.3	35,178 €	0.1	35,178 €	0.1
annuity other costs	2,702 €	0.0	2,702 €	0.0	2,753 €	0.0	2,753 €	0.0
sum	**89,913 €**	**0.7**	**89,913 €**	**0.7**	**93,763 €**	**0.4**	**93,763 €**	**0.4**

8.2.4 Capacity enhancing measures

Capacity enhancing measures become relevant when the biomethane volume flow exceeds the capacity of the gas network into which biomethane is injected. Due to the network buffer inside the gas network, the demand for capacity enhancing measures is not an exclusive function between biomethane volume flow and minimum exit volume flow in a network section. They become necessary when the withdrawal volume flow in

[271] Mischner, J.; Braune, V.; Dornack, C. (2013): Zur Wahl eines wirtschaftlich optimalen Verdichters für Biogaseinspeiseanlagen, Teil 1. Gwf-Gas | Erdgas, Juli/August 2013, S. 518 – 531.

a network section falls below the biomethane injection volume flow and the maximum operating pressure of the gas network is reached (see also Section 8.1.1 in this regard).

Furthermore, the need for the implementation of capacity enhancing measures depends within a regulated system on the political intention: Should all produced biomethane be injected or should it also be accepted that the biomethane capacity will not be injected completely (but used locally for power/heat generation or flared) avoiding potential costs for capacity enhancing measures.

Figure 8-10 shows the standard case of biomethane injection without any capacity enhancing measures.

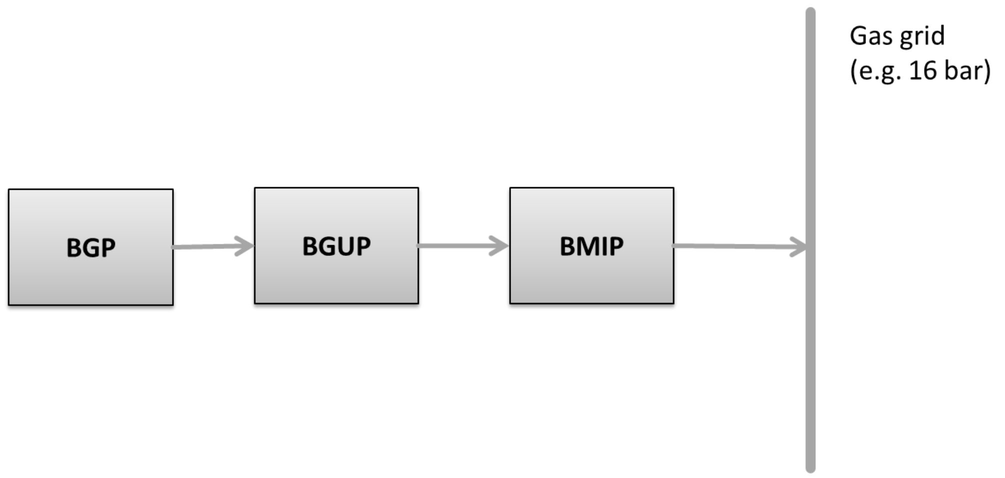

Figure 8-10: Standard case of biomethane injection without capacity enhancing measures. Source: own illustration based on Beil et al. (2019).

The following sub-chapters describe capacity enhancing options inside gas networks as well as alternatives to avoid such measures.

8.2.4.1 Capacity enhancing measures inside gas networks

This section describes possibilities of capacity enhancing measures inside gas networks.

For each option, advantages and disadvantages for relevant parameters are presented in a tabular form:

- "Feasibility" means the applicability of this option from a technical point of view.
- "Additional compression" means the need for an additional pressure increase of the gas quantity for which a capacity-expanding measure is necessary, to a higher-pressure level than that of the network into which gas is regularly fed.
- "Additional pipes" means the need to construct additional pipelines over distances greater than a few meters.
- "Deodorization" means the need to remove the odorant.
- "O2-removal" means the need to significantly reduce the oxygen content.
- "Additional drying" means the need for additional drying of the gas.
- "Biomethane conditioning" means the calorific value adjustment of the already upgraded biomethane, e.g. using a higher calorific gas such as LPG.

Reverse flow compression

The reverse flow compression into networks of higher pressure levels is one of the most relevant capacity-enhancing measures. Within a survey addressed to German biomethane injection plant operators 23 of 144 (≙ 16%) applied a reverse compression as capacity enhancing measure[272]. Depending on the biomethane-feed-in network pressure level, this reverse flow compression can take place into a higher-pressure level of the distribution network (e.g. 4 bar → 16 bar) or the transport network (e.g. 16 bar → 40 bar).

The lower the pressure difference between both grids, the lower also CAPEX as well as OPEX (mainly electricity) of this reverse flow compression station will occur. Depending on each specific local constellation, the gas to be compressed will be a mixture of natural gas and biomethane. As long as this reverse flow takes place between two distribution grids, no further gas cleaning measures are required. If there is the demand to inject the gas into the transmission grid, several gas cleaning measures can become necessary, such as deodorization, removal of oxygen and potentially additional drying. This measure has no influence on a potentially necessary biomethane conditioning at the BMIP.

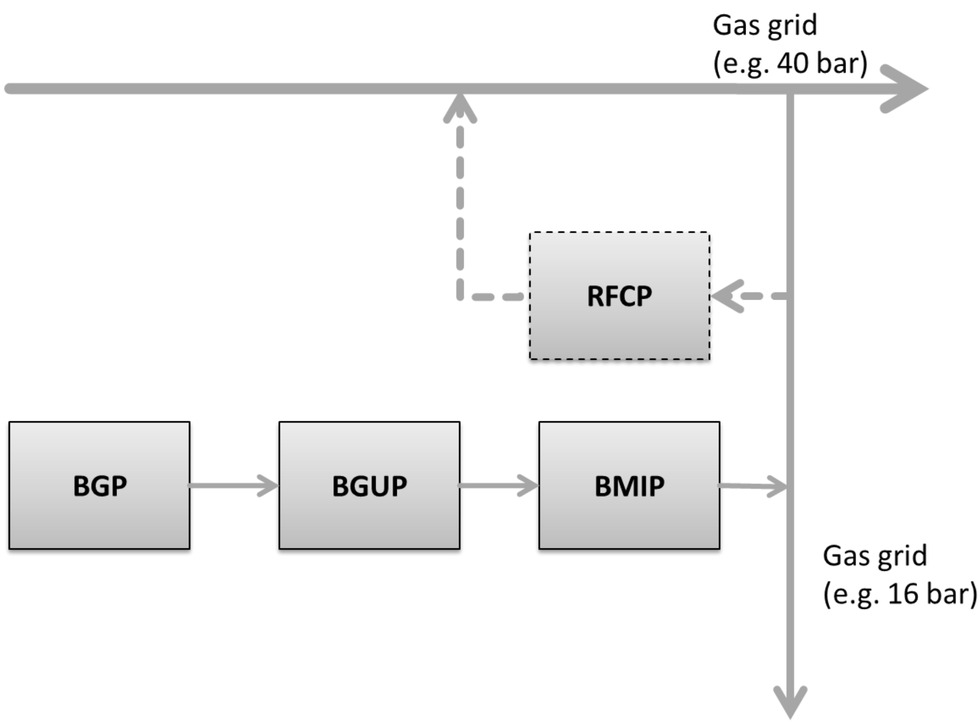

Figure 8-11: Reverse flow compression concept. Source: own illustration based on Beil et al. (2019).

[272] Bundenetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen (2014): Bericht | Biogas-Monitoringbericht 2014. Bonn.

Table 8-21: Pros and cons of reverse flow compression.

Parameter	Pros	Cons
Feasibility	Always applicable	
Additional compression	Only necessary for that gas amount that exceeds the capacity of the gas grid	
Additional pipes	Not necessary	
Deodorization		Can be necessary when injected into the transmission system
O_2-removal		Can be necessary when injected into the transmission system
Additional drying		Can be necessary
Biomethane conditioning		Potentially yes

Combined injection

Another practically relevant capacity-enhancing measure is the connection of the biomethane injection plant with two gas grids of different pressure levels. Within a survey addressed to German biomethane injection plant operators 15 of 144 (≙ 10%) applied an interconnection of existing grids as capacity enhancing measure.

In this case, the network with the lower pressure level is the network into which biomethane is predominantly fed until its intake capacity is reached. Only then does the feed-in into the network with the higher-pressure level begin. This variant is only possible if there is also a network with a higher-pressure level (and thus a higher intake capacity) in the vicinity of the biomethane plant.

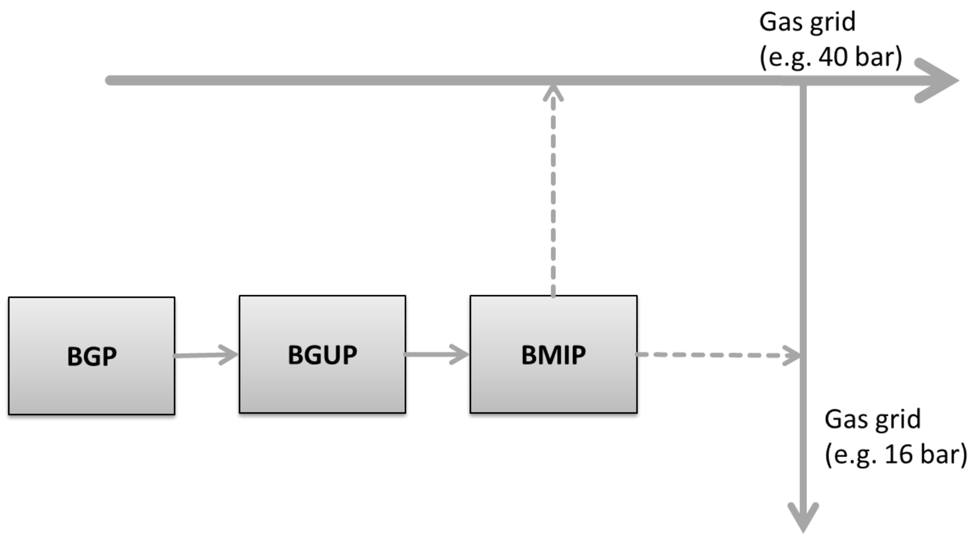

Figure 8-12: Combined injection in two gas grids concept. Source: own illustration based on Beil et al. (2019).

One advantage compared to conventional recompression from a gas network of lower pressure level into a network of higher-pressure level is that no deodorization would be necessary. Additional compression would only be necessary for the partial flow that is directed into the higher-pressure level network. Another advantage can be that for the partial stream fed into the higher-pressure network, calorific value adjustment by adding LPG could be dispensed with. The main disadvantage is the laying of additional pipes from the biomethane injection plant to the higher-pressure network. Assuming that the BMIP (incl. all necessary compressors) is located at the site of biomethane production and not as an additional station in direct proximity to the grid, this connecting pipeline would also have to be designed according to the pressure level of that grid. Whether oxygen removal would be necessary depends on the particular constellation. Further drying could theoretically become necessary, but practically not as a rule.

Table 8-22: Pros and cons of combined injection

Parameter	Pros	Cons
Feasibility		Not always applicable
Additional compression	Only necessary for that gas amount that exceeds the capacity of the gas grid	
Additional pipes		Necessary
Deodorization	Not necessary	
O_2-removal		Can be necessary when injected into the transmission system
Additional drying		Can be necessary
Biomethane conditioning	Potentially partly no	

Interconnection of existing distribution grids

Another practically relevant capacity-enhancing measure is the interconnection of existing distribution grids operated with the same pressure levels.

Within a survey addressed to German biomethane injection plant operators 15 of 144 (≙ 10%) applied an interconnection of existing grids as capacity enhancing measure.

The applicability of this capacity-expanding measure depends on local conditions and is therefore not possible everywhere. Its advantage compared to the above-described measures depends largely on the costs resulting from the connecting pipe to be built between two distribution network sections. The main advantage is that no additional cleaning steps are necessary.

Table 8-23: Pros and cons of interconnection of existing distribution grids

Parameter	Pros	Cons
Feasibility		Not always applicable
Additional compression	Not necessary	
Additional pipes		Necessary
Deodorization	Not necessary	
O_2-removal	Not necessary	

Additional drying	Not necessary	
Biomethane conditioning		Potentially yes

Increase of regional gas consumption

At least from the perspective of a demand to increase the capacity of a gas network for the injection of biomethane, an increase of the regional (area supplied by gas from the respective network) gas demand is the cheapest option of capacity enhancing measures.

Nevertheless, this option depends as well on national (incentive systems for biomethane) as regional (energy demand of potential consumers) framework conditions and is therefore not always possible.

In order to avoid more cost-intensive capacity-expanding measures described above, there is also a need to create incentives for the actors involved to avoid these costs.

Table 8-24: Pros and cons of the increase of regional gas consumption

Parameter	Pros	Cons
Feasibility		Not always applicable
Additional compression	Not necessary	
Additional pipes	Not necessary	
Deodorization	Not necessary	
O_2-removal	Not necessary	
Additional drying	Not necessary	
Biomethane conditioning		Potentially yes

8.2.4.2 Avoidance of capacity enhancing measures in the gas network

The following sub-chapter describes alternative options for the avoidance of capacity enhancing measures in the gas network.

Enable/enhance on-site gas consumption

Comparable to increasing regional gas sales is the creation of further consumers for biogas and/or biomethane directly at the site of biogas/biomethane production. Examples of this could be biogas-fuelled combined heat and power plants or biomethane filling stations. In relation to a maximum raw gas capacity available at a site, the (temporary) use of a biogas substream results in a higher specific CAPEX of both biogas upgrading and biomethane grid injection. The additional use of biomethane at the site, on the other hand, only leads to an increase in the specific CAPEX of the biomethane grid injection compared to the complete injection of biomethane.

The advantage is that this can reduce or avoid costs for potentially necessary capacity-expanding measures within the gas infrastructure. The disadvantage is that less biomethane is available in the gas infrastructure than would be possible and that infrastructure elements in biomethane production and network access cause higher specific costs.

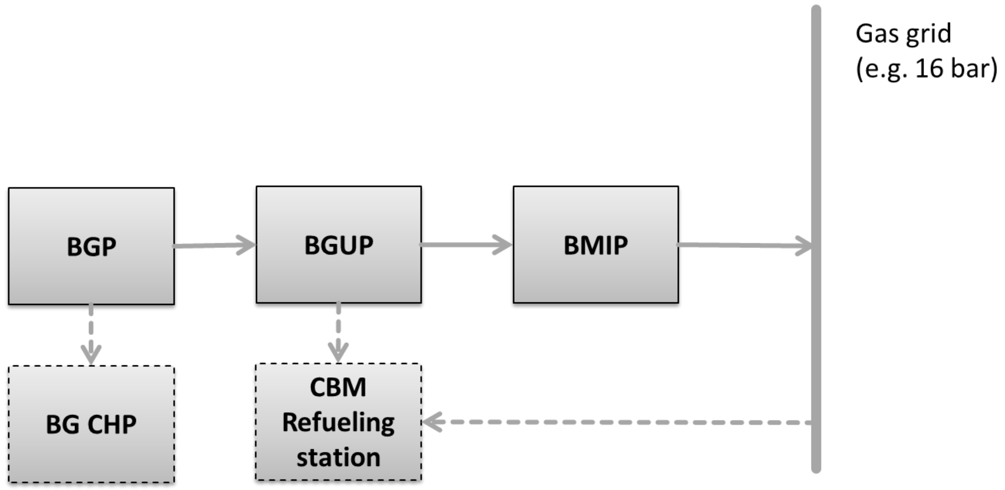

Figure 8-13: Generation of on-site gas consumption concept.

Installation of on-site storages

The installation of local storage facilities can be seen as a technically feasible option for compensating fluctuating gas offtakes in the gas grid. However, such storage capacities, which are created in addition to the gas grid storage itself, are not suitable from an economic point of view to create the seasonal capacities required here.

Demand oriented biomethane injection

Another option for avoiding capacity-expanding measures in the gas grid is demand-based biomethane injection. However, this measure can only be considered for biogas plants that have seasonally storable substrates. These include, in particular, plant substrates that can be preserved by ensiling. Theoretically, substrate conservation would be technically possible for all substrates. In particular, for substrates with low energy densities (high water contents) such as liquid manure or sewage sludge, conservation, as prevention of premature decomposition of organic matter, would lead to significantly higher raw gas production costs.

The goal with this method is to vary the biogas production seasonally between periods of higher gas sales and lower gas sales. Compared to continuous gas production, this would have the advantage of avoiding costs for capacity-expanding measures in the gas network, but also the disadvantage of higher CAPEX for the biogas plant, biogas upgrading plant and biomethane injection plant. This is caused by higher investments due to the need to design all three plants for larger capacities compared to the conventional variant.

The measure would be beneficial if the additional costs of the plant technology for biomethane production and injection into the grid were lower than capacity-expanding measures in the gas grid. In order for such measures to take effect, there is a need for a full cost analysis in the overall system already in the project development phase. The regulatory prerequisites for this must be created.

8.2.4.3 Conclusions

When creating and further developing regulatory frameworks with the aim of a sustainable integration of biomethane into energy systems, full cost optimized concepts should always be stimulated. If a biomethane injection project shows the need for capacity-expanding measures, it is necessary to extend the system boundary to the upstream gas infrastructures affected by the biomethane injection.

If the full cost optimized concepts result in such large economic disadvantages (e.g. for the producer of the biomethane or the grid operator) that projects are no longer feasible, approaches in the incentive systems should be developed to compensate for them.

To ensure the implementation of these fully cost-optimized concepts, it may be advisable to appoint an independent body (e.g., a regulatory authority) that reviews and approves the concepts submitted by the stakeholders already during the project development phase.

8.3 GTM++: Reform of the current entry/exit tariffication system

8.3.1 Computation of tariffs in the first iteration

In the METIS model, each cross-border pipeline is associated to one external entry and one external exit tariff (extracted from the TYNDP2020). These tariffs are recomputed for the first and second iteration of the GTM++ measures. This part presents the calculation of the tariffs in the first iteration, the methodology to compute the tariffs in the second iteration being explained in 4.2.2.1.4.

For intra-European pipelines in both GTM++ sub-measures, the tariffs are set at 0 €/MWh to reflect the measures' implementation.

For pipelines connecting European TSOs to third countries, the following methodology is applied in the first iteration to compute either the entry or exit tariff for each European TSO side (no tariff modification on the third country TSO side):

- Estimation of the investment costs for pipeline plus compressor in €/km
- Multiplication by the distance to a virtual centre of Europe to get the estimated investment for a pipeline that would go from the third country to this centre
- Annualisation and normalisation to get a tariff in €/MWh

The different steps are described in more detail below.

Costs for pipelines and compressors

A median value of 1.02 M€/km[273] has been determined for the pipeline investment costs, and a median investment cost of 2.03 M€/MW[274] has been determined for gas compressors. Assuming an average compressor capacity of 20 MW every 275 km of pipeline leads to an additional cost for compressors of 0.15 M€/km.

Distance-based investments computations

For every entry/exit pipeline in Europe, the distance from the cross-border point to a virtual point placed in centre of Europe (*Tillenberg, CZ*) is computed. From this distance and the specific costs outlined above, two types of investment costs are derived:

- The pipeline investment costs: the distance (in km) multiplied by the pipeline investment cost (in €/km);
- The gas compressor investment costs: the distance (in km) multiplied by the compressor investment cost (in €/km).

[273] (ACER, 2015)

[274] (ACER, 2015)

Financial parameters

Two financial parameters are used to derived the final *yearly* investment needed for a pipeline:

- The pipeline and compressor depreciation in years: 50 and 20 years respectively;
- A WACC (weighted average cost of capital) of 4.5%

Yearly investment costs and tariffs

The yearly investment costs (in €) for pipelines and compressors are then calculated as:

$$Investment_{yearly} = \frac{Investment_{total}}{Depreciation} * (1 + WACC)$$

With:

$\frac{Investment_{total}}{Depreciation}$ $(€/year)$: representing the yearly cost of the pipeline. After the depreciation period the investment shall be covered;

$(1 + WACC)$: the factor representing the interest rate of the loan for the project investment.

Once the yearly investments for both the pipeline considered and the compressors are determined, the tariff (in €/MWh) is derived using:

$$Tariff = \frac{Investment_{yearly,pipeline} + Investment_{yearly,capacity}}{Annual\ capacity}$$

With:

$Annual\ capacity$ (MWh): representing the annual capacity of the pipeline considered;

This tariff is then split into two halves as both TSOs concerned by the interconnection would participate in the pipeline investment. As mentioned above, only the EU TSO side tariff (either entry or exit) is then modified with this new tariff (no modification on third country TSO tariff under the given GTM++ sub-measures).

Specific remarks

Distances between some entry points and the centre of Europe are directly given by DG ENER. The remaining distances required are computed and a +25% increase is applied is performed based on the average spread with the data already given by the DG ENER.

Concerning the LNG entry points, the tariff computation methodology for Sub-measure 3+ is the same. When several LNG terminals exist in a country the average distance to the virtual centre of Europe weighted by the capacity of the terminals is taken.

Tariffs table

Table 8-25 details the pipelines’ and LNG terminals’ entry point tariffs in both GTM++ sub-measures. The intra-European pipelines are not shown as they are null in both sub-measures.

Table 8-25: Distance to the virtual centre of Europe and applied tariffs under GTM++ Sub-measures 3 and 3+.

Infrastructure	Distance to the virtual centre of Europe (Tillenberg, CZ)	GTM++ (Sub-measure 3)		GTM++ (Sub-measure 3+)	
		Entry fee (€/MWh)	Exit fee (€/MWh)	Entry fee (€/MWh)	Exit fee (€/MWh)
GR LNG terminal	1989	-	-	1.53	-
ES LNG terminal	2092	-	-	0.67	-
DE LNG terminal	615	-	-	0.18	-
IT LNG terminal	784	-	-	0.52	-
HR LNG terminal	708	-	-	0.72	-
FR LNG terminal	1136	-	-	0.25	-
PL LNG terminal	569	-	-	0.38	-
NL LNG terminal	789	-	-	0.16	-
SE LNG terminal	1075	-	-	3.30	-
GB LNG terminal	1354	-	-	0.19	-
LT LNG terminal	1076	-	-	0.70	-
EE LNG terminal	1617	-	-	0.99	-
IE LNG terminal	1674	-	-	0.50	-
PT LNG terminal	2698	-	-	1.07	-
LV LNG terminal	1366	-	-	0.33	-
CY LNG terminal	2991	-	-	5.94	-
BE LNG terminal	839	-	-	0.23	-
BY>LT Import pipeline	1300	0.16	0.06	0.16	0.06
BY>PL Import pipeline	1073	0.04	0.05	0.04	0.05
CH>DE Import pipeline	538	0.09	0.65	0.09	0.65
CH>FR Import pipeline	619	0.24	0.59	0.24	0.59
CH>IT Import pipeline	621	0.04	0.68	0.04	0.68
DZ>ES Import pipeline	2500	0.13	0.18	0.13	0.18
DZ>IT Import pipeline	2220	0.07	0.59	0.07	0.59
LY>IT Import pipeline	1800	0.17	0.55	0.17	0.55
NO>BE Import pipeline	850	0.07	0.05	0.07	0.05
NO>DE Import pipeline	770	0.02	0.24	0.02	0.24
NO>FR Import pipeline	915	0.06	0.14	0.06	0.14
NO>NL Import pipeline	760	0.03	0.05	0.03	0.05
RS>BG Import pipeline	1269	2.65	0.51	2.65	0.51
RS>HR Import pipeline	881	0.63	0.51	0.63	0.51

Infrastructure	Distance to the virtual centre of Europe (Tillenberg, CZ)	GTM++ (Sub-measure 3)		GTM++ (Sub-measure 3+)	
		Entry fee (€/MWh)	Exit fee (€/MWh)	Entry fee (€/MWh)	Exit fee (€/MWh)
RS>RO Import pipeline	1056	0.91	0.45	0.91	0.45
RU>DE Import pipeline	670	0.01	0.07	0.01	0.07
RU>EE Import pipeline	1955	0.36	0.02	0.36	0.02
RU>FI Import pipeline	2190	0.39	0.68	0.39	0.68
TR>BG Import pipeline	1776	0.11	0.29	0.11	0.29
TR>GR Import pipeline	1835	0.20	0.05	0.20	0.05
UA>PL Import pipeline	928	0.23	0.85	0.23	0.85
UA>RO Import pipeline	1000	0.04	0.54	0.04	0.54
UA>SK Import pipeline	895	0.02	0.97	0.02	0.97
GB>BE Import pipeline	850	0.05	0.26	0.05	0.26
GB>IE Import pipeline	1711	0.17	0.08	0.17	0.08
BE>GB Export pipeline	1063	0.18	0.05	0.18	0.05
BG>MK Export pipeline	1441	1.28	2.77	1.28	2.77
BG>RS Export pipeline	1269	0.61	0.12	0.61	0.12
BG>TR Export pipeline	1776	0.15	0.13	0.15	0.13
DE>CH Export pipeline	538	0.66	0.07	0.66	0.07
EE>RU Export pipeline	2444	0.00	0.93	0.00	0.93
FR>CH Export pipeline	619	0.95	0.09	0.95	0.09
GR>MK Export pipeline	1535	0.84	0.81	0.84	0.81
GR>TR Export pipeline	1835	0.45	0.22	0.45	0.22
HR>BA Export pipeline	733	0.41	0.10	0.41	0.10
HR>ME Export pipeline	1091	0.41	2.61	0.41	2.61
HR>RS Export pipeline	881	0.62	0.82	0.62	0.82
HU>RS Export pipeline	870	0.62	0.24	0.62	0.24
IE>GB Export pipeline	1711	0.45	0.48	0.45	0.48
IT>CH Export pipeline	621	0.67	0.05	0.67	0.05
LT>RU Export pipeline	1713	0.12	0.59	0.12	0.59
NL>GB Export pipeline	1100	0.44	0.09	0.44	0.09
PL>UA Export pipeline	928	0.47	0.23	0.47	0.23
RO>RS Export pipeline	1056	0.45	0.91	0.45	0.91
RO>UA Export pipeline	1000	0.53	1.41	0.53	1.41
SK>UA Export pipeline	895	0.63	0.08	0.63	0.08

8.3.2 Computation of tariffs in the second iteration

In a second iteration the external entry/exit tariffs are adapted in order to ensure the same level of EU TSO revenues (i.e., external entry plus external exit plus congestion rent).[275] This adaptation is made through a homothetic factor, defined as the overall differential of EU TSO revenues between the sub-measure considered and the baseline, normalized by the overall EU TSOs' baseline revenues. This factor is then applied to all external entry and exit point pipelines, on the entry (or exit) tariff for pipelines entering (or exiting) the GTM++ zone.

$$Factor = \frac{EU\ TSOs\ revenue_{baseline}}{EU\ TSOs\ revenue_{option}}$$

These factors were computed for the first iteration run (cf. Section 4.2.2.1) and applied in the "second iteration" model run presented in Section 4.2.2.2.

8.3.3 KPI definition

The assessment of the two policy measures (Sub-measure 3 and 3+) relies on a set of key performance indicators (KPIs) which are defined in the following in more detail.

Each of the following KPIs is derived as a sum over the year considered:

TSO revenues

The TSO revenues are defined as the sum of:

- Revenues stemming from external entry/exit tariffs (attributed to the relevant TSO);

$$TSO_{tariff\ revenues} = \sum_{t=1}^{365} Flow_{t,exit} * Exit\ tariff + Flow_{t,entry} * Entry\ tariff$$

- Congestion rent from congested interconnections (split in half between the two concerned TSOs).

$$TSO_{rent} = \sum_{t=1}^{365} Flow_{t,exit} * \left(Price_{t,exit} - Exit\ tariff\right) - Flow_{t,entry} * (Price_{t,entry} + Entry\ tariff)$$

With:

- $Price_{t,exit}$ (€/MWh): the gas price at each time step described as the marginal cost for the exit node of the pipeline;
- $Price_{t,entry}$ (€/MWh): the gas price at each time step described as the marginal cost for the entry node of the pipeline;
- $Flow_{t,exit}$ (MWh): the gas exiting the pipeline at each time step;
- $Flow_{t,entry}$ (MWh): the gas entering the pipeline at each time step;
- $Exit/Entry\ tariff$(€/MWh): the exit and entry tariffs

By construction, in the METIS model the TSO_{rent} is always positive.

[275] An adaptation of external entry/exit tariffs of the third countries is out of scope of this analysis.

Note that this KPI **does not embed the internal exit revenues,** hence it is not to be compared directly to the turnover of the European TSOs.

In the presentation of this KPI, only one TSO is considered per MS.

LSO revenues

The LSO revenues are defined as the sum of:

- Revenues stemming from terminal services tariffs (unloading, storage, regasification);

$$LSO_{tariff\ revenues} = \sum_{t=1}^{365} Flow_{t,exit} * Tariffs_{LSO}$$

- LSO rent representing the potential benefits/losses of the LSO due to both, the congestion rent and the value of LNG storage to the system. The LSO rent is defined as follows:

$$LSO_{rent} = \sum_{t=1}^{365} Flow_{t,exit} * \left(Price_{t,exit} - Tariffs_{LSO}\right) - Flow_{t,entry} * Price_{t,entry}$$

With:

- $Price_{t,exit}$ (€/MWh): the gas price at each time step described as the marginal cost for the exit node of the LNG terminal;
- $Price_{t,entry}$: (€/MWh): the gas price at each time step described as the marginal cost for the entry node of the LNG terminal;
- $Flow_{t,exit}$ (MWh): the gas injected at each time step on the TSO;
- $Flow_{t,entry}$: (MWh): the gas unloaded from LNG carriers at each time step describing at the LNG terminal considered;
- $Tariffs_{LSO}$:(€/MWh): terminal services tariffs (unloading, storage, regasification)

SSO revenues

The SSO revenues are defined as the sum of:

- Revenues stemming from injection and withdrawal tariffs

$$SSO_{tariff\ revenues} = \sum_{t=1}^{365} Injection_{t,z} * Fee_{inj} + Withdraw_{t,z} * Fee_{wdw}$$

- Rent representing the potential benefits/losses of the SSO due to a different gas price at the entry/exit time step. The SSO rent is defined as follows:

$$SSO_{rent} = \sum_{t=1}^{365} Injection_{t,z} * \left(Price_{t,z} - Fee_{inj}\right) - Withdraw_{t,z} * \left(Price_{t,z} + Fee_{wdw}\right)$$

With:

- $Price_{t,z}$: (€/MWh): the gas price at each time step described as the marginal cost for the node z considered;

- $Injection_{t,z}$ $(resp. Withdraw_{t,z})$: (MWh): the gas injection (resp. withdraw) at each time step describing the injection (resp. withdrawal) in (resp. from) the node z;
- Fee_{inj} (€/MWh): SSO tariff for injection in the grid;
- Fee_{wdw} (€/MWh): SSO tariff to withdraw from the grid

LNG shipping costs

The LNG shipping costs are defined as revenues stemming from shipping service tariffs (unloading, storage, regasification);

$$LNG\ shipping\ costs = \sum_{t=1}^{365} Flow_t * Fees_{shippers}$$

With:

- $Flow_t$ (MWh): the gas flow at each time step through the shipper;
- $Fees_{shippers}$ (€/MWh): the fees taken by the shippers

No congestion rent was computed for the shippers as their capacity was presumed as being infinite in the simulation.

Demand curtailment costs

The demand curtailment costs represent the estimated cost of energy not served. It is computed as:

$$Demand\ curtailment\ costs_z = \sum_{t=1}^{365} ENS_{t,z} * Demand\ curtailment\ price$$

With:

- $ENS_{t,z}$ (MWh): the energy not served for the day t at the node z ;
- $Demand\ curtailment\ price$ (€/MWh): the estimated cost for energy not served. It was considered as a global constant in the model (same value for every day and every node).

For the GTM++ sub-measures, the model builds upon the low and (where deemed necessary) advanced infrastructure scenario of the TYNDP, thus hardly any demand curtailment appears and this indicator is mostly equal to 0 €.

Consumer surplus

The consumer surplus is derived for each end-consumer node of the network over all the year considered as:

$$Consumer\ Surplus_z = -\sum_{t=1}^{365} Demand_{t,z} * Price_{t,z}$$

Thus, the consumer surplus is always negative. An alternative with a fixed cost representing the energy not served price could have been applied. However, as only the variation in consumer surplus is of interest in this study, it was chosen not to add this constant.

With:

- $Price_{t,z}$: (€/MWh): the gas price at each time step described as the marginal cost for the node *z* considered.
- $Demand_{t,z}$ (MWh): the gas demand at each time step modelling the end-consumer *z* considered linked to the node *z*.

Production costs

The gas production costs are derived for each node (Russia, Norway, LNG markets, but also MS for indigenous production) where a producer is present as the integral of the cost curve for each day of the year for each production modelled. Figure 8-14 depicts the area representing the production costs with an inelastic demand.

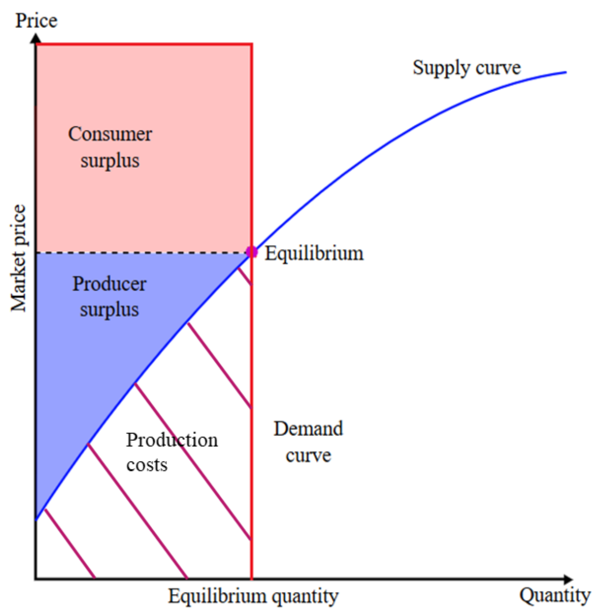

Figure 8-14: Illustration of production costs, consumer and producer surplus for an inelastic demand. Source: Artelys

Producer surplus

The gas producer surplus is derived as the difference between the producer revenue and the production cost:

$$Producer\ Surplus_z = \left(\sum_{t=1}^{365} Demand_{t,z} * Price_{t,z}\right) - Production\ costs_z$$

With:

- $Price_{t,z}$ (€/MWh): the gas price at each time step described as the marginal cost for the node z considered.
- $Demand_{t,z}$ (MWh): the gas demand at each time step modelling the end-consumer z considered linked to the node z.
- $Production\ costs_z$ (€): the production costs for the node z as defined in the previous section.

Adaptation of internal exit tariffs

For each EU TSO and for each measure assessed, the adaptation of internal exit tariffs to recover the same level of TSO revenues due to external entry + external exit + congestion rent is derived as follows:

$$\Delta_{Domestic} = \frac{TSO\ revenue_{baseline} - TSO\ revenue_{option}}{TSO\ demand}$$

With:

- $TSO\ revenue_{baseline}$: the TSO revenue computed in the baseline model run, where no measure is activated;
- $TSO\ revenue_{option}$: the TSO revenue computed in the model run where the measure studied is activated;
- $TSO\ demand$: the yearly gas demand aggregated at the TSO level

Thus:
- if $\Delta_{Domestic}$ is **positive**, the TSO revenue in the measure is smaller than in the baseline situation, and the internal exit tariffs need to **increase** to find the same level of TSO revenue.
- if $\Delta_{Domestic}$ is **negative**, the TSO revenue in the measure is greater than in the baseline situation, and the internal exit tariffs need to **decrease** to find the same level of TSO revenue.

Welfare and other indicators for EU and third countries

In order to quantify the effect of the measures on the system at the EU level, welfares of both MSs and third countries are derived.

The country welfare is composed by the sum of (a) TSO revenues, (b) SSO revenues, (c) LSO revenues and (d) Consumer surplus

Other indicators include (a) LNG shipping costs, (b) production costs and (c) producer surplus (pure exporters such as Russia and domestic producers such as the UK or the Netherlands)

These three last indicators are not added to the welfare as producers/shippers cannot be strictly associated to one or several distinct countries (both because producers/shippers are mostly international companies and because several intermediate companies intervene in the market, dividing the producer surplus between several entities) compared to TSOs, SSOs, LSOs and consumers.

Note that these KPIs relate to each other as the consumers are in the end paying for all the costs modelled in the simulation, thus:

$$\sum TSO\ revenues\ + \sum LSO\ revenues\ + \sum SSO\ revenues\ + \sum Producer\ Surplus + \sum LoL\ costs + \sum Production\ costs\ + \sum Shipping\ costs = -\sum Consumer\ surplus$$

8.3.4 Average annual gas prices weighted by demand at each country

In this part are presented the average annual marginal gas prices weighted by demand at each node computed by the METIS model for each iteration and the Nordstream 2 sensitivity analysis.

Table 8-26: Average annual gas prices in €/MWh weighted by demand at each country. Source: Own calculations

First iteration

Country	Base	GTM_sub3	GTM_sub3+
AT	20.6	19.5	19.5
BA	21.3	19.9	20.0
BE	19.6	19.4	19.4
BG	21.1	19.9	20.0
CH	20.7	20.2	20.3
CY	19.3	19.3	20.5
CZ	19.5	19.5	19.5
DE	19.3	19.4	19.5
DK	19.8	19.4	19.4
EE	19.2	19.8	19.8
ES	19.6	19.4	19.8
FI	20.1	20.3	20.3
FR	19.5	19.5	19.5
GB	20.0	20.0	20.0
GR	21.1	19.7	20.4
HR	20.5	19.4	19.5
HU	21.1	19.5	19.6
IE	20.0	20.1	20.1
IT	21.6	19.4	19.4
LT	18.9	19.3	19.4
LU	19.6	19.4	19.4
LV	19.2	19.7	19.7
ME	21.2	22.3	22.4
MK	22.8	21.4	22.1
MT	22.3	19.3	19.4
NL	19.2	19.3	19.4
NO	19.0	19.1	19.1
PL	19.2	19.3	19.4
PT	19.9	19.3	19.7
RO	20.1	19.7	19.9
RS	22.2	20.2	20.3
SE	19.8	19.3	19.3
SI	21.3	19.6	19.6
SK	20.2	19.5	19.6

Second Iteration

Country	Base	GTM_sub3	GTM_sub3+
AT	20.6	19.6	19.7
BA	21.3	20.5	20.4
BE	19.6	19.4	19.5
BG	21.1	20.1	20.1
CH	20.7	20.5	20.4
CY	19.3	19.5	21.6
CZ	19.5	19.6	19.6
DE	19.3	19.5	19.5
DK	19.8	19.4	19.4
EE	19.2	21.3	20.4
ES	19.6	19.5	20.1
FI	20.1	21.8	20.9
FR	19.5	19.6	19.6
GB	20.0	20.1	19.9
GR	21.1	20.0	21.0
HR	20.5	19.5	19.7
HU	21.1	19.7	19.8
IE	20.0	20.9	20.2
IT	21.6	19.5	19.5
LT	18.9	19.5	19.8
LU	19.6	19.4	19.4
LV	19.2	21.2	20.3
ME	21.2	33.3	26.7
MK	22.8	25.0	24.0
MT	22.3	19.5	19.5
NL	19.2	19.4	19.4
NO	19.0	19.0	19.2
PL	19.2	19.5	19.5
PT	19.9	19.4	20.0
RO	20.1	19.9	20.0
RS	22.2	21.2	20.9
SE	19.8	19.3	19.4
SI	21.3	19.7	19.7
SK	20.2	19.7	19.7

NS2 Sensitivity

Country	With NS2	Without NS2
AT	19.6	19.7
BA	20.5	20.6
BE	19.4	19.6
BG	20.1	20.1
CH	20.5	20.7
CY	19.5	19.6
CZ	19.6	19.7
DE	19.5	19.6
DK	19.4	19.5
EE	21.3	21.0
ES	19.5	19.6
FI	21.8	21.7
FR	19.6	19.7
GB	20.1	20.2
GR	20.0	19.9
HR	19.5	19.6
HU	19.7	19.7
IE	20.9	21.0
IT	19.5	19.6
LT	19.5	19.5
LU	19.4	19.6
LV	21.2	20.9
ME	33.3	33.4
MK	25.0	25.0
MT	19.5	19.6
NL	19.4	19.5
NO	19.0	19.2
PL	19.5	19.5
PT	19.4	19.5
RO	19.9	19.9
RS	21.2	21.1
SE	19.3	19.5
SI	19.7	19.8
SK	19.7	19.7

8.3.5 Differences in welfare and other economic indicators

Table 8-27 and Table 8-28 illustrate the difference in welfare and a number of other economic indicators for EU and non-EU countries in the first iteration under Sub-measure 3 and 3+, respectively. Table 8-29 and Table 8-30 provide the same information in the second iteration. Table 8-31 reveals the indicators for the Nord Stream 2 sensitivity analysis.

Table 8-27: Differences in welfare components (M€) under GTM++ Sub-measure 3, first iteration. Source: own calculations with METIS

EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AT	-119.7	-	-17.6	58.3	-	0.0	-7.6
BE	-53.9	-14.9	-0.2	42.4	-	0.0	-0.5
BG	-32.2	-	7.3	43.8	-	0.0	-0.3
CY	-0.8	-0.5	-	-0.1	-	0.0	0.0
CZ	-11.5	-	22.3	0.5	-	0.0	-0.5
DE	-186.6	0.0	89.8	-79.0	-	0.0	2.0
DK	-0.5	-	-1.0	10.0	-	0.0	-13.5
EE	-1.2	0.0	-	-1.3	-	0.0	0.0
ES	-65.5	-46.7	0.0	43.4	-	0.0	-1.2
FI	-4.4	-	-	-4.1	-	0.0	0.0
FR	-37.6	185.5	21.0	14.5	-	0.0	-0.2
GR	-25.5	-92.6	-	95.8	-	0.0	-0.3
HR	-14.5	-20.2	-0.6	21.3	-	0.0	-2.9
HU	-25.3	-	8.9	120.2	-	0.0	-41.7
IE	3.9	0.0	0.5	-2.7	-	0.0	0.4
IT	-217.9	-18.7	-20.6	891.4	-	0.0	-84.9
LT	-2.3	21.1	-	-14.4	-	0.0	0.1
LU	0.0	-	-	0.9	-	0.0	-0.1
LV	3.5	0.0	2.0	-5.0	-	0.0	0.1
MT	-1.8	-	-	13.5	-	0.0	-0.2
NL	-20.2	1.0	-18.2	-33.1	-	0.0	5.7
PL	-28.5	16.2	0.0	-26.8	-	0.0	4.2
PT	-7.5	-19.5	0.0	11.4	-	0.0	-0.2
RO	-56.8	-	3.4	38.4	-	0.0	-46.6
SE	0.0	0.0	-0.1	5.1	-	0.0	-0.9
SI	-4.6	-	-	23.3	-	0.0	-0.2
SK	-35.1	-	18.3	27.4	-	0.0	-0.4

Non-EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AN_LNG	-	-	-	-	-6.7	305.8	29.6
AU_LNG	-	-	-	-	0.0	0.0	0.0
BA	0.0	-	-	12.2	-	-	-
BY	-0.0	-	-	-	-	-	-
CH	0.0	-	-	21.0	-	0.0	0.0
DZ	-156.9	-	-	-	-	-5186.8	-162.2
GB	20.9	-60.7	11.3	21.8	-	0.0	-7.2
LY	-28.5	-	-	-	-	-1013.8	-31.0
ME	0.0	-	-	-1.6	-	-	-
ME_LNG	-	-	-	-	104.0	634.5	35.4
MK	0.0	-	-	10.1	-	0.0	0.0
NO	-28.6	-	-	-0.7	-1.7	1530.5	105.8
PE_LNG	-	-	-	-	0.0	0.0	0.0
RS	0.0	-	3.4	58.2	-	0.0	-5.5
RU	-3.5	-	-	-	-	2539.5	141.7
SS_LNG	-	-	-	-	74.5	729.9	20.6
TR	-1.2	-	-	-	-	-	-
TT_LNG	-	-	-	-	0.0	0.5	0.0
UA	-0.0	-	-	-	-	-	-
US_LNG	-	-	-	-	0.0	0.0	0.0

Table 8-28: Differences in welfare components (M€) under GTM++ Sub-measure 3+, first iteration. Source: own calculations with METIS

EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AT	-114.9	-	-17.9	57.3	-	0.0	-7.4
BE	-36.7	-14.9	-0.2	38.2	-	0.0	-0.4
BG	-17.3	-	-0.1	38.3	-	0.0	-0.2
CY	0.2	-11.8	-	-9.4	-	0.0	0.1
CZ	-10.4	-	20.9	-0.5	-	0.0	-0.4
DE	-187.1	0.0	82.2	-91.5	-	0.0	2.8
DK	-0.5	-	-1.0	9.9	-	0.0	-13.3
EE	-1.2	0.0	-	-1.3	-	0.0	0.0
ES	-13.7	-138.7	0.9	-36.3	-	0.0	1.0
FI	-4.4	-	-	-4.2	-	0.0	0.0
FR	33.0	218.4	9.1	4.9	-	0.0	-0.1
GR	-4.2	-213.3	-	47.1	-	0.0	-0.1
HR	-13.3	-58.6	-1.5	20.2	-	0.0	-2.8
HU	-19.7	-	24.6	116.1	-	0.0	-40.3
IE	3.9	0.0	0.5	-2.2	-	0.0	0.3
IT	-215.2	-18.7	-20.4	873.0	-	0.0	-83.1
LT	28.0	5.5	-	-15.2	-	0.0	0.1
LU	0.0	-	-	0.8	-	0.0	-0.1
LV	3.3	0.0	2.0	-5.0	-	0.0	0.1
MT	-1.8	-	-	13.2	-	0.0	-0.1
NL	-22.8	1.2	-18.1	-38.9	-	0.0	6.8
PL	-26.1	-9.5	0.0	-32.3	-	0.0	5.4
PT	-5.2	-20.4	0.3	2.7	-	0.0	-0.0
RO	-52.4	-	-0.1	18.7	-	0.0	-20.6
SE	0.0	0.0	-0.0	5.1	-	0.0	-0.9
SI	-4.2	-	-	22.8	-	0.0	-0.1
SK	-33.4	-	16.7	26.6	-	0.0	-0.4

Non-EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AN_LNG	-	-	-	-	-0.7	-83.9	-10.3
AU_LNG	-	-	-	-	0.0	0.0	0.0
BA	0.0	-	-	11.7	-	-	-
BY	-0.0	-	-	-	-	-	-
CH	-0.0	-	-	20.2	-	0.0	0.0
DZ	-141.8	-	-	-	-	-3575.4	-147.0
GB	20.2	-14.7	18.3	28.3	-	0.0	-9.4
LY	-28.5	-	-	-	-	-1013.8	-31.0
ME	0.0	-	-	-1.7	-	-	-
ME_LNG	-	-	-	-	3.1	-270.2	-11.5
MK	0.0	-	-	5.1	-	0.0	0.0
NO	-19.2	-	-	-0.8	-3.5	1649.8	105.1
PE_LNG	-	-	-	-	0.0	0.0	0.0
RS	0.1	-	1.8	56.1	-	0.0	-5.3
RU	28.9	-	-	-	-	3514.6	179.2
SS_LNG	-	-	-	-	-27.9	-271.9	-4.6
TR	5.9	-	-	-	-	-	-
TT_LNG	-	-	-	-	-0.0	-0.2	-0.0
UA	-0.0	-	-	-	-	-	-
US_LNG	-	-	-	-	0.0	0.0	0.0

Table 8-29: Differences in welfare components (M€) under GTM++ Sub-measure 3, second iteration. Source: own calculations with METIS

EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AT	-115.7	-	-2.8	51.6	-	0.0	-6.7
BE	-33.6	-14.7	-0.1	31.6	-	0.0	-0.3
BG	-15.8	-	5.7	35.6	-	0.0	-0.2
CY	-0.8	-1.0	-	-1.2	-	0.0	0.0
CZ	3.0	-	18.7	-1.9	-	0.0	-0.3
DE	-41.5	0.0	70.5	-110.7	-	0.0	4.2
DK	-0.5	-	-0.9	9.6	-	0.0	-12.9
EE	11.9	0.0	-	-5.0	-	0.0	0.2
ES	-65.6	-49.4	0.0	24.9	-	0.0	-0.7
FI	0.9	-	-	-41.4	-	0.0	0.4
FR	-52.8	210.9	-8.4	-7.1	-	0.0	0.2
GR	-1.0	-77.5	-	73.6	-	0.0	-0.2
HR	4.4	-20.0	-4.6	18.9	-	0.0	-2.6
HU	-27.2	-	6.5	111.1	-	0.0	-38.5
IE	32.7	0.0	0.5	-39.2	-	0.0	5.7
IT	-214.4	-18.7	-20.5	841.5	-	0.0	-80.1
LT	14.5	21.4	-	-18.7	-	0.0	0.1
LU	0.0	-	-	0.6	-	0.0	-0.1
LV	20.2	0.0	2.0	-19.6	-	0.0	0.2
MT	-1.8	-	-	12.9	-	0.0	-0.1
NL	24.2	0.8	-18.4	-47.8	-	0.0	8.4
PL	-24.6	19.6	10.8	-54.2	-	0.0	9.7
PT	-7.5	-19.5	0.0	9.3	-	0.0	-0.1
RO	-49.3	-	2.4	13.2	-	0.0	-17.0
SE	0.0	0.0	-0.1	4.9	-	0.0	-0.9
SI	-4.6	-	-	21.7	-	0.0	-0.1
SK	-21.0	-	24.4	22.3	-	0.0	-0.4

Non-EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AN_LNG	-	-	-	-	5.3	530.5	53.4
AU_LNG	-	-	-	-	0.0	0.0	0.0
BA	0.0	-	-	7.5	-	-	-
BY	-0.0	-	-	-	-	-	-
CH	0.1	-	-	6.8	-	0.0	0.0
DZ	-156.9	-	-	-	-	-5186.8	-162.2
GB	-27.4	-14.6	16.7	-11.2	-	0.0	4.2
LY	-28.5	-	-	-	-	-1013.8	-31.0
ME	0.0	-	-	-17.2	-	-	-
ME_LNG	-	-	-	-	192.9	1182.9	66.1
MK	0.0	-	-	-15.5	-	0.0	0.0
NO	-2.7	-	-	-0.2	0.2	611.2	48.1
PE_LNG	-	-	-	-	0.0	0.0	0.0
RS	-0.1	-	3.8	29.2	-	0.0	-2.8
RU	34.8	-	-	-	-	2244.2	118.9
SS_LNG	-	-	-	-	102.4	1005.4	30.1
TR	-1.2	-	-	-	-	-	-
TT_LNG	-	-	-	-	0.1	0.7	0.0
UA	-0.0	-	-	-	-	-	-
US_LNG	-	-	-	-	0.0	0.0	0.0

Table 8-30: Differences in welfare components (M€) under GTM++ Sub-measure 3+, second iteration. Source: own calculations with METIS

EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AT	-111.7	-	-17.3	51.1	-	0.0	-6.6
BE	-30.7	-33.5	-0.2	24.5	-	0.0	-0.3
BG	2.1	-	-0.1	34.3	-	0.0	-0.2
CY	2.2	-11.8	-	-17.5	-	0.0	0.1
CZ	-0.1	-	22.8	-4.3	-	0.0	-0.2
DE	-157.0	0.0	92.3	-136.2	-	0.0	5.0
DK	-0.5	-	-1.0	8.0	-	0.0	-10.8
EE	3.7	0.0	-	-2.9	-	0.0	0.1
ES	38.8	-177.1	3.7	-80.0	-	0.0	2.3
FI	-2.4	-	-	-20.1	-	0.0	0.2
FR	4.4	-1.3	69.9	-18.1	-	0.0	0.2
GR	27.3	-216.5	-	5.1	-	0.0	-0.0
HR	-3.9	-59.9	-4.6	15.1	-	0.0	-2.1
HU	-3.8	-	29.6	97.0	-	0.0	-33.7
IE	14.7	0.0	0.0	-9.5	-	0.0	1.4
IT	-218.9	-18.7	-20.2	838.2	-	0.0	-79.8
LT	18.2	-14.3	-	-28.9	-	0.0	0.1
LU	0.0	-	-	0.5	-	0.0	-0.0
LV	5.8	0.0	2.0	-11.3	-	0.0	0.1
MT	-1.8	-	-	12.9	-	0.0	-0.1
NL	-6.2	0.9	-14.9	-55.3	-	0.0	9.4
PL	-11.6	-10.6	0.0	-55.4	-	0.0	9.9
PT	-7.5	-24.2	0.6	-3.1	-	0.0	0.0
RO	-48.6	-	-0.2	8.3	-	0.0	-9.9
SE	0.0	0.0	0.0	4.1	-	0.0	-0.7
SI	-2.9	-	-	21.6	-	0.0	-0.1
SK	-19.9	-	18.2	22.0	-	0.0	-0.4

Non-EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AN_LNG	-	-	-	-	8.0	-359.7	-30.8
AU_LNG	-	-	-	-	0.0	0.0	0.0
BA	0.0	-	-	8.1	-	-	-
BY	0.0	-	-	-	-	-	-
CH	-0.0	-	-	12.2	-	0.0	0.0
DZ	-139.0	-	-	-	-	-3283.0	-139.8
GB	-13.8	253.4	-44.2	91.4	-	0.0	-31.0
LY	-28.5	-	-	-	-	-1013.8	-31.0
ME	0.0	-	-	-7.8	-	-	-
ME_LNG	-	-	-	-	-56.2	-807.4	-32.7
MK	0.0	-	-	-8.2	-	0.0	0.0
NO	-31.7	-	-	-0.9	0.9	1854.1	116.3
PE_LNG	-	-	-	-	0.0	0.0	0.0
RS	0.1	-	-0.1	37.5	-	0.0	-3.6
RU	33.3	-	-	-	-	4523.5	245.1
SS_LNG	-	-	-	-	-74.6	-722.9	-16.0
TR	6.1	-	-	-	-	-	-
TT_LNG	-	-	-	-	-0.1	-0.5	-0.0
UA	-0.0	-	-	-	-	-	-
US_LNG	-	-	-	-	0.0	0.0	0.0

Table 8-31: Differences in welfare components (M€) under the Nord Stream 2 sensitivity analysis. Source: own calculations with METIS

EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AT	1.2	-	-15.1	-3.4	-	0.0	0.5
BE	30.7	1.2	-0.1	-30.9	-	0.0	0.3
BG	0.3	-	1.1	1.5	-	0.0	-0.0
CY	0.0	-0.4	-	-1.0	-	0.0	0.0
CZ	-15.6	-	1.8	-8.4	-	0.0	0.6
DE	41.6	0.0	9.9	-99.8	-	0.0	5.2
DK	-0.0	-	-0.0	-3.6	-	0.0	4.9
EE	1.7	0.0	-	0.7	-	0.0	-0.0
ES	-0.1	1.1	0.0	-24.6	-	0.0	0.7
FI	1.7	-	-	2.2	-	0.0	-0.0
FR	-0.1	77.4	0.2	-36.6	-	0.0	0.4
GR	0.0	-16.6	-	5.3	-	0.0	-0.0
HR	0.0	-1.5	2.1	-1.7	-	0.0	0.2
HU	-1.6	-	-2.8	-6.2	-	0.0	2.2
IE	0.0	0.0	5.2	-6.3	-	0.0	0.9
IT	8.7	0.0	7.8	-40.4	-	0.0	3.9
LT	-4.2	0.0	-	-2.1	-	0.0	0.0
LU	0.0	-	-	-0.6	-	0.0	0.1
LV	-4.2	0.0	10.2	2.7	-	0.0	-0.0
MT	0.0	-	-	-0.4	-	0.0	0.0
NL	0.0	0.3	0.9	-38.2	-	0.0	6.3
PL	115.3	2.1	-10.8	-14.4	-	0.0	3.1
PT	0.0	0.1	0.0	-2.6	-	0.0	0.0
RO	-1.5	-	0.8	6.5	-	0.0	-8.9
SE	0.0	0.0	0.0	-1.9	-	0.0	0.3
SI	0.3	-	-	-1.1	-	0.0	0.0
SK	-15.0	-	-8.0	-2.5	-	0.0	0.0

Non-EU countries

Country	Total TSOs revenues	Total LSOs revenues	Total SSOs revenues	Consumer surplus	Shipping costs	Production costs	Producer surplus
AN_LNG	-	-	-	-	2.8	282.8	31.1
AU_LNG	-	-	-	-	0.0	0.0	0.0
BA	-0.0	-	-	-0.7	-	-	-
BY	45.0	-	-	-	-	-	-
CH	0.1	-	-	-6.4	-	0.0	0.0
DZ	0.0	-	-	-	-	0.0	0.0
GB	-2.7	11.0	10.2	-77.7	-	0.0	24.9
LY	0.0	-	-	-	-	0.0	0.0
ME	-0.0	-	-	-0.1	-	-	-
ME_LNG	-	-	-	-	104.1	645.1	42.7
MK	0.0	-	-	0.5	-	0.0	0.0
NO	4.8	-	-	-0.7	1.3	1872.2	133.6
PE_LNG	-	-	-	-	0.0	0.0	0.0
RS	-0.0	-	1.8	2.0	-	0.0	-0.2
RU	54.8	-	-	-	-	-3586.4	-170.6
SS_LNG	-	-	-	-	55.9	554.0	25.2
TR	0.0	-	-	-	-	-	-
TT_LNG	-	-	-	-	0.0	0.4	0.0
UA	0.0	-	-	-	-	-	-
US_LNG	-	-	-	-	0.0	0.0	0.0

8.4 Regulatory framework for the quality of gases (incl. hydrogen blend)

This section provides an overview about the methodology and assumptions applied to evaluate the policy options as outlined in Section 4.3, in particular with respect to the generation of the adaptation cost curve for hydrogen blending in gas networks.

