



The potential for renewable and low-carbon gas deployment and impact on enabling infrastructure development for the Baltic Sea Region

Final report



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Contact: Andreas Kaiser

E-mail: Andreas.Kaiser@ec.europa.eu

*European Commission
B-1049 Brussels*

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Authors

Trinomics

Csinszka Bene
Gergely Boldizsár
João Gorenstein Dedecca
Luc van Nuffel

Artelys

Juliette Lecarpentier
Grégoire de Jerphanion
Christopher Andrey
Jeanne Bourgarel

LBST

Christopher Kutz
Werner Weindorf
Franz Lust
Jan Zerhusen
Yanni Astono
Matthias Altmann

Abstract

The study focuses on the deployment of renewable and low-carbon gases in the Baltic Energy Market Interconnection Plan (BEMIP) region, focusing on the 8 BEMIP Member States (Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Poland, and Sweden). The report 1) assesses the economic and technical potential supply as well as demand for renewable and low-carbon gases in the BEMIP region; 2) maps current supply, infrastructure and demand policies and measures; 3) documents existing technical, safety and economic barriers for the development of infrastructure for the integration of biomethane and hydrogen; 4) identifies the hydrogen and methane infrastructure needs to facilitate the integration of renewable and low-carbon gases in the region; and 5) provides recommendations to address identified challenges.

Résumé

L'étude se concentre sur le déploiement des gaz renouvelables et à faible teneur en carbone dans la région couverte par le Plan d'interconnexion du marché énergétique de la Baltique (BEMIP), en mettant l'accent sur les huit États membres du BEMIP (Danemark, Estonie, Finlande, Allemagne, Lettonie, Lituanie, Pologne et Suède). Le rapport 1) évalue le potentiel économique et technique de l'offre et de la demande de gaz renouvelables et à faible teneur en carbone dans la région BEMIP ; 2) recense les politiques et mesures actuelles en matière d'offre, d'infrastructures et de demande ; 3) documente les obstacles techniques, économiques et en matière de sécurité qui entravent le développement des infrastructures nécessaires à l'intégration du biométhane et de l'hydrogène ; 4) identifie les besoins en infrastructures pour l'hydrogène et le méthane afin de faciliter l'intégration des gaz renouvelables et à faible teneur en carbone dans la région ; et 5) formule des recommandations pour relever les défis identifiés.

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List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BEMIP	Baltic Energy Market Interconnection Plan
CAPEX	Capital Expenditure
CBA	Cost-benefit analysis
CBAM	Carbon Border Adjustment Mechanism
CBG	Compressed Biogas
CCU/S	Carbon Capture, Utilisation and/or Storage
CEF	Connecting Europe Facility
CNG	Compressed natural gas
DSO	Distribution system operator
EBA	European Biogas Association
EEZ	Exclusive Economic Zone
EHB	European Hydrogen Backbone
ENNOH	European Network of Network Operators for Hydrogen
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
ERDF	European Regional Development Fund
ETS	Emission Trading System
FID	Final investment Decision
FLH	Full-load hours
FSRU	Floating storage and regasification units
GCV	Gross Calorific Value
GIPL	Gas Interconnection Poland–Lithuania
GO	Guarantees of Origin
HLG	High Level Group
HNO	Hydrogen Network Operator
IPCEI	Important Projects of Common European Interest
LBG	Liquified Biogas
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
NBHC	Nordic-Baltic Hydrogen Collector
NDP	National Network Development Plan
NECP	National Energy and Climate Plan
NRA	National Regulatory Authority
ONDP	Offshore Network Development Plan
OPEX	Operational expenditure
PCI	Projects of Common Interest
PMI	Projects of Mutual Interest
PV	Photovoltaic
RED	Renewable Energy Directive
RES	Renewable Energy Systems
RFNBO	Renewable fuel of non-biological origin
RGMCG	Regional Gas Market Coordination Group
RRF	Recovery and Resilience Facility
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
TEN-E	Trans-European Networks for Energy
TRL	Technology Readiness level
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UHS	Underground Hydrogen Storage
UGS	Underground Gas Storage
WACC	Weighted Average Cost of Capital
WI	Wobbe Index

Executive Summary

Introduction

This study examines the deployment of renewable and low-carbon gases and associated infrastructure needs towards 2050 within the Baltic Energy Market Interconnection Plan (BEMIP) region, focusing on the eight BEMIP Member States (MSs): Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Poland, and Sweden.

BEMIP aims to create an open and integrated regional energy market among Baltic Sea EU countries. With BEMIP MSs representing approximately 31% of natural gas demand in EU27 in 2023 and 23% of installed gas-fired capacity for power generation in EU27, natural gas still holds a central place in the BEMIP's energy system. But with the strong expansion of renewable electricity and potential for sustainable biomass (with the need to consider limitations and potential competition with other uses), renewable and low-carbon hydrogen as well as biomethane (and potentially synthetic methane) will decarbonise hard-to-electrify end-uses, diminish dependence on imported fossil fuels, offer flexibility to energy systems, and enhance energy security.