8.4.1 Introduction and definition of use cases

The blending of hydrogen into the natural gas network implies very complex needs in terms of the required infrastructure adaptation. A hydrogen blending share of 20% of the volume is often mentioned as a medium-term goal. However, this only accounts for approx. 6.6% of the energy content of the gas mixture (lower heating value - LHV) and, in the case of decarbonised hydrogen, also provides correspondingly only 6.6% CO2 savings compared to fossil natural gas. At the same time, blending small proportions can be a very cost-effective way to enable an initial market ramp-up for hydrogen.276

Without additional investments, the blending of hydrogen into the transmission grid is not feasible due to specific sensitive applications that are directly integrated or connected to the gas grid, even with low hydrogen contents. In the distribution network, on the other hand, it is already possible to go to 10% H2 content if no special customers are connected. However, feeding hydrogen from electrolysis into the distribution grids leads to much more fluctuating H2 shares than feeding it into the transmission grid, which is then better balanced via the seasonal storage facilities. Existing natural gas boilers are not adapted to fluctuating blending ratios, even if, with the use of the balancing effects of the transmission grid, an increase to 20% hydrogen is conceivable without premature boiler replacement. Past 20%, the costs for premature boiler replacement represent the highest part of the adaptation costs for hydrogen blending. Therefore, decentralized injection into distribution networks suitable for this purpose is advantageous for low hydrogen proportions, but then cannot be increased without using the supra-regional and seasonal balancing of the transmission network.

In contrast, a partial repurposing of the gas transmission system to 100% H2 allows high degrees of freedom for a transformation of natural gas supply, since H2-critical elements (pore storage, existing gas turbines, certain industrial consumers) can still be supplied with pure natural gas and hydrogen supply can be explicitly directed to the H2 consumers (industry, new gas-fired power plants). In addition, a dedicated H2 network could be complementary to blending as a constant H2 blending rate in distribution networks can be ensured if there is a pipeline with natural gas and a pipeline with hydrogen at the interface to the distribution network. In a recent study277, some European TSOs proposed such a dedicated H2 network, which would be present in the Netherlands, Belgium, North-West Germany and North-Eastern France in the first place and would be comprehensively expanded later.

[276] (Fraunhofer IEE, 2020)

[277] (Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, 2020)

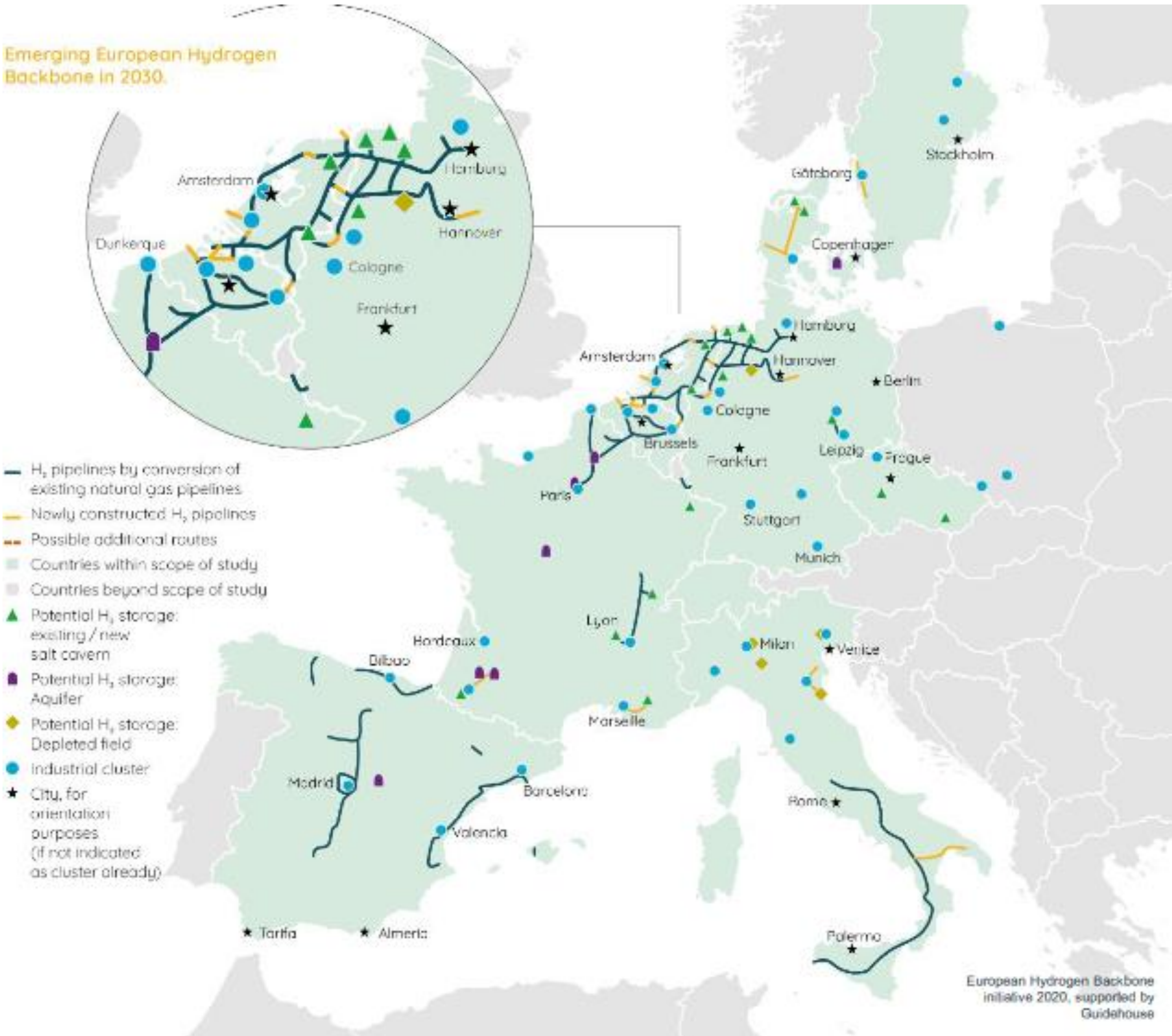

Figure 8-15: Emerging European Hydrogen Backbone in 2030 [278]

Three types of hydrogen integration into the gas network are possible and presented in **Table 8-32**.

Table 8-32: Description of the three types of H2 integration within the gas network

	Type 1	Type 2	Type 3
H2 feed in	Transport network >40bar	Supra-regional distribution network approx. 16 bar	H2 transport network in parallel to the CH4 transport network
Fluctuating H2 proportions in the distribution network	Low fluctuations (due to dilution) This would allow a max. 20% H2 share in 2030 without premature boiler replacement	High fluctuations This would allow a max. 10% H2 share in 2030 without premature boiler replacement	No fluctuations This would allow a max. 20% H2 share in 2030 without premature boiler replacement

[278] (Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, 2020)

	Type 1	Type 2	Type 3
Country examples in 2030	Germany (without Northwest) This would be a solution to bottlenecks in the power grid for wind in Northern Germany = H2 transport gas network	France The combination of nuclear power and wind in the electricity market could lead to site-independent electrolysis for distribution gas networks	NL, BE, Northwest Germany These countries have a high potential for blue hydrogen and green offshore hydrogen produced via offshore power plants

The exclusive adaptation of the distribution grid up to 10% (Type 2) can be implemented in individual countries as long as no other country begins to feed H2 into the transmission grid (Type 1). However, the European gas trade means that all countries will then also have to make infrastructure adjustments in the transmission grid due to the cross-border gas flows. Therefore, several pathways arise for the development of a hydrogen infrastructure:

- All countries chose Type 1 directly.
- The EU countries start with Type 2, and transition together to Type 1 in all countries as soon as:
    - a country switches to Type 1 due to the regionally dependent H2 supply (e.g., due to grid bottlenecks in the electricity transmission grid) already with H2 shares up to 10%.
    - a country's H2 share in the distribution grid exceeds 10% and the strongly fluctuating H2 share is no longer tolerable
- The EU countries start with Type 2, and transition together to Type 3 without adapting their gas network. The adjustment costs for H2 admixture in the transmission network are saved, but costs incur for the repurposing of the existing gas network, new pipelines and cavern storage facilities.

In this impact assessment, for the gas quality measure the first pathway is assumed: the MSs tackle directly the challenge to integrate H2 in their transport network.

8.4.2 Assumptions and simplifications

The literature around hydrogen blending into the transport network is not yet exhaustive, and simplifications, listed here, were to be done for this impact assessment.

8.4.2.1 Dependence of the blending impact to the origin of natural gas

In a position paper regarding the application of natural gas grid regulations concerning the feed-in biogas, the feed-in of hydrogen and synthetic methane, the German grid regulator BNetzA states[279]: "Hydrogen is a gas that differs substantially in its composition and combustion characteristics from natural gas and other grid-compatible gases. Furthermore, without mixing, it can cause damage to grids, storage facilities, and customer installations. Accordingly, pure hydrogen is not grid-compatible. However,

[279] (BNetzA, 2013)

hydrogen can still be grid-compatible, provided that intermixing with a grid-compatible gas downstream of the feed-in point does not have any effect on the interoperability of the gas supply grid."

This means that hydrogen can be fed into the grid as an additive gas. Additive gases are gas mixtures that differ substantially from the primary system gas, in their composition and combustion characteristics. They can be added to the primary system gas (which is usually natural gas) in limited quantities. The amount of blending is governed by the need for consistent combustion behaviour.[280]

The Wobbe index, which provides a measure of gas interchangeability (with regard to the heat load of gas systems), is of particular importance, especially for grid management. "When adding hydrogen to the publicly accessible network, the limits defined in G 260 for relative density, calorific value, and Wobbe index must always be observed".[281] Technical Regulation G 260 of the German association for gas and water DVGW specifies on "gas quality", among other things, the requirements for the quality of combustive gases in public gas grids.

In the following figure for the German case (for the distribution gas network without special customers), the change in gas composition characteristics is shown for three types of natural gas ("Holland-L," "North Sea-H," and "Russia-H") as a function of hydrogen concentration. While the natural gas types Holland-L and North Sea-H are still clearly within the permissible G 260 thresholds for H and L gases given a hydrogen concentration of 10%, this is no longer the case for Russia-H. The lower threshold for relative density (d = 0.55) is not met by Russian-H gas plus 10% hydrogen. Furthermore, at a hydrogen concentration of 20%, all three natural gas types fail to meet the required threshold value for relative density. If the relative density requirements are not met by higher blending levels, the G 260 Technical Regulation calls for individual testing. This means that gas mixtures containing hydrogen which fall below the lower threshold value for relative density can potentially be used.

280 (DVGW Deutscher Verein des Gas- und Wasserfaches e.V., 2013)

281 (GWI Gas und Wärme Institut Essen e.V., 2017)

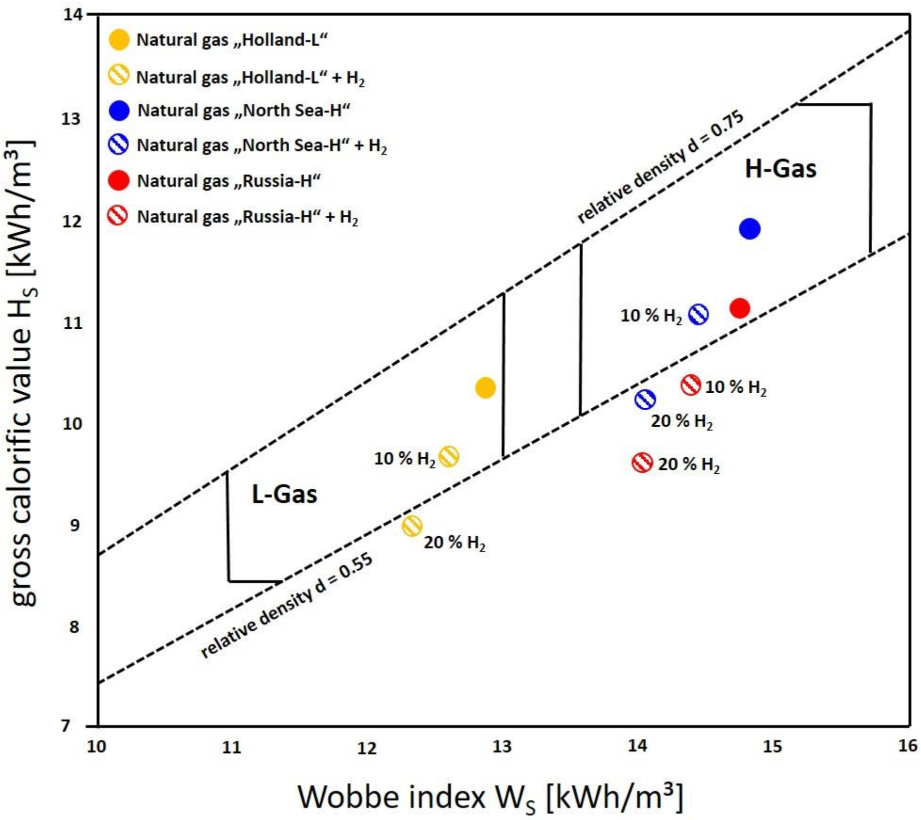

Figure 8-16: Change in gas quality characteristics (HS, WS, d) as a function of hydrogen concentration for three different natural gases, taking into account G 260 thresholds (status in 2013) - German case for the distribution gas network without special customers. Source: Authors' figure based on (DVGW Deutscher Verein des Gas- und Wasserfaches e.V., 2013), **(GWI Gas und Wärme Institut Essen e.V., 2017)**, **(Müller-Syring, 2011)**

In other European countries, the tolerance ranges may be defined differently without additional adjustment costs in the gas distribution network without special customers. Nevertheless, this gives a good example of the interrelationships.

The DVGW Technical Regulation Code of Practice G 262, titled "Using Gases from Renewable Sources in Public Gas Grids" (last updated: 2004), which is currently applicable to the feed-in of regenerative gases into natural gas grids in accordance with German grid regulations, states that the maximum share of hydrogen in combustive gases is to be limited to ≤ 5% by volume. However, the current version of DVGW Code of Practice G 262 (A) (September 2011) indicates that hydrogen concentrations in the single-digit percentage range (< 10%) in natural gas are non-critical in many cases if the requirements for combustion characteristics are observed. According to DVGW, the future regulations should initially aim for a hydrogen feed-in target of about 20 percent by volume.[282]

For blending in the transmission grid, and in the case of special customers in the distribution grid, infrastructure adaptation costs are incurred even for smaller shares. Higher shares than 10%, however, also cause additional adjustment costs in all distribution networks.

[282] (DVGW Deutscher Verein des Gas - und Wasserfaches e.V., 2019)

In this impact assessment, the influence of the gas origin in the individual countries is neglected.

8.4.2.2 Neglected costs for deblending at network nodes

The gas industry is currently discussing the option of a very widespread use of H2 deblending technologies. Instead of only protecting individual end users who do not tolerate H2, there should be a separation at network nodes to increase the H2 share in one network section up to 100% H2 and to reduce it in another network section down to 0%, ensuring a 100% CH4 concentration.

This is not possible in the transmission grid in the area of pore storage, since these storage facilities are charged and discharged seasonally and this would lead to a H2 blending rate limit violation in summer in the storage facility and in all downstream distribution grids. In addition, the necessary seasonal storage capability for hydrogen would be lost.

The question of a potential violation of H2 blending rate limits due to fluctuating H2 blending rates also arises in distribution networks. The concentration is indeed high with decentralized H2 feed (Type 2) or low with centralized H2 feed (Type 1). Another point is that membrane processes are relatively inexpensive when installed at the end user, as hydrogen and CH4 leave the purification at ambient pressure and can be used on site. However, for a new injection, hydrogen and CH4 have to be compressed again to the pressure level of the pipelines. Accordingly, additional costs for compressors are necessary. In addition, the membrane processes have only a limited purity of H2 and CH4. If necessary, additional costs are incurred for additional purification before new injection.

In this impact assessment, deblending was only considered for the relevant end-users and deblending at network nodes was not modelled.

8.4.2.3 Neglected costs for Compressed natural gas (CNG) vehicles replacement

An additional aspect that must be taken into account with the direct feed-in of hydrogen is the use of natural gas as a vehicle fuel. In the case of Germany, it is specified that a maximum hydrogen concentration of 2% by volume may not be exceeded in local distribution grids in which natural gas filling stations are located, due to the risk of gas tanks made of steel in older vehicles suffering from material failure.[283] Since gas tanks made of other materials (that no longer suffer from this weakness) are now commonly used, over the medium term the threshold value for CNG filling stations could potentially be raised.

As average lifetime for vehicles is approximately 8 years and new vehicles have natural gas tanks which are not concerned by these risks it is likely that in 2030, the share of concerned vehicles is low.

In this impact assessment, the costs for replacement of CNG vehicles were thus neglected.

[283] (GWI Gas und Wärme Institut Essen e.V., 2017)

8.4.2.4 Methane number and knock resistance for gas engines

Another important factor regarding the use of natural gas mixtures that contain hydrogen in CNG vehicles and combined heat and power plants is the "methane number," which is a measure of the knock resistance[284] of the fuel gas mixture in gasoline engines. Methane has a methane number of 100, while hydrogen has a methane number of 0. Higher hydrocarbons (ethane, propane, butane, etc.) also have a reduced methane number. The natural gas types "Denmark-H" and "North Sea-H" have a relatively high share of higher hydrocarbons (approx. 9%), which means that these gases already have relatively low methane numbers of 72 and 79, respectively. The German industry standard DIN 51624 specifies a minimum methane number of 70 for natural gas as a vehicle fuel.[285] The addition of hydrogen to natural gas is thus extremely limited for these two gas mixtures, and the use of a membrane for deblending would be necessary for gasoline engines.

In current energy scenarios, CNG vehicles are not expected to represent a large share of the transport solutions in the mid-term future, the focus being on e-mobility and fuel cell vehicles. Also, in the area of CHP engines, there is likely to be a focus on gas turbines at larger power sizes and high-temperature fuel cells (SOFC) at smaller power sizes due to the discussions on methane emissions from incomplete combustion with excess air.

In this impact assessment, adaptation costs linked to knock resistance were neglected.

8.4.2.5 Costs due to replacements

The analysis of infrastructure adaptation costs for allowing H2 blending at the transport level is done for 2030. It is assumed that many applications existing today have not yet been replaced by then.

In 2030, replacement is already taken into account for operating old gas-fired power plants (for electricity generation) and gas-fired boilers built before 2020. The new plants - built between 2020 and 2030 - are assumed to be H2 ready, which means that the plants are already designed for a specific H2 blending rate. The adaptation costs are thus cheaper than for a new plant. However, individual components of the plants still have to be replaced to reach 100% H2 later on.

In this impact assessment, replacement costs of gas compressors (part which drives the compressors) in the gas grid until 2030 (missing data) and the share of the already electrified compressor (drive part) are neglected.

8.4.2.6 Neglected costs for adaptation and replacement of pipelines

As indicated in Section 10.3.3, in case an internal coating for high-pressure steel pipelines is necessary, the Hydrogen Backbone Study estimates these costs at €40

[284] Knock resistance is the property of the fuel used in a gasoline engine (in this case gas) not to burn uncontrollably by spontaneous ignition ("knocking", for instance because of a compression), but to be triggered only by the ignition spark.

[285] (DVGW Deutscher Verein des Gas- und Wasserfaches e.V., 2013)

000/km for large transmission pipelines.[286] Due to the need for excavation works, coating existing pipelines could be associated to significant costs, although new coating processes are being developed.[287] However, coating costs for low to medium blending levels would likely be lower and represent only a marginal share of network costs.[288]

If necessary, existing pipes of cast iron must be replaced. However, this has a low impact as:

- Information is not available for low pressure pipelines made from cast iron, but most of these pipelines are generally replaced for other reasons and are not used on a large scale. In 2013 already, cast iron pipes represented only 3% of the distribution network in countries covered by Marcogaz's technical statistics[289] (AT, BE, CZ, DK, FR, FI, DE, EL, IT, IE, NL, NO, PL and PT). Polyethylene pipes then made up 54% of the 1.5 million km of distribution network pipes considered, while steel pipes came in second at 34%.
- Furthermore, old cast iron pipelines in the distribution grid are not compatible with hydrogen blending but their use is now very limited, to certain mostly urban areas. In these specific areas, hydrogen blending could require the replacement of the cast iron pipelines. Replacement would be at some point also necessary without hydrogen blending anyway, thus blending will merely be a driver to speed up the replacement process.

In this impact assessment, the costs for coating and the replacement of pipes were then neglected.

8.4.2.7 Neglected adaptation costs for shares of more than 20% of H2 blending

For high shares of blending, some adaptation costs were neglected. However, since for hydrogen shares higher than 20% the main cost driver of adaptation in 2030 is the replacement of gas boilers (which are explicitly considered), the missing adaptation costs are not impacting the conclusions of this impact assessment.

Logistics related to the conversion process of the gas supply

When converting from L-gas (gas with lower energy density) to H-gas (gas with higher energy density) in Northwest Germany, an adjustment of the individual appliances by a technician is necessary. During the entire conversion period of individual districts, the appliances can continue to be used. However, this is not possible with hydrogen as an interruption in supply must be tolerated during the conversion period. In addition to the damage to the activity of the consumers concerned, extra costs may have to be associated in order to keep this supply interruption as short as possible. Due to lacking data, the respective costs are neglected in the present assessment.

Replacement of valves

Up to 20% of hydrogen blending, there is no relevant leakage in the gas grid. However, beyond 20% valves of the distribution network have to be changed to prevent gas

[286] (Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, 2020)

[287] (Stolten, 2020)

[288] (GRTgaz, 2019)

[289] (Marcogaz, 2014)

leakage. This results in additional costs. However, the data basis for the associated costs is lacking, thus they are neglected.

Adaptation of compressors

Above a blending rate of 40% H2, the part without drive unit of the compressors for transport and storage linked to the transmission grid must be replaced, hence adding other adaptation costs. In this impact assessment, such a high share was not studied.

8.4.3 Assumptions of the infrastructure adaptation needed

This section analyses the devices that consume natural gas and are not able to handle hydrogen blending. The devices that are not able to handle time-varying mixing rates (and therefore only accept a fixed and very stable blending ratio as input) are studied as well.

It is assumed that up to 10% H2 content, high fluctuations in the distribution network are tolerable, for instance when hydrogen is injected into the distribution grid. Above 10%, it is assumed that hydrogen is injected into the transmission grid and that the spatial and temporal balancing effects in the transport network greatly reduce the fluctuations of the blending rate. Thus, it is assumed that under 20% of H2 blending levels, equipment is not damaged by the variation of blending rates.

8.4.3.1 Burners of gas heating systems in households and tertiary

Adaptation needs

With regard to the hydrogen tolerance of gas burners, manufacturers of gas-fired end-customer systems must ensure that all systems placed on the market can be operated safely with gases in accordance with national and European regulation. In the German case, this is the DVGW Code of Practice G 260. Furthermore, DIN EN 437, which applies to all gas systems connected to public gas grids, prescribes a test gas (G 222) with a 23% share by volume for the group natural gas H. This G 222 test gas is used to conduct a short-term test (to check the tendency of gas burners to flash back) and, accordingly, does not allow any statements to be made about the long-term suitability of the systems for hydrogen-blended gases.[290]

Decentralised gas burners can operate with up to 10% H2 blending without any problems. Above 10%, smaller modification measures are necessary. This means, however, that fluctuating hydrogen shares cannot be tolerated. After adjustment, the hydrogen content must be between 10 and 20% all year round. For this reason, hydrogen can only be fed into the distribution grid up to 10%. With higher shares, the balancing of the seasonal gas storage in the transmission grid should be used in conjunction with H2 feed in into the transmission grid to reduce the fluctuations in the H2 content.

For blending rates above 20%, there are additional adaptation costs at the DSO level to invest in new heating boilers.

Country-specific key figures

The number of remaining decentralised burners in the residential and tertiary sectors (installed before 2020) of the MIX H2 scenario is used individually for each country.

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[290] (DVGW, 2014)

For new boilers installed between 2020 and 2030, the additional costs compared to a standard device would be relatively low if they are H2 ready (meaning the boilers are designed to accept a specific positive H2 blending rate). One to two hours are needed to adapt the equipment, including the commissioning, and an additional 17% of invest is required for the replacement of burner components[291].

Cost calculation

It is assumed that:

- Buildings are represented by an average one- to two-family house with 185 m² living space and 10-12 kW boiler capacity [292]
- 11 000 €/unit investment cost, 20 years of lifetime
- H2-ready boilers have an additional investment costs of 17%[293]

This leads to costs of:

- 1 033 €/unit/year CAPEX (with 5% interest rate)

8.4.3.2 Gas turbines (for power generation, and compressors in case of gas grid and storage) and CHP for power generation (engine CHP and gas turbine steam power plants)

Adaptation needs

Gas turbines (power plants and compressors in case of gas grid and storage): The German DVGW Code of Practice G 262 (A) imposes clear restrictions on the hydrogen content of fuel used to operate gas turbines. Since gas turbines with low-pollution premix burners can react "sensitively" to hydrogen, depending on the gas turbine manufacturer, the limit values for hydrogen range between 1 and 5% by volume. Thus, adaptation costs for blending rates below 5% are neglected (however, individual cases must be examined on site). In the future, however, new gas turbines are likely to have significantly higher hydrogen tolerances (up to 100%). All European turbine manufacturers committed to enable a compatibility of 20 vol.-% of hydrogen blending for new H2-ready plants in 2020.[294] H2 ready plants mean that new gas turbines can accept at least 20% hydrogen or more, and that an adaptation to 100% only requires the replacement of individual components. However, the adaptation of new gas turbines to a 100% rate requires a replacement of the combustion chamber in the gas turbine and thus additional costs for a plant conversion.

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[291] EHI position paper 2021-02-26 – quote in presentation "Hydrogen and decarbonisation of buildings" 21. April 2020 meeting ehi with DG Ener

[292] Data comes from the chimney sweep survey.

[293] EHI position paper 2021-02-26 – quote in presentation "Hydrogen and decarbonisation of buildings" 21. April 2020 meeting ehi with DG Ener

[294] Fraunhofer ISE, Fraunhofer ISI 2019. Eine Wasserstoff-Roadmap für Deutschland. https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/2019-10_Fraunhofer_Wasserstoff-Roadmap_fuer_Deutschland.pdf

Engines and steam power plants: For engines, hydrogen contents of up to 10% are possible (knock resistance, seals). Furthermore, there are still some gas-fired steam power plants in the CHP sector. Here, too, a simplified limit of a maximum of 10% H2 content is assumed. Above a blending rate of 10%, for both applications it is necessary to purify the gas using a membrane for deblending.

- For gas turbines (power plants, transport, storage), additional adaptation costs at the TSO level need to be considered:
    - from 5 to 10% H2, investments in deblending, and additional operating costs in electricity demand and use of deblended H2 are required;
    - from 10 to 20% H2, additional investments in deblending and additional operating costs in H2 use are required.
- For engines and steam power plants, there are additional adaptation costs at the DSO level:
    - from 10 to 20% H2, investments in deblending and additional operating costs in electricity demand and use of deblended H2 are needed.

Country-specific key figures

For gas turbines (partly condensing power plants, partly CHP) and other CHP for power generation (old stock) the installed capacity (GW gas connection capacity) of remaining (installed before 2020) gas-fired power generation of the scenario MIX H2 is used individually for each country.

It is assumed that, for each country, 100% of the electricity-only plants and 50% of CHP plants are **gas turbines** and are connected to the transmission grid (higher capacity classes).

The remaining 50% of the CHP plants is assumed to be, for each country, either **engine CHP plants or steam power plants.** They are assumed to be connected to the distribution grid (higher capacity classes). The electrical efficiencies of electricity only plants and CHPs are assumed to be 50% and 40%, respectively.

The **compressors in the gas transport network** are mostly mechanically driven (with a mechanical efficiency of 33%) by **smaller gas turbines** with the same requirements as gas turbines in power generation. To obtain country-based estimations of the capacity needed for the compressors, an extrapolation of the compressor fleet in Germany is done. In Germany, 2.45 GW are installed and consume 0.4% of Germany's annually transported natural gas volume for transport[295]. A loss value is then determined for all other countries via the historical transit factor (GWh of import + export / gross consumption)[296]. This value is used to estimate the compressor drive capacity required in other countries for the transport of their total gas consumption.

The same applies to the **compressors at the gas storage facilities**. An internal database using the specific compression work of 0.040 kWh/m³ (or 40 MWh/M m³) is used for the existing storage volume per country. The average full load hours for the injection (between 539 in Sweden and 6076 h/year in Spain) is also taken from the database. Finally, the fact that some of the compressors are already electrified (in Germany 24%)[297] is neglected.

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[295] (Köppel et al, 2019)

[296] (IEA, 2021)

[297] (Köppel et al, 2019)

Cost calculation

Very high costs would be incurred for deblending if the deblended hydrogen was to be injected back into the gas network for further use (network node application). However, it is assumed that deblending only occurs at the level of end consumers. As these end consumers operate at a low pressure level, this reinjection of deblended hydrogen into the gas network is not considered.

The cost calculation takes into account the assumption that, for all applications, the H2 content is purified back to 0 as soon as the limit (5% for gas turbine and 10% for engines and steam power plant) is exceeded. The following cost distribution is assumed for power plants (in two steps - 0% → 10% → 20% - above 5% blending rate for gas turbines, respectively in one step only – 0% → 20% - above 10% blending rate for engine CHP plants or steam power plants):[298]

- From 5% to 10% H2
    - CAPEX: 15.6 €/m³/h/year fixed operating cost for deblending for 100 MW gas connection capacity 1.6 €/kW/year
    - OPEX due to additional electrical demand: 0.1 kWh_electr. /m3_gas → 0.0102 kWh_electr. / kWh_gas
    - OPEX due to resale of deblended hydrogen at a low cost: H2 sale revenue -0.1 m3_H2 / m3_gas → -0.033 kWh_H2 /kWh_gas mix. Assuming that the price of H2 in 2030 is 50 €/MWh and its resale price after deblending is 17 €/MWh, this results in a loss of 1.1 €/MWh of relevant gas demand due to the loss in value of H2 after deblending.
- From 10% to 20% H2
    - Additional CAPEX: 25 – 15.6 €/m³/h/year = 9.4 additional fixed operating costs for deblending for 10 MW gas connection capacity → 0.95 €/kW/year
    - Additional OPEX due to resale of deblended hydrogen at a low cos: H2 sale revenue –0.1 m3_H2 / m3_gas → -0.033 kWh_H2 /kWh_gas mix, which results in a loss of 1.1 €/MWh of relevant gas demand.

The following costs are assumed for gas turbines that power compressors for gas grids (for transport and storage):

- From 5% to 10%
    - CAPEX: 37.4 €/m³/h/year fixed operating cost for deblending for 10 MW gas connection capacity → 3.8 €/kW/year
    - OPEX due to additional electricity demand: 0.1 kWh_electr. /m3_gas ⇒ 0.0102 kWh_electr. / kWh_gas
    - OPEX due to resale of deblended hydrogen at a low cost: H2 sale revenues -0.1 m3_H2 / m3_gas → -0.033 kWh H2 /kWh gas mix, which results in a loss of 1.1€/MWh of relevant gas demand

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[298] Own assumptions based on Blending Hydrogen into Natural Gas Pipeline NetTechnical Report - A Review of Key Issues NREL/TP-5600-51995, March 2013, M. W. Melaina, O. Antonia, and M. Penev, and
Techno-economic evaluation on a hybrid technology for low hydrogen concentration separation and purification from natural gas grid; Maria Nordio, Solomon Assefa Wassie, Martin Van Sint Annaland, D. Alfredo Pacheco Tanaka, Jos Luis Viviente Sole, Fausto Gallucci

- From 10% to 20%
    - Additional CAPEX: 61 – 37.4 €/m³/h/year = 23.6 additional fixed operating cost for deblendig for 10 MW gas connection capacity → 2.6 €/kW/year
    - Additional OPEX due to resale of deblended hydrogen at a low cos: H2 sale revenue -0.1 m3_H2 / m3_gas → - 0.033 kWh_H2 /kWh_gas mix, which results in a loss of 1.1€/MWh of relevant gas demand

8.4.3.3 Industry (gas quality for glass, ceramics, feed stock use of the chemical industry)

Adaptation needs

Regarding industrial applications, the following is stated in the "Gas 2030 Dialog Process": "However, even small blending quantities in domains that depend on consistent gas quality (e.g. material use in chemistry (feedstock)) or constant temperatures (e.g. glass, ceramics) can pose significant risks for process reliability. … Consequently, hydrogen blending is not viewed as a priority option for the applications in the industrial sector".[299]

For these infrastructures, it is necessary to purify the gas through deblending.

- 50% gas demand of chemical industry (material use = feedstock) and glass is allocated at the TSO level. Additional adaptation costs are:
    - From 0 to 5% H2 blending rate: investment costs in deblending, and additional operating costs in electrical demand and deblended H2 use
    - From 5 to 10% H2 blending rate: additional investment costs in deblending, and additional operating costs in deblended H2 use
    - From 10 to 20% H2 blending rate: additional investment costs in deblending, and additional operating costs in deblended H2 use
- 50% gas demand of chemical industry (material use = feedstock) and glass is allocated at the DSO level. Additional adaptation costs are similar:
    - From 0 to 5% H2 blending rate: investment costs in deblending, and additional operating costs in electrical demand and deblended H2 use
    - From 5 to 10% H2 blending rate: additional investment costs in deblending, and additional operating costs in deblended H2 use
    - From 10 to 20% H2 blending rate: additional investment costs in deblending, and additional operating costs in deblended H2 use

Country-specific key figures

Generally, the data available at the country levels for gas use in industry is the yearly consumption. To estimate the corresponding gas connection capacity, the gas consumptions are divided by 8760 h/year.

It is assumed that all feedstock gas consumption has to be cleaned from hydrogen blending. The gas demand of feedstock (190 TWh for EU27) of the scenario MIX H2 is used for each country.

[299] (BMWI Bundesministerium für Wirtschaft und Energie, 2019)

For glass and ceramics, two data sets are used. On the one hand, the unpublished database of Fraunhofer ISI on the production volume is used. It contains specific data on ceramics, but the consumption share for ceramics is significantly lower than for glass. On the other hand, the relative sector gas consumption of non-metallic minerals (cement, ceramics, glass, and lime) is used for each country.[300] These volumes are related to the absolute industrial gas demand of the scenario MIX H2. Due to the uncertainty, the average between production volumes and sector gas consumption is used. This leads to a consumption of 55 TWh in the EU27 for glass and ceramics.

Due to a lack of data on the connection point and power classes of the industrial plants, it is assumed that 50% of the consumption is connected to the transmission grid and 50% to the distribution grid.

Cost calculation

It is assumed that:

- From 0% to 5% H2
    - CAPEX: 9.4 €/m³/h/year fixed operating cost for deblending for 100 MW gas connection capacity → 0.9 €/kW/year
    - OPEX due to additional electrical demand: 0.1 kWh_electr. / m3_gas → 0.0102 kWh_electr. / kWh gas
    - OPEX due to resale of deblended hydrogen at a low cost: H2 sale revenue – 0.05 m3_H2 / m3_gas → - 0.017 kWh H2 /kWh gas mix → 0.55 €/MWh of relevant gas demand
- From 5% to 10% H2
    - Additional CAPEX: 15.6 - 9.4 €/m³/h/year = 6.2 additional fixed operating cost for deblending for 10 MW gas connection capacity → 0.63 €/kW/year
    - Additional OPEX due to resale of deblended hydrogen at a low cost: H2 sale revenue – 0.05 m3_H2 / m3_gas → - 0.017 kWh H2 /kWh gas mix → 0.55 €/MWh of relevant gas demand
- From 10% to 20% H2
    - additional CAPEX: 25 - 15.6 €/m³/h/year = 9.4 additional fixed operating cost for deblending for 10 MW gas connection capacity → 0.95 €/kW/year
    - additional OPEX due to resale of deblended hydrogen at a low cost: H2 sale revenue - 0.1 m3_H2 / m3_gas → - 0.033 kWh H2 /kWh gas mix → 1.1 €/MWh of relevant gas demand

8.4.3.4 Industry (Flame temperature for industrial furnaces)

Adaptation needs

Regarding industrial applications, the following is stated in the "Gas 2030 Dialog Process": "… Moreover, as hydrogen has 1/3 the calorific value of natural gas, it is not suitable for all high-temperature applications in pure form. In the case of blending, given the increased need for measurement and control technologies, we can also anticipate

[300] Split of gas consumption (FEC) in industry by branch in 2015 without feedstock Source: IDEES

impairments to the energy efficiency of production processes. Consequently, hydrogen blending is not viewed as a priority option for the applications in the industrial sector”.[301]

In order to maintain the flame temperature level, a calorific value adjustment via Liquified Petroleum Gas (LPG) admixture is necessary (it is assumed that for all applications the calorific value is adjusted back to the value of natural gas without H2 as soon as the limit of 5% H2 blending is exceeded):

- For 50% gas demand of furnaces (industrial high temperature application >500°C) there are additional adaptation costs at the TSO level
  - From 5 to 10% H2 to invest in calorific value adjustment and operating costs in additional LPG use
  - From 10 to 20% H2 additional operating costs in LPG use
- For 50% of gas demand of furnaces (industrial high temperature application >500°C) there are additional adaptations cost at the DSO level
  - From 5 to 10% H2 to invest in calorific value adjustment and operating costs in additional LPG use
  - From 10 to 20% H2 additional operating costs in LPG use

Country-specific key figures

The relative shares of gas demand from industrial furnaces for each country are derived from the scenario "Industry Innovations 2050" (in%).[302] These are put in relation to the absolute demands of the data of final energy consumption (in GWh/year) of the MIX H2 scenario.

Cost calculation

For the calorific value adjustment of furnaces, the plant investments and the fuel costs for LPG must be distinguished. The gas connection capacity of the stoves is determined in a simplified way by dividing the consumption by 8760 hours. For the fuel costs, the cost difference between LPG and natural gas is considered. It is assumed that:

- From 5% to 10% H2
  - Investment costs of 411 €/m³/h (=42 €/kW)
    - 33 €/m³/h/year CAPEX
    - + 21 €/m3/h/year fixed operating cost (5% of invest)
    - The total amounts to 54 €/m3/h/year (=5.4 €/kW/year)
  - LPG costs of:
    - 3.9% m3_LPG / m3_gas (=0.11 kWh LPG/ kWh gas mix)
    - 76 €/MWh_LPG (incl. CO2 price of 44 €/t) – 28 €/MWh_gas (incl. CO2 price 44€/t) = 48 €/MWh cost difference
    - This amounts to 5.27 €/MWh of relevant gas demand
- From 10% to 20% H2

[301] (BMWI Bundesministerium für Wirtschaft und Energie, 2019)

[302] (ICF, Fraunhofer ISI, 2019)

- Additional LPG costs of 5.27 €/MWh of relevant gas demand

These assumptions are based on a raw data set adapted to 2020, used in the eMikroBGAA project.[303]

8.4.3.5 Sulphur in porous storage and general H2 loss through drying in storages

Adaptation needs

Since hydrogen serves as a substrate for sulphate-reducing bacteria, the stagnation of hydrogen triggers the risk of bacterial growth, especially in underground pore storage facilities. According to G 262, it is therefore recommended to limit the injection of hydrogen into pore storage facilities, other storage options such as cavern storage facilities being more appropriate.

The membrane process used for purifying H2 for deblending for the other infrastructures is not suitable for pore storage. Indeed, a bypass around the storage tank would lead to an increase in H2 concentration in the network outside the storage tank which would result in exceeding local limits in summer. To avoid going past these limits, the local stakeholders would lose the seasonal storage capability or have to use the valuable H2 in other, relatively inefficient, ways. On the other hand, bacteria in pore storage consume a small fraction of the seasonally stored H2. Thus, adaptation of storage installation is not a problem energetically, but implies a technical challenge due to sulphur production. There are therefore two types of adaptations required for H2 blending: desulphurization for porous storages, and drying, which is generally necessary for all types of storage. The infrastructure is already in place, but it leads to certain further hydrogen losses of 5% of the hydrogen (for instance at a blending level of 20% this represents 1% of hydrogen loss).

According to an interview with a storage operator, even a level of 10% of H2 blending can be a problem for some pore storage systems. From today's perspective, above 20% of blending rate it is not possible anymore to sufficiently empty the hydrogen in the storage tank once a year to reduce bacterial populations.

The publication of the "Underground Sun Storage" project[304] investigates whether it is possible to store renewable energy in the form of hydrogen(-blending) in existing underground pore storage facilities. As a result, no problems are expected for a 10% hydrogen content. Despite the uncertainties of bacterial population and individual storage form, it can at least be deduced that only small amounts of sulphur are produced. This advocates for the use of an adsorptive process with activated carbon - rather than washing processes - as the most relevant solution to prevent the presence of hydrogen in porous storages.

It is necessary to remove the water (drying) from the hydrogen stored after its removal from the cavern, since hydrogen is enriched with water from the cavern sump (depending on the residence time). Adsorption drying is recommended as the best drying technology available. This is different from the absorption drying with glycol,

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[303] Quelle: Beil, M.; Beyrich, W.; Kasten, J.; Krautkremer, B.; Daniel-Gromke, J.; Denysenko, V.; Rensberg, N.; Schmalfuß, T.; Erdmann, G.; Jacobs, B.; Müller-Syring, G.; Erler, R.; Hüttenrauch, J.; Schumann, E.; König, J.; Jakob, S.; Edel, M. (2019): Project report „Effiziente Mikro-Biogasaufbereitungsanlagen (eMikroBGAA)“.

[304] (Underground Sun Storage: Ein Projekt zur Erforschung der Wasserstoffverträglichkeit von Erdgasporenspeichern)

which is used for drying natural gas, but which introduces impurities into the hydrogen and cannot achieve sufficient drying. The new adsorption dryer consists of two parallel lines. While the moist hydrogen flows through one adsorption bed, the absorbed water can be expelled from the saturated adsorption bed by means of hot gas.[305] For the lower hydrogen fractions up to 20%, however, a continued use of the existing natural gas drying is assumed and the costs for a new technology are neglected.

- For H2 losses by drying in all storages there are additional adaptation costs at the TSO level:
    - From 5 to 10% H2 in additional operating costs for losses of 5% of H2
    - From 10 to 20% H2 in operating costs for additional losses of 5% of H2
- For sulphur in porous storage there are additional adaptation costs at the TSO level:
    - From 0 to 5% H2 to invest in desulphurization

Country-specific key figures

The volumes and withdrawal capacities of porous and cavern storage per country are taken from the database of the METIS 3 project (ongoing work).

Cost calculation

Desulphurization refers to the gas withdrawn from the natural gas storage before being re-injected into the pipeline system. From the above mentioned "Underground Sun Storage" project, it can be deduced that low H_2S concentrations are involved. This report argues for the use of an adsorptive process using activated carbon. Since no information was available on the expected H_2S concentrations, an average mass concentration of 10 mg/m³ was assumed. The volume flow was set at an average value of 459,000 m³/h for an operating time of 1,700 h/a on the basis of statistics on the operation of existing gas storage facilities.

The approach chosen was based on a recently implemented large-scale adsorber for the deodorization of natural gas. Investment costs of this adsorber are from Bilfinger.[306] The technical specification comes from another source.[307] The costs quoted in the above sources have been adjusted to the capacity used in the present analysis.

For sulphur in porous storage, it is assumed that:

- From 0% to 5% blending rate
    - Investment costs:
        - 44 €/m³/h invest for desulfurization plant → 3.5 €/m³/h/year
        - Fixed operating cost with 5% of invest → 2.2 €/m³/h/year
    - Variable operating costs - activated carbon:

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[305] (DLR, Fraunhofer ISE, LBST, KBB, 2014)

[306] https://www.bilfinger.com/media/news/bilfinger-erhaelt-prestigetraechtigen-auftrag-fuer-gasbehandlungsanlage/ (last access: 25.05.21)

[307] https://bis-austria.bilfinger.com/referenzen/energie-versorgung-hydro/behaelter-und-apparate/schwoerstadt/ (last access: 03.07.21)

        - 0.876 €/m³/h/year for continuous operation
        - Average withdrawal utilisation of European porous storage – 1700 h/year FLH → 0.17 €/m³/h/year (based on capacity utilisation)
    - The total amounts to 5.8 €/m³/h/year
- From 5% to 10% blending rate
    - Additional CAPEX: 25 - 15.6 €/m³/h/year = 9.4 additional fixed operating cost for deblending for 10 MW gas connection capacity → 0.95 €/kW/year
    - Additional OPEX: H2 sale revenue - 0.1 m3_H2 / m3_gas → - 0.033 kWh H2 /kWh_gas mix

An adjustment of the activated carbon demand (approx. 5,000 €/t) to the H2 blending rate was neglected, as the share of these costs is very low.