Methane and hydrogen infrastructure play an important role in regional market integration. Recent infrastructure projects, such as the enhanced gas interconnection between Estonia and Latvia completed in January 2023, highlight steps taken to integrate gas markets and reduce dependency on Russian gas. With increased deployment of hydrogen and biomethane in the region, infrastructure needs and flows will evolve, requiring coordinated decisions on development of hydrogen networks and storage, as well as decommissioning/repurposing of methane infrastructure (combined with limited investments to enhance the integration of biomethane, especially at the domestic level).

The main objectives of this study are to:

1. Identify the hydrogen and methane infrastructure needs to facilitate the integration of renewable and low-carbon gases in the region, and
2. Provide recommendations for concrete actions enabling the large-scale and cost-effective integration of renewable and low-carbon gases in the BEMIP region.

Technical potential and future development for biomethane and renewable and low-carbon hydrogen production and demand

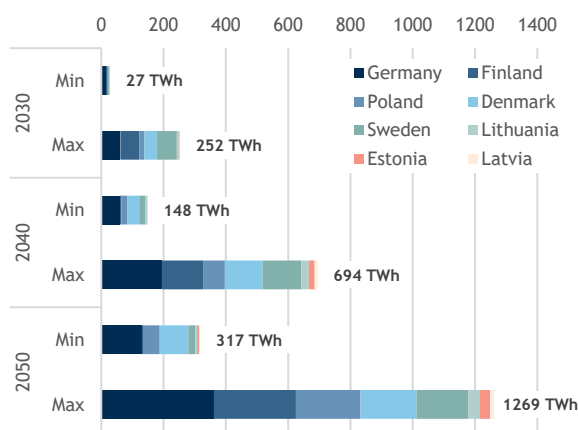
Chapter 2 conducts a detailed review of the **projections, technical potential, and targets for the development of renewable and low-carbon hydrogen and biomethane production and demand** in the BEMIP region (with in the case of biomethane, overall demand for methane gases being assessed). The aim is to provide a comprehensive overview and thorough understanding of the expected development in hydrogen and biomethane sectors, which serves as a basis for defining the baseline scenario and relevant sensitivity analysis for the infrastructure modelling in chapter 5.

Within this analysis, the scenarios from the Ten Year Network Development Plan (TYNDP) are set within the perspective of national projections and targets. Due their key role in European infrastructure planning, TYNDP scenarios as developed by European TSOs are identified to being suited as baseline scenario in chapter 5. The detailed analysis provided in chapter 2, however, also reveals major deviations between TYNDP scenarios and national (more recent projections) for hydrogen and biomethane ramp-up:

- The analysis confirms that overall biomethane and renewable hydrogen production levels increase significantly by 2050 throughout the BEMIP region.
- The results, however, also show a high bandwidth in projections, which indicate the high degree of uncertainty for infrastructure investments.

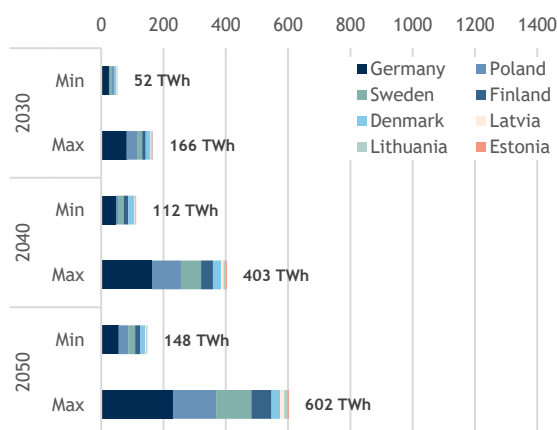
Consequently, the actual deployment of renewable and low carbon gases will largely depend on the political and regulatory framework set in each BEMIP Member State. This especially includes the timeframe and speed of hydrogen market ramp-up, which seems overly ambitious in the TYNDP scenarios. In addition, the role of biomethane is – to a large extent - target-driven, as projections show that only a minor share of theoretical potential will be exploited until 2050. Beside the regulatory framework, also technical limitations may hinder hydrogen and biomethane introduction into the market. Details are discussed in chapter 4 and Annex C.

Renewable and low-carbon H2 production outlook (TWh)*



* Data based on literature analysis by LBST.
Existing (conventional) hydrogen production not included.

Biomethane production outlook (TWh)*



* Data based on literature analysis by LBST.
Maximum values should rather be interpreted as potential, mainly based on estimations by EBA & Guidehouse (2024).

Supply, infrastructure and demand policies and measures

Chapter 3 delves into the **policy landscape for the deployment of biomethane and renewable and low-carbon hydrogen**. The supply and demand policies as well as infrastructure planning and measures for hydrogen and biomethane in the BEMIP region vary significantly, reflecting the distinct characteristics and strategic priorities of each energy carrier. While both hydrogen and biomethane are pivotal in the transition to a low-carbon economy, they face different regulatory, infrastructural, and market challenges.