For H2 losses by drying in all storage it is assumed that:

- From 5% to 10%
    - Bn m3 working gas 10% of H2 (the drying of the total hydrogen being balanced from 0 → 10% and not from 5 → 10%)
    - This amounts to 5% losses of hydrogen at a cost of 50 €/MWh H2

8.4.3.6 Thermodynamic influences of compression and expansion

Adaptation needs

The energy density (quantity of energy within a given volume) and the Joule-Thomson effect[308] have to be taken into account when analysing the H2 blending rates. As indicated in **Table 8-33**, hydrogen has a significantly lower energy density than natural gas.

Table 8-33: Energy density assumptions

Category	Criteria	Value (LHV - lower heating value)
Energy density	**Fuel**	**kWh/m³**
	H2	10.8
	Natural gas (EU high calorific natural gas)	38.2
Decreasing energy density with increasing H2 content	**H2-Vol%**	**kWh/m³**
	0%	10.61
	5%	10.23
	10%	9.85
	20%	9.09

[308] The Joule-Thomson effect refers to the change in temperature of a gas during a reduction in pressure. For natural gas, the temperature drops during expansion. For hydrogen, on the other hand, it rises.

For compression - As the H2 content in natural gas increases, the energy content decreases. If the H2 content is 10% by volume, the calorific value is reduced by approx. 6% (values given for illustrative purposes for the natural gases distributed in Germany: Russian natural gas-H). This lowered energy content must be compensated by higher delivered volume, if the same amount of energy is to be delivered. As a result, the power consumption of the compressor increases. Thereby, the power of compressors increases disproportionately with increasing H2 content. Therefore, more drive power for this infrastructure is needed (typically via a replacement of the drive). Additionally, a modification of the working machine (natural gas compressor) is required. At last, the additional compression effort for the transported energy equivalent should also be considered.[309]

When H2 is added to the natural gas network, the Joule-Thomson effect of the blended gas is reduced. At low concentrations, this effect is only very moderate. At a pressure increase of 30 bar, only small effects (temperature reduction due to the H2) can be expected. A calculation example with Russian natural gas-H shows a temperature reduction of 1.3 K with an H2 content of 20% by volume. Thus, no modifications to heat exchangers (coolers) downstream of the compressors are necessary.[310]

Compressors exist for transmission system transport and for storage. In a simplified way, only the cost of the additional capacity of the driving part is taken into account (and not a complete replacement by a larger new H2-ready plant). On the other hand, the fact that plants may have to be replaced between 2020 and 2030 anyway at the end of their lifetime is not taken into account. If the driving part needs to be completely replaced, but has not yet reached the end of its lifetime, the costs could be higher than expected (130% instead of +30%). On the other hand, functional drive units that are too small may have a resale value. Up to approx. 10% H2, the compressor itself (without drive section) can usually be used without major modifications. Up to approx. 40% H2, the compressor housing can be retained; impellers and feedback stages as well as gears must be adapted.[311]

For expansion: When injecting H2 into the natural gas network, a lower amount of preheat is required due to the negative Joule-Thomson effect of H2. At 10% H2 by volume in natural gas, this is about 86% of the preheating gas demand compared to pressure control of natural gas. The capacity of the gas pressure regulator would drop to about 98% at this H2 concentration. If the same amount of energy is to be delivered, the volumetric flow rate must be increased and, as a result, the surface load of the filters inside the gas pressure regulator increases to 110%. The increase in flow velocity may also result in increased noise. For H2 blending of up to 10% by volume, the expected effect is considered to be marginal and uncritical. For H2 concentrations above 10 vol.%, screening of the design of components in gas pressure regulator is recommended. [312]

Gas pressure regulators, with preheating are available both at the outlet of the storage tanks and at the interface between the transmission and distribution network. But in the case of high H2 contents, all gas pressure regulators must be replaced, even in the lower pressure stages of the distribution network (without preheating), because the design for relative density is no longer suitable.

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[309] (DVGW, 2014)

[310] (DVGW, 2014)

[311] (Siemens Energy, Nowega GmbH, Gascade Gastransport GmbH, 2020)

[312] (DVGW, 2014)

The following influences are accounted for:

- With the installation of higher gas turbine capacities for compressors (transport and storage) there are additional adaptation costs at the TSO level:
    - For an increase in the H2 share from 5% to 10%:
        - If the transport capacity is to remain the same with a 10% hydrogen blending rate, a stronger pressure gradient must be implemented on the affected pipeline sections. For this purpose, the national compressor capacity must be increased by approx. 30%.
        - This leads to an increase in investment cost in order to reach +30% of existing gas turbine capacity for compressors (transport and storage).
        - This also leads to an increase in operating costs for gas demand, due to a +30% increase in existing transport losses.
    - For an increase in the H2 share from 10% to 20% H2:
        - If the transport capacity is to remain the same when feeding in 20% hydrogen by volume, the national compressor capacity must be increased by approx. 70%.
        - This leads to additional investment cost in order to reach +40% of existing capacity.
        - This also leads to additional operating costs for gas demand, due to a 40% increase in existing transport losses.
- For the component exchange of compressors (without drive section) there are additional adaptation costs at the TSO level:
        - From 10% to 20% H2 to invest 50% of the value for compressor in gas grid and storage
- For central TSO gas pressure regulators (storage withdrawal and grid pressure regulator at the interface between >40 bar to 16 bar) there are additional adaptation savings at TSO level:
    - From 5% to 10% H2 for operating costs savings of +3% less energy for preheating required.
    - From 10% to 20% H2 for additional operating costs savings of +5% less energy for preheating required.
- For decentralized DSO gas pressure regulators (no preheating required) there are additional adaptation costs at the DSO level because:
    - From 10% to 20% H2 the design for relative density does no longer fit and requires a replacement.

Country-specific key figures

Installation of higher gas turbine capacities for compressors (transport and storage): As already described in Section 8.4.3.2, the data on gas shaft power capacities (mechanical energy) to drive compressors in the transmission network and at gas storage facilities is used. As already mentioned, there is uncertainty regarding age structure and residual value when the drives are replaced. An intermediate value for additional power costs for all plants was chosen. The additional investment costs only account for 6% of the total adaptation costs up to 20% H2 blending. The influence of uncertainty is therefore small. The data of gas shaft power capacities (mechanical energy) for the component exchange of compressors (without drive section) is also considered.

Gas demand for higher gas turbine capacities for compressors (transport and storage): The data on energy losses (consumption for compressor drive) for transmission network and storage facilities as described in the chapter on H2 deblending is also considered.

Preheating gas pressure regulator storage withdrawal: The technical potential of the net energy for gas preheating at the storage facility is estimated from the survey data of 4 storage operators in Germany. In the survey, these indicated preheating energies for 8 storage facilities operated by the 4 SSOs (porous and cavern storage facilities for the years 2013 and 2014, respectively), which represent a working gas volume of 14% of the total German working gas volume. Assuming similar operation of the storage facilities, the net energy of gas preheating at storage facilities via the working gas volume was extrapolated to approx. 146 GWh as a first approximation; the technical potential is thus 162 GWh in 2013.[313] The METIS 3 database of existing storage volumes per country is used and the German losses in relation to the storage volume are translated to these other countries. These losses are reduced by H2 blending.

Preheating gas pressure regulator >40 bar -> 16 bar: In 2013, the natural gas consumption of Germany was 941.5 TWh. Gas-fired power plants and large industrial plants usually have a direct connection to a high-pressure pipeline. For them, preheating is not required for expansion into lower-pressure downstream networks. Their gas offtake has been estimated at 30% of the total natural gas offtake, which on the other hand reduces the mass flow from transmission to distribution network. With this projection, the maximum net energy for preheating is 970 GWh/year in 2013.[314] This results in a gas consumption for preheating of 0.15%. The decentralized gas consumption is approximately calculated on the basis of the gas consumption data of the MIX H2 scenario and the factor is applied to this. These losses are reduced by H2 blending.

Gas pressure regulator (focus on decentralized DSOs): There are 40,257 gas pressure regulators in Germany alone. Ca. 2/13 of them are located at the transfer point between transmission network and distribution network (from >40 bar → 16 bar), but the majority are district controller without preheating.[315] The figures for the kilometres of the European gas distribution network[316] is used to infer the number of gas pressure regulators in other countries from Germany.

Cost calculation

There is an important uncertainty in the adaptation costs for gas turbine capacities for compressors (transport and storage). On the one hand, the compressors belong to small size classes (approx. 11 MW/unit), with an adaptation cost of 850 €/kW for small gas turbines in power generation. On the other hand, in the cost data in the literature, the question is what role peripheries play (building, electrical connections, ...), with

[313] (Martin Wietschel et al. Fraunhofer-Institut für System- und Innovationsforschung ISI , Karlsruhe, 2019)

[314] (Martin Wietschel et al. Fraunhofer-Institut für System- und Innovationsforschung ISI , Karlsruhe, 2019)

[315] (Fraunhofer-Institut für System- und Innovationsforschung ISI, Karlsruhe, DVGW-Forschungsstelle am Engler-Bunte-Institut des Karlsruher Instituts für Technolo-gie (KIT), 2019)

[316] (Trinomics, Enerdata, Cambridge Econometrics, VITO, LBST, 2020)

adaptation costs that can reach 1.5 M€/MW.[317] An alternative electrical choice of the drive shows comparable costs. It is assumed that:

- From 5% to 10% H2
    - 1.18 M€/MW investment cost (average of 1.5 and 0.85) → 94 €/kW/year which is to be added to 5% fixed operational cost → 59 €/kW/year, resulting into 153 €/kW/year for the 30% additional capacity needed
    - OPEX: Gas demand +30% of existing transport losses multiplied by the price of 10% H2 gas mix
- From 10% to 20% H2
    - 1.18 M€/MW investment costs (average of 1.5 and 0.85) → 94 €/kW/year which is to be added to 5% fixed operational cost → 59 €/kW/year, resulting into 153 €/kW/year for the 40% additional capacity needed
    - OPEX: Gas demand +40% of existing transport losses multiplied by the price of 20% H2 gas mix

For component exchange of compressors (without drive section) it is assumed that:

- From 10% to 20% H2
    - 2 M€/MW invest → 160 €/kW/year which is to be added to 1% fixed operational cost → 20 €/kW/year resulting into 180 €/kW/year, multiplied by 50% since only parts are replaced

The fact that in 2030 more expensive electricity could also be used for preheating is neglected. It is assumed that:

- From 5% to 10% H2
    - 3% decrease in energy required multiplied by the price of 10% H2 gas mix
- From 10% to 20% H2
    - 5% decrease in energy required multiplied by the price of 10% H2 gas mix

For gas pressure regulator it is assumed that:

- From 10% to 20% H2
    - Investment: 21,538 €/unit invest (new unit 30,000 € for transfer station (2/13), and 20,000 € for district controller (11/13))[318] → 1728 €/unit/year which is to be added to fixed operating cost with 5% of invest → 1,077 €/unit/year, resulting into 2,805 €/unit/year

8.4.3.7 Gas process chromatographs (GC) – Adaptation of existing and installation of additional instead of expensive meter replacement.

Adaptation needs

[317] (Martin Wietschel et al. Fraunhofer-Institut für System- und Innovationsforschung ISI , Karlsruhe, 2019)

[318] (Fraunhofer-Institut für System- und Innovationsforschung ISI, Karlsruhe, DVGW-Forschungsstelle am Engler-Bunte-Institut des Karlsruher Instituts für Technolo-gie (KIT), 2019)

The GCs currently used for natural gas use helium (He) as a carrier gas and therefore cannot precisely detect H2. The upper limit for the measurement of H2 with He as the carrier gas is usually set at 5%. For the measurement of higher H2 concentrations, an alternative carrier gas (e.g. argon, Ar) is required for unambiguous determination, which is used as a second carrier gas in addition to He, if necessary (retrofit an additional separation column with argon as the carrier gas for H2 detection). This requires a new approval by appropriate authorities responsible for calibration. Alternatively, new devices approved for the measurement of H2 must be installed.[319]

In transport networks, calorific value reconstruction systems have become increasingly established in recent decades. These systems allow the calorific value to be determined by computer at any time and at any place in the entire network. The prerequisites for this are calibrated measured values of the calorific value at the feed-in points as well as the volume at the feed-in and feed-out points, thus additional GC analysers are required to improve the calorific value reconstruction system. From a hydrogen concentration above 0.2 vol.-% in transport networks, these systems must be expanded to take hydrogen into account. However, the costs for this calorific value reconstruction systems at TSO level are low.

The existing volume meters for end customers can accept up to 10% blending rates of hydrogen. Above this threshold, the replacement of all meters would be very expensive. Compared to the established calorific value reconstruction systems at the transmission grid level, there is sometimes the problem of an insufficient measurement infrastructure in regional grids. This is also being discussed for grids with a high biomethane content. In the distribution network, this implies the installation of stationary GC as well as integrated systems for data transfer, mass flow determination and billing. Furthermore, the use of mobile GC is required for the calibration phase with the introduction of a calorific value reconstruction systems.

Measures are:

- from 5 to 10% at TSO level the adaptation/exchange of helium of existing GCs
- from 10 to 20% at DSO level the installation of additional GCs and calorific value reconstruction systems

Country-specific key figures

There are 575 GCs in Germany[320]. The length of the TSO network (km)[321] is used to determine the approximate number of GCs for the other countries.

It is still unclear how many additional GCs (partly also mobile) are required and what costs are incurred for the establishment and operation of a calorific value reconstruction systems instead of replacement of meters. The introduction of such a system is divided into three phases:

- Phase 1: Network analysis
- Phase 2: Validation
- Phase 3: Implementation

In the first phase, the network simulation is set up: the necessary network data is imported into the system and mapped. In the second phase, mobile measurement

[319] (DVGW, 2014)

[320] (DVGW, 2014)

[321] (Trinomics, Enerdata, Cambridge Econometrics, VITO, LBST, 2020)

technology is used (in addition to the measurements of the stationary measurement technology available in the network) at defined locations in the network area. In addition, coordination is carried out with the authorities and the system is validated by them. In the final phase, the system is adapted and tested, thus costs are expected both for the installation and operation of the system. Costs during operation are incurred for the licence, support and updates of the software, among other things.

There are 8,200 transfer stations between > 5 and 16 bar in the distribution network in Germany and 3,200 stations at the interface to the transmission grid >16 bar .[322] Due to data uncertainty, the number of 8.200 gas exit points (transfer station between >5 to 16 bar) in Germany is used as an indicator of how many new process chromatographs would have to be installed in the distribution grid at the EU level, as it may be necessary to determine the gas quality at any time due to fluctuating H2 content, leading to one GC per exit point. The length of the DSO network (km)[323] for the other countries is used to determine the approximate number of gas exit points and thus the number of GCs for each country.

Cost calculation

The GC costs used in this impact assessment are based on an interview with a GC manufacturer.
It is not known how many of the GCs in operation in the EU are already suitable for H2 measurement. The interview revealed that in Germany the quota should be around 50%, but only some of these units are already designed for 20% H2 blending. Outside Germany, the proportion should be much lower. When considering costs, it should be taken into account that GC also have to be replaced after lifetime (by H2-ready plants) and thus this share of investments is not necessarily attributable to the H2 adaptation cost.

The investment costs for new GCs are assumed to be:

- Measuring range from 5 to 10%-H2:
  - Pure investment for the device: 100,000 - 150,000 €
  - Plus 30,000 - 50,000 € for commissioning, etc.
  - In total 130,000 - 200,000 € total investment costs.
- Measuring range up to 20%-H2:
  - Pure investment for the device: 110,000 – 160,000 €
  - Plus 30,000 - 50,000 € for commissioning, etc.
  - In total 140,000 – 210,000 € total investment costs.

Countries like Germany with high legal metrology requirements tend to be at the upper end of the price range. It is assumed that:

- General costs of the GC
  - The investment costs of approx. 175 k€/piece (see above) lead to annual CAPEX of 14,042 €/piece/year (with 5% interest rate).
  - In addition, fixed operating costs of 1% (= 1,750 €/piece/year) must be taken into account.

[322] (Bundesnetzagentur für Elektrizität, Gas, Bundeskartellamt, 2020)

[323] (Trinomics, Enerdata, Cambridge Econometrics, VITO, LBST, 2020)

    - This leads to a sum of annual costs of 15,792 €/piece/year.
- Adjustment costs are incurred for 5% to 10% H2 for retrofit of existing GC at TSO level
    - Here a simplified 50% of the costs is assumed (some of the old plants will be replaced by H2-ready plants between 2020 and 2030; difficult to estimate whether old equipment must be replaced or can be adapted).
    - 7,896 €/piece/year
- Further adjustment costs arise for 10% to 20% H2 for additional GC at DSO level
    - 100% of the costs (but high uncertainty of the necessary number and permanent operating costs for a smart system.)
    - 15,792 €/piece/year

In principle, the cost approach for GCs is characterised by high uncertainties. But these only account for about 3% of the total adaptation costs up to 20% H2.

8.4.4 Results of the cost curves per country

8.4.4.1 Fuel costs assumptions for the reference scenario

The assumptions for the reference scenario are the following:

Table 8-34: Fuel cost assumptions

Category	Criteria	Cost
Specific costs	Natural gas without CO2	19.2 €/MWh LHV
	CO2	44 €/t
	Natural gas with CO2	28 €/MWh LHV
	H2	50 €/MWh
	H2 value for H2 obtained from deblending	17 €/MWh
	End-use electricity price	100 €/MWh
	LPG without CO2	65 €/MWh LHV
	LPG with CO2	76 €/MWh LHV
Absolute costs without adaptation measures	Total gas demand EU27 in 2030	2,750 TWh
	Gas costs EU27 0%H2	77,070 M€/year
	Gas costs EU27 5%H2	78,068 M€/year
	Gas costs EU27 10%H2	79,065 M€/year
	Gas costs EU27 20%H2	81,060 M€/year

The gas price and CO2 price are based on the 2030 value of the MIX H2 scenario of the European Commission.

A major question is what value hydrogen still has when it is produced during deblending and in a place where there is no demand for hydrogen. A remuneration of 1/3 of the value of hydrogen (50 €/MWh) - i.e., 17 €/MWh is assumed. For hydrogen use, additional costs would be incurred for intermediate storage, purification, compression and transport (e.g., to an H2 filling station). A lower limit would otherwise be the pure use of natural gas (i.e., on-site combustion).

The electricity price represents an average European electricity price for large consumers, which is also likely in 2030 in countries such as Germany if taxes on electricity are reduced. The LPG price is based on today's costs.

8.4.4.2 Total costs with more than 20%H2 share in the case of feeding H2 into the transmission grid

Europe aggregated

The following section shows the costs for the entire EU27. Separate country evaluations are provided subsequently.

Only Type 1 is assumed here, i.e. a feed-in into the transmission grid. Feeding hydrogen into the distribution grid (Type 2) would be relevant more before 2030 in our view. But anyway, Type 2 leads to the same costs. The only difference is that the costs of 0% to 10% will be incurred later in the range of 10% to 20%.

Above 20% H2 share in the whole EU, the role of boiler replacement becomes major. Boiler replacement results in 24,939 M€/year, which corresponds to +140% of adaptation costs, compared to adaptation costs to reach 20% blending rate (12,451 M€/year).

As already mentioned, the following costs for >20% H2 have not yet been taken into account:

- Logistical cost for transformation - avoid supply interruption (different from L-gas to H-gas conversion)
- Replacement of valves related to leakage
- New Compressors (without drive unit) - to 40%
- H2 loss of value due to deblending
- H2 losses due to storage drying

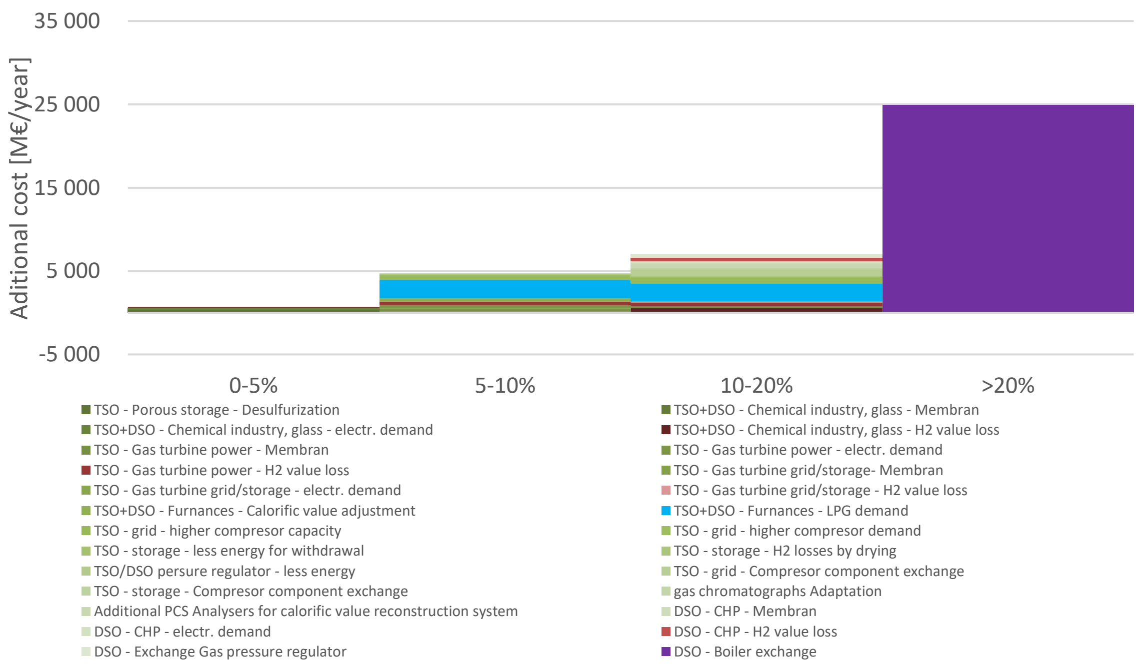

Figure 8-17: Total adaptation cost for H2 Blending EU27 in 2030 > 20%H2

In this sense, a 20% H2 share represents an upper limit that should not be exceeded in 2030. Adaptation costs up to 20% (without boiler exchange) amount to 12 451 M€/year = 15.4% of gas mix price at 20%H2.

The results show that the operating costs dominate the fixed adaptation costs. Investments have a minor influence. H2 (value) loss and LPG demand account for 6,499 M€/year or 52% of the costs. If electricity consumption for deblending is also included, these operating costs reach 58% of total adaptation costs.

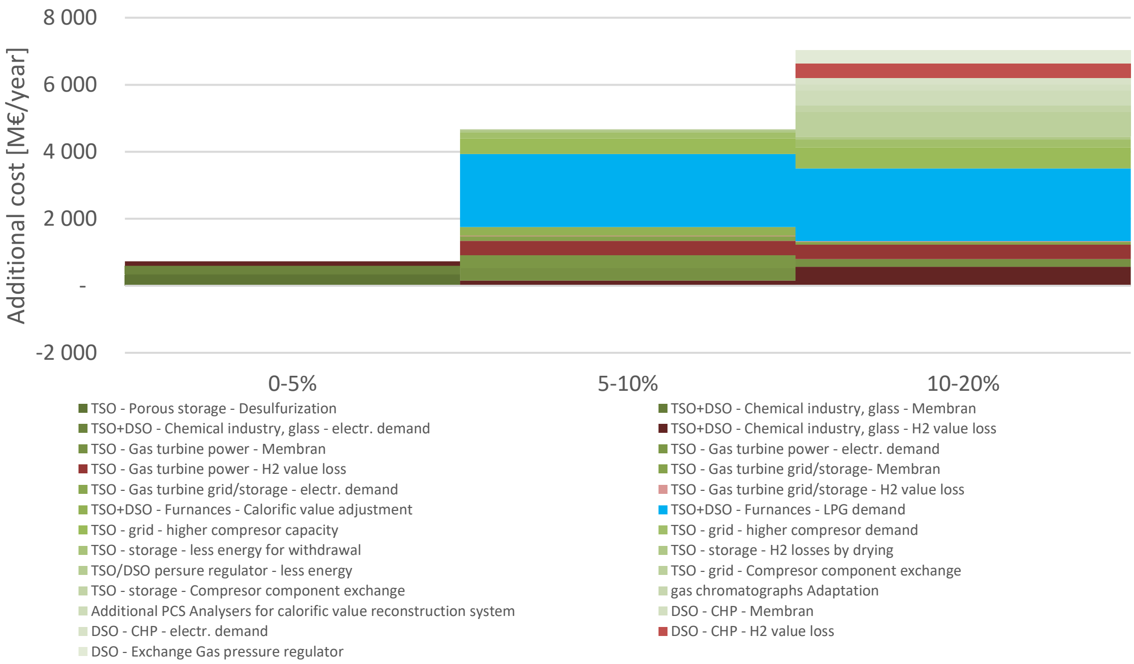

Figure 8-18: Total adaptation cost for H2 Blending EU27 in 2030 up to 20% H2

Cost curves of individual countries

The costs for four selected countries are shown below. These cost distributions illustrate that, in addition to the absolute costs, individual cost components dominate. In Portugal, the item "TSO+DSO - Furnaces - LPG demand" is very high. In Ireland, on the other hand, it is the cost item "TSO - Gas turbine power - H2 value loss". The cost curves between Germany and France, on the other hand, are relatively comparable up to 20%. France is somewhat facing lower costs. But above 20%, the costs for decentralized boiler replacement in France are comparatively higher.

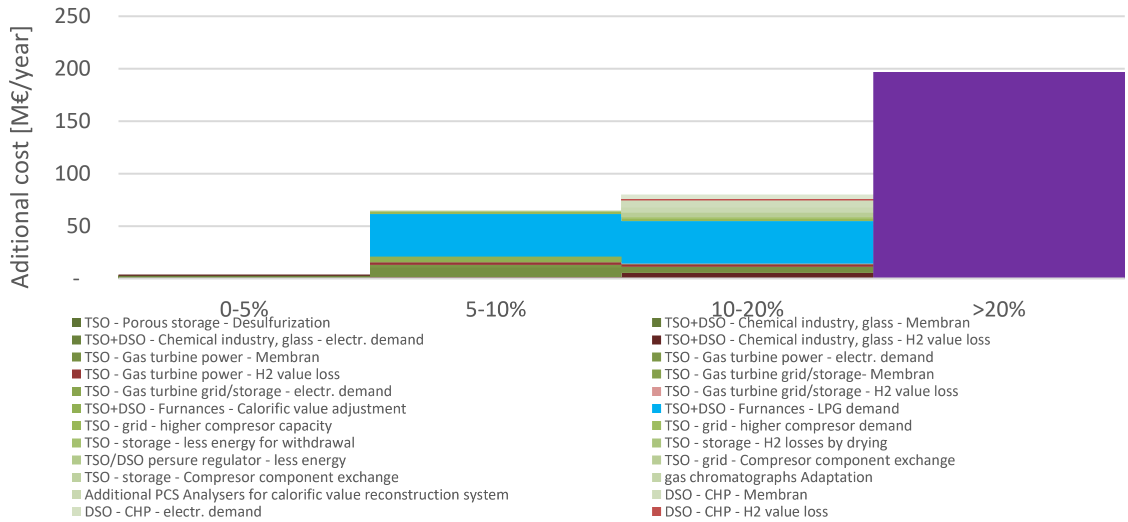

Figure 8-19 Adaptation cost for H2 Blending in Portugal in 2030 up to 20% H2

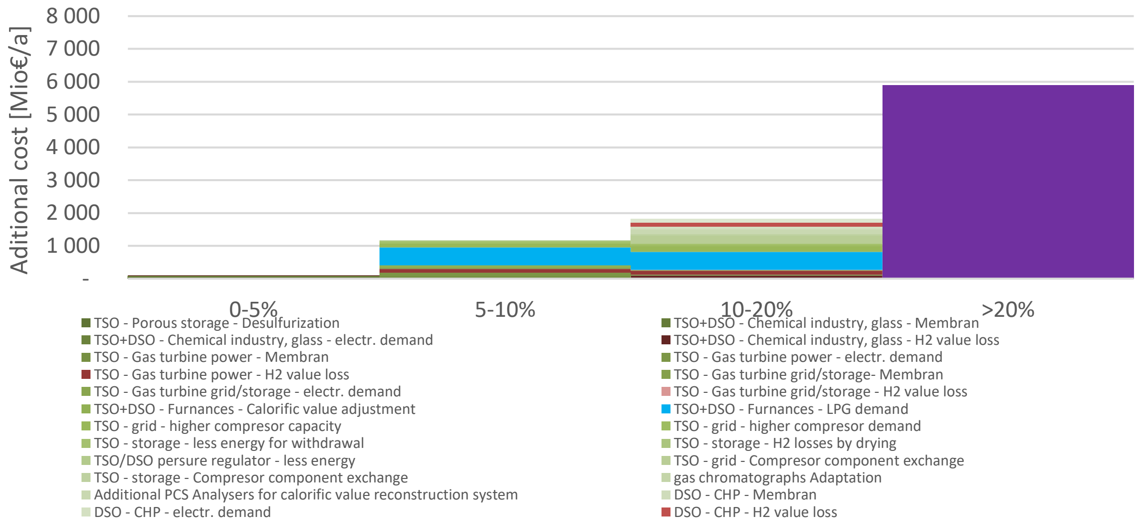

Figure 8-20 Adaptation cost for H2 Blending in Germany in 2030 up to 20% H2

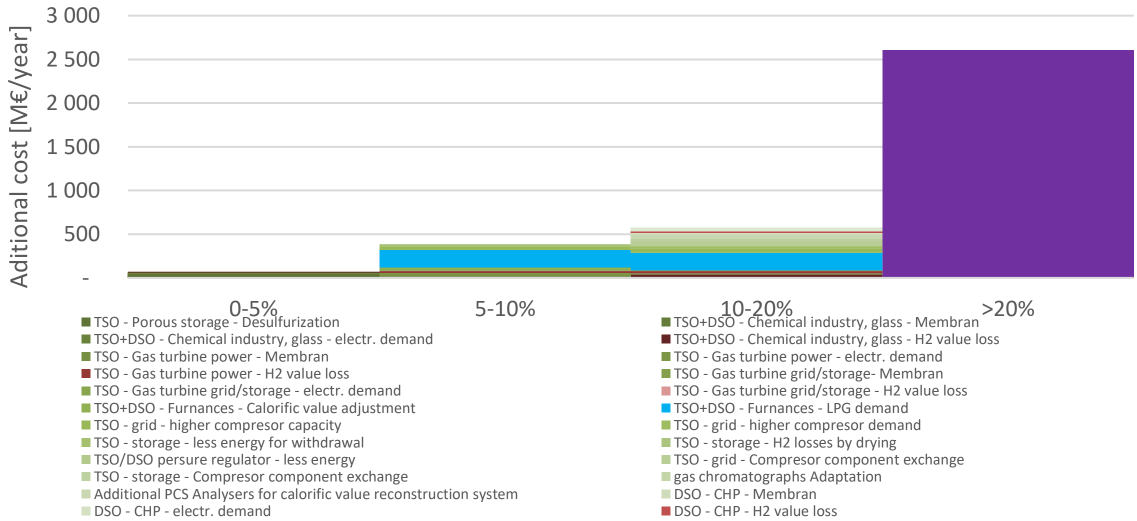

Figure 8-21 Adaptation cost for H2 Blending in France in 2030 up to 20% H2

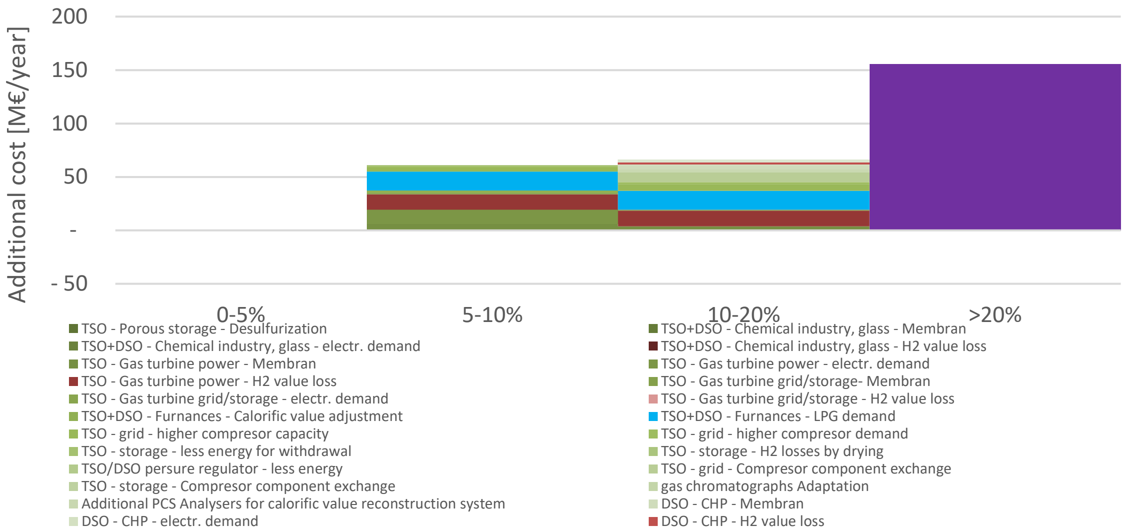

Figure 8-22 Adaptation cost for H2 Blending in Ireland in 2030 up to 20% H2

8.4.5 Discussion of uncertainties

8.4.5.1 Sensitivities of the fuel cost assumptions

The assumptions on adaptation measures are associated with uncertainties. But the investments only have a smaller share in the total costs. Therefore, the following section focuses on the impact of fuel cost assumptions as share of adaptation costs compared to the total costs of the European gas mix.

If it is assumed that hydrogen recovered from the deblending process can be sold at 100% of the H2 price on site (50 €/MWh), this results in 10,298 M€/year or 12.7% of European gas mix cost at 20%H2.

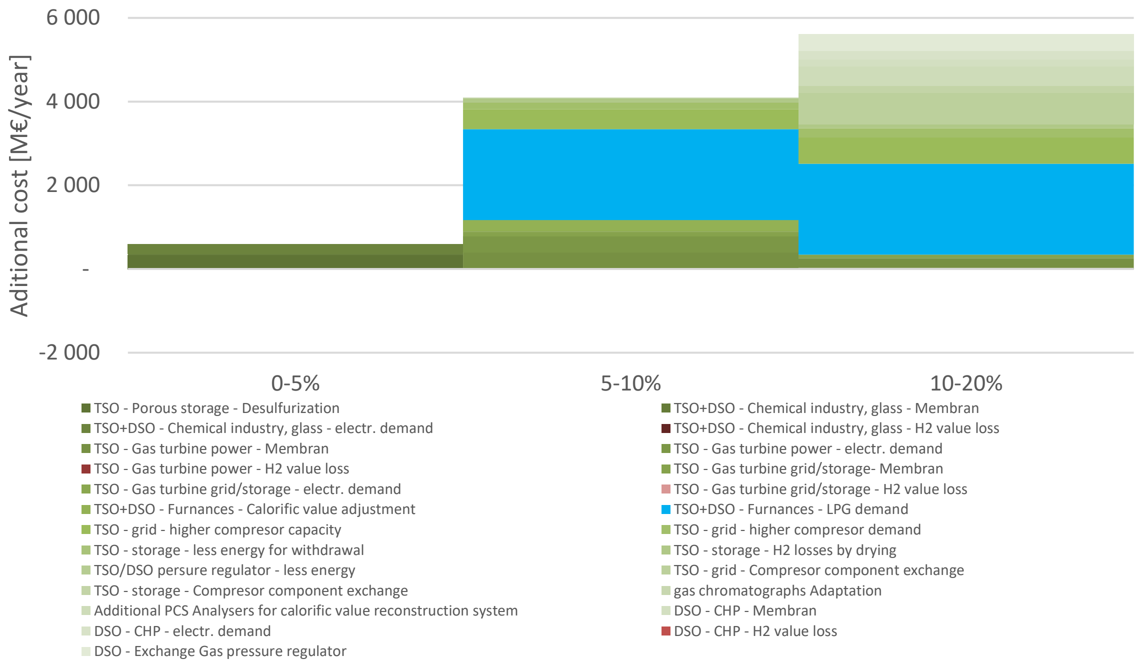

Figure 8-23: Total adaptation cost for H2 Blending EU27 in 2030 up to 20% H2 without H2 value loss due to deblending

If the lower limit that H2 can be used on site at natural gas prices (10 €/MWh) is instead chosen, this results in 12,881 M€/year or 15.9% of European gas mix cost to reach 20%H2.

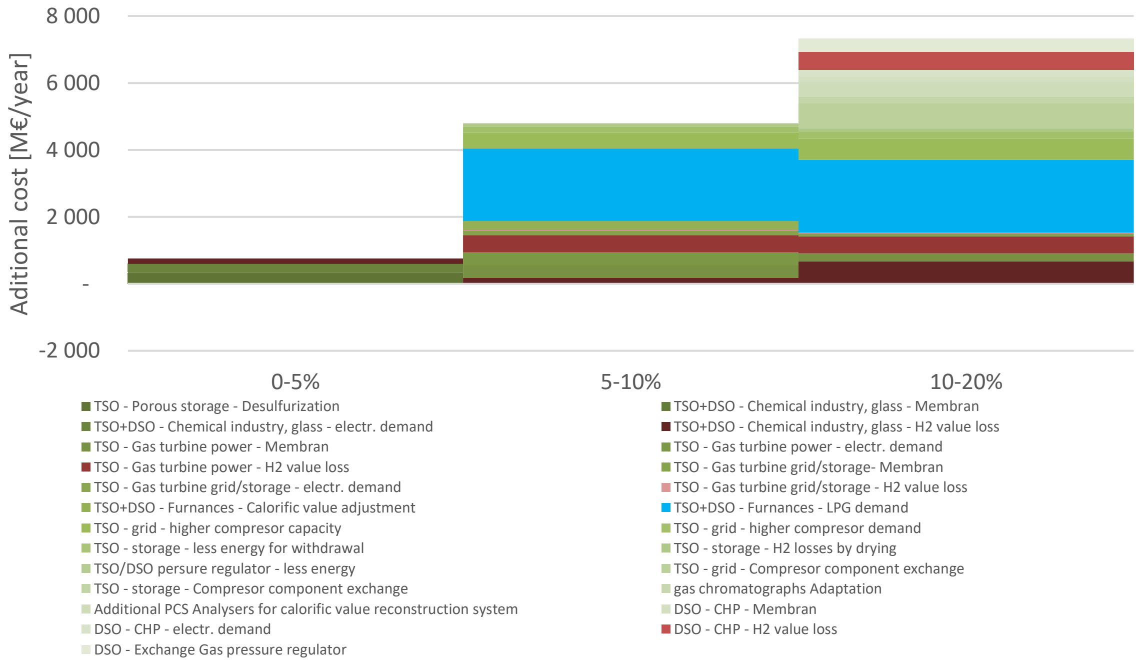

Figure 8-24: Total adaptation cost for H2 Blending EU27 in 2030 up to 20% H2 with full H2 value loss due to deblending up to natural gas price level

In addition, the influence of the gas price in 2030 was evaluated. If the gas price is 15 €/MWh instead of 19.2 €/MWh this leads to 18.2% of European gas mix cost with additional adaptation cost of 12,776 M€/year instead of 13.3% with 12,451 M€/year.

However, combined with a drop in the price of natural gas, it can be assumed that the CO2 price will increase. This can possibly compensate for the cost impact. Thus, the combination of 15 €/MWh natural gas price with a 65 €/t CO2 price leads to the same costs as a 19.2 €/MWh natural gas price with a 44 €/t CO2 price.

In addition, the influence of the electricity price was checked. An electricity price of 150 instead of 100 €/MWh leads to adaptation costs close to the costs of the reference situation: 12,869 M€/year (compared to 12,451 M€/year in the reference situation).

Adaptation costs needed to reach the associated blending rate	Baseline hypotheses	H2 value for H2 obtained from deblending = 50€/MWh	H2 value for H2 obtained from deblending = 10€/MWh	Gas price = 15€/MWh (without CO2 price)	Electricity price = 150€/MWh
0 - 5%	733 M€/year	598 M€/year	760 M€/year	733 M€/year	853 M€/year
5 - 10%	4 679 M€/year	4 093 M€/year	4 796 M€/year	4 846 M€/year	4 880 M€/year
10 - 20%	7 038 M€/year	5 607 M€/year	7 325 M€/year	7 197 M€/year	7 136 M€/year
> 20%	24 939 M€/year	24 939 M€/year	24 939 M€/year	24 939 M€/year	24 939 M€/year

8.4.5.2 Short classification with the literature

Due to the complexity, there is still a great deal of uncertainty in the present assessment as well as in the literature regarding the limits of hydrogen blending. For example, in the study of the French Natural Gas Association a maximum proportion over 6% means coating of transmission pipes and over 10% replacements of pipes.[324] While in Great Britain higher proportions appear early achievable.[325]

In the literature, the costs for a conversion to hydrogen by 2050 are estimated just at 3 to 6 Bn€ (in total until 2050), e.g. in Germany.[326] However, since many end consumer devices will be replaced at the end of their lifetime by 2050, this figure makes the difference clear with an early replacement of many systems before the end of their technical lifetime in 2030. In the case of decentralized boiler replacement, the calculated costs are 4.4 Bn€/year (per year and not in total), while with decentralized boiler replacement, the calculated costs are 10.3 Bn€/year. However, it makes clear that a

[324] (GRTgaz, 2019)

[325] (Northern Gas Netzworks, 2018)

[326] (Fraunhofer-Institut für System- und Innovationsforschung ISI, Karlsruhe, DVGW-Forschungsstelle am Engler-Bunte-Institut des Karlsruher Instituts für Technolo-gie (KIT), 2019)

slow changeover has significantly lower costs. On the other hand, the greenhouse gas savings are higher because fossil natural gas has to be used for a longer time.

8.5 Regulatory framework for LNG terminals

LNG is a significant source for natural gas supply in Europe by 2030. Under the MIX H2 scenario, EU imports about 600 TWh of LNG per year, representing almost 25% of the total natural gas supply. The LNG value chain involves various stakeholders from within and outside the EU:

- LNG shipped from outside the EU: The main exporting regions are Middle-East, North Africa, Australia, Norway and South Sahara. LNG suppliers' services include liquefaction and transport.
- LNG gasification at the EU border: 30 LNG terminals in Europe and 3 in Great-Britain are expected to exist by 2030 (cf. Figure 8-25). LSOs operate LNG terminals that provide unloading, storage and gasification services. Today, LNG terminals feature various regimes ranging from regulated TPA and tariff approval requirements to exempted or partially exempted terminals.
- Injection of natural gas into the EU network: Natural gas from LNG is sent to the main natural gas networks operated by TSOs. An entry-fee tariff is applied to LNG imports.

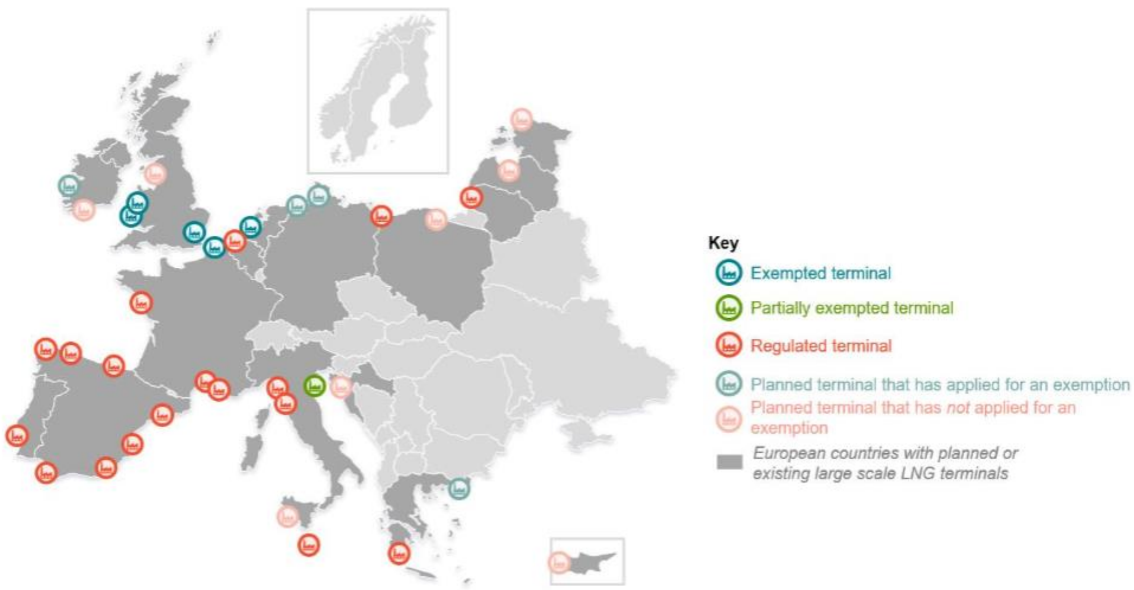

Figure 8-25: Location of LNG terminals. Source: (Trinomics; REKK; enquidity, 2020)

The goal of this analysis is to study three potential measures related to LNG terminal regulation and assess their economic, social and environmental impacts. A description of the measures is presented in Section 3.3.4 and a description of the results in Section 4.4. The underlying methodology for each studied measure is provided in the following.

8.5.1 Measure 1: Harmonised tariff setting methodology, introducing negotiated access regimes for all LNG terminals

The analysis of Measure 1 sheds light on the impact of switching from regulated tariffs to negotiated tariffs for the European LNG terminals. The following methodology is applied:

1. The first step consists in finding, for each European LNG terminal, the optimal tariff maximizing the terminal revenues (as a proxy of the negotiated tariff), while keeping all other terminal tariffs unaltered. The following steps are applied to find these optimal tariffs:
    a. Based on the MIX H2 scenario, scenario variants are created for each operational EU LNG terminal simulating an entry tariff (€/MWh) within [0.0, 0.5, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 4.5, 5.0]. That is, 11 scenario variants are created for each of the 22 EU LNG terminals[327] (242 scenario variants in total). Each scenario variant differs from the MIX H2 scenario only by the one value of deviating LNG entry tariff.
    b. For each scenario variant, a dispatch optimisation is launched, making use of the METIS gas market model (cf. Section 9 for further details about METIS).
    c. For each LNG terminal, a comparison is drawn between the 11 scenario variants with respective to the individual terminal's revenues. The tariff maximizing the LNG terminal's revenue is considered optimal and taken as a proxy for a negotiated tariff. The LNG terminal revenues considered for revenue maximization include unloading, storage and regasification services, as well as congestion rent through capacity auctions. The determined optimal tariffs for each LNG terminal are depicted in Figure 8-26.
2. The second step aims at understanding the impact of a change in tariff on the national gas market price and gas flows. Using the tariffs found in step #1, 3 scenarios are modelled:
    a. « Base » scenario: No measure is considered. All LNG terminals are regulated at the exception of the currently exempted terminals, with fixed predefined regasification and capacity tariffs[328]. LNG terminals tariffs are not modified in comparison to the MIX H2 scenario.
    b. « Intermediate » scenario: All LNG terminals are regulated, at the exception of the currently exempted terminals which have a negotiated regime. Exempted terminal use the optimal tariff found in step 1.
    c. « Intervention » scenario: All LNG terminals are transferred to the negotiated regime and their tariffs are the optimized ones identified in step 1.

Figure 8-27 illustrates the LNG terminal tariffs for the three scenarios. A dispatch optimisation with the METIS model is launched for each of the three scenarios and the results are compared. See Section 4.4 for detailed results.

[327] 8 LNG terminals are planned for 2030 without indication of a capacity. They are excluded from our analysis.

[328] Based on (Trinomics; REKK; enquidity, 2020).

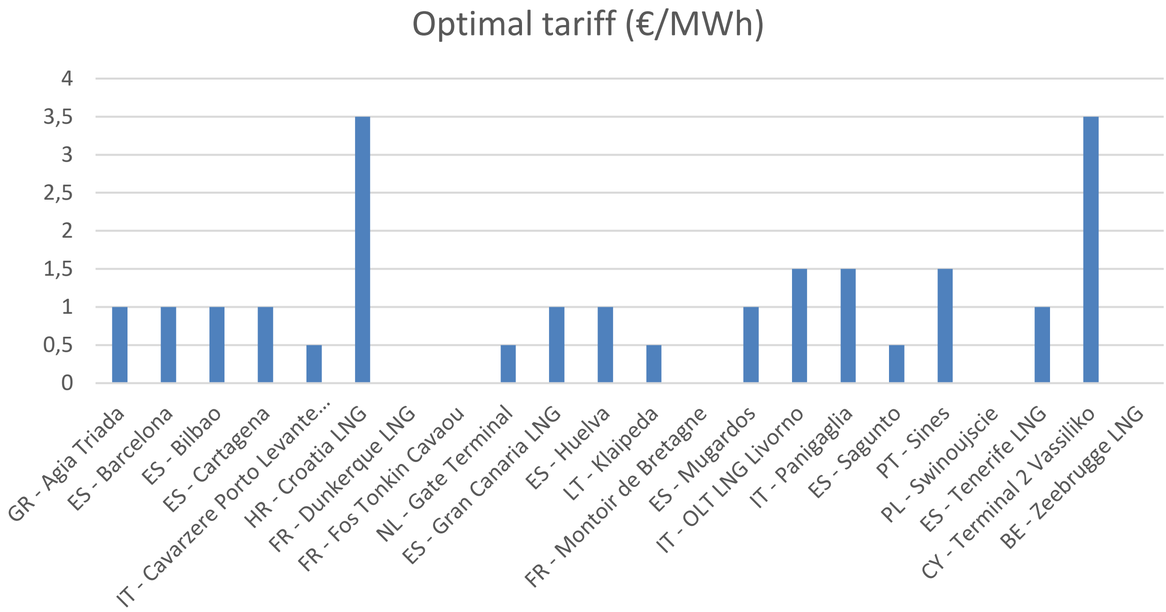

Figure 8-26: Negotiated tariffs for Measure 1. Source: Own calculation with METIS.

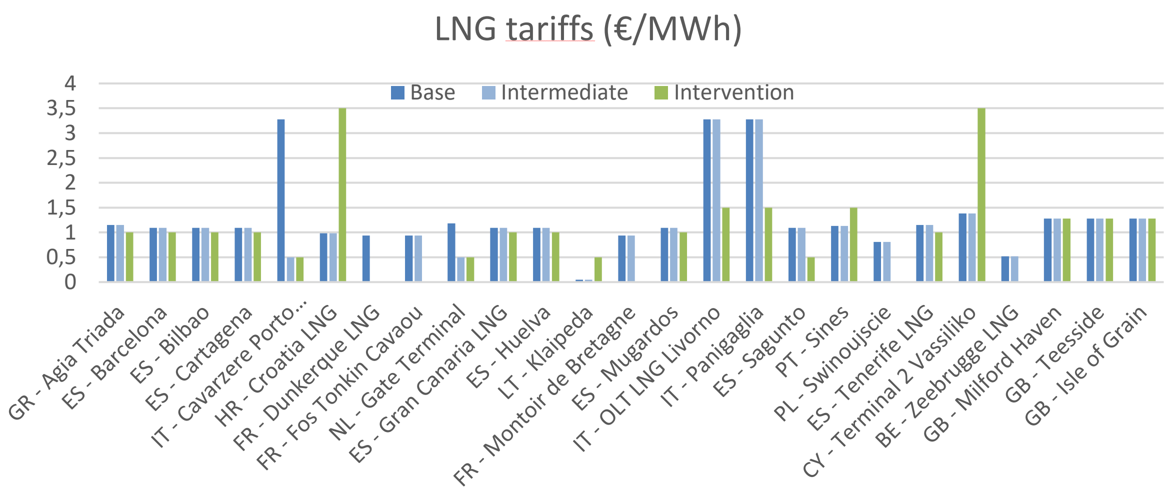

Figure 8-27: LNG terminal tariffs within the 3 scenarios. Source: own calculation with METIS.

8.5.2 Measure 2: Light intervention - Focus on optimal use of available capacity

For the purpose of evaluating Measure 2, an analysis is carried out to understand the current availability of the LNG terminals (i.e., the maximum utilisation rate). The objective is to identify whether a structural under-utilisation of LNG terminals may be observed despite market signals favourable to a maximum utilisation. The following methodology is applied:

- For each LNG terminal a historic period of 3 months is identified during which the LNG prices (including transport costs and regasification tariff) were lower than natural gas prices. The observed maximum utilisation rate of the LNG terminals in this period sets their maximum availability (meaning that their utilisation is limited to this threshold in the METIS modelling under the current regulatory regime due to technical reasons or market imperfections).
- If there is no such period, the maximum utilisation rate observed over the past years defines their maximal availability in the limited scenario.

The considered LNG terminals and the source of data used for the analysis is detailed below.

Table 8-35: List of LNG terminals analysed regarding maximum utilisation rate

Country	Terminal
Belgium	Zeebrugge LNG Terminal
Croatia	Krk LNG Terminal
France	Dunkerque LNG Terminal Fos Tonkin LNG Terminal Montoir de Bretagne LNG Terminal Fos Cavaou LNG Terminal
Greece	Revythoussa LNG Terminal
Italy	Porto Levante LNG Terminal Panigaglia LNG Terminal FSRU OLT Offshore LNG Toscana
Lithuania	FSRU Independence
Netherlands	Rotterdam Gate Terminal
Poland	Świnoujście LNG Terminal
Portugal	Sines LNG Terminal
Spain	Bilbao LNG Terminal Barcelona LNG Terminal Cartagena LNG Terminal Huelva LNG Terminal Mugardos LNG Terminal Sagunto LNG Terminal

The maximum utilisation rate is defined as the ratio between the aggregated gas flow out of the LNG facility within the gas day (called SEND-OUT) and the declared total reference send-out capacity (DTRS). Those data are available with daily granularity from https://alsi.gie.eu/.

The sources used for monthly natural gas prices rely on IHS Markit data[329] and DG Energy's EMOS (Energy Markets Observation System) with data provider ©S&P Global Platts, ECB.

Those sources were used to identify a historic period of 3 months (inside the period 01/01/2017 – 31/08/2020) where the LNG prices (either spot prices or including transport costs and regasification tariff) were lower than piped natural gas.

The European natural gas prices (cf. Figure 8-28) taken into account are the day ahead prices at the following hubs: NPB (United Kingdom), TTF (Netherlands), Zeebrugge (Belgium), NCG and GASPOOL (Germany), PEG (France), PSV (Italy), CEGH (Austria).

For the LNG spot prices, the daily spot Northwest Europe Marker (NWE) and Mediterranean Marker (MED) were used. NWE should reflect the deliveries into the terminals Zeebrugge LNG, Rotterdam Gate LNG, Montoir de Bretagne LNG, and Dunkerque LNG. MED should reflect the deliveries into the terminals located in the Mediterranean, including Spain and Portugal.

Moreover, as IHS Markit (IHS) publishes historical LNG spot prices for Spain, Italy and Greece, those prices were used instead of the MED Marker for the terminals located in these countries. The IHS prices are in USD/MMBtu, while the prices published by EMOS are in EUR/MWh. A conversion rate USD/EUR is used from https://www.exchangerates.org.uk/USD-EUR-spot-exchange-rates-history-2020.html.

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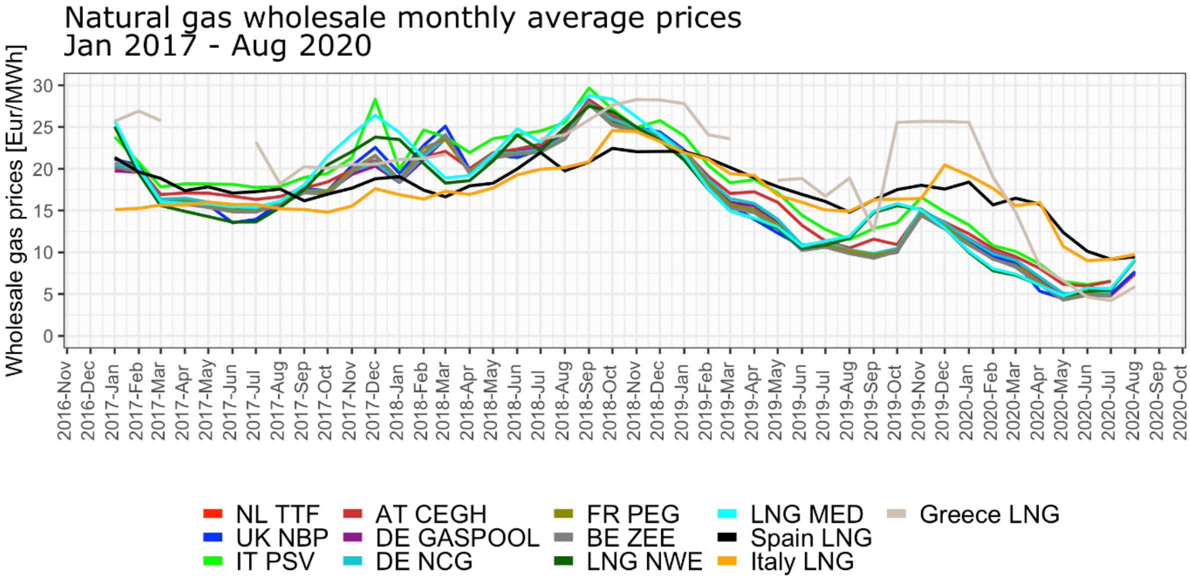


Figure 8-28: Comparison of monthly natural gas prices

For the terminals located in Poland and Lithuania, the NWE Marker is used as a proxy. The Croatian LNG terminal started being operational in January 2021; its maximum utilisation rate is computed for the period January-March 2021.

Regasification costs were computed for each terminal. LNG prices including transport costs and regasification tariff are computed by adding regasification cost to the LNG spot price for each terminal.

[329] https://connect.ihsmarkit.com/pgcr/lng/dashboard/overview

The 3 months where the LNG prices were lower than natural gas prices were obtained by simply identifying the months M, M+1, M+2, such that, for a given terminal,

LNG price ([M, M+2]) $\leq$ $\min_{hub}$ {NAT GAS hub price ([M, M+2])},

where hub represents the European gas hubs NPB, TTF, ZEE, NCG, GASPOOL, PEG, PSV, CEGH.

Table 8-36 gives for each terminal the name of the corresponding LNG price, the regasification costs, the maximum and the average of the utilisation rate for the whole period under consideration, the historic period of 3 months and some statistics of the utilisation rate for the 3 months period for both cases under consideration (LNG spot price and LNG prices including transport costs and regasification tariff).

Table 8-36. LNG terminals and total and 3 months utilisation rates

					LNG spot prices		LNG spot prices + regasification costs	
MS	**LNG Terminal**	**Spot price source**	**Regasification cost [EUR/MWh]**	**Utilisation rate statistics 01/01/2017-31/08/2020**	**3 months period with prices lower than the natural gas prices**	**Utilisation rate statistics for the 3 months period**	**3 months period with prices lower than the natural gas prices**	**Utilisation rate statistics for the 3 months period**
BE	Zeebrugge	LNG NWE	0.8	Maximum = 1.07 Average = 0.263	01-03/2019 (or 2020)	Maximum = 1.07 Average = 0.263 Average 01/2019 = 0.35 Average 02/2019 = 0.233 Average 03/2019 = 0.699	01-03/2020	Maximum = 1.071 Average = 0.487 Average 01/2020 = 0.37 Average 02/2020 = 0.321 Average 03/2020 = 0.758
HR	Krk (started 01/01/2021)	—	1	Maximum = 0.971 Average = 0.321 *(only 01-03/2021)*	01-03/2021	Maximum = 0.971 Average = 0.321 Average 01/2021 = 0.378 Average 02/2021 = 0 Average 03/2021 = 0.554	01-03/2021 (same as before)	
FR	Dunkerque	LNG NWE	1	Maximum = 0.956 Average = 0.202	01-03/2019 (or 2020)	Maximum = 0.836 Average = 0.409 Average 01/2019 = 0.322 Average 02/2019 = 0.372 Average 03/2019 = 0.53	—	use the statistics for the whole period
	Fos Tonkin	LNG MED	1.2	Maximum = 1.543 Average = 0.52	01-03/2019 (or 2020)	Maximum = 1.371 Average = 0.528 Average 01/2019 = 0.365 Average 02/2019 = 0.667 Average 03/2019 = 0.566	—	use the statistics for the whole period
	Montoir de Bretagne	LNG NWE	0.8	Maximum = 1.228 Average = 0.46	01-03/2019 (or 2020)	Maximum = 1.228 Average = 0.682 Average 01/2019 = 0.681 Average 02/2019 = 0.414 Average 03/2019 = 0.926	01-03/2020	Maximum = 1.213 Average = 0.81 Average 01/2020 = 0.488 Average 02/2020 = 0.897 Average 03/2020 = 1.052
	Fos Cavaou	LNG MED	1.4	Maximum = 1.042 Average = 0.464	01-03/2019 (or 2020)	Maximum = 1.006 Average = 0.588 Average 01/2019 = 0.276 Average 02/2019 = 0.636 Average 03/2019 = 0.77	—	use the statistics for the whole period
GR	Revythoussa	spot IHS	0.9	Maximum = 1.007 Average = 0.261	06-08/2020	Maximum = 1.007 Average = 0.336 Average 06/2020 = 0.39 Average 07/2020 = 0.32 Average 08/2020 = 0.3	—	use the statistics for the whole period
IT	Porto Levante	spot IHS	3.9	Maximum = 3.082 Average = 0.863	01-03/2018	Maximum = 1. Average = 0.761 Average 01/2018 = 0.799 Average 02/2018 = 0.608 Average 03/2018 = 0.86	01-03/2018 (same asbefore)	
	Panigaglia	spot IHS	0.7	Maximum = 2.33 Average = 0.383	01-03/2018	Maximum = 0.685 Average = 0.038 Average 01/2018 = 0.002 Average 02/2018 = 0.002 Average 03/2018 = 0.107	01-03/2018 (same asbefore)	
	FSRU OLT	spot IHS	3.2	Maximum = 0.977 Average = 0.39	01-03/2018	Maximum = 0.977 Average = 0.046 Average 01/2018 = 0 Average 02/2018 = 0.092 Average 03/2018 = 0.052	01-03/2018 (same asbefore)	
LT	FSRU Independence	LNG NWE	0.4	Maximum = 0.863 Average = 0.329	01-03/2019 (or 2020)	Maximum = 0.407 Average = 0.029 Average 01/2019 = 0.021 Average 02/2019 = 0.043 Average 03/2019 = 0.023	01-03/2018 (or 2020)	Maximum = 0.156 Average = 0.091 Average 01/2018 = 0.065 Average 02/2018 = 0.09 Average 03/2018 = 0.117
NL	Rotterdam Gate	LNG NWE	1	Maximum = 0.937 Average = 0.304	01-03/2019 (or 2020)	Maximum = 0.834 Average = 0.521 Average 01/2019 = 0.51 Average 02/2019 = 0.427 Average 03/2019 = 0.617	—	use the statistics for the whole period
PL	Świnoujście	LNG NWE	2.2	Maximum = 0.979 Average = 0.517	01-03/2019 (or 2020)	Maximum = 0.939 Average = 0.535 Average 01/2019 = 0.628 Average 02/2019 = 0.492 Average 03/2019 = 0.48	—	use the statistics for the whole period
PT	Sines	LNG MED	1.1	Maximum = 1.094 Average = 0.694	01-03/2019 (or 2020)	Maximum = 1.06 Average = 0.852 Average 01/2019 = 0.915 Average 02/2019 = 0.926 Average 03/2019 = 0.722	—	use the statistics for the whole period
ES	Bilbao	spot IHS	1.1	Maximum = 1.082 Average = 0.551	02-04/ (or 10-12) 2018	Maximum = 0.922 Average = 0.358 Average 02/2018 = 0.396 Average 03/2018 = 0.36 Average 04/2018 = 0.321	02-04/2018 (same as before)	
	Barcelona	spot IHS	1.1	Maximum = 0.702 Average = 0.278	02-04/ (or 10-12) 2018	Maximum = 0.417 Average = 0.216 Average 02/2018 = 0.281 Average 03/2018 = 0.22 Average 04/2018 = 0.15	02-04/2018 (same as before)	
	Cartagena	spot IHS	1.1	Maximum = 0.534 Average = 0.112	02-04/ (or 10-12) 2018	Maximum = 0.217 Average = 0.062 Average 02/2018 = 0.038 Average 03/2018 = 0.034 Average 04/2018 = 0.113	02-04/2018 (same as before)	
	Huelva	spot IHS	1.1	Maximum = 0.849 Average = 0.346	02-04/ (or 10-12) 2018	Maximum = 0.611 Average = 0.342 Average 02/2018 = 0.357 Average 03/2018 = 0.336 Average 04/2018 = 0.333	02-04/2018 (same as before)	
	Mugardos	spot IHS	1.1	Maximum = 2.401 Average = 0.32	02-04/ (or 10-12) 2018	Maximum = 0.517 Average = 0.244 Average 02/2018 = 0.324 Average 03/2018 = 0.238 Average 04/2018 = 0.177	02-04/2018 (same as before)	
	Sagunto	spot IHS	1.1	Maximum = 0.833 Average = 0.146	02-04/ (or 10-12) 2018	Maximum = 0.078 Average = 0.015 Average 02/2018 = 0.018 Average 03/2018 = 0.011 Average 04/2018 = 0.016	02-04/2018 (same as before)	

The maximal values in the green columns of Table 8-36 are set as the maximal capacity for the LNG terminals[330] within a "Base scenario" model run with METIS. The limited capacities for each LNG terminal are shown in Figure 8-29. The modelling results from the Base scenario are compared to a METIS model run with a "100%-availability scenario".

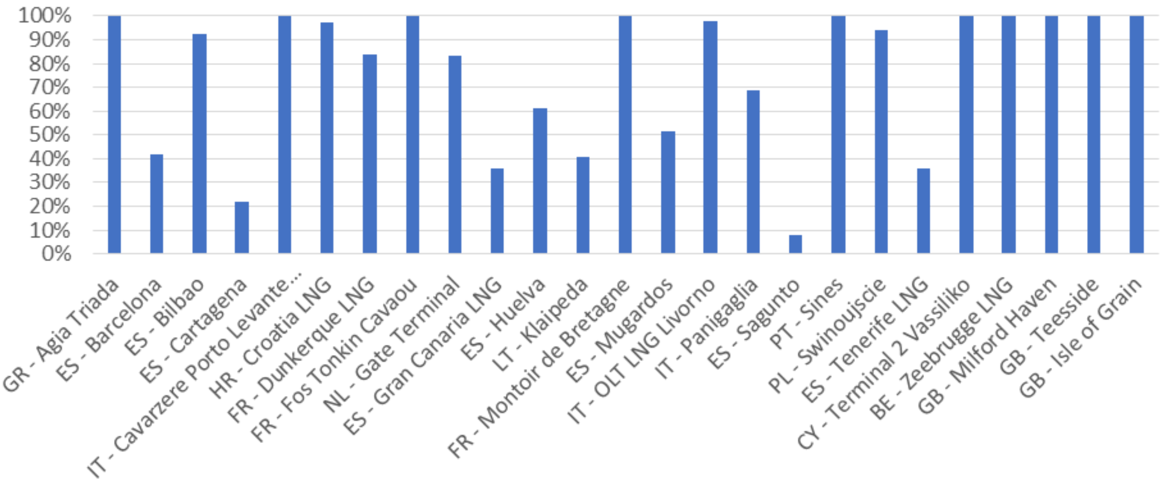


Figure 8-29: Limited capacity factor for each LNG terminal within the Base Scenario.

The Base scenario reflecting sub-optimal use of LNG terminals and the 100%-availability scenarios are then computed and compared. Detailed results are presented in Section 4.4.

8.6 Gas network planning – Review of national network development plans of gas networks

In the context of the present analysis a number of national NDPs have been analysed individually. Table 8-37 provides a summary of the analysis. The in-depth assessment of the individual plans may be found in the sub-sequent sections.

[330] All values exceeding 1 are set to 1. The average value of the availabilities of LNG terminals in Spain is used for the availability values of Gran Canaria LNG and Tenerife LNG, while the availability of Terminal 2 Vassiliko is set to 1.

Table 8-37: Synopsis of the role of reviewed NDPs. Source: NDPs, see (European Commission, 2021f).

	BE	DE	DK	EL	FR	IE	IT	LT	NL
Transparency and stakeholder consultation									
Information on decommissioning of methane pipelines									
Sustainability indicator for candidate infrastructure projects									
O1: One NDP per country									
O2: Joint electricity and gas scenario building									
O2: Alignment with NECPs and LTSs									
O2: DSO participation in scenario building									
O2: LSO and SSO participation in scenario building			(1)	(1)					
O2: Hydrogen is integrated in current NDPs									
O2: District heating and CO_2 are integrated in current NDPs									

(1) Terminals / Storages operated by the TSO

	Not retrievable from NDP (not implemented)
	Not clearly foreseen though related aspects are present in NDP
	Already implemented or clearly foreseen in NDP
	Not applicable

8.6.1 Belgium

8.6.1.1 Source

The Belgian gas NDP[331] is defined in conformity to the article 15/1, §5 of the Belgian Gas Act. The plan covers the TSO and LSO (LNG) infrastructure. DSO networks are not included.

8.6.1.2 Common: Transparency and stakeholder consultation

No reference was found to consultation processes and to measures to ensure transparency defining stakeholders' participation to the planning process.

8.6.1.3 Common: Information on decommissioning of methane pipelines

No systematic information on decommissioning of methane pipelines is provided. However, the plan foresees closure of the Belgian L-gas market of L-gas (due to the foreseen shut down of the Groningen gas fields). At 2030 no L-gas infrastructure is foreseen. The Groningen gas will still be transported for some time through Belgium to France through one main transmission dorsal (the black lines in the network scheme of figure 1). Another one is instead fully converted to be integrated in the H-gas market.

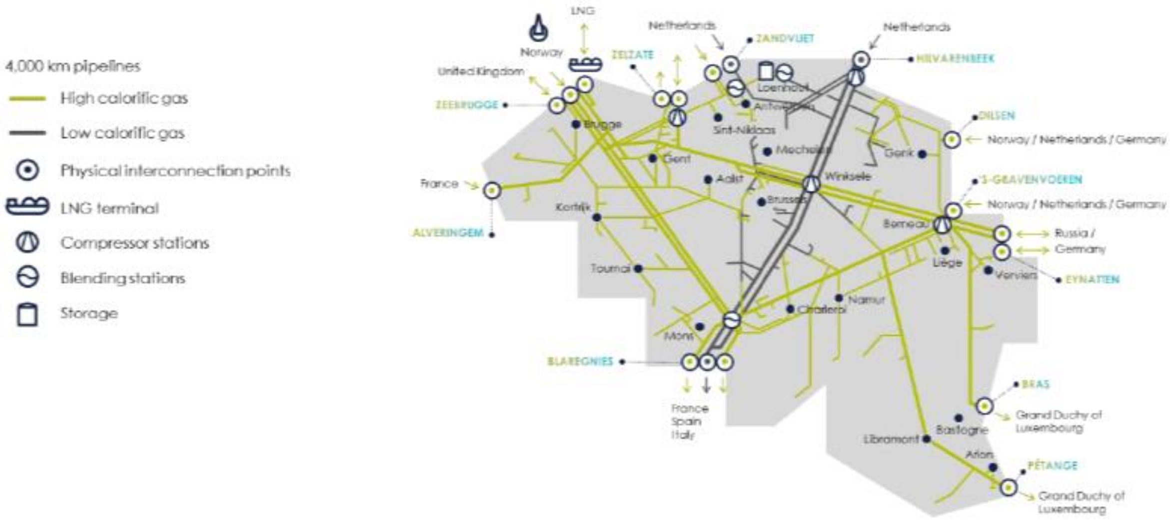


Figure 8-30: Fluxys gas network in Belgium. Source: Indicative investment plan Fluxys Belgium & Fluxys LNG 2021-2030

Concerning the use of the gas network for hydrogen, the Belgian plan states (pag.52):

"Existing gas transmission pipelines could be used to facilitate the development of hydrogen as an energy transmission carrier. In fact, where several gas pipelines are present, synergies could be unlocked to repurpose one of these pipelines to transmit the hydrogen needed, for example, in industrial processes or for transport."

[331] The content of the NDP for Belgium, is available at https://www.fluxys.com//media/project/fluxys/public/corporate/fluxyscom/documents/fluxys-belgium/corporate/tyndp/2021/tyndp_flx_be_lng_2021_2030_en_external.pdf

8.6.1.4 Common: Sustainability indicator

CBA indicators mentioning sustainability as one of the domains, beyond security of supply, market integration and competition. No more detailed information is provided in the plan.

8.6.1.5 O1: One NDP per country

Fluxys is the only certified TSO in Belgium.

8.6.1.6 O2: Alignment with NECPs and LTSs

The plan states consistency among the future demands forecast for scenario design and the "National trends" and "Global ambition" scenario implemented in the design of the ENTSOs scenarios for the TYNDPs.

8.6.1.7 O2: Joint electricity and gas scenario building

The plan refers to the electricity sector and to the interlinked electricity and gas ENTSOs scenarios. It also lists gas investments linked to changes in the power system, as investments in new gas fuelled power plants. These are directly integrated in the calculation e.g., of future peak gas demands.

8.6.1.8 O2: DSO participation in scenario building

No information is present.

8.6.1.9 O2: LSO and SSO participation in scenario building

The integration concerns especially the LNG operator (Fluxys LNG, co-authoring the plan).

8.6.1.10 O2: Hydrogen is integrated in current NDPs

The plan foresees development of hydrogen dedicated infrastructures for transmission. It mentions a demand for hydrogen between 80 and 99 TWh in 2050, with hydrogen used both for industrial sectoral energy services, and as a source of flexibility for power system. The plan does not contain detailed list of facilities/projects hydrogen related, but it presents a synthetic scheme of the future CO_2 and hydrogen transmission system (figure 2). The NDP refers to an external source: the study on the hydrogen backbone, that examines the feasibility on a dedicated hydrogen infrastructure.

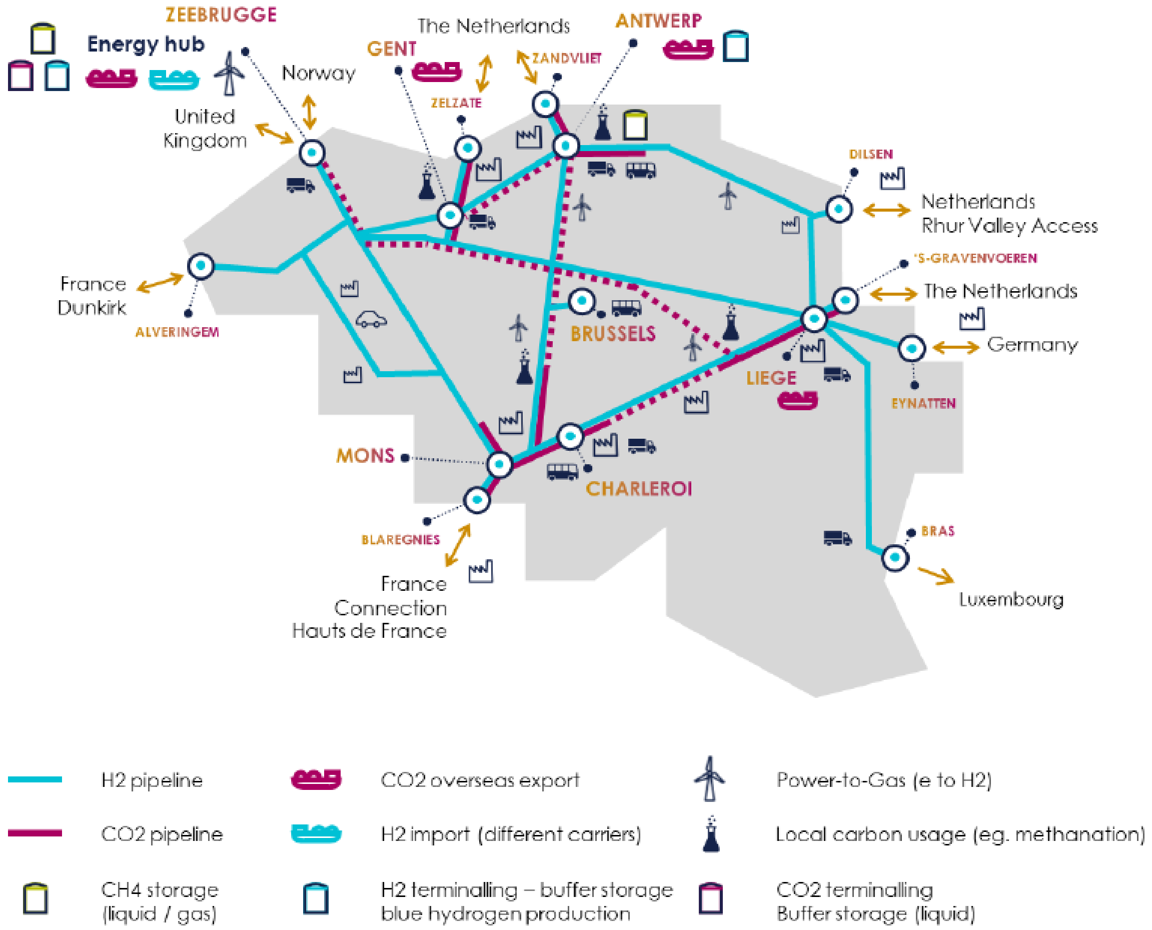


Figure 8-31 Long term vision of the Fluxys plan for Hydrogen and CO_2 networks. Source: Indicative investment plan Fluxys Belgium & Fluxys LNG 2021-2030.

8.6.1.11 O2: District heating and CO_2 are integrated in current NDPs

In analogy with the previous point (hydrogen) the plan addresses dedicated CO_2 infrastructures. District heating is not discussed.

8.6.2 Germany

8.6.2.1 Source

The content of the NDP for Germany, accessed at 30 April, is available at the following URL:
https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/Gas_grid/Draft_NDP2020_2030.pdf;jsessionid=C11D3386B7BAF0CB3864A47CB181887D?__blob=publicationFile&v=1

8.6.2.2 Common: Transparency and stakeholder consultation

German energy law (§ 15a EnWG) mandates the national regulatory authority (BNetzA) and the gas TSOs to broadly consult stakeholders during the development process of the NDP. The NRA is empowered to specify the terms under which the consultation process is carried out.2

8.6.2.3 Common: Information on decommissioning of methane pipelines

The most recent German NDP (2020-2030) does not contain in a generalized manner explicit statements on the decommissioning of methane pipelines. The NDP however discusses the implications of phasing out L-Gas for the pipeline system.

8.6.2.4 Common: Sustainability indicator

A sustainability indicator is not required to be included in the German NDP.

8.6.2.5 O1: One NDP per country

According to the ACER opinion on NDPs German gas TSOs publish one consolidated NDP per country.

8.6.2.6 O2: Alignment with NECPs and LTSs

The scenario framework for the German NDP is developed by the TSOs and evaluated and approved by the German NRA taking into account the feedback from the consultation process. While the energy law mandates the NDP to be based on reasonable assumptions there is no explicit requirement to take account EU energy and climate targets. The energy law however mandates that the German NDP is consistent with the TYNDP. The current NDP for the 2020-2030 timeframe is based on the dena-TM95 [dena 2018, Scenario I up to 2050] and EUCO30 [EUCO 2017, Scenario II up to 2030] scenarios.

8.6.2.7 O2: Joint electricity and gas scenario building

Currently a joint electricity and gas scenario building is not executed in Germany. Gas TSOs are however supportive of establishing a joint procedure. In their view a requirement for an integrated NDP in the future is the harmonisation of the planning horizons and the synchronization of the development processes for the electricity and Gas NDPs.

8.6.2.8 O2: DSO participation in scenario building

TSOs are in charge of the NDP development. DSOs are however a key stakeholder in the NDP consultation process. Moreover, cooperation agreements (BDEW/GEODE/VKU 2019) are in place to share relevant data and DSOs are also obliged by the EnWG to cooperate on all matters and share information with TSOs as needed for the NDP development.

8.6.2.9 O2: LSO and SSO participation in scenario building

This information could not be retrieved from the reviewed NDP.

8.6.2.10 O2: Hydrogen is integrated in current NDPs

Hydrogen is integrated in the current German NDP through a dedicated variant which includes repurposing of gas pipelines, hydrogen blending to the natural gas network and specific hydrogen pipelines. The development of infrastructure purely for hydrogen however is currently not covered by the legal framework of Section 15a(1) sentence 2 EnWG and thus cannot be the subject of the binding part of the Gas NDP.

8.6.2.11 O2: District heating and CO_2 are integrated in current NDPs

Not explicitly. Indirectly the gas demand for the generation of district heating is considered through the scenario framework.

8.6.3 Denmark

8.6.3.1 Source

The content of the NDP for Denmark, accessed at 30 April, is available at the following URL:

https://energinet.dk/Om-publikationer/Publikationer/Systemplan-2019

Denmark does not publish a dedicated gas NDP, but covers the topic through its Systemplan. The most recent Systemplan (2019) is not yet available in English and therefore could only be subject to limited review. This assessment is therefore primarily based on the preceding Systemplan 2018.

8.6.3.2 Common: Transparency and stakeholder consultation

The Danish Systemplan 2018 does not mention explicitly a specific stakeholder process. It could however be part of another process feeding into the Systemplan such as the scenario framework developed by the Danish Energy Agency.

8.6.3.3 Common: Information on decommissioning of methane pipelines

The 2018 Danish Systemplan does not contain explicit statements on the decommissioning of methane pipelines.

8.6.3.4 Common: Sustainability indicator

Not specifically on green gas. However, the Danish Natural Gas Supply Act (lov om naturgasforsyning) requires the Danish TSO to safeguard efficient gas transport and financial resources through holistic planning. This means that new construction projects must take due account of economic and environmental factors, and that gas grid operation must be optimised on an ongoing basis, with components routinely replaced with more energy-efficient models during operational maintenance.

8.6.3.5 O1: One NDP per country

According to the ACER opinion on NDPs Denmark has one TSO, no NDP but three publications covers the role of an NDP

8.6.3.6 O2: Alignment with NECPs and LTSs

The 2018 Danish Systemplan does not provide dedicated scenarios but builds on the results of two related exercises: The System Perspective 2035 study, which explores scenarios reflecting the high ambitions of Danish and EU climate policy targets and the analysis assumptions provided by the Danish Energy Agency. The latter constitute the assumptions used for the TSOs system planning and reflect Danish energy policy priorities and as such should be linked to the NECPs. This is however not explicitly stated / mandated in the Systemplan.

8.6.3.7 O2: Joint electricity and gas scenario building

One of the key objectives of the Danish system plan is to carry out a joint electricity and gas scenario building. This is facilitated by the integrated competence for both sectors, which are two organizational subsidiaries of the same TSOs.

8.6.3.8 O2: DSO participation in scenario building

The Danish TSO, energinet, also has holds the responsibility for the distribution network which ensures the proper integration in scenario building.

8.6.3.9 O2: LSO and SSO participation in scenario building

The Danish TSO, energinet, also has holds the responsibility for gas storage facilities which ensures the proper integration in scenario building.

8.6.3.10 O2: Hydrogen is integrated in current NDPs

Hydrogen is not integrated in the English version of the 2018 system plan.

8.6.3.11 O2: District heating and CO_2 are integrated in current NDPs

8.6.4 Greece

The Greek National Natural Gas System Operator is DESFA. A second (independent transmission) operator on Greek territory is TAP, responsible for the respective pipeline project, which is however exempt from the provisions of article 22 of the Gas Directive.

8.6.4.1 Source

The content of the NDP for Greece, accessed at 30 April, is available at the following URL:

https://www.desfa.gr/en/national-natural-gas-system/development-of-the-nngs/development-plan

8.6.4.2 Common: Transparency and stakeholder consultation

The national gas TSO Desfa sets in public consultation the draft development plan in Greek and English. The plan is approved by the Regulator (RAE).

8.6.4.3 Common: Information on decommissioning of methane pipelines

No specific information on decommissioning of pipelines is provided.

8.6.4.4 Common: Sustainability indicator

A sustainability indicator is not present. The environmental benefits of projects in terms of carbon abatement potential is considered (i.e. the LNG boil-off compressor).

8.6.4.5 O1: One NDP per country

A single TSO conducts the Greek NDP, since TAP is exempted.

8.6.4.6 O2: Alignment with NECPs and LTSs

The study on which the plan is based includes three scenarios regarding the evolution of the power sector. One of the scenarios is based on the Greek NECP.

8.6.4.7 O2: Joint electricity and gas scenario building

The two TSOs (Power and Gas) do not perform joint scenario analysis of the power and gas systems. However DESFA in the supportive to the NDP study, performs a power system analysis in order to predict future gas demand. The modelling-based analysis considers three power demand scenarios, one of them based on the NECP assumptions and a second based on one of the electricity TSO’s scenarios.

8.6.4.8 O2: DSO participation in scenario building

No information on DSO participation in the scenario building is available in the NDP or the respective study.

8.6.4.9 O2: LSO and SSO participation in scenario building

Not applicable as there are no independent LSO's or SSOs present in Greece.

8.6.4.10 O2: Hydrogen is integrated in current NDPs

No plans related to hydrogen are mentioned.

8.6.4.11 O2: District heating and CO_2 are integrated in current NDPs

No specific plans on district heating or CO_2 networks mentioned.

8.6.5 France

8.6.5.1 Source

The most recent NDPs are for the period 2018-2027. The content of the NDPs for France, accessed at 30 April, are available at the following URLs:

https://www.grtgaz.com/sites/default/files/2020-12/Plan_decennal_2018-2027.pdf (for GRTgaz)

https://assets.ctfassets.net/ztehsn2qe34u/407pjXRtf1c3xgaCKnltRV/3a3b241a042b4def554b4a869294c1e8/Terega_PDD_10ans_reseau_transport_2018-2027.pdf (for Teréga)

There are two TSO in France: GRTgaz and Teréga. The NRA is called the Energy Regulatory Commission (CRE) and it controls their activity. GRTgaz covers the main part of gaz transport in France (~86%), while Teréga covers roughly the south-west quarter of France (~14%).

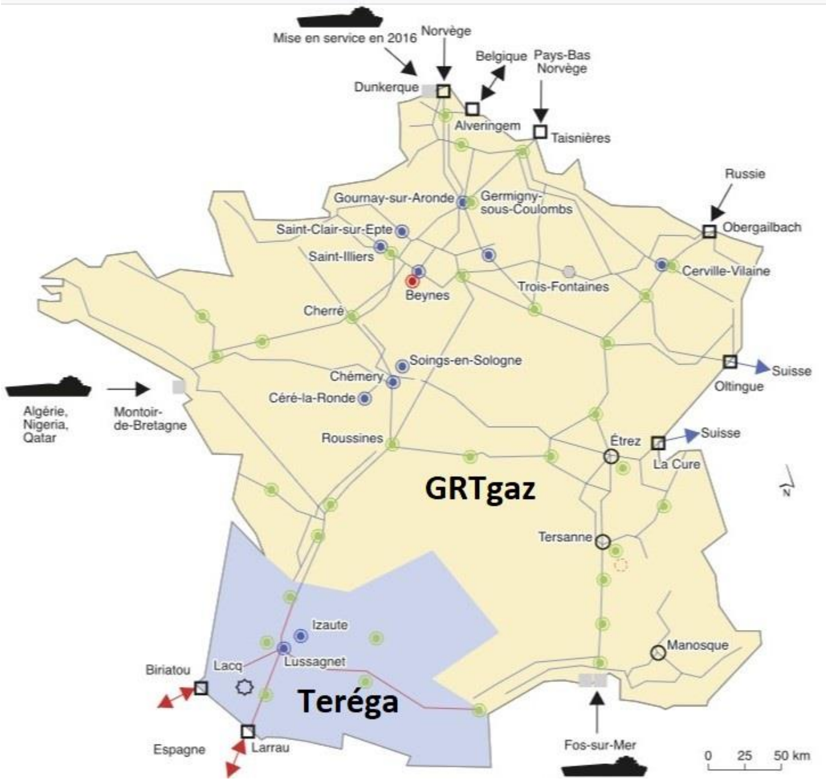


Figure 8-32: Territorial coverage of the two TSOs in France. Source: Ministère de la Transition Ecologique[332]

8.6.5.2 Common: Transparency and stakeholder consultation

The TSOs are obliged to consult the stakeholders when drawing up the 10-year plan.

The 10-year plan is subject to review by the CRE. CRE conducts a public consultation with all the market players to analyse the 10-year plans of GRTgaz and Teréga.

https://www.cre.fr/en/Documents/Public-consultations/Analysis-of-the-ten-year-development-plans-of-GRTgaz-and-TEREGA

The CRE concludes that the 10-year plans of the TSOs are coherent with the one of ENTSOG. However, GRTgaz and Teréga should add to their respective plans a common file including all the hypotheses used.

8.6.5.3 Common: Information on decommissioning of methane pipelines

None of the two French NDPs (2018-2027) mentions explicitly the decommissioning of methane pipelines.

8.6.5.4 Common: Sustainability indicator

A sustainability indicator is not defined in the NDPs. However, the scenarios for the demand and production of gas were defined using some sustainability indicators (production of renewable gases and amount of CO_2 emissions avoided) as can be found

[332] https://www.statistiques.developpement-durable.gouv.fr/edition-numerique/bilan-energetique-2019/13-32-stabilite-du-cout-des

in the detailed definition of the scenarios, in https://www.grdf.fr/institutionnel/actualites/perspectives-gaz-2018 .

Moreover, among the projects included in the network development, there is a specific section dedicated to projects linked to the production of renewable gases.

8.6.5.5 O1: One NDP per country

There are two NDPs in France. The two TSOs collaborated to build common scenarios for the total gas demand in France. The CRE's analysis of the NDPs does not mention an obligation for the TSOs to have a common NDP. However, the CRE recommends the TSOs to add to their respective plans a common file including all the hypotheses used.

8.6.5.6 O2: Alignment with NECPs and LTSs

The NDPs are consistent with the ENTSOG TYNDP as the NRA (CRE) is mentioning.

The scenarios developed by the ENTSOs consider the forecasts for gas demand and generation presented in the TSOs' 10-year development plans. Those of the TSOs' 2018 10-year development plans will be used to develop ENTSOG's 2020 TYNDP.

The French NECP was published in 2020, and the latest NDPs are from 2018, so there is no reference to the NECP.

The scenarios were elaborated in the context of the energy transition leading to a climate-neutral economy in EU by 2050. In this perspective, the gas consumed in France should/will be renewable in 2050. The Paris agreement and the EU strategy for 2050 are specifically mentioned in the NDPs.

8.6.5.7 O2: Joint electricity and gas scenario building

The TSOs brought the electricity generation assumptions in line with the electricity TSO (RTE) assumptions in its forward estimate published in 2017.

The TYNDP 2020 scenarios were jointly elaborated by ENTSOG and ENTSOE and are based on the scenarios developed in the NDPs from 2018. The two gas TSOs, in coordination with the electricity TSO, selected the correspondence between the national scenarios and the European ones.

8.6.5.8 O2: DSO participation in scenario building

The four demand/production scenarios used in the NDPs were jointly built by the TSOs (GRTgaz and Teréga) and the DSOs (GRDF and the group SPEGGN).

8.6.5.9 O2: LSO and SSO participation in scenario building

There is no explicit mention of LSO and SSO participation in the scenarios. However, all the operators of gas infrastructures were consulted for the preparation of the NDPs.

Concerning the LSO: Elengy is a subsidiary company of GRTgaz and Dunkerque LNG is a member of SPEGGN.

Concerning the SSO: Teréga (who is also TSO) and Storengy are not mentioned in the scenario building section.

8.6.5.10 O2: Hydrogen is integrated in current NDPs

Hydrogen is integrated in the current NDPs of France, through some investment projects: Jupiter1000 (GRTgaz and Teréga; Power to Gas demonstrator), FenHyx (GRTgaz), GRHYD (GRDF; distribution network for a mix of hydrogen and biomethane), Méthycentre (Storengy; storage).

Moreover, it is written in the NDPs that the TSOs have the mission to define the conditions under which the hydrogen and biomethane mix could be integrated in the French infrastructure.

8.6.5.11 O2: District heating and CO_2 are integrated in current NDPs

In the project Jupiter1000 there are a CO_2 capture and storage unit and a methanation unit.

The district heating is not explicitly mentioned.

8.6.6 Ireland

8.6.6.1 Source

The content of the NDPs for Ireland accessed at 30 April, is available at the following URL:

https://www.cru.ie/wp-content/uploads/2021/02/CRU21018-GNI-draft-Ten-year-Network-Development-Plan-2020.pdf

8.6.6.2 Common: Transparency and stakeholder consultation

The Irish gas NDP follows a process of engagement and consultation, both internally and through informal consultation with key industry stakeholders.

8.6.6.3 Common: Information on decommissioning of methane pipelines

The most recent Irish NDP (2020) does not contain explicit statements on the decommissioning of methane pipelines.

8.6.6.4 Common: Sustainability indicator

Gas Networks Ireland has implemented a registry system to issue certificates for renewable gas injected into the Gas Networks Ireland grid (Green Gas Certificates). This system provides proof of the origin and sustainability of renewable gas sources which will stimulate the use of renewable gas by industry and other sectors.

8.6.6.5 O1: One NDP per country

According to the ACER opinion on NDPs the Irish TSO publishes one NDP per country.

8.6.6.6 O2: Alignment with NECPs and LTSs

In the 2020 NDP the Best Estimate scenario aligns to existing policy measures in place per Ireland's National Energy and Climate Plan (NECP) for 2021 – 2030.

8.6.6.7 O2: Joint electricity and gas scenario building

Due to the high interconnectedness of the Irish gas and electricity sectors both sectors are included in the scenario building of the Irish TSO. Moreover, the linkage to the NECP further contributes to an integrated perspective.

8.6.6.8 O2: DSO participation in scenario building

The Irish TSO, Gas Networks Ireland is also responsible for operating distribution systems.

8.6.6.9 O2: LSO and SSO participation in scenario building

This information could not be retrieved from the reviewed NDP.

8.6.6.10 O2: Hydrogen is integrated in current NDPs

Hydrogen is not (yet) integrated in the 10 Year infrastructure planning perspective of the Irish NDP. It is though accompanied by a 2050 vision of a net zero carbon gas network for Ireland which also explores the future role of hydrogen in the Irish gas system.

8.6.6.11 O2: District heating and CO_2 are integrated in current NDPs

CO_2 networks are not (yet) integrated in the 10 Year infrastructure planning perspective of the Irish NDP. It is though accompanied by a 2050 vision of a net zero carbon gas network for Ireland which also explores the future role of CO_2 (storage) infrastructure in the Irish gas system. District heating is not mentioned.

8.6.7 Italy

8.6.7.1 Source

The documentation on the NDPs is available at the following URL: https://www.arera.it/it/operatori/pdstrasporto.htm

8.6.7.2 Common: Transparency and stakeholder consultation

In the preparation of plans, public sessions to illustrate the measures foreseen in the construction of the plans are organised by the major TSO (SNAM Retegas)1with consultation of interested stakeholders. Both the process of consultation and the evaluation via cost benefit analysis are required to be transparent, according to regulatory deliberations (351/2016/R/GAS, with the title "Disposizioni per la consultazione degli schemi di Piano decennale di Sviluppo della rete di trasporto del gas naturale" and "DELIBERAZIONE 27 SETTEMBRE 2018 468/2018/R/GAS disposizioni per la consultazione dei piani decennali di sviluppo della rete di trasporto del gas naturale e approvazione di requisiti minimi per la predisposizione dei piani e per l'analisi costi-benefici degli interventi"). With regards to the subsidiarity of the planning process, it seems the italian regulatory framework ensure an adequate level of subsidiarity. Operators that have competence over regional netorks on limited portions of the italian territory prepare their own plan and their ACB valuation. Coordination of plans and intervention by the major TSOs reflects adequately principle of subsidiarity. The following regional network operators are explicitly mentioned: Consorzio della Media Valtellina per il Trasporto del Gas, Energie Rete Gas S.p.a., Infrastrutture Trasporto Gas S.p.a., Metanodotto Alpino S.r.l., Retragas S.r.l., Società Gasdotti Italia S.p.a.

8.6.7.3 Common: Information on decommissioning of methane pipelines

The most recent Italian NDP (2020-2029) does not contain reference to the decommissioning or repurposing of methane pipelines.

8.6.7.4 Common: Sustainability indicator

Concerning the consistency to the objectives of the energy transition, sustainability indicators are mentioned in the Snam NDP, with reference to the consistency of the modelling to ENTSOG approaches (the use of NeMo and the set of indicators adopted as inputs for the CBAs of investments).

In reporting values of inputs for CBA of project (Annex 4) the NDP introduces 3 indicators: (B5: reduction of negative impacts from CO_2 emissions; B6: reduction of impacts non-related to CO_2 emissions; B7: higher integration renewable energy sources in the power system). Concerning local environmental impacts of additional gas infrastructures, the Snam NDP states that Environmental Impact Assessment procedures must be applied according to national legislation (legislative Decree 152/2006 on environmental protection).

A group of investments has a specific objective of increasing the sustainability of the system. For these further indicators are assessed: (B8b, reduction of gas consumption for compression; B8 reduction of negative externalities by methane leakage in atmosphere; B8d provision of flexibility to the power system).

Among the projects included in the network development, there is a specific section dedicated to projects linked to the production of renewable gases (injection ppints for biomethane)

8.6.7.5 O1: One NDP per country

Snam Retegas, as major gas TSO, has a main NDP. Other operators (produce their own plan and there is a coordination document illustrating their consistency (see also detail in 2.1.1). The other eight companies that operate in Italy (see Table 2) are already providing their own 10 years plans, with the same deadline of the main operator. There is one integrated coordination document entailing all the investments from all the operators. After a time span, for consultations and amendments, the coordination document is published at the same time of all the other company-specific plans. Snam is responsible for the operation of the national transmission system (lines in bold in the map of figure 4) and of a large portion of the regional network (thin lines in figure 4). In terms of km of pipelines, the table 2 provides a breakdown of the role of the operators on the regional network It must be noted that Infrastrutture Trasporto Gas (ITG) is the only other certified operator beyond Snam Retegas.

Table 8-38: The operators of transport of natural gas in Italy, and the coverage on the national and regional network. Source: ARERA (NRA), October 2020

Operator	National network (km)	Regional network (km)	Total (km)
Snam Rete Gas	9643	23000	32643
Società Gasdotti Italia	603	1062	1665
Retragas	0	411	411
Energie Rete Gas	0	126	126
Infrastrutture Trasporto Gas	83	0	83
Metanodotto Alpino	0	76	76
Consorzio della Media Valtellina per il trasporto del gas	0	51	51
GP Infrastrutture Trasporto	0	42	42
Netenergy Service	0	36	36
TOTAL	**10329**	**24804**	**35133**

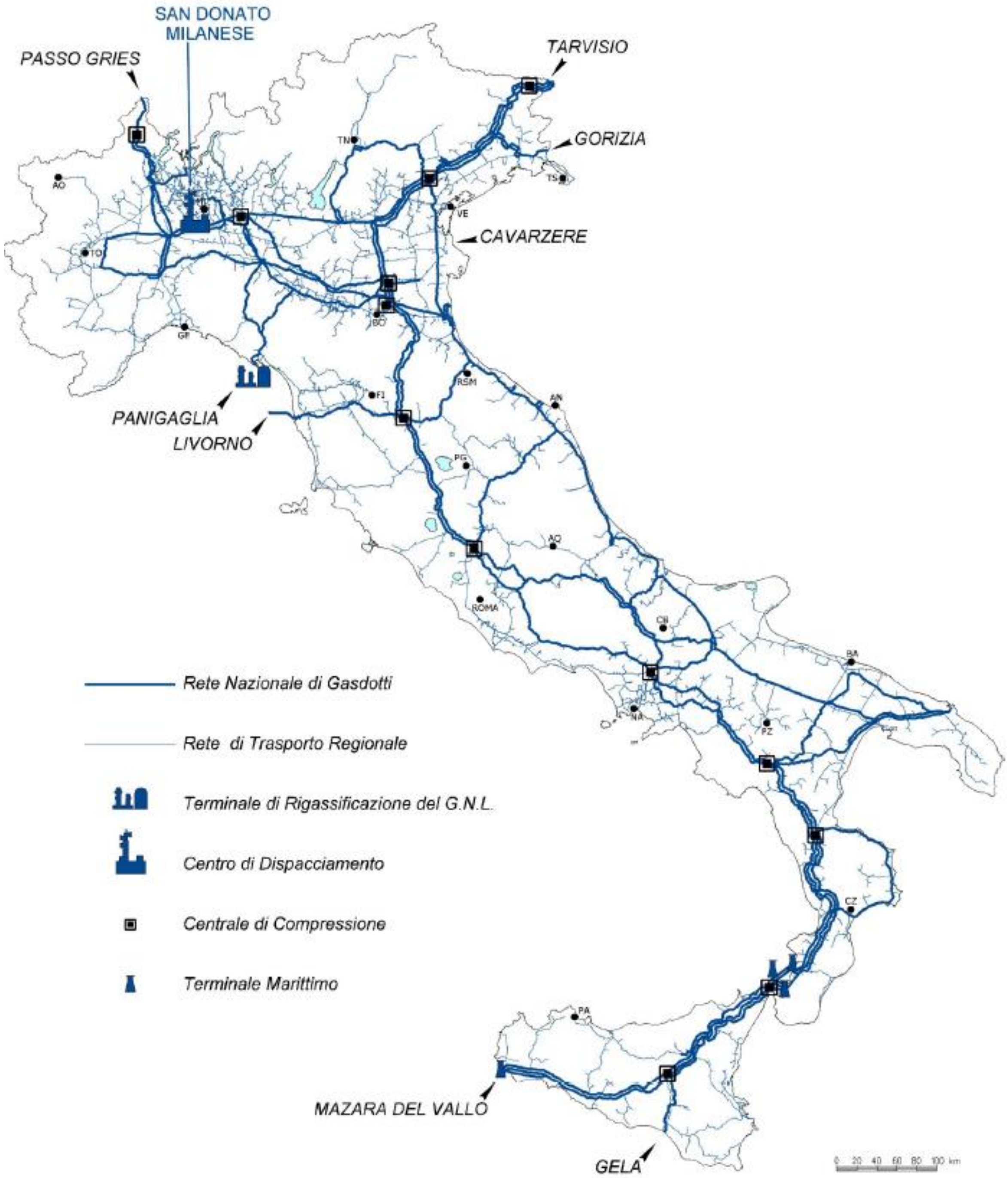


Figure 8-33: Italian gas transmission network map. Source: Snam Retegas NDP

8.6.7.6 O2: Alignment with NECPs and LTSs

The main aspect considered in terms of alignment with scenarios are the trends on the demands. The NDP for gas (as the one for electricity) puts emphasis on the consistency to TYNDPs plans and scenarios, (https://www.entsos-tyndp2020-scenarios.eu/):

National trends (this one is based on the NECP): here the time horizon is 2040

Distributed energy: the time horizon is 2050 and the system meets the targets of the COP21, with containment of temperature to 1.5 degrees. This has the objective of assessing the impact on infrastructures of the implementation of low emission systems.

Global ambition: similar to the previous one, with more extensive implementation of renewable gases.

8.6.7.7 O2: Joint electricity and gas scenario building

The planning process is required to have a strict integration between power and gas plans. The deliberation 654/2017/R/EEL and 689/2017/R/GAS, the NRA has given mandate for coordinated scenario design to Terna and Snam Retegas (the electricity and gas TSOs). The decision aims to optimise sector coupling objectives in planning of transmission networks.

8.6.7.8 O2: DSO participation in scenario building

The participation of DSO is mentioned in the forms of requests of developments connection. The role of DSO is active in participation to the cost benefit evaluation. Integrated ACB process. To keep into account in development plans of interdependencies between Distribution systems and National systems, compulsory an integrated cost benefits entailing the developments of local and national developments (page 9 of https://www.arera.it/allegati/docs/18/468-18.pdf) .

8.6.7.9 O2: LSO and SSO participation in scenario building

From the document, it is not clarified to which extent participation of LSO and SSO is implemented in scenario building.

8.6.7.10 O2: Hydrogen is integrated in current NDPs

The NDP illustrates current activities conducted to test viability of increasing blending of hydrogen into methane pipelines. A 5% admixture level is currently experimented in specific portions of the network and the plan presents future activities for the test of increased blending admixtures (10%) on the same portions of the network, dedicated to the supply to two industrial customers. The NDP mentions that additional capacities are built in order to be compatible with increasing admixtures of hydrogen-methane mixes, with the exception of some low value components (as devices for gas-chromatography).

8.6.7.11 O2: District heating and CO_2 are integrated in current NDPs

The NDP do not make specific references to district heating, Just a minor reference to the estimation of demands for heating. No reference to CO_2 networks is present.

8.6.8 Lithuania

8.6.8.1 Common: Transparency and stakeholder consultation

Cannot be verified from English version of the Lithuanian NDP.

8.6.8.2 Common: Information on decommissioning of methane pipelines

The most recent Lithuanian NDP (2018–2027) does not contain explicit statements on the decommissioning of methane pipelines.

8.6.8.3 Common: Sustainability indicator

A sustainability indicator is not required to be included in the Lithuanian NDP.

8.6.8.4 O1: One NDP per country

According to the ACER opinion on NDPs the Lithuanian TSO publishes one NDP per country.

8.6.8.5 O2: Alignment with NECPs and LTSs

The Lithuanian NDP (English version) does not explicitly state the underlying scenario(s). However, based on interpretation a linkage o the EU wide TYNDP can be assumed. Moreover, the National Energy Independence Strategy published by the Parliament of the Republic of Lithuania serves as reference for the future system development.

8.6.8.6 O2: Joint electricity and gas scenario building

Currently a joint electricity and gas scenario building is not included in the Lithuanian NDP. The gas demand of the electricity sector is accounted for in the projections.

8.6.8.7 O2: DSO participation in scenario building

Cannot be verified from English version of the Lithuanian NDP.

8.6.8.8 O2: LSO and SSO participation in scenario building

Cannot be retrieved from English version of the Lithuanian NDP.

8.6.8.9 O2: Hydrogen is integrated in current NDPs.

Hydrogen is not integrated in the current Lithuanian NDP.

8.6.8.10 O2: District heating and CO_2 are integrated in current NDPs.

District heating and CO_2 are not integrated in the current Lithuanian NDP.

8.6.9 Netherlands

8.6.9.1 Source

The version of the NDP currently in preparation is expected to be released on the1st April 2022. The version considered for this analysis is the 2020, available at https://www.gasunietransportservices.nl/en/gasmarket/investment-plan/investment-plan-2020.

8.6.9.2 Common: Transparency and stakeholder consultation

The process of consultation of stakeholders and transparency is confirmed. It includes public presentations of the draft plan, collections of feedbacks of stakeholders, and preparation of final plan. The process is documented at https://www.gasunietransportservices.nl/en/gasmarket/investment-plan/investment-plan-2020.

8.6.9.3 Common: Information on decommissioning of methane pipelines

Concerning the substantial reduction of the indigenous production, GTS points out that infrastructures of the L-gas system will be underutilised. Temporary decommission is foreseen for compressor stations and a reuse is foreseen in case of implementation of hydrogen backbone. The plan also states that GTS may sell assets to third parties, including for the transmission of hydrogen (page 57).

8.6.9.4 Common: Sustainability indicator

There is a generic reference to sustainability in the definition of risk based scores. The methodology to apply it is not explained in detail. Additionally, as sustainability driver the plan mention the total production of gasified biomasses, in one scenario reaching a production potential of 30 TWh.

8.6.9.5 O1: One NDP per country

The Netherlands have one certified TSO.

8.6.9.6 O2: Alignment with NECPs and LTSs

The NDP cites a 49% reduction of carbon emissions. Three scenarios/storylines are defined: (I) Climate Agreement, (ii) Alternative transition and (iii) Foundation for System Integration scenario.

8.6.9.7 O2: Joint electricity and gas scenario building

Looking also at the current practice methodology presented for the 2022 NDP5, results from the electricity scenarios are taken as input for the gas scenario design.

8.6.9.8 O2: DSO participation in scenario building

Gasunie mentions a joint work with DSOs (other network operators) in the scenario design.

8.6.9.9 O2: LSO and SSO participation in scenario building

The plan does not clarify to what extent these operators may have contributed to the scenario design.

8.6.9.10 O2: Hydrogen is integrated in current NDPs

Despite not having an integrated and detailed planning for hydrogen related investments, the study foresees the benefit of addressing the topic. It cites a project (also co-ordinated by The Dutch Ministry of Economic Affairs and Climate, together with Gasunie and TenneT, are investigating which part of the existing gas network in the Netherlands can be used for the transport of hydrogen (the name of the project is "HyWay27").

The NDP explains how GTS considered two viable options:

Making hydrogen transport "one of the GTS's duties and charging a cost-reflective tariff for hydrogen as well

Creating a separate hydrogen entity dedicated to hydrogen transport.

8.6.9.11 O2: District heating and CO_2 are integrated in current NDPs

Yes, in the assessment of future transmission capacities, peak demand situations are defined based on the presence of heating technologies as hybrid solutions and district heating.

8.7 Gas network planning - Cluster analysis identifying the level of interlinkage between national power and gas sectors

A basic set of indicators of gas/electricity interlinkages present in EU MSs has been defined with the purpose to calculate some metrics of interlinkage for the expected future energy scenario. The scenario taken as reference for the development of the indicators is the MIX H2 scenario. The set of indicators includes[333]:

- I1, Share of gas on total final consumption of energy
- I2, Share of electricity in final consumption of electricity
- I3, Gas to power (G2P) consumption vs final consumption of electricity
- I4, Share of gas in the Final Energy Demand of residential and commercial sector
- I5, Share of electricity in the Final Energy Demand of residential and commercial sector

The present exercise develops the task of grouping countries based on the quantitative metrics listed above, where:

- The indicators I_1 and I_2 provide a more generic information on the composition of the final consumption with regard to power and gas.
- Indicator I_3 captures the direct interlinkage referred to gas fuelled power production.
- I_4 and I_5 approximate the indirect interlinkage in the power vs gas competition for space heating, space cooling, water heating and other uses included in the final consumption of the sectors.

The MIX H2 data received do not allow for a breakdown of the technology level for each of these uses; (i.e., no specific data for hybrid consumption technologies). Given the limited data availability, a more generic indicator was chosen, referring to the sectoral final consumption for the calculation of the shares I_4 and I_5.

Table 8-39 provides an overview of the indicators for all EU MSs.

[333] Due to the unavailability of some datasets, these indicators differ from the ones defined by Artelys in the studies carried out on behalf of the ENTSOs. See (Artelys, 2019) for more details.

Table 8-39: Indicators for the cluster analysis. Source: own calculations

	I_1 Share of gas in national FED	I_2 Share of electricity in national FED	I_3 G2P vs total final consumption electricity	I_4 Share of gas in res+com sector FED	I_5 Share of electricity in res+com sector FED
AT	17.80%	24.50%	12.10%	25.50%	28.50%
BE	30.90%	31.30%	83.80%	46.60%	39.50%
BG	13.50%	30.60%	46.90%	6.40%	50.50%
CY	2.90%	35.60%	121.00%	0.00%	67.70%
CZ	19.40%	26.10%	13.61%	24.70%	30.80%
DE	22.00%	33.10%	41.78%	30.20%	41.20%
DK	11.10%	30.00%	1.71%	11.40%	38.70%
EE	7.00%	29.70%	21.08%	9.20%	37.60%
EL	9.90%	36.00%	71.93%	12.40%	64.50%
ES	15.30%	33.90%	13.97%	16.60%	58.20%
FI	2.10%	39.70%	18.80%	1.00%	55.20%
FR	15.70%	35.60%	9.72%	21.50%	52.60%
HR	17.20%	33.30%	13.60%	25.10%	56.80%
HU	23.60%	26.60%	29.75%	31.40%	31.00%
IE	15.30%	40.00%	69.35%	17.00%	70.90%
IT	22.30%	31.60%	50.15%	28.50%	43.90%
LT	7.50%	22.20%	89.52%	4.30%	31.20%
LU	15.20%	26.10%	0.18%	24.90%	52.30%
LV	7.30%	19.30%	88.50%	8.50%	27.90%
MT	0.30%	50.40%	140.00%	0.00%	75.20%
NL	34.40%	30.40%	66.56%	47.50%	40.90%
PL	15.00%	27.00%	40.44%	18.10%	37.20%
PT	10.80%	34.10%	5.71%	7.20%	65.50%
RO	20.80%	25.10%	39.29%	27.00%	28.70%
SE	2.60%	41.80%	1.78%	1.10%	57.70%
SI	12.90%	32.60%	34.93%	7.20%	45.80%
SK	26.60%	28.20%	26.59%	36.20%	36.90%

The analysis applies a hierarchical clustering approach, the Ward method[334]. It aggregates single units of observations into bigger partitions. At each iteration, the Ward's method assesses the 'convenience', so to speak, to merge the identified clusters into bigger ones. Ward's method starts out with clusters of size 1 and continues until all the observations are included into one cluster. This method is based on the minimization of variance within clusters, and is appropriate for quantitative variables (not binary).

An r^2 statistics is defined as the portion of variance explained by a specific clustering of the data. Let X_{ijk} the value for variable k observation j belonging to cluster i.

The Error Sum of Square $ESS = \sum_i \sum_j \sum_k \left|X_{ijk} - \overline{x_{i.k}}\right|^2$

The Total Sum of Square $TSS = \sum_i \sum_j \sum_k \left|X_{ijk} - \overline{x_{..k}}\right|^2$

Are used to specify r^2as follows: $r^2 = \frac{TSS-ESS}{TSS}$

The Ward method (implemented with the software STATA for this exercise) starts with n clusters of size 1 each. A first step forms $n-1$ clusters are formed, one of size two and the remaining of size 1, computing ESS and r^2. It aggregates then selecting the pair of sample units that yield the smallest error sum of squares, (i.e., the largest r^2) building the first cluster. Then, in the second step of the algorithm, $n-2$ clusters are formed from those defined in step 1. These may include two clusters of size 2, or a single cluster of size 3 including the two items clustered in step 1. Also, in the second and in the following steps is the maximization of the r^2 that describes how the algorithm builds, at each round, a new configuration with smaller number of clusters. The method does not select an optimal number of clusters. The procedure stops when all sample units are combined into a single large cluster of size n.

A robustness check applies another cluster technique, the Kmean approach. It is conform with the same composition of clusters of the hierarchical clustering with the Ward method.

Figure 8-34 illustrates how the implemented cluster analysis with the Ward method has been applied to the classification of groups with different level of interlinkage.

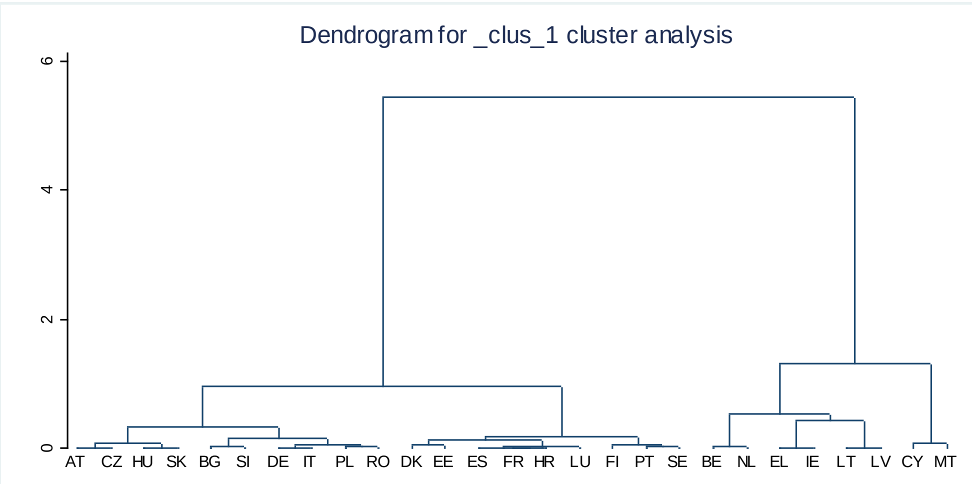


Figure 8-34: Results of the clustering

- Cluster 1 includes 10 countries: AT, CZ, HU, SK, BG, SI, DE, IT, PL, RO

[334] The original paper presented the algorithm is Ward, J.H.(1963), Hierarchical grouping to optimize and objective function, Journal of the American Statistical Association Vol. 58, No. 301 (Mar., 1963), pp. 236-244.

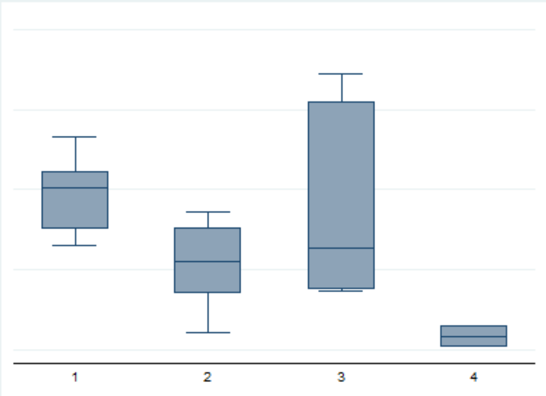
- Cluster 2 includes 9 countries: DK, EE, ES, FR, HR, LU, FI, PT, SE
- Cluster 3 includes 6 countries: BE, NL, GR, IE, LT, LV
- Cluster 4 includes 2 countries: CY, MT

To get a simplified idea of the position of each cluster with respect to the indicators of interlinkage, Table 8-40 reports the medians for each cluster. Figure 8-35 illustrates the range of the five indicators across the four different clusters.

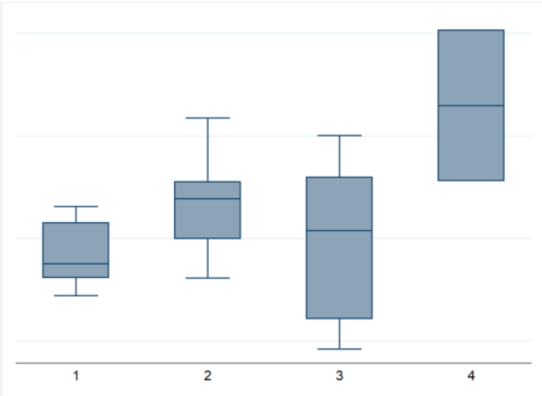
Table 8-40: Median values for the four clusters

		Cluster (median values)			
Id	Indicator	1	2	3	4
I1	Share of gas in national FED	20.13%	11.08%	12.60%	1.61%
I2	Share of electricity in national FED	27.58%	33.92%	30.81%	42.98%
I3	G2P vs final consumption of electricity	37.11%	9.72%	77.86%	130.90%
I4	Share of gas in res+com sector FED	26.27%	11.35%	14.70%	0%
I5	Share of electricity in res+com sector FED	37.05%	55.18%	40.20%	71.48%

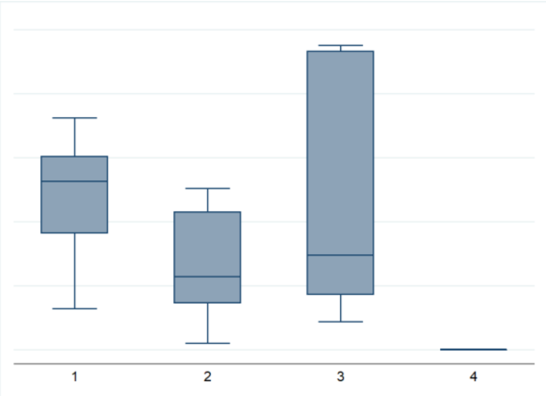
(a) Share of gas on total final consumption of energy



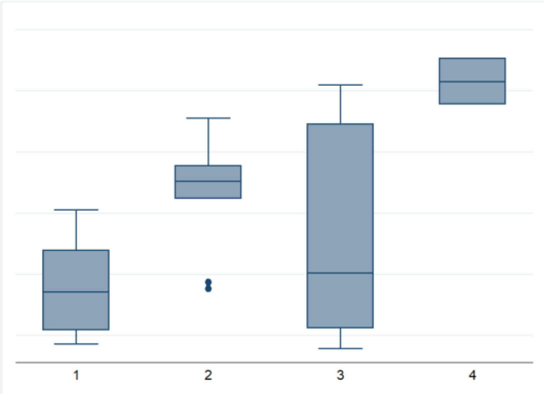
(b) Share of electricity on total final consumption of energy



(c) Share of gas in total final consumption of energy of residential and commercial



(d) Share of electricity in total final consumption of energy of residential and commercial



(e) Share of G2P consumption in final consumption of electricity

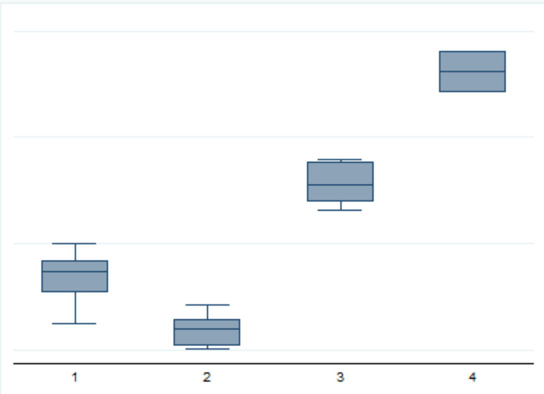


Figure 8-35 Distributions of the indicators' values across the four clusters (boxplots)

Table 8-41 provides a comparison between the exercise described above and the one carried out by ENTSOG and ENTSO-E[335].

[335] (Artelys, 2019)

Table 8-41: Comparison between the analysis on behalf of the ENTSOs and the present analysis.

	ENTSOs	This study
Scenarios data from modelling	ENTSOs TYNDP 2020 scenarios: • National trend 2040, • Distributed energy 2040, • Global ambition 2040) • Security of supply scenarios to model constraints on infrastructures (as disruption main infrastructure)	European Commission scenario • MIX H2
Modelling approach	Gas network modelling / Power system modelling.	Energy system modelling
Evaluation approach	Based on assessment whether threshold conditions are fulfilled. Discrete dichotomous (yes/no) conditions based on comparison of indicator values with thresholds. Dichotomous outcome (dual vs single system assessment requirement).	Continuous approach (based on degree of similarity among countries). Statistical approach on clustering that minimises losses of information, suggesting degree of interlinkage of groups of countries.
Indicators	G2P gas consumption vs Overall gas consumption (2030 and 2040) CR (Demand Curtailment) SLID (Single Largest Infrastructure Disruption) MASD (Minimum Annual Supply Dependence) LOLE (Loss of Load Expectation) Presence of electricity flexibility (how much generation and interconnection capacity are still available in countries with gas constraints in order to reduce the G2P consumption and (partially) relieve the constraints on the gas system) Stress on gas demands due to weather conditions and scarcity of electricity (2 weeks cold spell under low VRES availability) Price convergence Electricity capacity margins P2G capacity vs Nuclear + VRES capacity Percentage of variable RES + Nuclear generation vs overall electricity demand, assuming all P2G capacities P2G gas conversion vs Local gas demand + storable volume + exportable volume HCT Hybrid consumption technologies	G2P gas consumption over overall gas consumption (2030) G2P electricity production over overall electricity generation (2030)

9 ANNEX II – METIS MODEL DESCRIPTION

9.1 METIS General description

METIS is a software designed to simulate the operations of the EU energy market, taking into account techno-economic and environmental constraints. It is particularly well suited to analyse the role played by the flexibility solutions in power, gas and hydrogen systems and to quantify their benefits. It relies on a technology developed by Artelys: Artelys Crystal Super Grid.

METIS can jointly optimize the dispatch of generation, storage and cross-border interconnection assets to meet the energy (and reserves) demands, and investments to ensure that a given security of supply criterion is met. The software has the ability to simulate several energy vectors and their interactions: gas, electricity, heat, hydrogen, etc. Other resources (e.g. biomass, coal, etc.) can be included in the modelling so as to identify synergies between sectors. Figure 9-1 provides an overall of major input data and outputs of Artelys Crystal Super Grid, which is the underlying platform of METIS.

Figure 9-1 : High-level description of Artelys Crystal Super Grid, the modelling platform that is used by METIS

In the following paragraphs we briefly present some of the most important features of METIS so as to demonstrate the appropriateness of the tool:

- **Bottom-up model** – All energy demand and supply are represented at the country level along with the demand-response capacities, and storage technologies. Interconnection capacities between countries are explicitly represented.
- **Time resolution** – The software can use different time resolution, from hourly for electricity simulations to daily for pure gas modelling
- **Weather years and stress cases** – METIS is able to perform a stress-case analysis of the energy system by considering several weather years. The resulting energy system is therefore guaranteed to be robust, and to perform adequately during stress periods.
- **Joint dispatch of electricity and reserves** – Artelys Crystal Super Grid is able to jointly optimize the dispatch of electricity generation and the portfolio of technologies that provide reserves.

- **Resource adequacy assessment** – When performing capacity expansion planning, one should make sure that the investments are sufficient to satisfy a given security of supply criterion (e.g. less than 3 hours of scarcity pricing). This assessment can be performed either at the national level (interconnections are assumed not to improve security of supply) or at the regional level (interconnections are taken into account, with a de-rating factor).
- **Easy manipulation of data** – All scenarios can easily be modified and re-run, allowing to perform sensitivity analyses (e.g., on fuel and CO2 prices).
- **Comparison mode** - Artelys Crystal Super Grid includes an automatic comparison mode allowing to assess the impact of a given infrastructure project or of a change of parameter without having to handle large quantities of data, thereby reducing the risks of error and generating tangible visuals.

METIS comes with a comprehensive set of pre-defined key performance indicators (KPIs). All indicators (e.g., total system cost, LOLE, LOL, socio-economic welfare, consumer surplus, producer surplus, congestion rent, gas & electricity prices, CO2 emissions, RES curtailment) are automatically computed by METIS.

9.2 The METIS Gas Modules

The METIS Gas Modules were developed in two major phases that are described below.

First, the **Gas System Module** of METIS has been designed to address multiple gas system problematics, following a welfare-maximization principle. It allows for the analysis of the European gas systems' dynamics, by providing production plans, gas flows, unserved energy volumes and durations, or other standard indicators.

Such a modelling tool can be used to conduct different types of studies or quantitative analysis on gas systems, among which:

- Gas security of supply analysis
- Supply dependence analysis
- Study of the impact of infrastructure projects on security of supply

The **Gas Market Module** of METIS is an updated and extended version of the METIS Gas System Module. Using the same modelling approach, features have been added notably to make gas prices endogenous results of simulation, depending on the optimal supply mix and on supply routes used.

In addition to the above-mentioned analyses on security of supply and supply dependence, the Gas Market Module can be used to conduct assessments involving gas prices:

- Can new infrastructures give access to cheaper gas sources?
- How do additional infrastructures and entry/exit fees impact import routes?
- What are the related impacts on market prices and social welfare?

In this impact assessment, all the METIS runs were developed with the Gas Market Module in dispatch mode (i.e., no capacity optimization was carried out, but all scenario data relied on the MIX H2 scenario).

9.2.1 General modelling principles

In METIS, the gas system is represented as a network in which each node represents a couple (geographical zone, energy). Geographical zones can be linked to one another with transmissions (e.g. pipelines to exchange gas). Energies represented in the gas module are gas (representing natural gas, biomethane or synthetic gas), LNG and CO2.

At each of the nodes, assets are attached. These assets represent all supply and withdrawal of energy at this node. The model aims at minimizing the overall cost of supplying the demand at each node and at each time steps.

The following section describes the list of assets available for gas system modelling in the METIS asset library.

9.2.1.1 Asset library

The METIS gas module contains a library of assets for production, consumption, storage and transmission of gas that can be attached to each node of the network.

The following assets are included:

- **Gas consumption**: demand of natural gas withdrawn from a given node,
- **Gas production**: production of gas injected at a given node,
- **Gas storage**: storage facilities for natural gas,
- **LNG terminal**: gasification terminals which can withdraw and store LNG and convert it to natural gas and inject it on the network,
- **LNG imports** [System Module]: imports of LNG, injected to a node from which LNG terminals can withdraw it,
- **LNG exports** [System Module]: exports of LNG to countries outside the modelled perimeter,
- **LNG liquefaction train** [Market Module]: liquefaction train, liquefying natural gas and exporting LNG. It withdraws gas from the network to export it to the global LNG market. It is modelled as a gas transmission from a node to which a gas production asset is attached to the global LNG market (virtual) node,
- **Gas imports** [System Module]: imports of gas from non-modelled countries through pipelines,
- **Gas exports** [System Module]: exports of gas to non-modelled countries through pipelines,
- **Pipelines**: gas transmission capacities between modelled zones,
- **Import pipelines** [Market Module]: gas transmissions from external suppliers,
- **CO2 emissions**: CO2 emissions due to the consumption of natural gas, associated with a CO2 price.

A detailed description of each asset's underlying mathematical model and all configurable parameters can be found in the detailed documentation of the METIS library[336].

9.2.1.2 Granularity, Horizons, and Objective Function

General Structure of the optimization problem

Simulations of the gas system in METIS are performed with Artelys Crystal Optimisation Engine and aim at determining a cost-minimizing production plan that ensures a supply-demand equilibrium at each node over the study period, using a daily time step. This is done by solving the following optimisation problem:

[336] https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en

For each energy, the **supply-demand equilibrium constraint** at each node $\boldsymbol{n}$ and each time step $\boldsymbol{t}$ is the following:

$$\mathrm{Supply}_{n,t} = \mathrm{Demand}_{n,t}$$

with

$$\mathrm{Supply}_{n,t} = \sum_{\substack{\text{producers p} \\ \text{at node n}}} \mathrm{Production}_{p,t} + \sum_{\text{neighbours n}'\text{of n}} \mathrm{Flow}_{n' \rightarrow n,t} + \mathrm{UnservedEnergy}_{n,t}$$

$$\mathrm{Consumption}_{n,t} = \sum_{\substack{\text{consumers c} \\ \text{at node n}}} \mathrm{Demand}_{c,t} + \sum_{\text{neighbours n}'\text{of n}} \mathrm{Flow}_{n \rightarrow n',t} + \mathrm{GasFlare}_{n,t}$$

Assets corresponding to consumers at node n are:

- For gas: Gas consumption, Gas storage, Gas exports and LNG exports, LNG liquefaction train
- For LNG: LNG terminals
- For CO2: CO2 emissions.

Assets corresponding to producers at node n are:

- For natural gas: Gas production, Gas storage, Gas imports, LNG terminal,
- For LNG: LNG imports, LNG liquefaction train
- For CO2: Gas consumption

The objective function of the system is the total cost of the system:

$$\mathrm{TotalCost} = \sum_{\text{producers p}} \mathrm{ProductionCosts}_p + \sum_{\text{consumers p}} \mathrm{ConsumptionCosts}_p + \mathrm{UnservedEnergyPenalties} + \mathrm{GasFlarePenalties}$$

Where:

- $\mathrm{ProductionCosts}_p$ represents the cost of supply from producer p, i.e. production and import costs.
- $\mathrm{ConsumptionCosts}_p$ represents the cost or earnings associated to energy withdrawal and consumption of consumer p. It usually includes CO2 emissions costs and export earnings.
- $\mathrm{UnservedEnergyPenalties}$ represents penalties proportional to the volume of unserved energy.
- $\mathrm{GasFlarePenalties}$ represents a virtual penalty applied on the exceeding gas volume when actual supplies exceed the overall withdrawal from the network (including storing and exports). It is usually close to 0€/MWh but one could use other values to penalise unused energy and losses.

Horizons and optimisation process

While for power system models the horizon is broken down into smaller periods to facilitate the optimisation process, gas system models are solved in a single run, by jointly optimizing all days of the year in order to properly capture the annual management of gas storage facilities. That is, the present analysis applied a prefect-foresight approach. This implies that gas storage injections and withdrawals are planned with perfect anticipation of future needs.

9.2.1.3 Model structure

Gas System Module

The European gas supply chain is structured using the following principles in the Gas System Module:

- Represented zones are linked to one another by **pipeline** assets.
- **LNG imports** assets are attached to nodes representing geographical zones where LNG terminals exist
- **Gas imports** assets are attached to nodes representing geographical zones connected by pipeline to external (and non-explicitly represented) suppliers. Gas imports assets stand for the whole supply chain: pipeline and upstream production.
- **Gas production** assets are attached to nodes representing geographical zones which have internal gas wells.

Different **gas import** assets may represent imports from the same source supplying different destinations. All these imports are represented by independent variables in the underlying mathematical problem, therefore the import level from Russia to Germany would not affect prices of other imports from Russia. Consequently, the model structure is not suited to study gas prices and should be used with a fixed gas price. A main feature of the Gas Market Module is to allow for a refined representation of gas supply by introducing supply curves that link imports from a single supplier to different destinations.

Gas Market Module

The analyses realised with the Gas Market Module involve **piecewise-linear gas production costs with respect to the production level**. Evaluating the total production of a supplier is therefore necessary to determine its marginal production costs[337]. This is done by including the main external suppliers into the modelling scope. The following principles then apply:

- Represented zones are linked to one another by **pipeline** assets.
- All internal and external suppliers exporting to Europe are represented by **gas production** assets (including main LNG producers that do not have pipeline access to Europe like the Middle-East, the United Arabic Emirates, Egypt, South America, North America and Western Africa)
- A dedicated node (located on the map in Iceland for visualization purposes[338]) stands for the global LNG market. All external suppliers can supply the global LNG market using **LNG liquefaction train** assets which link suppliers' nodes to the LNG market node. **LNG terminal** assets are LNG entry points in all other nodes and can only withdraw LNG from the dedicated LNG market node.
- All external suppliers that have pipeline access to Europe have consequently two streams to supply Europe: direct pipeline flows or LNG supply (transiting through the LNG market node)

Production and transmission are modelled as separated assets in the gas market module (whereas they are merged into one asset in the Gas System Module). Several

[337] In METIS modelling, based on economic fundamentals (supply-demand equilibrium), marginal costs are used as a proxy for prices.

[338] Iceland is not part of the METIS scope

transmissions can link the same producer to several destinations, making **all destinations co-dependent since it is the overall supply from a given source that determines the source's marginal production cost**.

The second major difference between the two models is the way the LNG circuit is modelled. In particular, **the LNG supply is modelled as a chain** where are separated the gas production in the export countries (using a gas production asset with a piecewise linear cost curve), the costs for liquefaction and transportation towards the different LNG terminals (using a liquefaction train asset), the costs of the LNG terminals services (using the LNG terminal asset) and the entry tariffs to the transmission systems (using a pipeline asset, with an infinite capacity and an entry tariff).

9.2.2 Main outputs and visualization in the interface

METIS provides functionalities to display model inputs and results as tables, charts or geographical illustrations. An extensive list of predefined Key Performance Indicators (KPIs) was delivered within METIS. Among others, the following high-level indicators can be computed, analysed at different granularity level and displayed in various ways:

- **Demand** [input data]
- **Installed capacities** [input data in standard SIMULATION mode, result in CAPACITY_EXPANSION mode]
- **Storage capacity** [input data in standard SIMULATION mode, result in CAPACITY_EXPANSION mode]
- **Transmission capacities** [input data in standard SIMULATION mode, result in CAPACITY_EXPANSION mode]
- **Supply** [simulation results]
- **Consumption** [simulation results]
- **Capacity factor** (detailed by infrastructure type) [simulation results]
- **Expected unserved energy** [simulation results]
- **Marginal costs statistics** [simulation results]
- **Producer surplus** [simulation results]
- **Consumer surplus** [simulation results]
- **Congestion rent** [simulation results]
- **Welfare** [simulation results]

In METIS, KPIs can be displayed in tables or directly on a map. Their equations are further described in the GTM++ Annex, cf. Section 8.3.2. A set of KPIs were extended and upgraded to be able to distinguish the revenues of all stakeholders in the model, and how the different stakeholders are impacted by the measures.

These KPIs were especially used for the measures where the revenues were disentangled between LSOs, TSOs, SSOs, consumers, producers, shippers.

10 ANNEX III – DATA COLLECTION

10.1 Methodology

Data collected for the problem description focuses on the most recent years (2018-2020 where available), unless indicated otherwise. Only data related to the methane gas infrastructure and markets was collected (including on hydrogen blending).

Energy content data is presented in TWh (higher heating value). Where applicable, power/energy refers to equipment output, and is presented in MW_{output} or MWh_{output} (higher heating value where applicable), unless stated otherwise. Costs and prices are converted to $€_{2020}$ using Eurostat annual exchange rates.

The steps for collecting data under Task 1 were:

1. Definition and agreement on the data collection indicators
2. Desk research to complete available indicators
3. Development and submission of questionnaire to cover remaining data gaps
4. Internal data quality control

Given the challenges in collecting reliable data for multiple data parameters, especially related to adaptation costs to hydrogen blending and representative distribution networks, a questionnaire was elaborated and sent to national regulators, network operators and biogas/biomethane associations.

Between March and April 2021, 15 separate responses were received from stakeholders from 7 Member States. Some stakeholders combined their responses in a single submission. In general, the information received was highly useful to develop the infrastructure and equipment/appliance cost analysis, as well as to obtain data on the distribution network archetypes.

Table 10-1 presents all indicators collected and compiled under task 1, organised per policy category. The 'format' field indicates whether the information is presented in textual form (i.e., in this report) or in a separate Excel spreadsheet. The 'granularity' field indicates whether the data is on an EU-level, MS-level or global. MS-specific information does not necessarily mean that data is available for all MS. For all indicators presented in the Excel a brief summary is given in this chapter. The following sections present the collected information for all indicators.

Table 10-1: Overview of indicators collected in Task 1 for the four policy categories

Category	Indicator		Format	Granularity[339]
Renewable and low carbon gases integration	1.1	Number and capacity of biogas plants	Excel	MS-specific
	1.2	Number and capacity of biomethane plants	Excel	MS-specific
	1.3	Annual production of biomethane	Excel	MS-specific
	1.4	Number and capacity of power-to-hydrogen projects	Excel	MS-specific
	1.5	Number and capacity of power-to-synthetic methane projects	Excel	MS-specific
	1.6	Current use for biomethane	Word/Excel	MS-specific
	1.7	Production potential of biomethane and biogas	Word/Excel	EU-level
	1.8	Biomethane injection profile	Excel	Other
	1.9	Potential and costs of biomethane imports	Excel	Global regions
	1.10	Current and potential costs of synthetic methane imports until 2030	Word	Global regions
	1.11	Total cost of transport of biomethane and synthetic methane from third countries	Word/excel	Techno-economic
	1.12	Domestic natural gas production in the EU	Excel	MS-specific
	1.13	Capacity of cross-border pipelines between Member States	Excel	MS-specific
	1.14	Entry/Exit tariffs for intra/extra-EU IPs and for LNG terminals	Excel	MS-specific
	1.15	Long-term booked capacity	Excel	EU-level
	1.16	Injection and withdrawal capacities of large natural gas storages	Excel	MS-specific
	1.17	Tariffs for large natural gas storages	Excel	MS-specific
	1.18	Distribution network archetypes	Separate excel	MS-specific
	1.19	Available pipeline capacity in the EU that can be used for decarbonised gas imports in 2030	Excel	MS-specific
	1.20	Flexible methane demand	Word	EU-level
	1.21	Number of DSOs per Member State	Excel	MS-specific

339 MS-specific data has Member States as the unit of analysis. The data may cover all Member States or a sub-set depending on data availability.

Category	Indicator		Format	Granularity[339]
	1.22	TSO & DSO expenditures	Excel	MS-specific
	1.23	TSO allowed revenues	Excel	MS-specific
	1.24	TSO & DSO network length	Excel	MS-specific
	1.25	Supply costs of biogas	Excel	Other
	1.26	Cost of biogas upgrading to biomethane	Word	Techno-economic
	1.27	Cost of hydrogen methanation	Word	Techno-economic
	1.28	Costs of connection of biomethane plant to DSO or TSO grid	Word	Techno-economic
	1.29	Cost allocation of biomethane plant connection	Excel	MS-specific
	1.30	Biomethane connection obligation/request denials	Excel	MS-specific
	1.31	Costs of other key components in methane network	Word	Techno-economic
	1.32	Costs of reverse flow installations	Word	Techno-economic
	1.33	Cost of de-odorization in case of reverse flow from DSO to TSO.	Word	Techno-economic
	1.34	Grid injection tariffs for biomethane, synthetic methane and hydrogen	Excel	MS-specific
	1.35	Expected cost reductions for techno-economic parameters	Excel	Techno-economic
	1.36	Current MS status regarding the policy options for the integration of renewable and low-carbon gases	Excel	MS-specific
Gas quality	2.1	Overview of technical hydrogen admixture thresholds	Word	Techno-economic
	2.2	Analysis of needed adaptations in the gas infrastructure network	Word	Techno-economic
	2.3	Costs of adapting distribution and transmission infrastructure to hydrogen blending	Word	Techno-economic
	2.4	Costs and feasibility of adapting end-use appliances to hydrogen blending rates	Word	Techno-economic

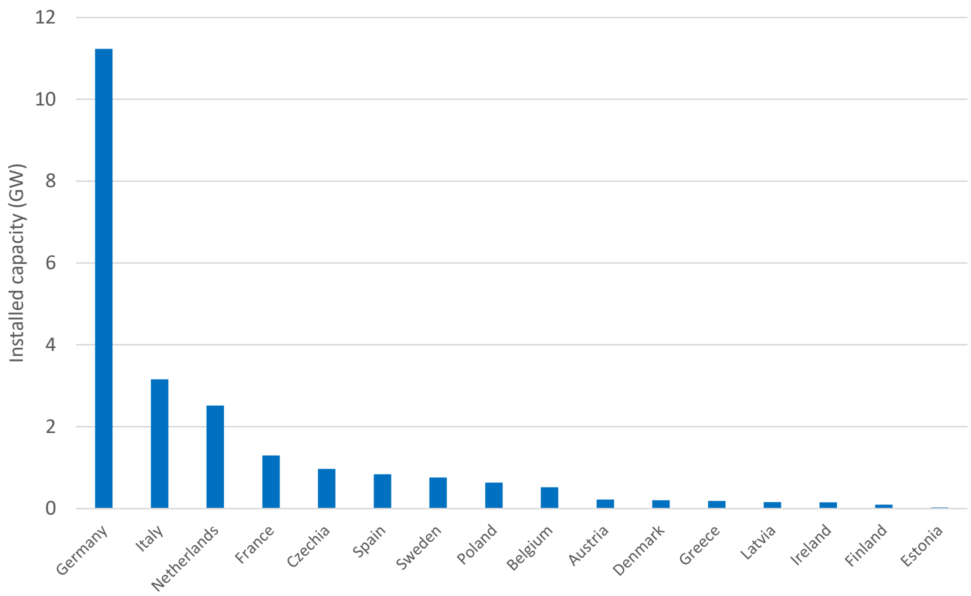
Category	Indicator		Format	Granularity[339]
	2.5	Feasibility of using gas storage for hydrogen blended gas	Word	Techno-economic
	2.6	Potential administrative costs of reinforced cross-border regulatory framework for gas quality	Word	Techno-economic
	2.7	Current national hydrogen admixture regulation	Excel	MS-specific
LNG terminals	3.1	Costs of adapting LNG terminals	Word	Techno-economic
	3.2	Transport costs of re-exporting decarbonized gas within the EU via LNG route.	Excel	Techno-economic
	3.3	Number and capacity of current LNG terminal projects	Word/Excel	MS-specific
	3.4	Number and capacity of planned LNG terminal projects	Excel	MS-specific
	3.5	Available LNG storage capacity in the EU that can be used for decarbonised gas imports in 2030	Excel	EU-level
	3.6	Supply potential and supply costs for LNG imports	Excel	Main suppliers
	3.7	Utilization profile of LNG terminals per hour/day	Excel	Other
System integration planning	4.1	Costs and benefits of changes in unbundling of DSOs to avoid conflicts of interests	Word	Literature review
	4.2	Costs and benefits of additional coordination and cooperation requirements (electricity/gas, TSO/DSO, storage)	Word	Literature review
	4.3	Analysis of current planning procedures in MSs	Excel	MS-specific
	4.4	Current MS status regarding the policy options for integrated network planning	Excel	MS-specific

10.2 Option category 1: Access of renewable and low carbon gases

10.2.1 Indicator 1.1: Number and capacity of biogas plants

In 2019 there were 16 859 biogas plants in the EU (excluding biomethane plants).[340] The majority (66%) can be found in Germany, followed by Italy (10%), France (5%) and the Czech Republic (3.4%). In total, the heat and electricity production capacity in 2019 was 23.0 GW. Again, Germany had the largest installed capacity (11.2 GW), followed by Italy (3.1GW) and the Netherlands (2.5 GW). In Figure 10-1 an overview of the production capacity of biogas plants in the EU can be seen. More detailed information can be found in the Excel annex.

Figure 10-1 Installed heat and electricity capacity of biogas plants in the EU



10.2.2 Indicator 1.2: Number and capacity of biomethane plants

In 2019 there were 593 biomethane plants in the EU with an annual production capacity of 2.8 GW.[341] This means that around 3% of all biogas plants and 14% of the installed capacity (including biomethane) has the equipment for upgrading to biomethane. Similar to biogas plants, Germany has the largest production capacity (48% of total capacity), followed by Sweden (16%), France (11%) and the Netherlands (9%).

Biomethane plants in the EU rely for feedstock mainly on energy crops[342] (~50%, mainly in Germany), agricultural residues (~25%), bio- and municipal waste (~15%), sewage sludge (~5%), waste from the food and beverage industry (~4%), and landfill (~1%).

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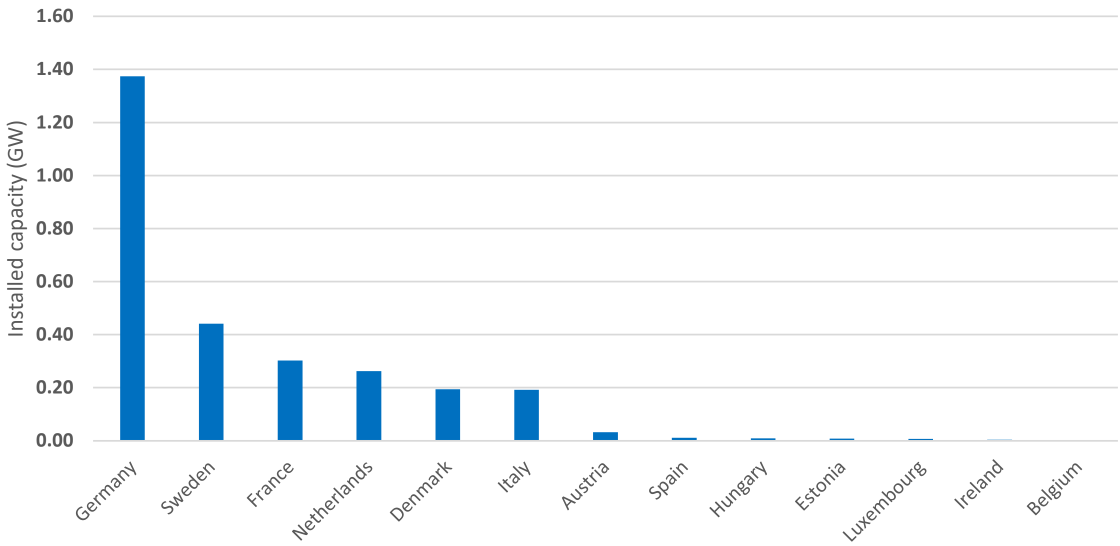
[340] EBA (2020). EBA statistical report 2020.

[341] GIE (2020). European Biomethane map 2020.

[342] No further information available regarding if the ‘energy crop’ category complies with RED II requirements, as it is based on the interpretation of mostly national biogas associations. Therefore, it is possible that some of the energy crop feedstock would not comply with the RED II requirements.

The majority of the biomethane plants is connected to the gas grid (90%), with about half of this capacity being connected to the transmission grid and half to the distribution grid. The majority of biomethane plants connected to the transmission grid use mainly energy crops (68% of all transmission grid capacity) while plants connected to the distribution grid are more likely to rely on agricultural residues (48% of all distribution grid capacity). Generally speaking, plants connected to the transmission grid are larger than those connected to the distribution grid. This is partly the result of the higher connection costs of a transmission grid connection. In Figure 10-2 the installed capacity of biomethane plants is presented.

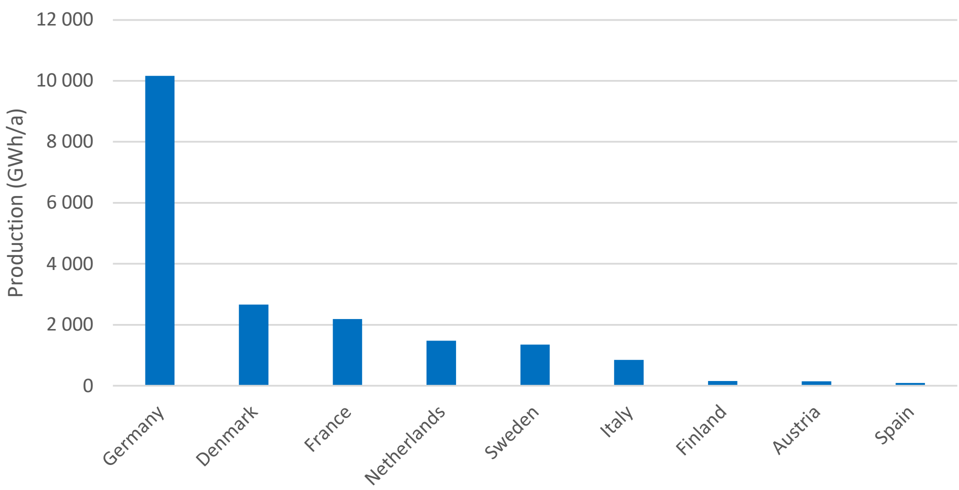
Figure 10-2 Installed biomethane production capacity in the EU in 2019



10.2.3 Indicator 1.3: Annual production of biomethane

In terms of the actual production of biomethane, 20 406 GWh was produced in 2019.[340] Germany had the largest production (10 167 GWh), followed by Denmark (2 667 GWh) and France (2 192 GWh). In Figure 10-3 the annual production of biomethane in 2019 in the EU for the largest producers is presented, some smaller biomethane producing countries are not displayed.

Figure 10-3 Annual biomethane production in the EU in 2019

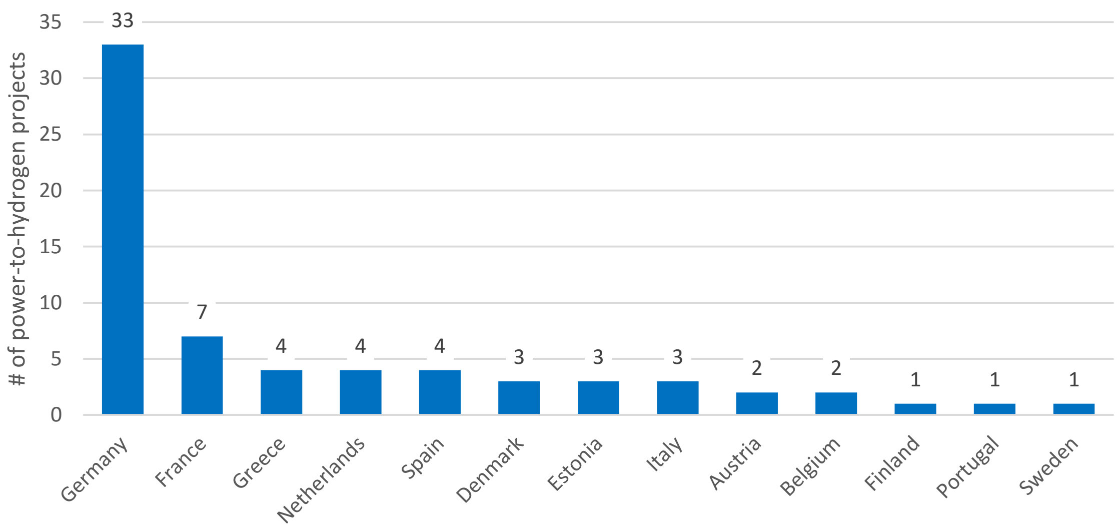


10.2.4 Indicator 1.4: Number and capacity of power-to-hydrogen projects

According to the IEA Hydrogen projects database there are currently 68 power-to-hydrogen projects in operation in the EU.[343] These projects have a total electrolyser capacity of 49 MW_{el}. Using the Higher Heating Value of hydrogen this leads to a total potential hydrogen production of 34.2 MWh_{H2}/h, at an average efficiency of 70%. This is insignificant compared with the total gas and energy demand in Europe but most power-to-hydrogen projects play an important role as pilot projects to enable further commercial expansion in the future.

Almost half of the projects are in Germany (33) with a total electrolyser capacity of 29.9 MW_{el}. 7 projects are in France, 4 in the Netherlands, 4 in Spain and the other 20 projects are located in other member states. The large majority of the power-to-hydrogen projects are not connected to the natural gas grid and use dedicated hydrogen pipelines or are directly used for transport or industrial applications. The 3 projects that are connected to the natural gas grid are in Germany, France and the Netherlands and have a combined electrolyser capacity of 2 MW_{el}. In Figure 10-4 the number of power-to-hydrogen projects per member state is presented.

Figure 10-4 Number of Power-to-hydrogen projects in the EU



10.2.5 Indicator 1.5: Number and capacity of power-to-synthetic methane projects

In the EU there are also several power-to-synthetic methane projects in operation in which the hydrogen produced from electrolysis is further converted to synthetic methane. Those projects are not included in the information presented in indicator 1.4. There are in total 21 power-to-synthetic methane projects in the EU according to the IEA hydrogen projects database.[343] 11 projects are located in Germany, 3 in Denmark, 2 in France and 1 in Austria, Italy, Poland, Spain and Sweden. The projects have a combined electrolyser capacity of 10.6 MW_{el} which leads to 7.4 MWh/h output capacity taking into account conversion losses.

[343] IEA (2020). Hydrogen Projects Database, updated in June 2020.

Although their production capacity is small, the projects play - similar to current power-to-hydrogen projects - an important function in enabling a possible future commercialisation of synthetic methane production. About 90% of the current synthetic methane produced in power-to-synthetic methane projects has a grid connection and can be injected into the natural gas grid. The largest of those, the ETOGAS project, is connected to the distribution grid[344], indicating most should be connected at the distribution level. This does not mean that most synthetic methane is actually injected into the grid. For example, the largest operating synthetic methane production project in the EU with an electrolyser capacity of 6 MW_{el} is an Audi plant in Wertle where, although there is a grid connection, most synthetic methane is used as a vehicle fuel.

In addition to the current PtG-projects, many other projects with more significant production capacities have been commissioned or are in the development stage, leading to an expected increase in PtG-projects in the EU and globally in the coming years.

10.2.6 Indicator 1.6: Current uses of biomethane

As can be seen in indicator 1.2 (number and capacity of biomethane plants), 88% of the installed biomethane production capacity in 2020 was connected to the distribution or transmission grid. Thus, the large majority of biomethane is used by end-users connected to the gas grid.

Most biomethane that is not injected into the gas grid is used as a transport fuel. In Sweden, 83% of biomethane is used in the transport sector, thanks to a favourable support mechanism. Sweden is hence responsible for 90% of the biomethane produced in the EU that is not injected into the grid. The biomethane is mainly used as bio-CNG and to a limited but increasing extent, as bio-LNG. The bio-CNG market is relatively developed in Sweden, relying on favourable support mechanisms, among others a tax exemption for green fuels including biomethane until 2020 (EBA, 2020).

10.2.7 Indicator 1.7: Production potential of biomethane and biogas

Several studies assess the production potential of biogas in the EU or in specific EU countries. In this study it is assumed that the production potential for biomethane is identical to biogas and that the technical production potential is mainly limited by feedstock availability and competition with other uses. This section focuses on several studies to estimate the technical production potential in the EU.

The production potential can vary significantly based on the assumptions and the inclusion of different feedstock types. For example, one could only consider feedstock that can be converted to biogas through the current prevailing anaerobic digestion technique, or also include the feedstock potential of woody biomass that can be converted through thermal gasification – a technique that is not yet used on industrial scale; this study includes the disaggregated potential for both anaerobic digestion-based gas and for forestry residues-based gas, that requires gasification technology.

For additional info, the technical production potential and cost curves for imports of biomethane can be found under indicator 1.9. Also, under indicator 1.7 in the Excel database more data can be found on the production potential.

[344] https://www.umweltbundesamt.de/sites/default/files/medien/378/dokumente/06_session_i_1_specht.pdf

To estimate the technical potential of several feedstocks, different sources were used.[345] This leads to a total technical potential of 1 080 TWh for the EU when including agricultural biomass (manure and energy crops), biological waste (household and municipal), straw, forestry residues (using gasification technology) and sewage sludge. The technical potential is equal to 24% of the gas consumption in the EU in 2019 and less than 35% of the forecasted gas consumption in 2030 in the European Commission's MIX H2 scenario.[346]

While the estimates of the technical production potential vary significantly based on the scope and assumptions of the studies, the economic potential levels also vary significantly depending on policy pathways and support mechanisms, which influence to a large extent the future use of the different feedstocks for the biogas/biomethane market and make it difficult to assess and compare production potential studies on a Member State or EU-wide level. In general, the economic production potential can be significantly lower than the technical production potential as not all of the technical potential can be used in an economically viable way or would require unrealistically high levels of support. Also, most studies indicate that the potential for biogas production from sewage sludge and landfills is limited. Most growth could be achieved through increased use of manure, agricultural (crop) residues (potentially through energy crops or sequential cropping) and organic waste (EC, 2016). Additional increases in potential depend on market developments of gasification technology which can enable new potentials of woody biomass. However, it is important to consider the sustainability of feedstocks. For example, energy crops can lead to land use changes that are not in line with e.g. LULUCF regulation, and biomass that is suitable for use as food, feed or feedstock, should in principle not be used for energy purposes.

10.2.8 Indicator 1.8: Biomethane injection profile

In the Excel annex several examples of biomethane injection profiles are presented. Based on information gathered via consultations with stakeholders and other sources, biomethane injection profiles in the gas grid are relatively stable and do not show a large seasonal, monthly or daily variance. Based on information from a large European

[345] Several sources, including: Deutsches Biomasseforschungszentrum - DBFZ (2016), Bewertung technischer und wirtschaftlicher Entwicklungspotenziale künftiger und bestehender Biomasse-zu- Methan-Konversionsprozesse;

Ecofys (2018). Gas for Climate - The optimal role gas in a net-zero emissions energy system, Utrecht;

Scarlat, N., Fahl, F., Dallemand, J-F., Monforti, F., & Motola, V. (2018). A spatial analysis of biogas potential from manure in Europe. Renewable and Sustainable Energy Reviews 94(2018): 915-930;

Kovacs (2015). Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015;

DENA, LBST (2017). "E-Fuels" Study, The Potential of electricity-based fuels for low-emission transport in the EU, Berlin;

CE Delft, Eclarion & Wageningen Research (2017). Optimal use of biogas from waste streams;

GreenGasGrids (2013), Biomethane Guide for Decision Makers, Oberhausen;

Biosurf (2015). Report on current and future sustainable biomass supply for biomethane production

[346] The gross consumption of gas in the EU-27 in 2019 was 4444 TWh according to Eurostat. Gas consumption in 2030 is 2861 TWh in the MIX 55 scenario.

TSO, average running hours are around 8000 hours per year, or an availability rate of 91%. This is mainly because it is economically beneficial to use the full capacity of the biomethane installation. Although the feedstock inputs can change during the year, producers can store feedstock (such as corn) and control to a certain extent the amounts that are used as input for the anaerobic digestion process. Additionally, some feedstocks are available the whole year round, such as manure. Other relevant productions processes (namely recovery of landfill and sewage gas) should provide a more stable production profile than anaerobic digestion of feedstocks with seasonal variability. Nonetheless, anaerobic digestion remains the dominant process in the EU. Nonetheless, anaerobic digestion remains the dominant process in the EU.

10.2.9 Indicator 1.9: Potential and costs of biomethane imports

Current biomethane imports to the EU are insignificant. This might change in the future given possible price reductions of biomethane and regional differences in production costs. Therefore, it is worthwhile to consider the availability and potential costs of future biomethane imports. In the Excel annex the cost curve of biomethane for 2018 and 2040 can be found based on International Energy Agency data.[347] The IEA data is converted in order to include shipping costs and to exclude the European potential. As a result, the non-EU European potential is not included. Using the IEA data, the global biomethane export potential is estimated at 8084 TWh in 2018, rising to 9731 TWh in 2040. Import costs to the EU in 2020 range between €12/MWh and €98/MWh, in 2040 import costs are estimated in the range of €13/MWh and €70/MWh, depending on the region from which the biomethane will be imported and other variables. There might be realistic potential for imports from European Energy Community Contracting Parties from the Western Balkan and Black Sea region. The biomethane potential for Ukraine was estimated at around 212 TWh/y.[348] Biomethane from Eastern Europe could be imported using existing natural gas pipelines. The Energy Community is looking into related aspects for enabling this (e.g. options for developing a guarantees of origin system across Contracting Parties)[349] but the regulatory framework needs to be further developed.

10.2.10 Indicator 1.10: Current and potential costs of synthetic methane imports until 2030

Current production and use of synthetic methane is limited. Therefore, there is limited information on the current and potential costs, especially when taking region-specific characteristics into account. The main cost parameter that will determine the potential and cost difference between potential exporting countries is the availability and cost of renewable electricity for the electrolysis (assuming that synthetic methane is generated from green hydrogen); the conversion process costs are assumed to be similar between countries (see indicator 1.27 on hydrogen methanation costs).

Thus, main possible export countries are countries that (1) have cheap renewable energy sources and (2) have the ambition to become a leading exporter of renewable energy and might not have/want to invest in dedicated hydrogen infrastructure. Besides

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[347] IEA (2020). Cost curve of potential global biomethane supply by region, 2018 & 2040.

[348] Deutsches Biomasseforschungszentrum - DBFZ (2012) Energetische Biomassenutzung 01/2012 – Focus on Biomethane; Trinomics, LBST et al. (2020) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

[349] Energy Community Secretariat (2021) Discussion Paper on Implementation of the Guarantees of Origin System in the Energy Community

these factors, the volume of potential synthetic methane exports to the EU will depend on the economics between direct hydrogen use and further conversion to synthetic methane via methanation.

10.2.10.1 Current and potential costs of synthetic methane imports

The current synthetic methane market is still in an early developing stage. Therefore, most literature sources estimate the synthetic methane cost in 2030 or later. Therefore, this section looks at the situation in 2030. Current imports into the EU can be assumed to be non-existent or marginal.

Gorre et al (2019) show that electricity costs contribute significantly to the cost of synthetic methane from electrolytic hydrogen, with electricity costs responsible for half of the total costs, when assuming a low €20/MWh electricity price.[350] This shows that the competitivity of synthetic methane is highly dependent on a cheap source of renewable energy, leading to competitive advantages for countries with a high potential for e.g. wind or solar power generation. Other cost drivers are the plant size, utilization rate, electrolyser CAPEX and methanation costs. For more details on hydrogen methanation costs see indicator 1.27.

Because the cost heavily depends on assumed electricity costs and operating hours, estimates for current and potential costs in 2030 for synthetic methane heavily differ. Gorre et al (2019) estimate the production costs to be €77.85/MWh in 2030, based on an assumed electricity price of €20 /MWh. Davis & Martin (2014) estimate costs to be €49/MWh in 2030, assuming a cheap source of wind-based electricity. Based on an extensive literature review, CE Delft (2020) estimates the 2030 cost to be between €71/MWh and €341/MWh .[351] The large range is due to the assumptions on operating hours and cost of electricity.

10.2.10.2 Transport costs

Many uncertainties remain regarding the future transport costs of synthetic methane. Transport costs depend on what may become major future exporter countries of synthetic methane, and whether the synthetic methane is shipped in liquefied form or through pipelines. As can be seen in indicator 1.11, shipping costs are estimated between €0.97/MWh and €3.86/MWh depending on the export region. When taking liquefaction costs into account, costs can rise to between €13/MWh and €20/MWh (see indicator 1.11).

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[350] Gorre et al (2019). Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-Gas plant with intermediate hydrogen storage

[351] CE Delft (2020). Availability and costs of liquefied bio- and synthetic methane – the maritime shipping perspective.

10.2.11 Indicator 1.11: Total cost of transport and production of biomethane and synthetic methane from third countries

There are two main foreseen import routes: via LNG shipping or via pipelines. The same transport infrastructure for natural gas can be used for both biomethane and synthetic methane, as these three carriers have similar characteristics. Thus, the main difference between transport costs for natural gas, biomethane and synthetic biomethane depends on the origin of the gas and the distance to EU markets. The analysis below discusses both the LNG and pipeline routes for (potentially) large exporters of biomethane. For LNG, only maritime transport costs up until the EU border at an LNG terminal or pipeline interconnection point are considered. As a result, the total transport costs are likely to be higher in reality, as the bio- or synthetic methane also has to be transported in the country of origin to a LNG export terminal, if applicable. Especially for regions at a far distance from these export terminals, the local transport costs could contribute significantly to the total transport cost, if done by truck.

10.2.11.1 Shipping costs of LNG

ENTSOG (2020) has estimated LNG shipping costs to EU LNG terminals from major LNG export regions.[352] An overview is provided in the Excel database under indicator 1.11. It is important to note that LNG shipping rates are highly volatile, and this can influence shipping costs significantly.[353] Based on this analysis, the estimated average shipping costs for global regions are presented in Table 10-2.

Table 10-2: Average LNG shipping costs from global regions to the EU

Origin region	€/MWh
Africa	1.3
Asia Pacific	3.9
Central and South America	2.5
Eurasia	0.6
Middle East	2.5
North America	2.0

It is uncertain whether and which countries or regions will develop into (large) biomethane exporters. With regard to feedstock production potential, IEA (2018) estimates that Asia-Pacific and North America might become major producers, but there is a wide array of other variables that influence whether this will lead to major biomethane exports that could be available for the EU. There is also high uncertainty concerning the potential future exports of synthetic methane (see indicator 1.10).

10.2.11.2 Additional costs related to LNG route

Besides shipping costs, LNG also has to be liquefied before shipping and in many cases regasified after shipping (when not used directly as a transport fuel in liquefied form). DNV GL (2019) estimates liquefaction costs at between €9/MWh and €15/MWh, Oxford (2018) finds liquefaction costs between €7/MWh and €13/MWh. Regasification costs (not including network injection tariffs) are relatively low, with European LNG terminals

[352] ENTSOG (2020). Ten Year Development Plan – Annex D Methodology

[353] FT (2018). Record LNG shipping rates raise capacity concerns

regasification fees around €1/MWh (with a minimum of 0.4 €/MWh and a maximum of 3.9 €/MWh – see indicator 1.14).

In summary, total transport costs via the LNG route fall in the range of €13/MWh to €20/MWh with liquefaction being responsible for between 50-75% of the total costs.

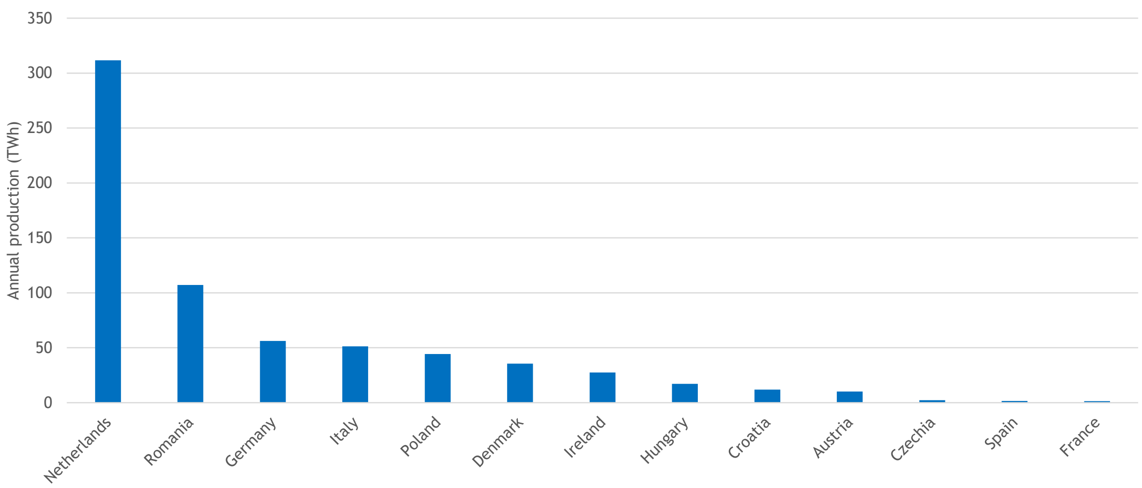
10.2.11.3 Pipeline transport costs

Transport costs via pipeline in general become more viable than LNG shipping for larger gas volumes that need to be transported over relatively shorter distances. The EU current main pipeline imports are from Russia, Norway, Algeria and Libya. Therefore, for possible biomethane imports from these countries, using existing methane pipelines could become a viable option. Especially for Eastern Europe there might be a potential for future biomethane exports to the EU (via existing) pipelines, most notably from Energy Community Contracting Parties. Tariffs for pipeline import interconnection points are presented in indicator 1.14.

10.2.12 Indicator 1.12: Domestic natural gas production in the EU

Several member states domestically produce natural gas originating from underground reservoirs both under land or water. In 2019 the Netherlands was the largest natural gas producer in the EU (312 TWh annually), although Dutch gas production is declining every year. Other large gas producers were Romania (107 TWh), Germany (56 TWh) and Italy (51 TWh).[354] Major gas producers geographically close to the EU-zone are the United Kingdom (445 TWh in 2019) and Norway (1299 TWh) of which a large amount flows into the EU via pipelines. In Figure 10-5 an overview of natural gas producers in the EU can be seen.

Figure 10-5 Domestic natural gas production in the EU in 2019



10.2.13 Indicator 1.13: Capacity of cross-border natural gas pipelines between Member States

In the Excel annex an overview is presented of the capacity of cross-border natural gas pipelines between Member States. The largest outgoing pipeline capacity is in the Netherlands (3131 GWh/d), Germany (3113 GWh/d) and Czechia (2517 GWh/d). Ingoing capacity is largest in Germany (3900 GWh/d), Belgium (2759 GWh/d) and

[354] Eurostat (2020). Supply of gas - monthly data.

Austria (2146 GWh/d). Having a large cross-border pipeline capacity can have multiple reasons. Among others, it can be the result of being a large gas consumer, transit country (for gas streams from e.g. Russia) or gas producer.

10.2.14 Indicator 1.14: Entry/Exit tariffs for intra/extra-EU IPs and for LNG terminals

In the Excel annex entry/exit tariffs can be found for intra-EU interconnection points (IP) (1.14a in Excel annex) as well as extra-EU interconnection points (1.14c in Excel annex). Additionally, several indicative tariffs for LNG terminals (1.14b in Excel annex) in the EU are presented in the annex, including the network injection tariff and an indicative 'package' tariff for unloading, storage and regasification.

Intra-EU IP cross-border commodity-equivalent tariffs[355] range between €0.15/MWh and €2.08/MWh in 2020, depending on the Interconnection Point and other factors. In addition, the FI-EE-LV, DK-SE and BE-LU markets are assumed to be integrated, with tariffs being therefore set at €0/MWh. Extra-EU IP cross-border tariffs are in a similar range of up to €1.94/MWh.

The tariffs are based on data from the 2020 TYNDP, which assumes a 100% utilisation of the IPs for converting any capacity-based tariffs into commodity-equivalents. Therefore, actual equivalent tariffs may be higher, as e.g. a 50% utilisation would mean the actual commodity-equivalent of a purely capacity-based tariff is twice as high. Moreover, for shippers with booked capacity, the tariffs are actually sunk costs. Therefore, capacity already booked should not influence shipper's decisions. However, currently capacity booked already for 2030 amounts to around 12 TWh/d, and of that only 5 TWh/d concerns legacy bookings (down from around 40 TWh/d in 2016), as indicated in indicator 1.15. Thus, to a significant extent shippers still need to decide on their capacity needs for 2030.

At LNG terminals tariffs can vary significantly depending on the LNG terminal, size of the order and type of tariff. However, the costs for unloading, storage and regasification are on average around €1.3/MWh. Network injection tariffs are on average €0.3/MWh

10.2.15 Indicator 1.15: Long-term booked capacity at IPs

The Excel annex comprises an overview of the long-term booked capacity at EU interconnection points based on the ACER-CEER Market Monitoring Report on gas wholesale volumes.[356] It includes all IP points, also with third countries, which are in the scope of the EU regulation on transmission capacity allocation (CAM Network Code). Thus, legacy long-term booked capacity as well as CAM yearly, quarterly, monthly and daily booked capacity are included. Legacy bookings gradually decrease from an average of around 20 TWh/d in 2020 to less than 5 TWh/d in 2030. More details can also be found in the Excel annex.

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[355] The tariffs are derived from the 2020 gas TYNDP. The Methodology Annex D indicates that an utilisation factor of 100% is used to convert capacity components to the commodity-based equivalents, which is the same approach as applied by ACER in the Market Monitoring Reports.

ENSOG (2020) Ten-Year Network Development Plan - Annex D – Methodology

[356] ACER/CEER (2020). ACER-CEER Market Monitoring Report (MMR) 2019.

10.2.16 Indicator 1.16: Injection and withdrawal capacities of large natural gas storages

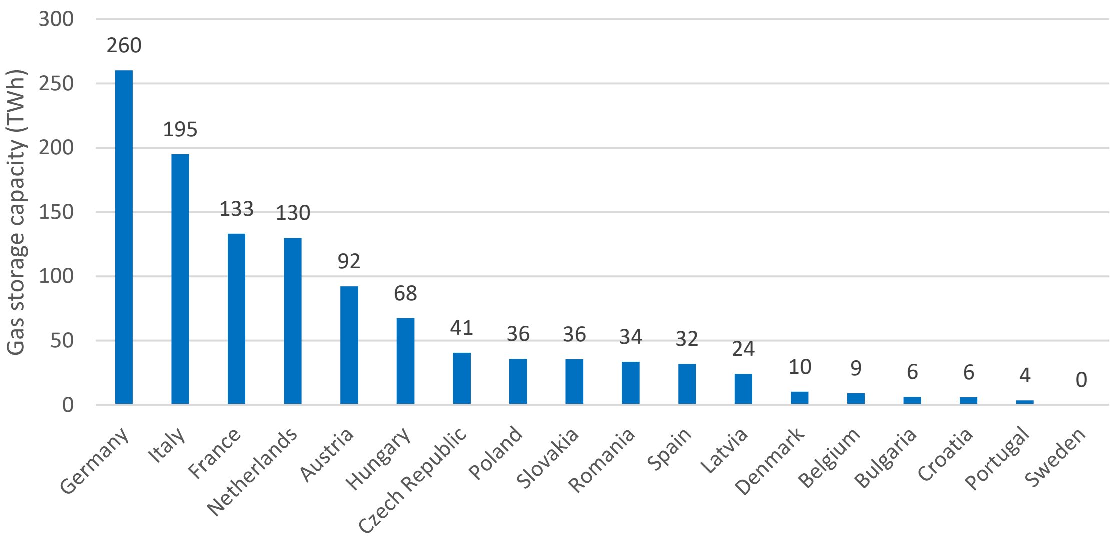
Gas storages will probably continue to play an important role in the future EU gas system. They can help provide (seasonal) and shorter term flexibility services that are of high value in an increasingly intermittent energy system increasingly relying on (green) electricity, hydrogen and biomethane.

In 2018 the total working capacity of large natural gas storages was 1115 TWh.[357] As a comparison, this is equal to 26% of the total EU gas consumption in 2019. Additionally, 133 TWh of working storage capacity is planned or currently under construction. Member States with large natural gas storage capacity are Germany (260 TWh), Italy (195 TWh) and France (133 TWh). In Figure 10-6 the gas storage capacity per Member state is presented.

The maximum daily withdrawal capacity of all storages combined was 20424 GWh in 2019, the injection capacity is lower at 11689 GWh.

The majority of storage capacity is formed by depleted gas fields (64% of total), aquifers (15%) and salt caverns (15%). In indicator 2.1. more information can be found about the suitability of these storage types for hydrogen blending rates.

Figure 10-6 Overview of natural gas storage capacity per Member State in 2019



10.2.17 Indicator 1.17: Tariffs for large natural gas storages

The costs of using natural gas storages vary depending on storage location, season and other variables. The ENTSOG TYNDP 2020 estimates that the average cost of using gas storage capacity is €0.7/MWh for injection and €0.7/MWh for withdrawal. The cost of injection, withdrawal and storage combined €1.5/MWh.[358] This cost is separate from regular entry/exit tariffs.

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[357] GIE (2018). GIE Gas Storage Database 2018.

[358] ENTSOG (2020). TYNDP 2020, *annex D.1 Methodology*

10.2.18 Indicator 1.18: Distribution network archetypes

In a separate Excel annex several distribution network archetypes are presented. The archetypes were collected via the questionnaire and are confidential.

10.2.19 Indicator 1.19: Available pipeline capacity in the EU that can be used for renewable and low-carbon gas imports in 2030

In order to estimate the available pipeline capacity in the EU that can be used for renewable and low-carbon gas imports in 2030, such as hydrogen and biomethane, the IP capacity with non-EU countries serves as a good starting point. Given that gas consumption and gas flows will probably decrease until 2030, the available pipeline capacity might become higher depending on the potential decommissioning of existing pipelines. In the modelling phase of this project the available pipeline capacity will be further estimated.

In total the import capacity is 14 059 GWh per day. Most gas pipeline imports are originating from Norway, Russia (via direct Nord Stream pipeline or transit through Belarus or Ukraine), United Kingdom and Algeria and Libya.

10.2.20 Indicator 1.20: Flexible gas demand

A study for ACER on demand side flexibility[359] (DSF) distinguishes between implicit and explicit DSF. The study indicates that the potential for implicit DSF was limited in 2014 given the 'relatively limited' roll-out of gas smart meters and the limited opportunity for shifting demand of uses such as space and water heating on a useful timescale for balancing. As of 2018, five Member States (FR, IE, IT, LU, NL) and the UK started conducting a large scale roll-out of gas smart meters, scheduled to be finished by 2024. In 2018 14% of all gas meters were smart, with the NRA-forecasted penetration rate in 2024 being 51%, while the study for the Commission estimates the rate will actually be closer to 44%.[360]

Also, while there is significant experience in interruptible gas supply contracts, the study indicates that the opportunity for large gas consumers to re-trade their gas contracts - enabled by increasingly liquid and integrated gas markets - has reduced the attractiveness of interruptible supply contracts.[361] Interruptible contracts in industry are now as a consequence limited and in practice the interruption clause is rarely activated. For example, the number of interruptible gas contracts for industry represents less than 5% of industrial gas demand in Belgium[362] and around 2% of demand of large consumers in France.[363]

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[359] CEPA, Imperial College London and TPA Solutions (2014) Demand Side Flexibility – The Potential Benefits and State of Play in the European Union

[360] Tractebel Impact (2020) Benchmarking smart metering deployment in the EU-28

[361] CEPA, Imperial College London and TPA Solutions (2014) Demand Side Flexibility – The Potential Benefits and State of Play in the European Union

[362] FPS Economy (2019) Preventive Action Plan Belgium - After Regulation (EU) 2017/1938 concerning measures to safeguard security of gas supply

[363] French Environment Ministry (2016) Programmation Pluriannuelle de l'Énergie

When looking at the residential sector, curtailable residential gas demand is limited to non-existent across the EU, also due to the fact that it would require additional capex (thermal storage). For example, in Belgium such contracts existed but are not financially attractive anymore due to the low discounts compared to firm contracts and are thus not offered.[364] Limited or non-existent demand response flexibility from residential consumers should be assumed for the future. A theoretical case study for small Italian towns (10 000 to 20 000 inhabitants) indicated that at most ~11% of total gas demand would be available for demand shifting at a cost of 12.9 EUR/MWh, in an optimistic scenario.[365]

The study for ACER also indicates that there is a potential for explicit DSF managed by the system operator, but the cost of managing imbalances through gas supply and storage is lower compared to the DSF cost or the value of lost load. Explicit DSF would then be most valuable to manage very rare supply scarcity events which cannot be (fully) solved by gas storages or other supply sources. Moreover, an increased deployment of hybrid devices capable of using gas or electricity (such as hybrid boilers) will provide an opportunity for gas DSF and the use of surplus renewable electricity. In 2014, half of the EU Member States had system operator-managed interruptible contracts, while only 20% of Member States had supplier-managed ones, although activation is rare.[366]

Of course, power generators, industrial users and in the future electrolysers are sensitive to the volatility of gas (and electricity) prices and time-of-use grid tariffs, being able to provide implicit DSF. Across Europe, most new transmission tariff methodologies provide, following the TAR network code, discounts for interruptible transmission capacity, between 10 and 20% for the discounts indicated in ACER (2020).[367] This may, combined with interruptible supply contracts and sensitivity to gas prices, increase the implicit DSF of large gas consumers and producers. For example, in Belgium specific flexible transmission capacity contracts (based on fix/flex-tariffs) are since 1 January 2016 employed to reduce costs for gas-fired power plants, in exchange for increased demand flexibility from those plants.[368]

Only a limited share of gas demand in 2030 can be assumed to be flexible, especially in a context of increasingly liquid and integrated gas markets and falling gas demand, which reduce the need for more extreme and costly measures such as load curtailment. Nonetheless, gas-fired power generation and electrolysers will be sensitive to volatile gas prices and time-of-use transport costs, representing the main demand-side flexibility resources available in the gas system. In 2030, up to 5% of the EU industrial gas demand (and most probably significantly less than that) can be assumed to be interruptible (i.e. providing explicit DSF), and a marginal share of residential gas demand, around 2% (load shifting, at an additional cost of around 12 €/MWh for each MWh shifted). In addition, the long-run cost of load curtailment as a last-resort flexibility

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[364] FPS Economy (2019) Preventive Action Plan Belgium - After Regulation (EU) 2017/1938 concerning measures to safeguard security of gas supply

[365] Lina (2017) Application of demand response strategies for the management of natural gas systems under the smart grid configuration: development of a methodology for technical, economic and environmental evaluation

[366] CEPA, Imperial College London and TPA Solutions (2014) Demand Side Flexibility – The Potential Benefits and State of Play in the European Union

[367] ACER (2020) The Internal Gas Market in Europe: The Role of Transmission Tariffs

[368] CREG (2017) Studie over de operationele winstgevendheid van de bestaande STEG-centrales in België

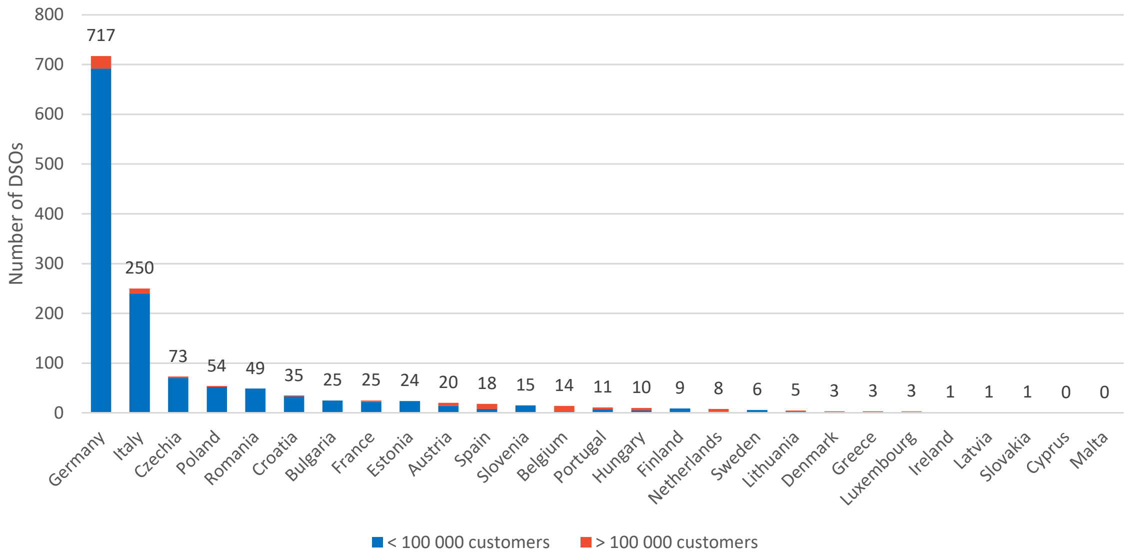
measure can be defined according to the values defined in the study commissioned by ACER on the cost of gas disruption in Europe.[369]

10.2.21 Indicator 1.21 Number of DSOs per Member State

The number of gas DSOs varies per Member State, with some Member States having a structure with many smaller DSOs, while in other Member States there are several large DSOs. In total there are 1380 gas DSOs in the EU.[370] 337 DSOs serve more than 100 000 customers and 1043 DSOs have less than 100 000 customers. Depending on the number of customers, DSOs have to comply with different unbundling requirements.

In Figure 10-7 the number of DSOs per Member State are presented.

Figure 10-7 Number of gas DSOs per Member State. The number above the bar indicates the total number of DSOs.



10.2.22 Indicator 1.22: TSO & DSO expenditures

In the Excel annex an overview of TSO and DSO expenditures per Member State is presented, based on a wide range of national sources. In 2018 the total expenditure of EU27 TSOs and DSOs was €17.9 billion. This includes €9.7 billion of capital investments as well as €8.2 billion of O&M costs (not included depreciation). Expenditures of TSOs were €7.1 billion and €10.5 billion for DSOs, with €0.37 billion that could not be allocated to either TSOs or DSOs. Germany (€4.6 billion), France (€3.6 billion), Italy (€3.3 billion) and the Netherlands (€1.5 billion) had the highest expenditures per Member State.

10.2.23 Indicator 1.23: TSO allowed revenues

Based on national sources and info of DG ENER the combined maximum allowed revenues of TSOs in the EU is currently of around €14.1 billion. Revenues of more than €1.0 billion are allowed in Germany, France, and Italy. It must be noted that indicator 1.22 indicates investments and O&M expenditures from network operators and thus the

[369] Kantor and ECA for ACER (2018) Study on the estimation of the cost of disruption of gas supply in Europe

[370] CEER (2019). Implementation of TSO and DSO Unbundling Provisions

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values indicated are separate from those indicated in the present indicator. Further Member State level information can be found in the Excel annex.

10.2.24 Indicator 1.24: TSO & DSO network length

In the Excel annex an overview per Member State is presented of the grid length of both the DSO and TSO network, based on several national sources. On EU-level, the DSO gas grid is 1.82 million km in length. The TSO grid is significantly shorter at 208 491 km in length. The DSO grid is longer than 100 000 km in Germany, Italy, France, Poland and the Netherlands. The TSO grid is most substantial in Germany (38 500 km), France (37 628 km), Italy (35 008 km) and Spain (24 730 km).

10.2.25 Indicator 1.25: Supply costs of biogas

Biogas production costs mainly depend on the feedstock cost and type, plant size and production technology. Costs can differ significantly based on local circumstances such as an abundant feedstock source in close proximity or that does not require extensive processing.[371] Table 10-3 below shows an estimation of the total biogas costs per feedstock type. Additional information and methodological details can be found in the Excel annex.

10.2.25.1 Feedstock costs

In general energy crops are relatively expensive, with feedstocks such as manure, sewage sludge or forestry residues being cheaper or having close to zero costs. Despite the large variance for feedstock costs, an estimate is made for the categories also used in indicator 1.7 (on production potential).[372,373]

10.2.25.2 Processing costs

Processing costs in biodigesters depend mainly on the size of the biogas installation and auxiliary energy needs, with larger plants being able to reach significant cost reductions in comparison with smaller plants.[374] For medium-sized plants with a capacity of 250 m^3/h, processing costs are around 37.8 €/MWh, but the actual costs can vary significantly also depending on the assumptions.

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[371] CE Delft (2017). Optimal use of biogas from waste streams

[372] Oxford Energy (2017). Biogas: A significant contribution to decarbonising gas markets?

[373] IRENA (2014). Biogas for road vehicles: technology brief.

[374] IEA (2020). Outlook for biogas and biomethane: Prospects for organic growth

Table 10-3: Supply costs of biogas in the EU per feedstock type

Feedstock type	Feedstock cost (€/MWh)	Processing cost (€/MWh)	Total biogas cost (€/MWh)
Energy crops	31.4	37.8	69.2
Manure	9.0		46.8
Biological waste	9.0		46.8
Sewage sludge	0.0		37.8
Forestry residues	4.5		42.3
Straw	31.4		69.2

10.2.26 Indicator 1.26: Cost of upgrading biogas to biomethane

10.2.26.1 Main data sources available

Several data sources present a detailed cost estimation of upgrading biogas to biomethane. Biosurf (2015) estimated costs based on a survey in which 15 biomethane producers in France and Austria participated.[375] In IRENA (2017) a 2013 German survey based on data from 7 biomethane producers addressed the production costs for a variety of upgrading techniques, but the source did not separate CAPEX and OPEX.[376] The Biosurf (2015) survey, although five years old, gives a detailed description of production costs (indicating OPEX, CAPEX and further separation of costs).

10.2.26.2 Main cost drivers and technologies

Biogas has to be upgraded and purified in order to comply with technical requirements for grid injection. The main components that have to be removed from biogas are CO_2, H_2O and H_2S.

The main cost driver is the size of the upgrading unit. There are four main upgrading techniques that remove the CO2 to upgrade the percentage of methane in the gas: membrane separation (34% of the number of installations in Europe[377]), water scrubbing (22%), chemical scrubbing (18%) and pressure swing absorption (13%). Recently, the most used technique is the relatively new membrane separation with 69% of plants built in the EU in 2019 using membrane separation as upgrading technology. Biosurf (2015) analysis of these main techniques shows that the upgrading costs for the four techniques are similar and for a large 500 m3/h biomethane installation, total upgrading costs only differ around 10% between the techniques.

Costs decrease significantly for higher upgrading capacity, thus favouring large size biomethane plants; for example, unit upgrading costs for 100 m3/h installations can be

[375] Biosurf (2015). Technical-economic analysis for determining the feasibility threshold for tradable biomethane certificates

[376] IRENA (2017). Biogas for road vehicles usage: technology brief.

[377] EBA (2020). Statistical report 2020

three times the value of a large 1000 m3/h installation.[378] Thus, upgrading in large plants seems to be economically more viable. However, the plant size is in most cases restricted by factors such as feedstock availability or prices. As a result, the most economical plant size is project-specific. In certain cases, it is possible to develop a centralised biogas production and/or biomethane upgrading plant, collecting feedstock or biogas (respectively) from the region. Some projects considered in the gas TYNDP 2020 seem to indicate this possibility.[379]

10.2.26.3 Indicative cost levels

The cost estimates of upgrading biogas to grid-quality biomethane mentioned in this section include the costs for removal of CO_2, water vapour and hydrogen sulphide, but do not consider the cost for biogas production.

The costs for biomethane transport to the grid connection point, compression and other grid injection costs are addressed under indicator 1.28 on 'costs of connection to grid'.

Biosurf (2015) gives a cost estimate for upgrading with the currently most used membrane separation technique. Costs are for a 500 m3/h (5.4 MW) capacity installation, which is similar to the average biogas installation size in the EU.[376] Energy costs are also included in the operational costs.

Based on these figures, the upgrading costs for a representative installation (500 m³/h capacity) would amount to 518 000 €/MW (CAPEX) and 14.26 €/MWh (OPEX). Further parameters are indicated in Table 10-4 below. However, all parameters except energy efficiency and lifetime may vary significantly per facility.

Table 10-4: Indicative cost levels for biogas upgrading to biomethane

Data	Unit	Value	Comment	Source
Investment cost	EUR_{2019}/MW	€ 518 000	5.4 MW capacity membrane separation plant	Biosurf (2015)
Operational cost	EUR_{2019}/MWh	€ 14.26	Including costs for energy inputs	Biosurf (2015)
Utilisation	% / No of full load hours	76%	Anaerobic digestion stage is limiting step.	
Lifetime	years	20		Lorenzi et al (2019) [380]

10.2.27 Indicator 1.27: Cost of hydrogen methanation

10.2.27.1 Main data sources available

There is a wide number of literature sources on the costs of hydrogen methanation. The main data sources employed here are the STORE&GO project[381] and the Advanced

[378] IRENA (2017). Biogas for road vehicles usage: technology brief.

[379] See for example project ETR-N-291. ENTSOG (2020) TYDNP 2020 – Annex A – Project details

[380] Lorenzi et al (2019). Life Cycle Assessment of biogas upgrading routes.

[381] Store & GO (2018). Report on the costs involved with PtG technologies and their potentials across the EU

System Studies for Energy Transition (ASSET) project.[382] Results of this ASSET study are used for PRIMES modelling and are thus well-aligned with the scope of this project.

10.2.27.2 Main cost drivers and technologies

Hydrogen methanation is the conversion process of hydrogen and CO_2 into methane. There are two main technologies for hydrogen methanation: chemical catalytic and biological methanation.

Catalytic methanation uses a methanation catalyst such as nickel in a reactor at high temperature to convert hydrogen. Catalytic methanation is the most developed technology of the two and is already being applied in several industrial setups.

Biological methanation is not applied on a large scale yet and is seen as a future suitable technique for smaller methanation plants. It uses microorganisms instead of a catalyst for the conversion to methane, and takes place under moderate conditions compared with catalytic methanation (lower temperatures and at ambient pressure). The main advantage of biological methanation is the high tolerance for impurities such as hydrogen sulphide during the conversion process (STORE&GO, 2018).

When analysing the whole power to gas chain, the electrolyser is responsible for the largest share of costs; STORE&GO (2018) estimates that for a 1 MW PtG-plant electrolysers take up two thirds of total investment costs and more than half of operational costs. For the methanation process itself, CAPEX costs for the installation are significant, as well as the costs for the required CO_2 supply and storage.

10.2.27.3 Indicative cost levels

Investment costs: Manufacturers do in general not disclose specific capex levels, making it difficult to estimate costs accurately; cost estimations that are available vary significantly, ranging from €200/kW_{output} to €1500/kW_{output}, depending on installation size, technology and other cost parameters (apparatus, steel construction, instrumentation, engineering costs - Gotz et al. 2016). Besides the methanation installation, additional equipment needs include piping, measurement equipment, structure housing and heating and cooling equipment (depending on the technology).

Costs for the supply of CO_2 can be significant in case direct air capture of CO_2 is needed. However, if there is a reliable CO_2 source – such as at industrial sites - the costs become much lower.[382] For smaller-scale methanation plants without a reliable supply of CO_2, the supply costs via air capture can become significant though.

Another main cost driver is the need for storage of CO_2. These costs can be significant, including for a storage tank and a compressor needed to inject the CO_2 in the tank. These costs influence the costs of the whole hydrogen methanation installation significantly; STORE&GO (2018) estimates that for a 1 MW hydrogen installation the investment costs for CO_2 storage are similar to the investments costs for the methanation reactor.

Operational costs: Estimates for the operational costs for chemical (catalytic) methanation range from 10% of CAPEX per year (Grond et al, 2013) to 3% (Gorre et al, 2020; ASSET, 2018). Information on the main drivers for the operational costs is scarce.

Efficiency: The energy efficiency is limited to 77.85%, when only considering methane as a useful end-product. When the residual hydrogen in the end-product is also taken into account, the efficiency can reach up to 80% with the residual energy being

[382] ASSET (2018). Sectoral integration- long-term perspective in the EU Energy System.

converted into heat during the reaction. The efficiency for both chemical as well as biological methanation is in practice around 78%.[383] This is excluding the conversion step during electrolysis, which has an efficiency of about 70%, leading to a combined efficiency of around 50%-60% of the whole process from power to methane.

Scope: The cost estimates in this indicator include the methanation reactor and CO_2 storage, including the compressor needed for high-pressure storage. Out of scope are pipeline costs to the storage, injection costs, possible revenue streams for rest products such as oxygen and residual heat, hydrogen storage and electrolysis. Costs for the supply of CO_2 are not included but additional info on these costs can be found in ASSET (2018) as well.

Table 10-5: Indicative cost levels for hydrogen methanation installation.

Data	Unit	Value	Comment	Source
Investment cost	EUR_{2019}/MW	M€ 1.20	Chemical methanation, relatively high estimate in comparison with other sources.	ASSET (2018)
Operational cost	EUR_{2019}/MW	€42 000	Thermal energy losses included	ASSET (2018)
Efficiency	%	77.85%	Theoretical efficiency of methanation step, excluding electrolysis.	ASSET (2018)
Utilisation	% / No of full load hours	-	(No information available)	
Lifetime	Years	15	Depending on operating hours	Store and Go (2018)[384]

10.2.28 Indicator 1.28: Costs of connection of biomethane plant to DSO or TSO grid.

10.2.28.1 Main data sources available

IRENA (2017)[385] provides a qualitative overview of biomethane production costs, also including the cost drivers for grid connection. STORE&GO (2018)[386] provides an overview of costs of PtG installations, including grid connection costs, which can be adapted to biomethane plants. In addition, several other sources provide additional information to estimate the average cost of connection.

10.2.28.2 Main cost drivers

Costs are mainly dependent on the connection pipe length, injection capacity and compression costs. Compression costs are significantly higher for connection to the TSO grid (40-60 bar) as the pressure is higher than in the DSO grids (up to 10 bar normally). As the compression costs are responsible for a large share of the costs, connections to the transmission grid are significantly more expensive than to the distribution grid. Also, because of the higher pressure there are more requirements for the transmission

[383] ASSET (2018). Sectoral integration- long-term perspective in the EU Energy System.

[384] Store & GO (2018). Report on the costs involved with PtG technologies and their potentials across the EU

[385] IRENA (2017). Biogas for road vehicles usage: technology brief

[386] Store & Go (2018). Report on the costs involved with PtG technologies and their potentials across the EU

pipelines that lead to a higher cost. The compression costs depend on the output pressure, which is influenced by the upgrading technology of biogas. For example, upgrading through membrane separation can lead to an already higher output pressure from the upgrading installation and can hence lead to reduced compression costs. In addition, conditioning with LPG to increase the gas calorific value also contributes to the costs of the grid connection.

Pipeline costs increase less than linearly for different injection capacities (at a similar injection pressure), and this can lead to significant relative cost reductions per MWh for larger connection volumes compared to smaller volumes. Pipeline length can also become a major cost driver in case long pipeline lengths (e.g. >5 km) are required to reach the transmission or distribution grid.

10.2.28.3 Indicative cost levels

Within scope are the costs made to transport and handle biomethane from the upgrading facility to the grid connection point. This means that costs for the pipeline, compressor, and additional activities such as LPG conditioning are within scope. Out of scope are costs made after grid injection, thus gas grid injection tariffs are not within scope. In addition, some used sources include gas quality monitoring costs within the scope, which are also discussed in more detail in indicator 2.2.

Thus, transport costs per energy unit are highly variable, depending on the injection pressure, injection volumes, connection pipe distance and need for other measures such as gas conditioning with LPG. Given the difference for pipeline and compression costs for TSO and DSO connections, different cost estimations are presented. The estimates consider a medium-sized plant with a capacity of 5 MW for both the distribution and transmission grid connection. The pipeline length is 1 km for the DSO connection and 100 m for the transmission connection, as in general TSO connections are shorter. In reality it is likely that plants connected to the transmission grid are larger than those connected to the distribution grid, leading to economies of scale; for comparison purposes the same capacity is assumed here.

Pipe investment costs are around €100 000/km for rural distribution pipelines and €350 000/km for transmission pipelines with operational costs being 2% of CAPEX.[387] KEMA (2011) estimates the gas grid injection cost including gas quality measurement costs for distribution at €50 000 for investments and €10 000 for annual operational costs.[388] Costs for a transmission connection are higher at €350 000 investment costs and €25 000 operational costs. Compression investment costs are estimated at €200 000/MW for distribution and €0.5 million/MW for transmission. Operational costs are 3% of investment costs.[389]

Table 10-6: provides estimates for the average costs of grid connection for a 5 MW biomethane plant (pipeline, compression, gas quality measurement, LPG conditioning). Transmission investment cost estimations match well with the representative value provided by a Western European TSO.

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[387] Butenko et al (2012). Injecting green gas into the grid, Dutch example.

[388] KEMA (2011). Overstort van het distributienet naar het landelijke transportnet.

[389] Albrecht (2013). Analyse der Kosten erneuerbarer Gase. Bundesverband Erneuerbare Energie

Table 10-6: Indicative costs for grid connection, including compression, for connections to the transmission and distribution grid

Connection to grid	Data	Unit	Value	Comment	Source
Distribution	Investment cost	EUR_{2019}/MW	€ 230 000	Based on a pipeline length of 1 km and 5 MW plant.	Butenko et al (2012), Store & GO (2018)
Distribution	Operational cost (annual)	EUR_{2019}/MW	€ 8 400		
Transmission	Investment cost	EUR_{2019}/MW	€ 577 000	Based on a pipeline length of 100 m and 5 MW plant.	Butenko et al (2012), Store & GO (2018), KEMA (2011)
Transmission	Operational cost (annual)	EUR_{2019}/MW	€ 20 140		
Transmission & distribution	Lifetime	Years	50 years	Lifetime for pipes. Compressors or other equipment have shorter lifetime.	Qadrdan et al (2015)[390]

According to a European TSO, the connection costs would be significantly lower however. This is among others the result of compression costs and possible LPG conditioning not being included in the cost estimate of the TSO. Its indicative costs are presented in Table 10-7:.

Table 10-7: Indicative costs for grid connection excluding compression and LPG conditioning costs

Connection to grid	Data	Unit	Value	Comment	Source
Distribution	Investment cost	EUR_{2019}/MW	€ 100 000	Based on a pipeline length of 1 km and 5 MW plant.	European TSO
Distribution	Operational cost (annual)	EUR_{2019}/MW	€ 3 000		
Transmission	Investment cost	EUR_{2019}/MW	€ 120 000	Based on a pipeline length of 100 m and 5 MW plant.	European TSO
Transmission	Operational cost (annual)	EUR_{2019}/MW	€ 6 500		

Above costs however exclude compression costs and LPG conditioning costs. LPG conditioning costs are no main cost driver and is no requirement in all MS. For example, it is not applied in France, Italy and the Netherlands. Compression costs can be significant. Based on information of European biomethane producers, the investment costs for a compressor for distribution grid pressure are between €22 000/MW and €46 000/MW. Investment costs are higher for a compressor for compression to transmission grid pressure (above 40 bar), with costs being around €70 000/MW for a 320 Nm3/h installation based on information of biomethane producers. Operational costs are estimated at €5/MWh, including energy costs.

[390] Qadrdan et al (2015). Role of power-to-gas in an integrated gas and electricity system in Great Britain

10.2.29 Indicator 1.29: Cost allocation of biomethane plant connection

The cost allocation of the biomethane plant connection to the grid varies between Member States. For example, some Member States have decided to apply relatively favourable connection terms for producers (in comparison with the grid connection terms for end-users) in order to support biomethane producers.

Based on an analysis of cost allocation regimes in general terms, one can distinguish between several cost allocation types:[391]

- **Deep cost allocation** where producers pay all costs associated with the connection. This allocation is applied in Ireland, Italy and Spain;
- **Shallow cost allocation** where producers pay the cost for the physical grid connection and the system operator pays the necessary network reinforcement. This allocation is applied in Austria, Czechia, Denmark, Finland and Sweden;
- **Super shallow cost allocation** where producers only partially pay for the physical grid connection and system operators the whole network reinforcement and part of the physical connection. This allocation is applied in the following Member States, with the physical grid connection costs allocated in different ratios: Belgium (Wallonia), Estonia, France, Germany and Lithuania. Notably, France and Germany are also the two largest biomethane producers in the EU and they have also with other favourable support schemes in place.

The allocation of the connection costs for biomethane plants is related to the allocation of biomethane injection costs. Depending on the cost allocation, the charges for connection and/or injection can be used to recover from biomethane producers the costs of e.g. reverse flow installations, meshing of distribution networks, and other reinforcement costs. Indicator 1.34 surveys the injection charges for a selected number of EU Member States. It indicates that out of 6 Member States surveyed, none had charges for biomethane injection at the distribution level. This indicates that socialisation of injection costs is more common than that of connection costs for the surveyed Member States.

A more detailed description of the cost allocation types in Member States can be found in the Excel annex.

10.2.30 Indicator 1.30: Biomethane connection obligation/request denials

In order to estimate the cases in which potential biomethane plants cannot be connected to the grid, for example because there is no spare capacity in the grid and reinforcements costs are high, it might be worthwhile to look at prior cases in which connection requests have been denied in Member States and the reasons for it. The questionnaire has delivered insightful (confidential) input with regards to denied requests which can be found in the Excel annex.

The number of denied connection requests might be limited because of obligations by law to connect any potential network user/biomethane producer to the grid. An ACER survey identified that such regulations are in place in at least 16 Member States, including most large biomethane producers.[392] Five countries, of which Sweden is the only significant biomethane producer indicated that there is no such obligation (other

[391] Regatrace (2020). Mapping the state of play of renewable gases in Europe.

[392] ACER (2020). ACER Report on NRAs Survey - Hydrogen, Biomethane, and Related Network Adaptations

countries are Belgium, Portugal, Slovakia and Poland). More detailed information can be found in the Excel Annex.

10.2.31 Indicator 1.31: Costs of hydrogen deblending

In the context of this study, one key component relevant to the injection of renewable gases in the methane network is **hydrogen deblending**. Based on the analysis of literature and feedback received from stakeholders, deblending facilities may need to be deployed to enable a low to medium level of hydrogen blending also in areas with sensitive users downstream(up to 10% in volume). Other important components which may need to be refurbished or replaced are analysed in the indicators 2.3 – 2.5.

Hydrogen deblending can be a required option for sensitive end-use applications where modifications in equipment and processes to accept methane gases with blended hydrogen can be troublesome. For several end-uses such as the use of natural gas as feedstock for chemical processes or gas turbines deblending could become a realistic option in case adjustments to allow hydrogen blending rates are costly or difficult for these applications (see indicator 2.4). Research on the need for deblending for end-uses and on the associated costs is still in an early phase and additional research is needed for a more detailed assessment.

Possible techniques for hydrogen deblending overlap with the techniques used for biogas upgrading such as cryogenic separation, membrane separation or pressure swing absorption. An initial cost estimation of ENA (2020) shows that costs for the hydrogen separation could be between €1.15/kgH_2 to €3.39/kgH_2, or 45-133 €/MWh of deblended hydrogen, for an input mixture with 20%$_{mol}$ of hydrogen.[393] Costs per kgH_2 rise quickly for lower blending rates in the gas grid, and deblending costs for an input blend with 5%$_{mol}$ of hydrogen can reach 230 €/MWh H_2 and more. Therefore, while further research is needed, deblending large volumes of gas with a low blending rate (e.g. at interconnection points) might be less economically attractive than deblending lower volumes at specific sensitive end-users. Additionally, the costs among others depend on the inlet and outlet pressure of the separation process.

10.2.32 Indicator 1.32: Costs of reverse flow installations between DSO and TSO networks

Reverse flow installations can play an important role in utilizing potential local oversupply of gas through injecting it into the transmission network. The number of such reverse flow installations is slightly increasing since a few years. Several pilot projects are currently operational and in several Member States there are detailed plans for investing in reverse flow installations.[394]

10.2.32.1 Main data sources

Only very few sources provide detailed cost assessments for reverse flow installations. The main used sources are two Dutch reports of KEMA (2011) and Netbeheer NL (2018) on the costs and feasibility of reverse flow in the Netherlands.[395,396] In addition, several other sources are used to verify and compare assumptions and estimates.

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393 Mitchell (2020). Hydrogen Deblending – Work by the Networks. In Gas Goes Green hydrogen deblending workshop

394 Gas for Climate (2020). 2020 Market state and trends report

395 KEMA (2011). Overstort van het distributienet naar het landelijke transportnet.

396 Netbeheer NL (2018). Advies: ‘creëren voldoende invoedruimte voor groen gas’

10.2.32.2 Main cost drivers

Reverse flow installations have large similarities with direct connections to the transmission grid, for which costs are estimated in indicator 1.28 on connection costs. Similarly, compressors to pressurize the gas from distribution grid pressure (lower than 10 bar) to the higher transmission grid pressure (above 40 bar) are responsible for the majority of the costs. Netbeheer Nederland (2018) estimates that the compressor and associated installation and connection costs represent around 80% of total investment costs. Other main cost components are the potential expansion of the distribution grid capacity to the compressor point and additional (cheaper) intermediate compressors needed for compression within the transmission network, resulting from the additionally injected gas.

As mentioned in indicator 1.28, compression costs are more dependent on the capacity of the compressor than on the occurring gas flow. As a result, the costs for reverse flow installations per energy unit are dependent on the total operational hours of a reverse flow installation. This is particularly relevant as it is expected that most reverse flow installations will not be used at full capacity; they are mostly used in case of gas oversupply, particularly during summer months when gas demand is low. Moreover, unit costs for a reverse flow installation are not linear to the capacity; for example, a €2.5 M unit is able to handle flows ranging from 1000 m3/h to 3000 m3/h.[397]

Scale advantages lead to lower costs per energy unit which makes it attractive to build reverse flow installations with large capacities. In practice, the capacity of reverse flow installations is relatively large and can handle the oversupply of several biomethane plants that are connected to the same distribution grid. For this and other reasons, a reverse flow installation might be a more attractive solution than a direct connection to the transmission grid. As an example, the six reverse flow installations of ONTRAS, a German TSO, have an average capacity of 9.5 MW.[394]

10.2.32.3 Indicative cost levels

Given that most reverse flow installations will enable the injection of several downstream biomethane plants, a relatively large reference installation with a 20 MW capacity is used at 40% utilisation to display the varying input of gas to the reverse flow installation. A lower utilisation rate would lead to higher equivalent costs. The scope for the reverse flow installation includes the compression costs and needed modifications to the distribution and transmission network. Other minor cost components such as gas quality measurement are not systematically accounted for.

Considering the above assumptions Netbeheer NL (2018) estimates the total investment costs for a reverse flow installation at €120 000/MW. KEMA (2011) estimates similar costs at €117 000/MW. The average of both cost estimates is used. Given the similarity to the connection costs, it is assumed that operational costs are 3% of the CAPEX.

Table 10-8: Indicative cost levels for a reverse flow installation for DSO-TSO flows.

[397] Based on internal information of EU TSO

Data	Unit	Value	Comment	Source
Investment cost	EUR_{2019}/MW	€118 500	20 MW reverse flow installation	KEMA (2011) and Netbeheer NL (2018)
Operational cost	EUR_{2019}/MW	€4 200	3% of investment costs	Store and Go (2018)[398]
Utilisation	% / No of full load hours	40%	Considering varying use, mostly in summer time	KEMA (2011)
Lifetime	Years	30		Netbeheer NL (2018)

10.2.33 Indicator 1.33: Cost of de-odorization in case of reverse flow from DSO to TSO.

In case of increased reverse flows in the future European gas grid, there will be a need to take into account the odorization of DSO and TSO grids. This odorization regime differs between Member States:[399]

- Only distribution networks are odorised: AT, BE, CZ, DE, DK, HU, IT, NL, SK, PL
- Distribution networks are odorised, transmission networks partially odorised (transport or transit sections): EL, RO, PT
- All networks are odorised: FR, ES, IE

In countries where reverse flow installations will inject odorized gas from the DSO grid into the unodorized TSO grid, de-odorization may be necessary.

Gas is in the EU mainly odorized with Tetrahydrothiophene (THT). The minimum and maximum allowed concentrations of this component vary between Member States, with maximum concentrations varying from 40 mg/Nm3, in among others the Netherlands and France, to 10 mg/Nm3 in Denmark and Germany.[400] De-odorization technology is already employed in large facilities, mainly at interconnector points (IPs) where TSO odorization practices vary. De-odorization accompanying a reverse flow installation between DSO and TSO networks is different, as it operates on a smaller scale than large cross-border de-odorization installations. Hence, because of its smaller scale, it is expected that its specific costs are higher than for de-odorization facilities at IPs.

No costs estimations can be found publicly for de-odorization facilities for reverse flows from DSO to TSO networks. According to information of a European TSO the costs vary depending on several variables, in particular the capacity of the de-odorization installation, the number of operating hours and the concentration of the odorant in the DSO grid. Investment costs are estimated at €6500/MW and operational costs at €0.4/MWh, with a lifetime of 15 years.[401]

Thus, based on the limited available information, costs for de-odorization are not significant compared with the reverse flow installation or other cost components.

Table 10-9: Indicative cost levels for de-odorization at a reverse flow installation.

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398 Store and Go (2018). Report on the costs involved with PtG technologies and their potentials across the EU

399 Marcogaz (2020). Natural Gas Odorisation practices in Europe

400 Marcogaz (2016). Odorization in Europe – The Marcogaz overview

401 Based on input of European TSO via questionnaire.

Data	Unit	Value	Comment	Source
Investment cost	EUR_{2019}/MW	€6500		European TSO
Operational cost	EUR_{2019}/MWh	€0.4		European TSO
Utilisation	% / No of full load hours		Depending on gas input in reverse flow installation. De-odorization is no limiting factor.	European TSO
Lifetime	Years	15		European TSO

10.2.34 Indicator 1.34: Grid injection tariffs for biomethane, synthetic methane and hydrogen

In the Excel annex an overview is presented of grid injection tariffs for biomethane, synthetic methane and hydrogen in several Member States. The analysis is not exhaustive and for some Member States no information is publicly available.

In several Member States injection tariffs are lower for biomethane and hydrogen compared with natural gas. Among others, there is no injection tariff for biomethane in both the TSO and DSO grid in France, Germany and Sweden. Additionally, there are no biomethane injection tariffs in the DSO grid in Italy, the Netherlands and Spain. In case of hydrogen, there is an exemption from injection tariffs in both the TSO and DSO grid in Germany. Injection tariffs for hydrogen are zero in the DSO grid in the Netherlands, Sweden and Spain. Given the current low penetration of biomethane and hydrogen, it is expected that tariff structures can change or might be updated in the near future in many Member States, depending on the priority to stimulate biomethane and/or hydrogen deployment.

Furthermore, given the more early development stage of synthetic methane, no specific tariffs can be found for synthetic methane but it is expected that those tariffs are comparable with biomethane.

10.2.35 Indicator 1.35: Expected cost reductions for techno-economic parameters

In order to assess the expected cost path of hydrogen and biomethane, it is worthwhile to estimate the possible cost reductions resulting from technological advancements. Therefore, in the Excel annex estimates for the expected cost reductions for the techno-economic parameters discussed in other indicators in the report are presented. However, given the need for more detailed studies, different developments can take place.

In general, it is expected that the technological learning rate for biomethane will be more modest in comparison with e.g. solar, wind or battery technologies which have seen significant cost reductions during upscaling in recent years. But as biogas installations are reliant on support schemes currently, it could be possible that further cost reductions in digesters and upgrading installations take place when support schemes are reduced in the future, due to competitive pressures. Moreover, in case significant biomethane deployment takes place, economies of scale (which are an important factor in determining the cost of specific installations) could lead to more important cost reductions. This is important as the size of a biogas installation is limited by the local availability of feedstock, which makes larger installations not always the best solution and counteracting any cost reductions coming from the economies of scale. Anaerobic digestion technology for biogas and several biogas upgrading technologies are relatively well developed and maximum expected cost reductions are of around 20%. In this study, gasification technology is not considered, and major cost reductions in low-technological parameters such as feedstock are not expected (while prices could increase due to e.g. competing uses).

For hydrogen networks, the expected cost reductions will be moderate among others as many necessary technologies are already mature for methane gas and need to be adapted for hydrogen. Cost reductions are expected for the power-to-synthetic methane pathway. Reductions in electrolyser costs, as well as cost reductions resulting from improvements or scale-up of hydrogen methanation technology are expected to improve the competitiveness of these pathways.[402]

10.2.36 Indicator 1.36: Current MS status regarding the policy options for the integration of renewable and low-carbon gases

In this indicator the current national alignment with the different considered policy options for the IA are discussed. In the Excel annex a complete overview can be found on the current alignment of MS with possible policy options, based on information of DG ENER and ACER.[403] Among others, the following aspects are discussed:

- Improved DSO/TSO coordination regarding connection requests
- Improved DSO/TSO coordination regarding information exchange for imbalance forecasting
- Definition of an entry-exit zone to include DSOs
- Enable physical reverse flows between DSO and TSO networks
- Allowing energy communities to sell locally-produced gas to their members
- Connection obligation with firm capacity
- Zero grid injection tariffs

10.3 Option category 2: Gas quality

In this section the indicators concerning the policy options on gas quality are discussed. Indicator 2.1 presents an overview of the technical admixture thresholds for hydrogen blending, while indicators 2.2 to 2.6 provide more details on specific issues and components.

Indicators 2.2 to 2.5 focus on the feasibility and potential costs for hydrogen blending rates up to 10% in volume in the gas grid.[404] EU blending rates higher than 10% are not expected by 2030 based on the Commission scenarios of the 2030 Climate Target Plan Impact Assessment.[405] Moreover, limited knowledge on adaptation costs for processes, appliances and equipment for blending rates higher than 10% is available.

This section is structured as follows:

[402] Store & Go (2018). Innovative large-scale energy storage technologies and Power-to-Gas concepts after

Optimization Report on experience curves and economies of scale

[403] ACER (2020). ACER Report on NRAs Survey - Hydrogen, Biomethane, and Related Network Adaptations

[404] Unless specified, blending rates in this section refer to the% of volume and not energy content of the gas.

[405] European Commission (2020). Impact Assessment of Europe’s 2030 climate ambition plan: Investing in a climate-neutral future for the benefit of our people.

- **Indicator 2.1** presents an overview of technical hydrogen admixture thresholds. This information serves to identify the equipment, appliances and processes with the lowest thresholds to be analysed in the following sections;
- **Indicator 2.2** overviews the needed adaptations in the gas infrastructure for the injection of renewable and low-carbon gases, from a system perspective;
- **Indicator 2.3** presents the costs of adapting distribution and transmission infrastructure to different hydrogen blending rates, focusing on the most relevant components;
- **Indicator 2.4** presents the cost of adapting end-use appliances to different hydrogen blending rates;
- **Indicator 2.5** provides information on the feasibility and costs of using current natural gas storage facilities to store hydrogen;
- **Indicator 2.6** presents the potential administrative costs of a reinforced cross-border regulatory framework for gas quality, which are not captured in the costs presented in the previous indicators.
- **Indicator 2.7** presents an overview of the currently allowed national hydrogen blending rates.

10.3.1 Indicator 2.1: Overview of technical hydrogen admixture thresholds

Marcogaz (2019) presents an extensive overview (see Figure 10-8) concerning the technical possibility of hydrogen blending in different stages of the gas chain.[406] The overview shows that hydrogen blending is feasible for many components for rates of up to 10%vol with no or limited modifications to the gas infrastructure and most end-user equipment and appliances. Other sources confirm this, and the modifications that still are needed are discussed in indicators 2.3, 2.4 and 2.5.[407,408] For higher blending rates, less research into the effects has been conducted, but it is expected that blending rates higher than 10% or 20% could lead to sharply rising costs, in particular when end-use equipment and appliances or gas infrastructure components have to be replaced or adapted on a large scale.

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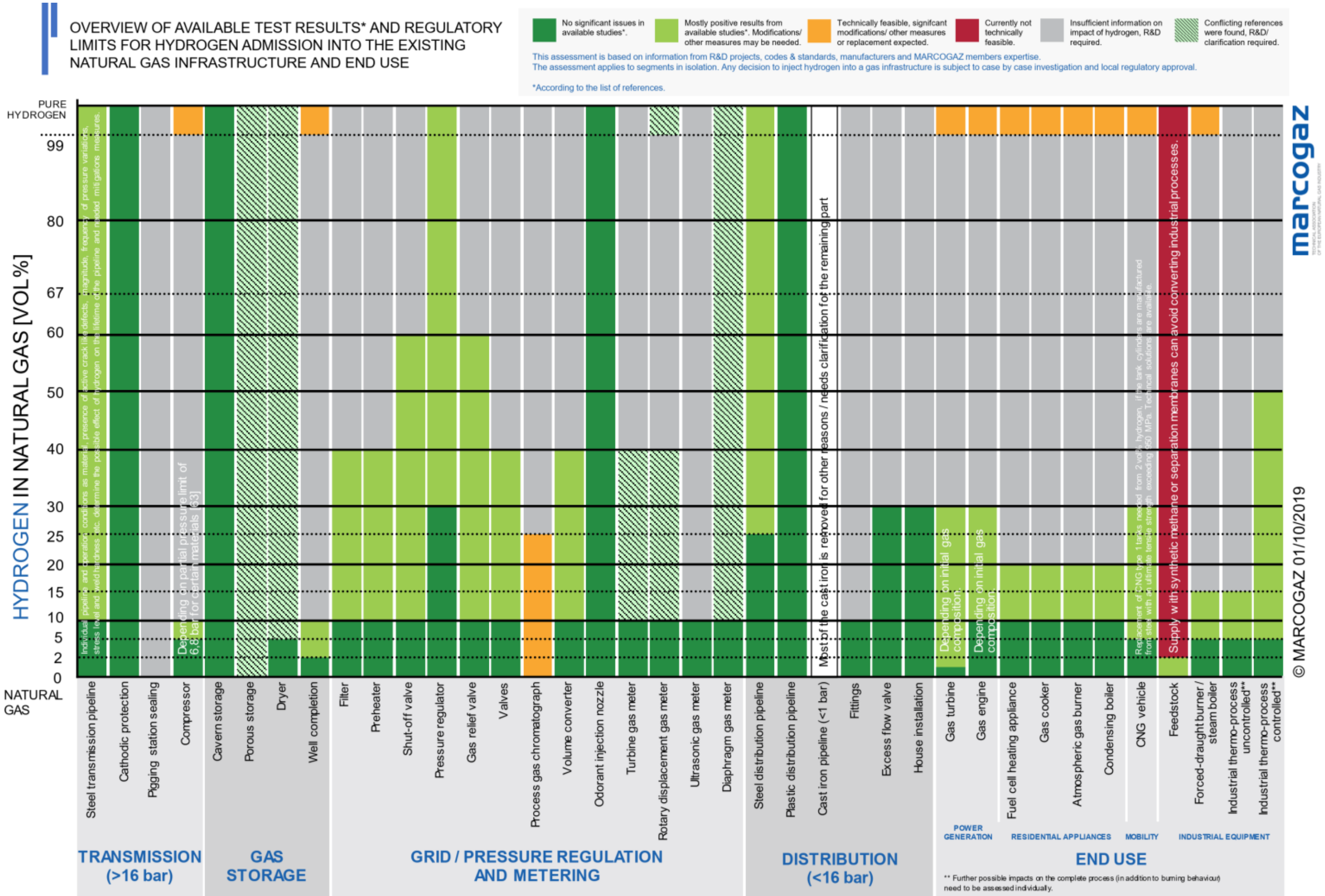
[406] Marcogaz (2019). Overview of test results & regulatory limits for hydrogen admission into existing natural gas infrastructure & end use

[407] GRTgaz et al. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[408] Netbeheer NL (2020). De impact van het bijmengen van waterstof op het gasdistributienet en de gebruiksapparatuur.

Figure 10-8 Technical tolerance limits for the admission of hydrogen in natural gas infrastructure and end-use equipment, appliances and processes



Source: Marcogaz (2019). Overview of test results & regulatory limits for hydrogen admission into existing natural gas infrastructure & end use

In the next sub-sections, a **summary of the main admixture threshold constraints in the gas chain is presented (highlighted in bold)**. The tolerances and costs for adaptation for these main constraints are discussed in more detail in indicators 2.3, 2.4 and 2.5.

10.3.1.1 Transmission & distribution network

Steel transmission pipelines can handle up to 10% blending without modifications. More research is needed on the hydrogen tolerance of the **pigging station sealing and of compressors**. In the distribution network, for steel and plastic (polyethylene) pipes it is also expected that no large modifications are needed for blending rates of up to 10%, although some sources indicate the need for additional research into the effect of hydrogen on steel.

Information is not available for low-pressure pipelines made from cast iron, but most of these pipelines are generally replaced for other reasons and are not used on a large scale. In 2013 already, cast iron pipes represented only 3% of the distribution network in countries covered by Marcogaz's technical statistics[409] (AT, BE, CZ, DK, FR, FI, DE, EL, IT, IE, NL, NO, PL and PT). Polyethylene pipes then made up 54% of the 1.5 million km of distribution network pipes considered, while steel pipes represented 34%.

10.3.1.2 Gas metering in grid

For up to 10% blending rates no issues are expected, except for **process gas chromatographs**, for which significant modifications are needed for all blending rates. When increasing the blending rate to 30%, modifications are required for most metering components.

10.3.1.3 Gas storage

No obstacles are envisioned for salt cavern storages. For **porous gas storages**, which form the majority of storage capacity through depleted gas fields, additional research is needed. Also, for aquifer storages obstacles are foreseen for blending rates of up to 10%. More info on underground storage can be found under Indicator 2.5: Feasibility of using gas storage for hydrogen blended gas.[410]

10.3.1.4 End-use

Further research is needed on the influence of hydrogen blending on **several important end-use equipment and appliances**.

Gas turbines used for power generation are highly sensitive to hydrogen blending as their operation is calibrated to achieve a high efficiency and turbines operate under high pressure. However, most low-emissions gas turbines in place can handle up to 5%vol hydrogen concentrations, with some capable of handling blending rates of up to 20%.[411] For older turbines, the threshold for hydrogen blending will be lower.

For residential appliances, such as gas boilers, blending rates of up to 10% will most likely not lead to any obstacles nor costs. For higher blending rates, especially above 20%, the

[409] Marcogaz (2014) European Gas Network Technical Statistics. Technical_statistics_01-01-2013_revision.

https://www.marcogaz.org/publications-1/statistics/

[410] RVO (2017). The effects of hydrogen injection in natural gas networks for the Dutch underground storages'

[411] Abbott (2021) Power generation gas turbines: Mitigation of issues associated with gas quality variation & hydrogen addition

impact could be costly and warrant the replacement of the appliance.[412,413] In case residential appliances have to be replaced, costs can quickly become very high. For example, a study on the Netherlands (where gas is used on a large scale for residential appliances) identified that the costs for replacing gas appliances for one household would cost around €1600-2000, including write-off of old equipment. Given that around 7 million residential buildings use gas appliances, total costs in the Netherlands could rise to more than €11 billion.[414]

For many **industrial processes that use natural gas as feedstock**, hydrogen blending can lead to significant issues. Downstream hydrogen deblending at the industrial facility can become a possible solution that will still allow hydrogen blending in the rest of the gas grid (see indicator 1.17 for additional details on hydrogen deblending). However, hydrogen deblending has not been applied on a commercial scale yet.

10.3.2 Indicator 2.2: Analysis of needed adaptations in the gas infrastructure

This section focuses on the analysis at the system level of potentially required adaptations in the gas infrastructure resulting from hydrogen or biomethane injection in the methane gas system. The following sections 2.3-2.4 focus on the analysis of tolerances and adaptation costs for equipment and appliances. Under indicator 2.3 the associated costs for modifying/replacing equipment are discussed in more detail. Gas storage and end-use applications are discussed in 2.4 and 2.5.

Overview of impacts of renewable and low-carbon gas injection in methane networks

The injection of hydrogen and biomethane will influence the gas quality in the grid. Hydrogen has different properties such as a lower specific energy content which reduces the calorific value of the gas mix and the methane number (important for gas engines), and can affect combustion properties.[415] Additionally, the properties of biomethane can vary per feedstock or upgrading technology, so that biomethane can vary in characteristics such as the Wobbe index and the concentration of compounds such as sulphur or oxygen.[416] Also related to gas quality issues, LNG can increase the Wobbe index of the gas mix in the gas grid. Moreover, renewable and low-carbon gas injections may change the gas flows in the grid, for example by requiring reverse flows from the DSO to TSO network.

Depending on the injection rates of hydrogen and biomethane, this raises the need for system-wide adaptations to ensure the functioning of the whole methane gas system and gas quality management that considers the possibly adverse effects of gas quality fluctuations on the operation of the system and on end-users.

Hydrogen blending rates might significantly differ between Member States and even local networks in the future. Greater gas quality differences between systems or Member States and variations in time can lead to trade restrictions on cross-border gas flows, if they are not actively managed by TSOs, for example by assessing gas flows in order that even if off-specifications gas entries the national system, the mixture of different gas sources still leads to on-spec gas at exit points. Different oxygen concentrations arising from biomethane injection can also lead to cross-border flow constraints. Constraints will arise especially from high blending rate regions to regions with a lower blending rate. Cross-

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412 GRTGAZ (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

413 EHI (2020) Presentation for 3rd meeting of Prime movers' group on Gas Quality and H2 handling

414 Natuur en Milieu (2020). Gasmonitor: marktcijfers warmtetechnieken.

415 THYGA (2020). Impact of hydrogen admixture on combustion processes – Part I: Theory

416 ENTSOG (2018). A flexible approach for handling different and varying gas qualities

border flows are currently managed on a bilateral basis. Hydrogen blending, a varying gas quality in time, and to a lesser extent biomethane injection may thus raise the need for further EU-level or bilateral coordination to actively manage the gas quality of cross-border flows and cross-network flows between neighbouring TSOs

The possible system-wide adaptations discussed in this section are categorised as related to gas quality standards on one hand, and to metering and quality control on the other hand. Indicators 2.3 - 2.5 then discuss the tolerances and adaptation costs for specific equipment, appliances and processes.

Gas quality standards

In a context of increased injection of hydrogen and biomethane and consequent decentralisation of gas supply (while in the past only few non-EU and EU sources injected gas in the system), EU-level coordination of gas quality standards is one way to improve the management of gas quality and provide clarity to network users, from producers to storage operators and end-users. Currently, European standards for gas quality exist but are not binding, with Member States setting the actual mandatory gas quality specifications (possibly referring to European standards).

The CEN standard EN 16726:2015 "Gas infrastructure - Quality of gas - Group H" provides a harmonised H-gas quality standard covering specifications for:[417]

- Relative density
- Oxygen
- Carbon dioxide
- Hydrocarbon dewpoint
- Water dewpoint
- Methane number
- Total sulphur without odorant
- Hydrogen sulphide and carbonyl sulphide
- Mercaptan sulphur without odorant
- Contaminants

The EN 16726 standard is, as mentioned, not mandatory, and Member States have their own gas standards which may deviate from the CEN standard. In 2016, ENTSOG published an impact analysis of referring to the EN 16726 standard in the interoperability network code, and thus making it binding for cross-border gas flows. ENTSOG concluded that "despite providing certainty on the rules and removing any contracting difficulties, [a reference to the EN 16726 standard in the interoperability network code] would face significant legal barriers and produce widespread negative impacts across segments and Member States".[418]

In addition, CEN has published the EN 16723 specifications for biomethane in the case of injection in the natural gas network (part 1) and for use as automotive fuel (part 2). This standard provides additional specifications for biomethane injection on top of those of EN 16726, namely regarding CO, NH3, amine, dust impurities, and others.[419]

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[417] ENTSOG (2016) Impact analysis of a reference to the EN16726:2015 in the network code on Interoperability and Data Exchange

[418] ENTSOG (2016) Impact analysis of a reference to the EN16726:2015 in the network code on Interoperability and Data Exchange

[419] EBA (2017) Biosurf: D3.7 - Report on the practical experiences with the application of European Biomethane Standards

However, the standard EN 16726 did not include specifications on the Wobbe index (WI). CEN is continuing the work towards an eventual inclusion of the WI. The current proposal for including WI specifications as presented at the Madrid Forum in April 2021 foresees:[420]

- One recommendation for WI specification for entry points allowing the injection of both LNG imports with high WI and of renewable and low-carbon (incl. hydrogen) gases with lower WI. The range covers 46.44 – 54.00 MJ/m^3.
- One class specified exit-point WI specification within a bandwidth of 3.7 in the range 46.44 -54.00 MJ/m^3
- One 'class extended' for any other situation as the above specified class. In this case CEN recommends an assessment of the presence of sensitive users downstream and implementation of appropriate mitigation measures.

CEN is also conducting work in order to update / develop relevant standards considering blended / pure hydrogen. Relevant foreseen standardisation work covers natural gas quality (revision of EN 16726 is planned for before 2023), gas analysis(that is measurement, concerning standards for e.g. sensors, pressure regulators and valves) installations (such as underground storage sites and pre-mixing stations), grid integrity and end-users.[421]

The gas network code on interoperability and data exchange[422] foresees a number of requirements regarding gas quality and odorization (chapter IV), including for TSOs to manage cross-border trade restrictions due to quality differences, publishing data on gas quality, and providing information to sensitive gas users.

EU-level gas quality standards might **stay voluntary, or can become mandatory.** Voluntary standards could lead to gas quality specifications alignment between Member States, if national authorities or network operators adopt them. For example, several interconnected Member States with high current or future ambitions for hydrogen or biomethane might have an incentive to align their gas quality standards in order to ensure cross-border flows of these renewable gases. Mandatory standards on the other hand will ensure that standards are aligned within the EU but might not reflect the national contexts and lead to unreasonable costs for adapting gas infrastructure and end-user equipment, appliances and processes. While it may be difficult to obtain an overview of which Member States have adopted standard EN 16726 as mandatory, it seems that while it was translated for a few Member States, e.g. the Netherlands and Sweden,[423] most gas specifications set by law or network operators do not refer to the standard. Hence, voluntary adoption of a revised EN 16726 and other standards would lead to a convergence of gas standards across Europe only slowly, or not at all.

There are several other aspects that must be considered when establishing gas quality standards that take into account hydrogen and/or biomethane, of which the main ones are hereafter introduced.

The **difference between the WI ranges for entry and exit points** influences where the responsibility for compliance with gas quality standards lies. Larger differences between entry and exit point bandwidths will lead to challenges for the grid operators in order to ensure specific gas quality characteristics downstream. Similarly, a narrower gas quality range at entry points may restrict the capacity of gas producers to inject and potentially require the use of measures such as gas enrichment in order to keep the

[420] CEN (2021). The Wobbe Index in the H-gas standard and renewable gases in gas quality standardisation; Madrid forum presentation.

[421] CEN – CENELEC (2019). Sector Forum Energy Management – Working Group Hydrogen. 2018 update report.

[422] Commission Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules

[423] https://www.sis.se/api/document/preview/8018247/

injected gas within the specified gas quality range, while facilitating the gas quality management by network operators. Future EU gas quality standards should aim to minimise total costs for producers, infrastructure and end-users by adopting specifications which achieve a balance in limiting costs to infrastructure operators and end-users while maximising flexibility for producers as much as possible.

Another aspect is whether binding EU-level gas quality standards would in the future set **specifications for the whole EU gas system or solely for cross-border flows**. In the former case, it might also apply in a different extent to the **transmission and distribution networks**, especially if there is a higher penetration of renewable and low-carbon gases at the distribution level.

A **minimum allowed hydrogen blending rate** can be set explicitly, which should be accepted by all network operators or at least at interconnections points. A maximum hydrogen blending which should not be exceeded at interconnection point could also be set. These limits could be set in gas quality standards or alternatively by legislative provisions at the EU level.

In case of an explicit minimum and/or maximum blending rate, Member States then would have to accept up to a certain blending rate at a border point and take the necessary measures to handle this blending rate in the national gas grid. A maximum blending rate could ensure a greater consistency between admissible hydrogen ranges across Member States and thus guide network operators and users in the necessary adaptation measures. It could also avoid high adaptation costs for MS with low blending rates that otherwise have to accept relatively high blending rates However, a maximum blending rate could also hold back ambitious Member States, as they would have to potentially restrict the blending rate at the border. If set too high (i.e. beyond what is economically beneficial from an individual Member State point of view), a maximum blending rate would not have any practical benefits nor costs (except for eventual implementation and administration costs).

The same arguments apply to the minimum blending rate. If set too low, it does not encourage MS to allow hydrogen in their systems and does not avoid quality-related issues impacting cross-border flows. If set too high, it can lead to high adaptation costs for MS with low expected blending rates. It could also be possible to evaluate and gradually increase the minimum allowed blending rate. However, a gradual increase of the minimum rate can lead to higher adaptation costs and uncertainty for Member States. Therefore, it is important to provide visibility on a minimum blending rate that strikes a balance between these aspects.

Member States could be allowed the freedom to bilaterally agree on and change these lower or upper blending rate limits. This would enable easier cross-border flows between Member States with high hydrogen blending rates, without unduly burdening other regions with unnecessary adaptation costs. However, if significantly different levels of blending are expected between Member States, this may not resolve cross-border flow constraints. Also, a process may be established to adjust (upwards) the EU-wide minimum and/or maximum blending rates with some agreed frequency depending on effective blending developments in the EU.

The increased injection of biomethane of varying quality might also raise the need for well-functioning cross-border flow management. Among others, biomethane can be naturally rich in sulphur. To remove the sulphur generally oxygen is used, which leads to a high oxygen content in the gas. As an example of such an issue, Danish gas has a high oxygen content because sulphur has to be removed on a large scale as a result of high biomethane production. This can lead to difficulties for border flows to Germany where gas standards do not allow a high oxygen content, mainly due to the tolerance of underground gas storages close to the DK-DE border. High oxygen contents could also impact underground storages and some industrial users in other countries, as indicated by a number of European network operators in the present study survey. This is currently addressed through adding natural gas to the biomethane to reduce the oxygen concentration. In case of future higher penetration rates of biomethane, and thus a higher oxygen content, such a solution might not be sufficient anymore. Network operators are working with network users to understand their actual limitations, as some sensitive network users may be able to tolerate higher oxygen content.

10.3.2.1 Feasibility of biomethane-based gas standards

As mentioned before, biomethane has different characteristics compared with the main natural gas sources supplying the EU. Therefore, this section first discusses in more detail the characteristics of biomethane, and then the advantages and disadvantages of developing an EU gas quality standard based on biomethane rather than natural gas.

In summary, although it is difficult to quantify costs due to the different gas quality specifications and the need for additional research, it is doubtful whether the biomethane production cost savings are higher than the infrastructure and network user costs incurred, especially for relatively low biomethane penetration rates. It should be further assessed at which biomethane injection rates an inflection occurs and a biomethane-based gas quality standard would be more cost-efficient from a system perspective.

It is also important to assess how costs related to purification and/or enrichment increase for higher penetration rates. Thus, at which point are the system costs for gas infrastructure and end-user adaptations lower than the costs for biomethane cleaning and conditioning at the biomethane injection site? This is also discussed in this section.

Characteristics of biomethane and potential impacts on gas quality

Firstly, biomethane has generally a lower Wobbe index and calorific value than natural gas from most EU and especially non-EU sources (the exceptions are DE, HU, IE, NL as well as Libyan gas which has a lower average WI, while DE and IE gas has a lower gross calorific value).[424] Also, the Wobbe index of biomethane can be intrinsically variable given the various biomass feedstocks and production processes. Gas quality fluctuations can also occur in case of fluctuating biomethane injection rates (on a system level biomethane production in the EU does not seem to exhibit significant seasonality, but there can be daily / intra-daily fluctuations) and due to demand seasonality. This would require that users in networks where the share of biomethane injection to total gas demand varies considerably (due to short-term injection fluctuations and demand seasonality) are able to accept both biomethane and natural gas.

For low injection rates the influence of biomethane on the average gas WI or calorific value is not substantial but considering the higher expected production of biomethane and decreasing demand for natural gas, the situation might change. The average biomethane WI is around 14.2 kWh/m3 (25/0 °C) versus 14.7 kWh/m3 (25/0 °C) for Norwegian kWh/m3 (25/0 °C).[425] The lower and varying calorific value of the gas at high biomethane injection rates could lead to issues related to metering and billing to end-users, as flow meters could incorrectly measure the user's energy consumption. A study for the Dutch distribution network found this was a major cost driver for allowing greater biomethane injection.[426] On the other hand, other consulted stakeholders do not foresee large issues for biomethane blending rates of up to 30%. As an example, high blending rates of biomethane in Denmark have not led to major technical issues within the Danish gas grid or at end-users.

Secondly, higher biomethane blending rates can increase the concentration of certain components that could potentially negatively impact gas infrastructure or network users. The main trace components in biomethane are:

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[424] CEN (2020). The Wobbe Index in the H-gas standard and renewable gases in gas quality standardisation

[425] ENTSOG (2020) Ten-Year Network Development Plan – Annex F – Gas Quality Outlook

[426] Netbeheer Nederland (2018). Toekomstbestendige gasdistributienetten

- Sulphur - Sulphur can be present in biomethane in different concentrations depending on the feedstock used. Sulphur can among others corrode metal components in the gas grid. However, in most cases biomethane is desulphurised after upgrading.[427]
- Oxygen - Biomethane has on average a higher oxygen content than natural gas. Additionally, desulphurization can further increase the oxygen content of biomethane. A high oxygen content can influence several system components such as increasing the precipitation of solids in the gas, which could lead to clogging or function as nutrient for micro-organisms present in the gas. GERG (2019) and other stakeholders indicate that although the impact of a higher oxygen content on the gas network and equipment is limited, it could influence natural gas storages.[428] This can lead to situations similar to the example of border flows from Denmark to Germany mentioned before, where additional measures were needed to comply with the allowed oxygen content in the German gas standard.
- Carbon dioxide – Non-upgraded biogas consists of about 40% carbon dioxide. However, biogas upgrading to biomethane removes most carbon dioxide.[429]
- Siloxane – Siloxanes can be present in biomethane generated from solid and sewage waste, which constitutes a minority of the produced biomethane in the EU (see indicator 1.3). The presence of siloxanes can lead to oxidation in several components such as gas engines and gas turbines.[430]
- Micro-organisms – Different micro-organisms can be present in biomethane. The effect of these micro-organisms is not well studied yet and their impact is therefore unknown but expected to be limited.[431]

The questionnaire feedback from stakeholders confirms that oxygen is the main component which may lead to gas quality issues. However, this is mainly the result of the currently low reference concentration for oxygen in among others the CEN gas quality standards. It seems that oxygen related obstacles are in the first place regulatory and that the technical obstacles for allowing a higher oxygen content are limited. Therefore, regulators and network operators do not see the issue as a major barrier. Biomethane producers are concerned however on the impacts that the costs to meet strict oxygen concentration specifications could have on the economic feasibility of biomethane projects. Producers thus argue that taking measures to reduce oxygen concentrations at the entrance to storage sites would be a more cost-effective solution.

Biomethane-based gas quality standard

To facilitate the injection of biomethane, gas quality standards could be based on the characteristics of biomethane. In practice this could mean a lower and wider range for the allowed calorific value and Wobbe index, and higher allowed concentrations for some of the trace components present in biomethane, especially oxygen. Netbeheer Nederland[432]

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[427] GERG (2019). GERG Biomethane project – Biomethane trace components and their potential impact on European gas industry

[428] GERG (2019). GERG Biomethane project – Biomethane trace components and their potential impact on European gas industry

[429] GIE (2011). GIE Position Paper on Gas Quality.

[430] GERG (2019). GERG Biomethane project – Biomethane trace components and their potential impact on European gas industry

[431] GIE (2011). GIE Position Paper on Gas Quality.

[432] Netbeheer Nederland (2018). Toekomstbestendige gasdistributienetten

indicates that such standards could also allow higher concentrations of hydrogen sulphide (H_2S) and carbon monoxide (CO), which currently need to be filtered so that the biomethane can meet gas standards.

The European Commission's MIX H2 scenario estimates that in 2030 biogas (including biomethane) will be responsible for less than 10% of total gross gas supply in the EU. Therefore, for most transmission and distribution grids, the blending rate for biomethane will in the near future still be limited and consequently its influence on gas quality as well, except for potential constraints related to underground gas storage or gas quality variations affecting sensitive industrial end-users.

According to the ENTSOG 2020 gas quality outlook, the system-wide average gas quality (Wobbe index and gross calorific value) would up to 2030 remain relatively stable in all regions, in both the Russian gas or LNG supply scenarios. Depending on the region, a higher upper limit for the Wobbe Index and gross calorific value can be observed due to LNG imports, or some widening of those indices occurs due to the injection of biomethane.[433] However, in general gas quality in the regions assessed would be stable.

Therefore, if a binding biomethane-based gas standard was applied in the EU, an important question would be accommodating LNG supplies, which on average have a higher gross calorific value and WI than most EU and non-EU pipeline sources (Algeria, UK and Danish gas in particular can have higher WI).[434] As mentioned before, currently there are no binding EU-wide standards for natural gas quality. If adaptation of standards is needed, a wider WI and gross calorific value range as well as eventually higher allowed oxygen concentrations could be more sensible than a biomethane-based standard. A biomethane-based binding standard might however be feasible for specific distribution grids with high local biomethane injection, which is discussed next.

System costs for a biomethane-based gas quality in a DSO grid

System costs for a biomethane-based standard have not been assessed in detail yet in a published study, to the extent known. Allowing a lower and possibly wider Wobbe index range and higher concentrations for several components present in biomethane, especially oxygen, H_2S and carbon monoxide, can require the adaptation of both gas infrastructure as well as end-user equipment, appliances and processes. It is important to assess if resulting system adaptation costs weigh up against the avoided costs for biomethane production and resulting higher production volumes.[435] This also raises the question of how additional system costs will be allocated.

One potential cost saving of a biomethane-based gas quality standard would be the avoidance of some of the costs for purifying biomethane. Biomethane must be upgraded (CO_2 removal) and purified (removal of several other components, for more info on trace components see section above) to comply with national gas quality standards.

Non-upgraded biogas with a high CO_2 content of around 40% is not suitable for grid injection because it significantly lowers the Wobbe index and calorific value, and the CO_2 can corrode gas infrastructure and pose safety risks for end-users.[436] Therefore, biogas must be upgraded prior to injection and there is only a degree of freedom in the purification stage. Note that depending on the upgrading technique, several trace components are already removed from the biogas during the upgrading stage.

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433 ENTSOG (2020) Ten-Year Network Development Plan – Annex F – Gas Quality Outlook

434 ENTSOG (2020) Ten-Year Network Development Plan – Annex F – Gas Quality Outlook

435 Netbeheer Nederland (2018). Toekomstbestendige gasdistributienetten

436 Angelidaki et al (2019). Chapter 33 - Biogas Upgrading: Current and Emerging Technologies

No separate cost indications are available for the biogas purification stage of e.g. oxygen or sulphur which makes it difficult to quantitatively asses the production cost reductions that can be achieved with a biomethane-based standard allowing higher concentrations of e.g. oxygen. However, the standard EN 16723-1 already foresees the possibility of an oxygen concentration of up to 1%, in the absence of sensitive network users.

Currently many biomethane producers condition the biomethane with LPG before grid injection in order to increase the calorific value of the gas. The costs for LPG conditioning are a major operational cost component, amounting to up to 40% of operational costs when such gas enrichment is necessary. In case of a biomethane-based gas quality standard, this should not be necessary anymore and this could thus lead to significant savings.[437] However, it is difficult to quantify this impact in detail.

If a dedicated biomethane-based standard was applied for specific distribution networks, additional purification and/or enrichment may be needed at the TSO/DSO interface in case reverse flows were to take place. This could still lead to cost savings resulting from the economies of scale of centralized purification and enrichment, as well as lower volumes of gas to be conditioned as most gas will be used in the distribution grid.

Due to the larger range of possible calorific values of gas in the case of a biomethane-based standard, there could be additional costs for metering and billing within specified margins of error. A study of several Dutch DSOs mentions the metering and billing costs as a major potential cost driver, although a comparison has not been conducted on whether the avoided costs for biomethane producers would compensate the metering and billing costs.[438]

Metering and quality control in the distribution network

The injection of hydrogen and biomethane raises the need for altering some metering and quality control components in the gas grid. Among others, gas quality meters have to be able to measure the hydrogen content of the gas and other equipment has to be recalibrated.

Biomethane injection in the distribution grid can also raise the need for installing reverse flow installations to enable upstream flow of gas to the TSO grid (see indicator 1.21). In most Member States gas is odorised only at distribution networks (e.g. Germany, Italy, Poland). Non-odorization of gas in transmission networks is the widespread practice in the EU and is the preferred approach in the interoperability and data exchange network code. Therefore, there would be a need for de-odorization installations in case of upstream flows from the DSO to TSO level. In some countries, gas is odorised in sections of the transmission system (e.g. Greece, Portugal) or the entire transmission system (e.g. Spain, France).[439] Odorization issues should thus also be considered for cross-border flows, in case odorization regimes differ between countries. Article 19 of the Interoperability and Data Exchange Network Code addresses the management of cross-border trade restrictions due to odorization practices.

Varying gas quality levels resulting from the injection of hydrogen and/or biomethane increase the need for enhanced gas quality and flow metering to monitor the gas quality levels in the gas grid at TSO/DSO interfaces, network user connections or different network points. Even more so, to mitigate the costs for decentralized quality control at the biomethane producers' sites, it has been suggested (see section on biomethane-based gas quality standards) to have different gas quality requirements for parts of the DSO and TSO

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[437] IRENA (2018). Biogas for road vehicles: Technology brief.

[438] Netbeheer Nederland (2018). Toekomstbestendige gasdistributienetten

[439] Marcogaz (2020). Natural Gas Odorisation practices in Europe

grids, depending on the level of biomethane injection and the downstream users in each particular distribution grid.

In most countries the biomethane producer is responsible for guaranteeing the quality of biomethane for injection into the grid, while the DSO or TSO is responsible for quality control, i.e. verifying the gas quality (except in the Netherlands and Italy) and for managing the gas quality in the overall network. [440]

As is further discussed in 2.3, some end-use equipment and appliances might not be able to function properly in case of high or varying hydrogen blending levels. Hydrogen storage could be used by the network operator to maintain a constant hydrogen blending rate and thus mitigate gas quality fluctuations due to varying injection and demand, but to the knowledge of the authors not done yet on a commercial scale

10.3.3 Indicator 2.3: Costs of adapting distribution and transmission infrastructure to hydrogen blending

This section focuses on the gas transmission and distribution infrastructure components that would need to be adapted for hydrogen blending, including a cost indication of the adaptation costs when possible/applicable. The scope is limited to hydrogen blending rates of 10% or lower. Most cost indications in this section are based on information of system operators, while regulators were generally less able to provide information on costs.

In general, responses to the stakeholder questionnaire identify that associated costs for a blending rate of up to 10% are limited. GRTgaz et al. (2019) estimates that the needed investment costs (network, storage and end-users) for adaptation for a 10% or 20% blending rate will also be limited but will strongly rise for higher blending rates.[441] They estimate costs for adapting the current gas infrastructure to blending rates higher than 20% at between €1/MWh and €8/MWh in 2050 depending on the scenario. Netbeheer Nederland (2020) estimates the costs for hydrogen blending of up to 20% at about €900 per household.[442]

Distribution and transmission pipelines

Although most major components in the gas distribution and transmission network can handle blending rates of up to 10%, minor modifications are still needed.

With regards to piping, polyethylene pipes that are widely used in low pressure distribution grids are compatible for all hydrogen blending rates. For steel pipelines which are also used in the transmission grid, the main foreseen issue is deterioration of the steel resulting from hydrogen embrittlement that could induce cracks in the steel. The extent of deterioration is pipeline-specific and depends among others on the diameter, gas composition and operating pressure (higher pressure pipelines are more sensitive to deterioration).[443] This could be combatted by increased pigging (monitoring) of the pipes, applying an inner coating, or operational strategies that keep the pressure in the grid stable. However, for a 10% blending rate, steel pipelines can still be used at limited retrofitting cost. Additional research is needed to assess the precise influence of hydrogen embrittlement on the lifespan of steel pipelines and the system-wide impact and costs of modifying the steel

[440] Marcogaz & EBA (2019). Biomethane: responsibilities for injection into natural gas grid.

[441] GRTgaz et al. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[442] Netbeheer NL (2020). De impact van het bijmengen van waterstof op het gasdistributienet en de gebruiksapparatuur.

[443] GRTgaz et al. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

pipeline infrastructure.[444] Costs will rise for higher blending rates as there is more hydrogen present that could deteriorate the steel.

In case an internal coating for high-pressure steel pipelines is necessary, the Hydrogen Backbone Study estimates these costs at €40 000/km for large transmission pipelines.[445] Significant costs could be associated with coating existing pipelines, due to the need for excavation works, although new coating processes are being developed.[446] However, GRTgaz et al. indicates coating costs for low to medium blending levels would likely be lower and represent only a small share of overall network costs.[447]

Furthermore, old cast iron pipelines in the distribution grid are not compatible with hydrogen blending but their use is now very limited, to certain mostly urban areas. For example, in France only 4 500 km of cast iron pipelines remain (e.g. in Paris) and 5 000 km in the Netherlands which is in both countries less than 3% of the distribution grid length.[443,448] In these specific areas, hydrogen blending could require the replacement of the cast iron pipelines. Replacement would at some point be necessary for safety reasons without hydrogen blending anyway, thus blending will merely be a driver to speed up the replacement process.

Gas metering and monitoring

Modifications to the gas quality metering and monitoring equipment will also be needed, although for 10% blending rate modifications are limited. For most meters adjustments for a blending rate of up to 10% will be limited to a re-calibration. For higher blending rates metering accuracy or functioning will be influenced by the different gas composition.

Process gas chromatographs do require modifications for a 10% blending rate, but the related costs are limited.[449] European gas network operators estimate the cost of a new gas chromatograph between 100 000 and 200 000 €/unit, and the adaptation costs to measure hydrogen concentrations of up to 20%vol at 20 000 to 60 000 €/unit. A major TSO estimates modification costs for all chromatographs at less than €15 million. Also in general, although metering stations within the gas grid, for example at entry or exit points, have an important function, their share in the total infrastructure cost is relatively limited – for example, the mentioned €15 million would represent around 2-3% of the transmission-level investments that take place annually in the TSO's country.[450]

Fittings in the transmission and distribution pipelines do not have to be replaced at a 10% blending rate but potentially the inspection rate should be increased leading to limited additional costs (approximately doubling inspection costs). For higher blending rates, volume flow meters and pressure regulators possibly must be dismantled and replaced. The costs for a volume flow meter are around €270 000 according to a European TSO. However, more research is needed to indicate at which blending rate replacement is needed. It is expected that this will be with a blending rate of at least 20%.

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[444] Enagás et al. (2020). European Hydrogen Backbone: How a dedicated hydrogen infrastructure can be created.

[445] Enagás et al. (2020). European Hydrogen Backbone: How a dedicated hydrogen infrastructure can be created.

[446] Stolten et al. (2020) Wasserstofftransport im Gas-Fernleitungsnetz: Eine techno-ökonomische Bewertung

[447] GRTgaz et al. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[448] DG ENV (2011). Assessing the case for EU legislation on the safety of pipelines and the possible impacts of such an initiative.

[449] IEA (2003). Reduction of CO_2 emissions by adding hydrogen to natural gas.

[450] Enagás et al. (2020). European Hydrogen Backbone: How a dedicated hydrogen infrastructure can be created.

The Umweltbundesamt (2019) estimates the dismantling costs for volume flow meters and pressure regulators in the distribution grid at €10 000/unit, and costs for new volume flow meters and pressure regulators at around €30 000/unit. As there are around 23 000 volume flow meters and 40 000 pressure regulators in the German distribution grid, total replacement costs would be around €2.5 billion for the German DSO grid and several times higher for the whole EU grid.[451]

Other network equipment. French gas network operators indicated that, after replacing/refurbishing gas chromatographs and coating pipelines, gas compressors might be the next bottleneck for hydrogen blending in the transmission network (for a blending of 10%/vol or higher).[452] Both centrifugal (for large gas volumes) and reciprocating (for small gas volumes) compressors are indeed not critical elements for a blending rate of up to 10%vol.[453]

The European Hydrogen Backbone study[454] assumes that the investment cost for retrofitting a compressor station for pure hydrogen transport is the same as for a new compressor. For a blending of 10 to 20%vol, however, costs are limited according to GRTgaz et al. (2019), and for blending levels above 20% replacement of compressors would be necessary to some extent.[455]

European TSOs indicate that compressor station equipment manufacturers are actively working on developing equipment which is tolerant to various hydrogen blending levels. In 2021 Snam will install a gas turbine in one of its compression stations ready to accept any level of hydrogen blending.[456]

10.3.4 Indicator 2.4: Costs and feasibility of adapting end-use equipment and appliances to hydrogen blending rates

This section discusses the costs and feasibility of adapting end-use appliances and equipment to hydrogen blending. The influence of hydrogen blending on several important end-uses is not mapped in detail yet, although obstacles are identified for some end-uses. In general, modifications are needed for a hydrogen blending rate of 10% or above. Below that threshold, most equipment, appliances and processes would be compatible. This is except the use of natural gas as a feedstock for among others the production of chemicals, steel, glass and other certain industrial processes, for which specific solutions may be needed, including hydrogen deblending. For higher blending rates above 20% the situation becomes very different as many end-use appliances have to be replaced, leading to significant costs.[457]

10.3.4.1 Power generation

For power generation, natural gas is mainly used in gas turbines. Gas turbines are highly sensitive to varying amounts of hydrogen, due to their operation under high pressure and

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[451] Umwelt Bundesamt (2019). Roadmap Gas für die Energiewende – Nachhaltiger Klimabeitrag des Gassektors

[452] GRTgaz et al. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[453] TNO et al. (2020). North Sea Energy Technical assessment of Hydrogen transport, compression, processing offshore

[454] Enagás et al. (2020). European Hydrogen Backbone: How a dedicated hydrogen infrastructure can be created.

[455] GRTgaz et al. (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[456] Snam (2020) Snam and Baker Hughes Test World’s First Hydrogen Blend Turbine for Gas Networks

[457] GRTgaz (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

the need to achieve high efficiency.[458,459] Nonetheless, most low-emissions gas turbines in place can handle up to 5%vol hydrogen concentrations, with some capable of handling blending rates of up to 20%.[460] Research is ongoing to identify the needed adjustments for a 10% blending rate. These adjustments depend on the turbine type and manufacturer and must be assessed ad hoc. Adjustments are likely unnecessary or restricted to e.g. software adjustments only, depending on the system. For blending rates in the range of 10-30%, further adaptation may be needed, but would still be limited compared to higher blending rates. Adaptation might aim to avoid embrittlement issues in the gas delivery system (e.g. piping and seals), guarantee purging of H_2 for ensuring the safety of maintenance works, conditioning the fuel or adapting the turbine for start-up and shut-down. Manufacturers are already offering in their portfolios turbines capable of handling at least 30%vol blending rates, and often higher.[461,462] Related to hydrogen blending, a constant WI is also of importance for gas turbines. Thus, not only the blending rate itself is relevant, but also how it could lead to a varying gas quality and WI. While TSOs are working with sensitive network users to understand actual tolerances, hydrogen blending can indeed significantly alter combustion processes and requires case-by-case considerations.

10.3.4.2 Gas engines and compressed natural gas containers

CNG containers employed in vehicles and refuelling stations have a low tolerance to hydrogen, with Regulation UN/ECE 110 limiting the blending rate to 2% when steel cylinders are employed.[463] Gas engines themselves also have a low tolerance of 2% if the methane number of the natural gas is already low. Thus, blending rates of 2 to 5% might be technically acceptable depending on the natural gas quality, and even 10% might be possible for certain cases. Another concern is the formation of NOx, which might need the adaptation of post-catalyst converters.[464,465] These constraints regarding gas engines will be most relevant to Member States with significant CNG vehicle fleets (currently or planned). Information is limitedly available regarding adaptation costs of stationary and mobile gas engines for hydrogen blending.

10.3.4.3 Residential and commercial appliances

For residential appliances, such as gas cookers, blending rates of up to 10% will most likely not lead to any obstacles nor replacement/refurbishment costs. The same assessment

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[458] Abbott (2021) Power generation gas turbines: Mitigation of issues associated with gas quality variation & hydrogen addition

[459] Marcogaz (2017). Impact of hydrogen in natural gas on end-use applications

[460] Abbott (2021) Power generation gas turbines: Mitigation of issues associated with gas quality variation & hydrogen addition

[461] Altfeld & Pincheck (2016). Admissible hydrogen concentrations in natural gas systems

[462] ETN global (2020). The path towards a zero-carbon gas turbine.

[463] Regulation No 110 of the Economic Commission for Europe of the United Nations (UN/ECE)

[464] Altfeld & Pincheck (2016). Admissible hydrogen concentrations in natural gas systems

[465] Marcogaz (2017). Impact of hydrogen in natural gas on end-use applications

applies to blending rates of 20% to 30%, but additional research is needed regarding e.g. impacts on the appliance lifetime.[466,467]

One important question is the cost for adapting existing gas boilers to hydrogen blending levels. In the UK, it is estimated that about half of commercial boilers could be converted to 100% H_2, while the other half would need to be replaced.[468] The cost to convert a medium capacity commercial boiler (73-110 kW) to 100% H_2 would be approximately 61 EUR/kW. Residential boilers are assumed to have a capacity of 30 kW. For low to medium blending levels, the number of commercial and residential boilers that merely need adaptation instead of replacement would be much higher. This leads to lower associated costs (or non-existent for e.g. boilers with combustion control tolerating low blending rates). Manufacturers indicate that combustion control represents a small share of the manufacturing cost for new boilers.[469] Hence, in general residential and commercial (condensing gas) boilers could tolerate up to 20%vol hydrogen blending at limited or no cost.[470]

However, for blending rates higher than 20%, costs can rise strongly if end-use appliances have to be replaced. For example, Netbeheer (2020) argues that most costs for a blending rate of more than 20% would be for converting or replacing household appliances. Costs can be around €1 600 per household for buying new appliances and gas metering equipment. These costs are probably similar for a 20% or 100% hydrogen blending rate as in both cases all equipment has probably to be replaced. This can make residential appliances a significant bottleneck for high blending rates.

Similarly, it is expected that residential gas meters will also be still accurate for a 10% blending rate.[471] However, the influence of hydrogen on the durability of gas meters is still unsure.[472] Marcogaz (2019) does also not identify issues for industrial gas meters for a blending rate of up to 10%. For higher blending rates rotor or turbine meters must be recalibrated. Netbeheer Nederland (2020) identifies the cost per gas meter at €100.[442] Given that there are more than 20 million households in the EU with a gas grid connection, adaptation costs could exceed €2 billion.

10.3.4.4 Industrial equipment

In the industrial sector, natural gas is either used as a chemical feedstock or to provide heat to industrial processes via gas burners, steam boilers or other equipment. Marcogaz (2019) identifies possible modifications for feedstock already at very low blending rates and for steam boilers and industrial heat processes for blending rates higher than 5%. Hy4Heat (2019) assessed industrial equipment connected to the low-pressure distribution

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[466] GRTgaz (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[467] EHI (2020) Presentation for 3rd meeting of Prime movers' group on Gas Quality and H2 handling

[468] ERM (2020). Hy4Heat WP5: Understanding Commercial Appliances for UK Hydrogen for Heat Demonstration. Final Report.

[469] Engie et al. (2018). Self-regulated gas boilers able to cope with gas quality variation: State of the art and performances

[470] EHI (2021). EHI position paper on the use of green gases for heating.

[471] Marcogaz (2019). Overview of test results & regulatory limits for hydrogen admission into existing natural gas infrastructure & end use

[472] Netbeheer NL (2020). De impact van het bijmengen van waterstof op het gasdistributienet en de gebruiksapparatuur.

grid and saw no major challenges for the conversion to high hydrogen blending rates. It assessed the total costs for conversion at €3 billion for the UK.[473]

Steam boilers and other industrial thermal processes have possibly to be retrofitted for blending rates higher than 5% in order to reach e.g. stable gas quality input, high efficiency and low NOx emissions.[474] Hy4Heat (2019) estimates the conversion costs at €40 000 - €80 000 per MW installed capacity. However, these costs are for a conversion to 100% hydrogen. VNP (2018) estimates the costs for retrofitting a steam boiler to 100% hydrogen at €250 000 per MW capacity.[475] Thus, costs for retrofitting for a 10% blending rate are expected to be lower.

Lastly, the use of natural gas as a chemical feedstock can be very sensitive to the presence of hydrogen. To still allow the use of natural gas as a chemical feedstock, hydrogen deblending (see indicator 1.3.1) might be a possible solution that will not limit the blending rate in other parts of the downstream gas grid. However, while further research is needed, deblending large volumes of gas with a low blending rate (e.g. at interconnection points) might be less economically attractive than deblending lower volumes at specific sensitive end-users. Additionally, the costs among others depend on the inlet and outlet pressure of the separation process.

10.3.5 Indicator 2.5: Feasibility of using gas storage for hydrogen blended gas

Gas storages form an integral part of the EU natural gas grid. For (salt) cavern storages (13% of total EU storage capacity, see indicator 5.4) hydrogen blending will likely not lead to any issues as several pilot projects have shown,[476] although further pilot projects are needed to actually confirm the issue However, for porous storages, which include aquifers (19% of EU total storage capacity) and depleted gas fields (64% of EU total storage capacity), for blending rates of up to 10% there are still doubts about the feasibility and additional research is needed.[477]

For aquifers and depleted fields, the dissolution and transport of hydrogen in water is well understood though, and is similar to natural gas. The main research gap lies with the identification of possible chemical reactions in the solution that could lead to impurities such as hydrogen sulphide or corrosion.[477] Additional research is also needed to investigate e.g. the degree of sealing of the caprock for varying percentages of hydrogen in the gas.[478]

In practice, these research gaps limit current hydrogen grid injection pilot projects to parts of the distribution and transmission grid where no porous underground storages are present. However, several pilot projects are currently running in the EU that further investigate these research gaps. It is therefore expected that in the near future it will be more clear whether aquifer and depleted field storages will need modifications for blending.

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[473] Hy4Heat (2019). Conversion of Industrial Heating Equipment to Hydrogen

[474] Marcogaz (2017). Impact of hydrogen in natural gas on end-use applications

[475] VNP (2018). Decarbonising the steam supply of the Dutch paper and board industry.

[476] Moss Bluff and Clemens Dome projects in Texas, USA.

[477] GRTGAZ (2019). Technical and economic conditions for injecting hydrogen into natural gas networks

[478] Larre et al (2019). Assessment of underground energy storage potential to support the energy transition in the Netherlands

10.3.6 Indicator 2.6: Potential administrative costs of reinforced cross-border regulatory framework for gas quality

A reinforced cross-border regulatory framework for gas quality would involve administrative costs for TSOs. This section does not discuss other implementation or operational costs.

In ACER's impact assessment of the framework guidelines on the interoperability network code[479], the implementation costs of gas quality management options are qualitatively assessed. 'Require cooperation' is assumed to have the lowest implementation costs, 'improving information' provision to have medium implementation costs, and 'requiring forecasting' to have the highest implementation costs. No values are provided for these estimates.

The interoperability and data exchange network code already contains a provision requiring data publication on gas quality (Art. 16) at interconnection points and a provision on information to specific sensitive users and storage operators, or DSOs with such users in their networks (Art. 17). Hence, a requirement to publish additional relevant information such as the hydrogen concentration would lead to limited additional administrative costs compared to the present situation. Establishing further cross-border regulatory requirements for gas quality would involve some administrative costs by ACER and ENTSOG as well as to NRAs and TSOs to monitor the implementation of the measures, but if this task is incorporated within current monitoring obligations in the interoperability network code, costs to ACER and ENTSOG would likewise be limited.

The 2012 ACER study on gas quality assessed the costs associated with the adjustment of gas quality (through enrichment/derichment) and appliance replacement/refurbishing, while it does not take into account issues related to blending of hydrogen. It also estimated TSO costs associated with requirements for the provision of gas quality forecasting services. This is useful to gas traders, which could incorporate the information and eventual flow restrictions in spot gas prices and prices for (large-scale) consumers. Associated costs per TSO were estimated at 1 or 2 full-time equivalents (FTE) positions. With the original assumption of 100 k€ per FTE and 1.5 FTEs per TSO, the 46 ENTSOG member TSOs active in the EU27 would incur a cost of around 6.9 M€ per year.

10.3.7 Indicator 2.7: Current national hydrogen admixture regulation

Allowed hydrogen admixture rates are, if at all, determined per Member State and vary significantly. The highest allowed hydrogen admixture rates are in Germany (10%), France (6%), Greece (6%) and Spain (5%). Allowed hydrogen admixture blending rates are lower in Finland (1%), Ireland (0.1%mol[480]), Italy (0.5%), Lithuania (0.1%mol) and the Netherlands (0.02%). Belgium, Czechia and Denmark do not allow hydrogen blending while in the not earlier mentioned 15 Member States there is no regulation yet. Thus, national hydrogen admixture regulation highly varies and might raise a need for closer cooperation and alignment between Member States, as discussed in indicator 2.2.

10.4 Option category 3: LNG terminals

In this section indicators concerning LNG terminals are discussed.

[479] ACER (2012) Initial Impact Assessment Accompanying the Document Framework Guidelines on Interoperability and Data Exchange Rules for European Gas Transmission Networks Ref: ACER/AP/TG/2012/992

[480] Percentages are in%vol if not indicated otherwise.

10.4.1 Indicator 3.1: Costs of adapting LNG terminals to biomethane or synthetic methane

The properties of biomethane or synthetic methane are similar to those of natural gas (for more info on gas quality see indicator 2.2). Therefore, in case the biomethane or synthetic methane meets the gas quality specifications, no changes are needed in EU LNG terminals.[481] Administrative measures may be needed for shippers regarding the management of guarantees of origin / sustainability certificates as well as guaranteeing the gas meets technical specifications, but no investments or additional O&M at LNG terminals are necessary.[482]

10.4.2 Indicator 3.2: Transport costs of trading decarbonized gas within the EU via LNG route

In the future, it might become efficient to transport liquefied methane gases from renewable sources such as biomethane, between European LNG terminals by ship, thereby further integrating the European LNG market. Several services are offered at LNG terminals that enable such intra-EU trade:

- **Reloading:** The liquefied gas is transferred from the LNG terminal storage tank to a ship. This can be done for large-scale ships with a capacity of more than 30 000 m^3, and small-scale ships.
- **Transhipment:** Transferring of LNG between ships. This can be done between ships moored at separate berths (berth to berth) or between one ship moored to a berth and the other ship alongside the ship (ship to ship).

Gas sector stakeholders consider these reloading and transhipment services at present as an important service offered by LNG terminals.[483]

Currently, reloading to large-scale ships in Europe is offered at 15 LNG terminals, to small-scale ships at 10 terminals, berth to berth transhipment at 5, and ship to ship transhipment at 1 terminal. An overview can be seen in Table 10-10. Based on information from a number of LNG terminals, tariffs for the use of these services range between €0.28 - €0.47/MWh for large-scale reloading, €1.11-€1.50/MWh for small-scale reloading, and between €0.39 - €1.74/MWh for berth to berth transhipment.[484] Compared with total biomethane costs, the reloading costs are limited, but when compared with intra-EU shipping costs, reloading and transhipment would substantially contribute to a higher transport cost.

The above cost indications do not consider additional LNG storage costs. In case of reloading, the costs increase based on the period the LNG has to be stored in terminal tanks prior to loading. LNG storage costs vary per terminal. As an example, storage costs at the Zeebrugge LNG terminal range between €0.026 and €0.056/MWh/day.[485]

On top of the reloading or transshipment costs, intra-EU shipping costs should be added. Considering the relatively low distances between LNG terminals in the EU compared with

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[481] Frontier Economics for GLE (2020). The role of LNG in the energy sector transition: Regulatory recommendations

[482] GLE (2020). Readiness of European LNG terminals to receive hydrogen: Regulatory and technical aspects

[483] Trinomics (2020). Study on Gas market upgrading and modernisation – Regulatory framework for LNG terminals.

[484] Based on data of several LNG terminals in the EU: Zeebrugge, Fos Cavaou, Fos-Tonkin, Montoir-de-Bretagne and Barcelona. Reference volume for reloading and transshipment was 1 TWh for large-scale and 50 GWh for small-scale reloading.

[485] Fluxys (2021). Fluxys LNG tariffs web page, consulted on 26-03-2021.

global shipping distances, these shipping costs are estimated at between €0.60 and €1.30/MWh (see indicator 1.11 for shipping costs).

Table 10-10: Availability of reloading and transshipment services at EU LNG Terminals

Country	Terminal	Reloading (large-scale)	Reloading (small-scale)	Transhipment (berth to berth)	Transhipment (ship to ship)
Belgium	Zeebrugge	X	X	X	
France	Dunkerque	X	X		
	Fos Cavaou	X	X		X
	Fos-Tonkin	X	X		Under study
	Montoir-de-Bretagne	X	X	X	
Greece	Revithoussa	Planned	Under study		
Italy	FSRU OLT Toscana	Under study	Planned		
	Panigaglia	Planned	Planned		
	Porto Levante	Under study			
Lithuania	FSRU Independence	X	X		
Malta	Malta Delimara				
Netherlands	Gate terminal	X	X	X	Under study
Poland	Świnoujście	Under study	Under study	Under study	Under study
Portugal	Sines	X	Under study		
Spain	Barcelona	X	X	X	
	Bilbao	X	X		
	Cartagena	X	X	X	Planned
	Gijón (Musel)	X	Under study		Under study
	Huelva	X	X		
	Mugardos	X	Under study		Under study
	Sagunto	X	Under study		
	Total terminals offering these services	15	11	5	1

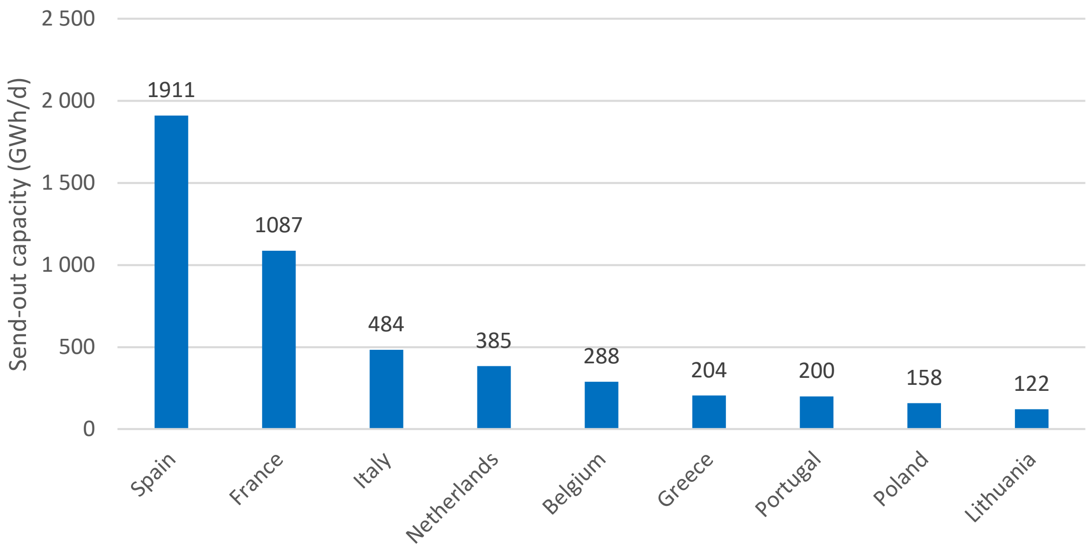
10.4.3 Indicator 3.3: Number and capacity of current LNG terminals

The number of LNG terminals has been increasing in recent years for several reasons, including ensuring security of supply by diversifying gas import sources and routes. In

2019 there were 18 large-scale LNG terminals in the EU.[486] Small-scale LNG terminals are not taken into account as they do not contribute significantly to the total LNG terminal capacity. The aggregate maximum daily send-out capacity of the 18 LNG terminals is 4 840 GWh/d, which represents 40% of the average daily EU gas consumption in 2019.[354]

Most LNG terminal capacity is in Spain (1911 GWh/d, 6 terminals), France (1087 GWh/d, 3 terminals) and Italy (484 GWh/d, 3 terminals). In the Excel Annex more detailed information on the large-scale currently operational LNG terminals in the EU can be found.

Figure 10-9 Overview of large-scale LNG terminal send-out capacity per Member State



10.4.4 Indicator 3.4: Number and capacity of planned LNG terminal projects

The trend of increasing LNG terminals in the EU is expected to continue with several import large-scale LNG terminal projects being planned or under construction. 13 additional LNG terminals are in the Final Investment Decision stage or further planning/construction phases. Their aggregate capacity is at least 749 GWh/d (15.4% of the current LNG send-out capacity), although for several projects the planned capacity is not defined yet.

10.4.5 Indicator 3.5: Available LNG storage capacity in the EU that can be used for renewable and low-carbon gas imports in 2030.

The storage capacity in LNG terminals (48.9 TWh) is limited compared with the underground storage capacity (around 1 115 TWh) (see indicator 1.16). The utilisation rate was in 2018 on average around 48%, rising to around 60% in 2019.[487] CEER refers to LNG unbundled storage capacity as 'scarce'[488]. Storage tanks in LNG terminals are in general mainly used for operational purposes, and provide storage services unbundled from re-gasification / liquefaction services only to a limited extent. As most storage capacity is offered in standard bundled products, unbundled storage capacity is limitedly available and

[486] ENTSOG (2020). TYNDP 2020 Annex C.1 – Capacities per IP.

[487] GIE (2020). GIE Aggregate LNG Storage Inventory webpage. https://alsi.gie.eu/#/

[488] CEER (2017). Removing LNG barriers on gas markets

in practice only used for short-term purposes. Nonetheless, this should not constitute an argument against measures guaranteeing a level playing field for the sourcing of flexibility resources in gas markets, including from LNG storage services.

In the Excel annex the storage capacity per LNG terminal can be found, as well as the utilization rate of the storage capacity in 2017 and 2018.[487]

10.4.6 Indicator 3.6: Supply potential and supply costs for LNG imports

In order to improve the modelling outcome, the expected supply potential and related supply costs for (fossil) LNG imports to the EU is estimated. In the Excel annex the supply cost model also used in the ENTSOG TYNDP 2020 is presented for the supply costs in 2020 and 2025, for both LNG as well as pipeline imports.[489] The model presents cost estimates - transport costs not included - for most large global LNG exporters. According to this model, LNG import costs in 2025 vary between €19.17/MWh (Azerbaijan) and €29.60/MWh (Australia).

10.4.7 Indicator 3.7: Daily utilization profiles of LNG terminals in the EU

In the Excel annex all daily send-out and storage capacity as well as its utilization is presented for 2017, 2018 and partially for 2019, based on GIE data.[490]

The EU total monthly EU send-out capacity utilization in 2019 varied between 36% and 57%. Average monthly EU storage utilization was higher in 2019 between 47% and 74%. Most capacity is used during the winter season. Since the COVID-19 pandemic in 2020 send-out capacity utilization rates have declined to 33%, while storage utilization was affected to a lesser extent.

10.5 Option category 4: System integration planning

10.5.1 Indicator 4.1: Costs and benefits of changes in unbundling DSOs to avoid conflicts of interests

In 2018 there were 1380 gas DSOs in the EU, of which 1283 have less than 100 000 customers and are thus not subject to unbundling requirements if the concerned Member States chose to exempt them.[491] At EU level, 48% to 100% of total distribution-connected gas demand is served by large DSOs (with more than 100 000 customers).[492]

Functional or accounts unbundling is generally applied for small gas DSOs.[493] In the EU, only the Netherlands and Belgium require full unbundling of their gas DSOs. Unbundling of accounts and confidentiality obligations are required according to Art. 27 and 31(3) of the Gas Directive for all DSOs. By removing incentives to network operators from exercising market power, adequate unbundling rules (coupled with other measures) can foster the efficient and non-discriminatory development and operation of gas infrastructure.

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[489] ENTSOG (2020). TYNDP: Annex D.1 methodology.

[490] GIE (2021). Aggregated LNG Storage Inventory.

[491] CEER (2019). Implementation of TSO and DSO Unbundling Provisions–Update and Clean Energy Package Outlook

[492] Ref-E (2015) Study on tariff design for distribution systems

[493] Ref-E (2015) Study on tariff design for distribution systems

In almost all Member States with gas distribution networks (except Austria, the Netherlands and Slovenia) rules on the independence of staff and management have been adopted. Generally, most NRAs are satisfied with the present regulatory framework. They believe that the current legal incorporation form of their DSOs assures an adequate level of independence and they are satisfied with the monitoring by the compliance officer and with the data management service. Most DSOs can fully independently define their financial plans (with the exception of CZ, DK, FR, DE and PT) and most DSOs (77%) had in 2019 shared services with their vertically integrated undertaking (VIU). One point for improvement mentioned by the NRAs regards the behaviour of employees vis-à-vis customers, the VIU and other companies, where 47% of the NRAs are either not satisfied or not always.[494]

Large DSOs must at least be legally unbundled from gas production and trade/retail activities. Art. 33 of the Gas Directive on access to storage refers to storage connected to the transmission system. This could be revised to also include storage connected to the distribution system given that more (operational) storage facilities may potentially be connected to the distribution grid in the future.[495]

Several other changes to unbundling rules are possible:

- Define allowed and non-allowed tasks for DSOs regarding gas production (renewable and low-carbon, including power-to-gas), storage, and/or biomethane upgrading and collection facilities;
- Harmonised EU unbundling rules can be specified in order to establish minimum requirements to guarantee the separation of distribution and other tasks between the DSO and the VIU, for example concerning shared services and non-discriminatory access to DSO information;
- Lowering or eliminating the number of customers threshold for small DSOs, or changing it to another metric such as gas demand volumes or turnover.

It could be beneficial to align requirements for electricity and gas DSOs unless specific considerations justify an asymmetric approach.

Unbundling is an effective measure in order to ensure that gas DSOs do not discriminate against certain network users. There are other possible solutions to reduce the potential conflicts of interest between DSOs and other branches of the VIU, including information transparency, planning, purchasing of services and stakeholder consultation requirements. The new electricity market design implemented several of such requirements, for example for electricity DSOs to develop network plans, and on the procurement of products and services, including non-frequency ancillary services and to cover network losses (Art. 31 of recast Electricity Directive).

10.5.1.1 Define allowed and non-allowed tasks for DSOs regarding gas production (renewable and low-carbon, including through power-to-gas), storage, and/or biomethane collection points

The Impact Assessment for the new electricity market design[496] acknowledges that the DSO landscape in the EU is varied, and that DSOs face different challenges in each Member State. Given the different degrees of development of gas distribution networks across the EU regarding e.g. size, injection of biomethane, as well as the regulatory regime, gas DSOs also face different challenges. Currently DSOs have, depending on the Member State,

[494] CEER (2019). Implementation of TSO and DSO Unbundling Provisions–Update and Clean Energy Package Outlook

[495] E3M (2020) The role of Gas DSOs and distribution networks in the context of the energy transition

[496] European Commission (2016) SWD(2016) 410.

different responsibilities regarding tasks such as data management, smart metering[497] and provision of services to renewable gas producers such as metering and odorization services.

The Gas Directive does not require legal unbundling between gas storage and distribution activities. Moreover, Article 26 explicitly allows combined gas distribution and storage operators. The actual involvement of DSOs in gas storage in the EU is however very limited. Hence, any measures requiring legal unbundling of gas storage and distribution would have limited administrative costs for DSOs.

Regarding gas production activities, large DSOs have to be unbundled according to the Gas Directive. New rules may be introduced for small DSOs, or to allow large DSOs to be involved under certain conditions, if such a measure was desired in case of e.g. lack of market interest. Two main possible approaches would exist:[498] (1) allowing the DSO to develop, own and operate the gas production facility, including the gas, with appropriate accounts unbundling; (2) allowing the DSO to develop, own and operate the facility, offering production/energy conversion services to market parties.

On storage, the Clean Energy Package has introduced unbundling obligations between energy storage and electricity distribution activities, with a time-limited exemption allowed in case of a lack of market interest that is demonstrated through a market test. The measure provides an adequate balance in incentivising storage as a competitive activity and enabling DSOs to participate in its development by offering storage services to the market in specific cases, in case of a lack of market interest. In the case of gas, currently network operators are allowed to operate also storage facilities. However, similar requirements as for electricity could be introduced for gas DSOs regarding gas storage, in case it was considered e.g. that small-scale gas storage through power-to-gas could be considered a competitive activity.

10.5.1.2 Changing the Art. 26(3) DSO unbundling threshold of 100 000 customers

Lowering the threshold for small DSOs to a value of less than 100 000 customers, or eliminate the possibility for Member States not to impose unbundling requirements to small DSOs, are possible measures to strengthen unbundling of gas DSOs in the EU. It is also possible to change the metric to for example a defined balance sheet size or turnover.[499]

Energy regulators indicate that reducing the threshold so that small DSOs cover only a minor share of the total customers in each Member State would increase economic efficiency, as only 189 of the 2400 electricity and gas DSOs are now subject to legal unbundling requirements.[500] The regulators recognise that specific measures would have to be taken in order to avoid that certain DSOs would face unreasonable expenses.[501] In practice, unbundling requirements for certain gas DSOs would not be economically viable.[502] Moreover, in the past unbundling of network companies from VIUs has in some

[497] CEER (2021) Report on Regulatory Frameworks for European Energy Networks 2020

[498] E3M (2020) The role of Gas DSOs and distribution networks in the context of the energy transition

[499] CEER (2015) The Future Role of DSOs

[500] CEER (2015) The Future Role of DSOs

[501] CEER (2015) The Future Role of DSOs

[502] Barnes (2020) Can the current EU regulatory framework deliver decarbonisation of gas?

cases led to the re-evaluation of assets,[503] which may have negatively impacted tariff levels.

The DSO customer threshold was not modified in the recent revision of the Electricity Directive. Hence keeping the current threshold would increase the coherence with the electricity market design. Otherwise, it would be recommended to change the threshold for both electricity and gas DSOs. Anyway, other measures such as transparency, planning, purchasing of services and stakeholder consultation applicable to all DSOs irrespective of size as well as a clear definition of regulated activities and activities DSOs may perform under certain conditions might be solutions with lower administrative costs.

10.5.1.3 Harmonised EU unbundling rules

Harmonised EU unbundling rules could be specified in order to establish minimum requirements to guarantee an adequate separation of distribution and other assets/activities between the DSO and the VIU. This could apply for example for shared services and non-discriminatory access to DSO information, expanding on the current high-level requirements of the Gas Directive.

Shared services with VIU allow gas DSOs to reduce fixed costs, at the risk of inappropriate exchange of information between the DSO and other VIU entities, potentially leading to discriminatory treatment of other network users. While noticing that this is a possibility, CEER does not identify evidence that this risk of discrimination is materialising due to the increasing use of shared services by gas DSOs and their VIUs.[504]

Harmonisation of rules would reduce the regulatory framework flexibility to account for the various situations in the EU, such as DSO size, nature of the network (e.g. rural vs urban), use of shared services and tasks of the DSO. Nonetheless, national regulators are generally satisfied with the rules in place for assuring the independence of the DSOs, despite a few cases of non-compliance (with no fines imposed, but in one particular case the Austrian regulator has mandated the return to compliance).[505]

10.5.2 Indicator 4.2: Costs and benefits of additional coordination and cooperation requirements (electricity/gas, TSO/DSO, storage)

10.5.2.1 Costs and benefits of increased coordination between transmission and distribution infrastructure planning

Current planning practices and obligations on gas TSOs and DSOs to cooperate on network planning vary significantly across Member States.

Domestic DSO to TSO reverse flow capacity needs are addressed in NDPs of five Member States (BE, DK, EE, FR and NL).[506] Only the French TSOs need to publish actual and future available capacity for biomethane injection in transmission networks[507].

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[503] CEER (2021) Report on Regulatory Frameworks for European Energy Networks 2020

[504] CEER (2019). Implementation of TSO and DSO Unbundling Provisions–Update and Clean Energy Package Outlook

[505] CEER (2019). Implementation of TSO and DSO Unbundling Provisions–Update and Clean Energy Package Outlook

[506] ACER (2020) Opinion 09/2020 On the Review of Gas National Network Development Plans to Assess Their Consistency With the EU Ten-year Network Development Plan

[507] ACER (2020) ACER Report on NRAs Survey - Hydrogen, Biomethane, and Related Network Adaptations

At least 16 Member States have currently obligations in place for network operators to connect biomethane producers (AT, CZ, DK, ES, DE, HU, IE, IT, LV, LT, LU, SI, ES, FR, NL and HR). The NRAs of BE and PT indicate that work is on-going to introduce this obligation. This does not mean that biomethane producers should not bear any costs – for example at least in AT, DK, ES, HU, IT, SI producers pay some or all of the connection costs. In France biomethane producers pay the reinforcement costs incurred by the network operator if the ratio of necessary investments / injection volumes is higher than a threshold set by the regulator. Moreover, at least in several Member States network operators are allowed to refuse the connection on technical grounds. According to ACER this happens for example in HR, IE, IT, LV, but most likely also in other Member States.

Regarding the right for biomethane producers to inject, i.e. the obligation for network operators to provide firm capacity for biomethane producers, this exists in a few Member States. Biomethane producers have priority access to the network for example in Germany and France, while no priority rules exist in Austria.[508]

Some Member States have obligations for the TSO(s) and DSOs to cooperate in order to define the most appropriate level for connection of new biomethane plants. This includes France, where the French NRA deliberation 2019-242[509] defines the procedures for assuring the 'right to connect' established by law 2018-938. The deliberation 242 requires French gas TSOs and DSOs to cooperate in order to establish a zoning program for the connection of biomethane projects. Candidate biomethane producers must register in a capacity management register, which triggers the development of detailed (for the distribution level) or feasibility (for the transmission level) studies. Based on the estimated costs and the cost allocation rules defined in deliberation 242, the preliminary connection agreement can be signed (with the producer eventually paying for part of the connection and reinforcement costs).

Such planning cooperation between TSOs and DSOs, including on issues such as reverse flow installations or meshing of distribution networks, should facilitate the cost-efficient integration of biomethane and other gas types. For example, in France the gas network operators are currently able to accommodate the gas injected by most commissioned projects, but the gas system capacity can further accommodate only a third of the projects in the capacity management registry. By 2028, network reinforcement investments (for reverse flow and distribution network meshing especially) are forecasted to cost 500 million € and will enable up to 22 TWh of annual biomethane injection,[510], compared to an actual injection level of 2.2 TWh in 2019.

Limited information is available on gas TSO-DSO cooperation obligations in other Member States. ACER and CEER note that while generally TSOs provide/publish information on the network and DSOs on connections, the level of information sharing varies per country and usually there is no obligation for the TSO to take the information from DSOs in consideration. In some countries combined transmission and distribution system operators exist, such as in Denmark (Energinet) and Luxembourg (Creos, which also owns and operates distribution assets following an exemption to TSO unbundling requirements of the Gas Directive). However, most EU Member States have separate operators for gas transmission and distribution networks. Indicator 4.4 of the Excel database shows that for

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[508] E3M (2020) ASSET study on the role of gas DSOs and distribution networks in the context of the energy transition

Gonzalez et al. (2019) Future markets for renewable gases and hydrogen

[509] CRE (2019) Délibération N°2019-242 Délibération de la Commission de régulation de l'énergie du 14 Novembre 2019 portant décision sur les mécanismes encadrant l'insertion du biométhane dans les réseaux de gaz

[510] CRE (2019) Délibération N°2019-242 Délibération de la Commission de régulation de l'énergie du 14 Novembre 2019 portant décision sur les mécanismes encadrant l'insertion du biométhane dans les réseaux de gaz

most Member States the national regulatory framework does not foresee mandatory TSO-DSO cooperation mechanisms.

The EU network code on gas balancing establishes an obligation for the TSO to consult with DSOs on a number of aspects, and comprises information provision obligations for the DSO towards the TSO. The EU interoperability and data exchange network code also includes information provision obligations on gas quality variations from the TSO towards the DSOs with sensitive end-users. The new electricity market design establishes an EU DSO entity for electricity with various tasks. CEER and other organisations (e.g. GD4S) support the creation of such an EU DSO entity for gas

10.5.2.2 Benefits and barriers to the development of storage

The expected reduction in natural gas demand and the uncertainty on the exact future demand levels will increase the risks for natural gas storage operators. These risks will depend on the market conditions and any regulatory measures put in place to address the risk, for example storage obligations, and the adequacy of storage capacity given developments such as the increasing penetration of renewable and low-carbon gases[511]

In 2018, 12 Member States had a storage obligation as a means of meeting the gas supply standard (BE, CZ, DK, FI, FR, HU, IT, LV, LT, PL, PT and ES). These obligations varied in their characteristics. For example, Belgium, the Czech Republic, Hungary and France establish minimum filling level. In Lithuania, gas reserves are only available in case of disruptions or emergency situations. In Portugal, France and Slovenia market parties must ensure minimum levels of storage, while strategic storage measures are in place in Hungary, Italy, Latvia, Lithuania, Poland, Portugal and Spain. The survey conducted by CEER does not allow to assess whether the different security of supply standards, the definition of vulnerable customers and the measures adopted by Member States negatively impact market integration or cooperation between Member States. Nonetheless, CEER raises the question whether a more uniform methodology to assess security of gas supply and the needs for measures would help avoid that storage obligations and other measures constitute a market barrier across Europe.[512]

Other conditions for storage vary strongly per Member State:[513]

- Whether access to storage capacity is regulated or left to the market;
- Whether prices are defined in bilateral contracts, tendering procedures or are regulated;
- Whether the storage is considered to be located in the virtual trading point or whether transmission tariffs are due to access the trading point.

Technical constraints also exist for methane gas storage operators, for storing e.g. biomethane.[514] This is illustrated by the cross-border flow restrictions from Denmark to Germany due to the lower oxygen concentration limits in Germany, put in place due to the

[511] Frontier Economics (2020) Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU

[512] CEER (2018) Status review on application of the supply standard foreseen in the security of supply regulation

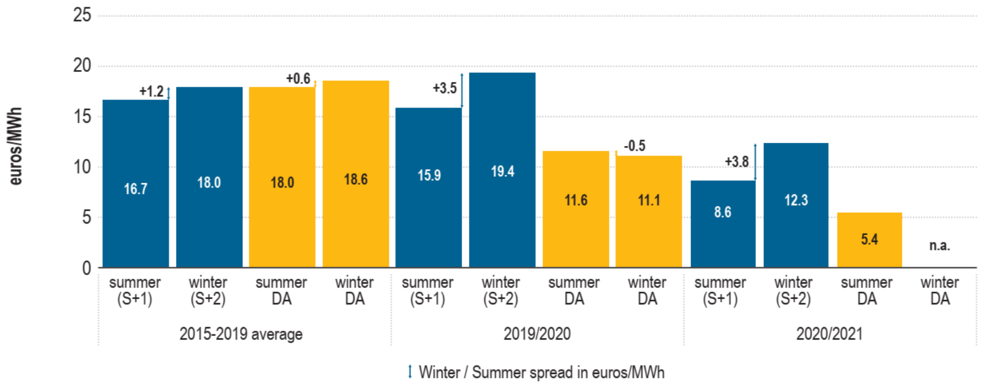
[513] EY and REKK (2018) Quo vadis EU gas market regulatory framework – Study on a Gas Market Design for Europe

[514] Frontier Economics (2020) Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU

storage facilities located near the German-Danish border.[515] Technical risks to storage are related to gas quality issues and are addressed under indicator 2.5.

In the 2015-2019 period, summer/winter gas price spreads have narrowed, reducing the profitability for gas storages. However, in the last two gas years (2019/2020 and 2020/2021) ex-ante gas spreads have increased again (Figure 10-10). These higher spreads resulted from expectations of depressed summer gas prices, rather than the usual driver of higher expected winter prices.[516]

Figure 10-10 Comparison of ex-ante seasonal summer/winter spreads vs actual spot prices at the TTF hub in 2015–2020



Source: ACER calculation based on Platt's and ICIS Heren data.

Note: The ex-ante summer/winter spread is calculated as the difference between the Season-ahead+2 and Season-ahead+1 hub product prices, both negotiated on the month of March. The actual summer/winter spread is calculated as the difference between the spot average prices along both seasons. Summer 2020 day ahead prices have been assessed until mid-July. It was not possible to assess winter 2020/2021 day ahead prices given MMR publication dates.

Source: ACER (2020) Market Monitoring Report 2019 – Gas Wholesale Market Volume

14 Member States (will) provide transmission tariff discounts of at least 50% to/from gas storages in their (next) tariff methodologies, to reflect the contribution of storage to system flexibility[517] and security of supply as foreseen in the EU harmonised transmission tariffs structure network code. Six Member States provide discounts of 90-100% in both directions. The countries are (with to/from discounts indicated, if different): AT (50%), BE (100% to, 50% from), CZ (70%), HR (90% to, 100% from), DK (100%), FR (80%), DE (75%), HU (90% to, 100% from), IT (50%), LV (100%), NL (60%), PL (80%), PT (100%), RO (50%).[518]

Gas storage operators recommend a number of measures to facilitate gas storage in the EU, including:[519]

- Ensuring coordinated planning between network levels and energy carriers;

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[515] ACER (2017). First ACER Implementation Monitoring Report of the Network Code on Interoperability and Data Exchange

[516] ACER (2020) Market Monitoring Report 2019 – Gas Wholesale Market Volume

[517] Noting that storage is one of the potential flexibility resources available to the gas system, along with pipeline and LNG terminal supplies and demand response (mainly from gas-fired power plants).

[518] ACER (2020) The internal gas market in Europe: The role of transmission tariffs

[519] Frontier Economics et al. (2021) Elaborating concrete European legislative proposals on gas storage

- Including storage system operators in planning discussions at the EU and national levels;
- Ensure that network operators consider all flexibility resources;
- Ensure that 'sunk' transmission costs are not charged to storage given its higher price sensitivity than end-users, which would lead to a reduced use of storage and an inefficient outcome (i.e. apply a Ramsey pricing that charges fixed costs to the least elastic consumers). Marginal transmission costs would still be charged to storage.

Some studies have emphasized the current and future contribution of flexibility resources and gas storage in the clean energy transition and the security of the EU's energy supply.

- The EU Strategy for Energy System Integration[520] highlights the importance of different flexibility resources in the energy system, including the various forms of energy storage, contributing to the cost-effective integration of renewable energy sources and the EU security of energy supply.
- Artelys finds that:[521]
    - The absence of 10% of the gas storage capacity would increase the energy system operational costs by around € 1 billion per year;
    - The absence of 30% of gas storage would require 23 GW of additional electricity generation capacity, representing an investment cost of € 55 billion, and an increase of the electricity system's operational costs by € 8 billion per year. While this represents an unlikely scenario and in reality electricity generators have long-term contracts for gas supply and transmission capacity, the objective of the analysis is to represent the additional system costs which would be incurred if gas storage was not available;
    - The lack of gas storage would increase the volatility of electricity prices, with a tipping point when the current gas storage capacity would be reduced by around 20%.

10.5.3 Indicator 4.3: Analysis of current planning procedures in EU Member States

In this section the current planning procedures in the EU Member States are discussed in more detail.

The ACER survey linked to the review of the gas National Network Development Plans (NDP) provides an indication of the national planning procedures. Detailed information per Member State can be found in the Excel annex. The following topics are discussed in the survey:

- **Legal nature of NDP:** There is no clear alignment between Member States in this regard. In several Member States, NDPs are mandatory for all projects, in some they are only indicative for all projects, while in other Member States the legal nature depends on a project-by-project basis. For example, Belgium, Greece and Romania's NDPs are indicative (TSOs are not obliged to implement them). The Czech Republic, Hungary, Lithuania and Slovenia have NDPs which are mandatory for projects to be commissioned in the next 3 years, while in Croatia and the Netherlands NDPs are mandatory for projects to be commissioned within the next 5 years. ACER does not indicate any NDP which is mandatory for all projects.

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[520] European Commission (2020) Powering a climate-neutral economy: An EU Strategy for Energy System Integration. COM(2020) 299 final.

[521] Artelys (2019) Value of the gas storage infrastructure for the electricity system

- **Gas-specific NDP:** In most MS NDPs are gas-specific, while only in Denmark the NDP is cross-sectoral and covers both electricity and gas. The Spanish NDP is also cross-sectoral, but the last published one dates from 2008 (a law was published in 2019 to give the Spanish NRA competences to oversee the NDP).
- **Time horizon of NDP:** The time horizon of the NDP is 10 years in all MS. However, in 9 MS the covered period is flexible while in others it is fixed.

Other topics discussed for which more information can be found in the Excel annex are:

- One or more gas transmission NDPs per country
- Use of sector integrated studies
- Inclusion of hydrogen in NDPs
- Inclusion of biomethane in NDPs

10.5.3.1 Gas infrastructure projects implementation and delays

Gas infrastructure projects have a long implementation time, starting from the pre-feasibility studies to the permitting, final investment decision, construction and commissioning phase.

The TEN-E Regulation[522] specifies regulatory measures to facilitate gas Projects of Common Interest, including a priority status, a requirement that a single national competent authority should be responsible for permitting, and a maximum permitting duration of 3.5 years. The latest ACER PCI monitoring report[523] covering the period from February 2019 to early 2020 indicates that 84% of gas PCIs are planned to be commissioned by 2025, according to information from project developers, which ACER deems too optimistic. The average duration from the market test to the commissioning date, based on data provided for 8 gas PCIs, is around 5 years. Permitting lasts on average 3.4 years, but for 25% of the gas PCIs was above the limit of 3.5 years established by the TEN-E regulation. Concerning delays:

- 38% of gas PCIs were delayed (7 transmission pipelines, 2 LNG terminals and 3 underground gas storage projects), which represents an increase in delayed projects compared to the 2018 monitoring report. In addition, 22% were rescheduled;
- The NSI East corridor (North-South gas interconnections in Central Eastern and South Eastern Europe) comprises the most delayed PCIs (5, or 28% of PCIs in the corridor);
- The average duration of delays is 33 months, but ranges from 2 months to 9 years;
- The most common reason for delay was financing difficulties (4 out of 12 gas PCIs)[524].

While the gas PCIs may provide an indication of the implementation times and delays for gas infrastructure projects in general, PCIs have particular characteristics such as regulatory incentives established in the TEN-E regulation as well as additional cross-border coordination requirements, which means that implementation times or delay patterns for other gas projects may not be the same.

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[522] Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure

[523] ACER (2020) Consolidated Report on the progress of electricity and gas Projects of Common Interest (2020)

[524] ACER (2020) Consolidated Report on the progress of electricity and gas Projects of Common Interest (2020)

Of the 2020 TYNDP list of projects[525], 11% were delayed, 19% were rescheduled and 22% were on time. However, 36% of the projects did not have a defined schedule status. Hence, in fact 17% of the projects for which a schedule status was available were delayed. Delays were observed for 21 out of 151 pipeline projects (14%), 5 out of 23 LNG terminals (22%), and 2 out of 13 storage facilities (15%). The analysis of the available data on project time schedules indicates that the average duration from the start of the permitting to commissioning was the highest for LNG terminals (8.1 years) and the lowest for pipelines (4.5 years). Of that time, permitting accounted for 3.1 years in LNG terminal schedules, and 1.8 years for pipelines. This suggests that, according to the data available, permitting and total implementation times for TYNDP projects were on average shorter than for PCIs, although further data would be needed for a more complete comparison.

Figure 10-11 Average duration in years of TYNDP projects

(in years)	Permitting	From permitting start to commissioning
Pipeline including compression stations	1.8	4.5
LNG terminal	3.1	8.1
Storage facility	2.7	5.8
Energy transition-related project	2.5	6.5

10.5.4 Indicator 4.4: Current Member State status regarding the policy options for integrated network planning

In this indicator, the current alignment of national legislation and practice with the different considered integrated network planning policy options for the IA are discussed. In the Excel annex a complete overview can be found. Among others, the following aspects are discussed:

- Elements common to all options regarding transparency and stakeholder consultations, decommissioning of methane pipelines, a sustainability indicator and alignment with National Energy & Climate Plans / Long-Term Strategies;
- Option 1: one NDP per country
- Option 2:
    - Joint electricity and gas scenario building
    - DSO participation in scenario building
    - LNG terminals and storage operators participation in scenario building
    - Integration of hydrogen in current NDPs
    - Integration/consideration of district heating and CO_2 infrastructure in current NDPs

The analysis indicates that while consultation processes on NDPs are in place for all Member States following the gas regulatory framework, in several of those the improvement of the consultation process is marked as a main solution to improve the regulatory framework according to Ecorys et al. (2019),[526] namely BG, HR, DE, LU, PT, SI and ES. The assessment of decommissioning needs is rarely or never included in NDPs, same as a sustainability indicator to assess and incentivise projects enabling renewable and low-carbon gases (although the latter topic is discussed in various forms in several NDPs). Most scenarios

[525] ENTSOG (2020) Ten-Year Network Development Plan 2020 – Annex A – Project Tables

[526] Ecorys et al. (2019) Do current regulatory frameworks in the EU support innovation and security of supply in electricity and gas infrastructure?

employed in the NDPs are often not aligned to EU or national decarbonisation targets as they were developed before the National Energy and Climate Plans were made available.

Moreover, most countries have a single NDP, with the main exceptions of IT and FR. Integrated modelling is rare but does occur in some Member States. The structural involvement of distribution network, storage or LGN terminal storage operators varies per Member State. Finally, 9 Member States with gas networks indicate they integrate hydrogen in their planning processes (BE, HR, DK, FR, HU, IE, LV, PT and SI).

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