On hydrogen policies, most BEMIP MSs have published national hydrogen strategies, although the level of detail and ambition varies. These strategies outline targets for production capacities, often with a focus on renewable hydrogen. Moreover, multiple support schemes exist, including CAPEX and OPEX subsidies, tax incentives, and specific consumption obligations to stimulate hydrogen production and use – but with important differences across BEMIP MSs. Significant efforts are being made to plan and develop hydrogen infrastructure, including pipelines and storage facilities. Germany, for instance, has a detailed hydrogen network development plan and Denmark recently finalised a political agreement to develop a national hydrogen backbone to the German border. However, other BEMIP MSs' hydrogen network development plans are less advanced, even though network operators' cooperation on regional projects such as the Nordic-Baltic Hydrogen Corridor and Baltic Sea Hydrogen Collector is significant.

Policies for biomethane are generally even less uniform across the BEMIP region. Seven MSs have set specific biomethane targets. While there are support schemes for biogas production, these often focus on electricity generation rather than upgrading biogas to biomethane and injection in grids. Policies to support infrastructure development for integration of infrastructure are less comprehensive compared to hydrogen. Additionally, biomethane policies must address challenges

such as feedstock availability and sustainability, coordination of TSO and DSO network development plans, planning of decommissioning of (parts of) the gas network, and the need for harmonized gas quality standards to facilitate cross-border trade.

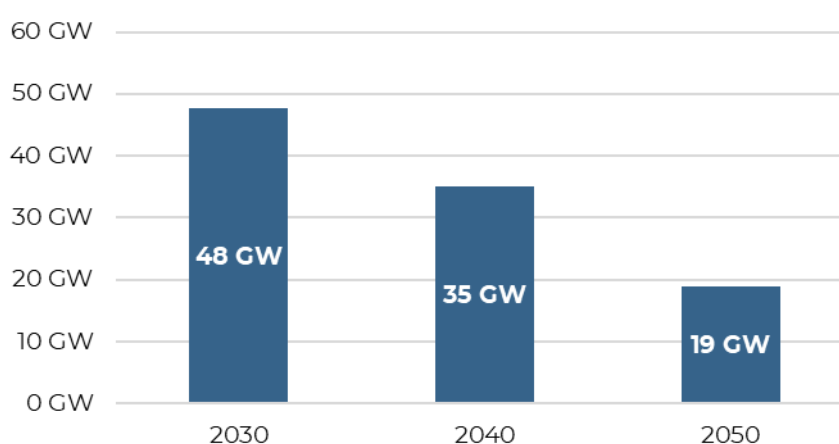
Role of methane gases and hydrogen infrastructure and potential energy system interlinkages and synergies

Chapter 4 analyses **infrastructure challenges for renewable and low-carbon gas integration**. The chapter first describes the state of the existing natural gas network in the BEMIP region, reflecting separately on the readiness and associated challenges with repurposing this infrastructure for the future utilisation as a hydrogen/biomethane transmission network instead. It then provides an overview of a specific case study (Denmark) – including challenges and measures taken to solve them – to serve as a good-practice in the integration of biomethane in the existing infrastructure. The chapter also provides a detailed description of hydrogen PCIs in the BEMIP region.

Chapter 5 presents a **quantitative assessment of the cost-optimal pathway for the development of hydrogen and methane infrastructure in the BEMIP region** up to 2050, focusing on storage and cross-border transport, considering two scenarios (baseline and sensitivity analysis).

The figure below presents the **aggregated cross-border methane transmission** capacities for the BEMIP borders in the study horizon. Although methane cross-border pipeline and storage capacity needs decrease, part of the methane infrastructure capacities remain necessary in 2050 due to residual (renewable and low-carbon) methane demand (primarily in Poland and Germany) and due to high biomethane injection into the grid (in particular in Denmark, Sweden and Finland, which will become net exporters by 2050). In the baseline scenario, by 2050 19 GW of methane cross-border capacities are still necessary along the corridors ranging from Finland to Poland via the Baltic states and from Sweden and Denmark to Poland and Germany, representing a 45% reduction in total cross-border capacity in the BEMIP region compared to 2025. Additionally, at least 18 TWh of methane storage capacities are still necessary, marking a 95% reduction from 2022 levels. In the sensitivity analysis scenario, which assumes a delayed transition from methane to hydrogen and consequently higher methane demand, the model maintains an additional 2 GW of methane transmission capacity and 2 TWh of methane storage, while repurposing fewer assets to hydrogen. Hence, the integration of renewable and low-carbon methane gases will, in the long term, impact the structure of methane flows in BEMIP, thus requiring maintaining part of existing methane infrastructure. Additional investments might be necessary to integrate biomethane in the gas networks (not represented in the model).

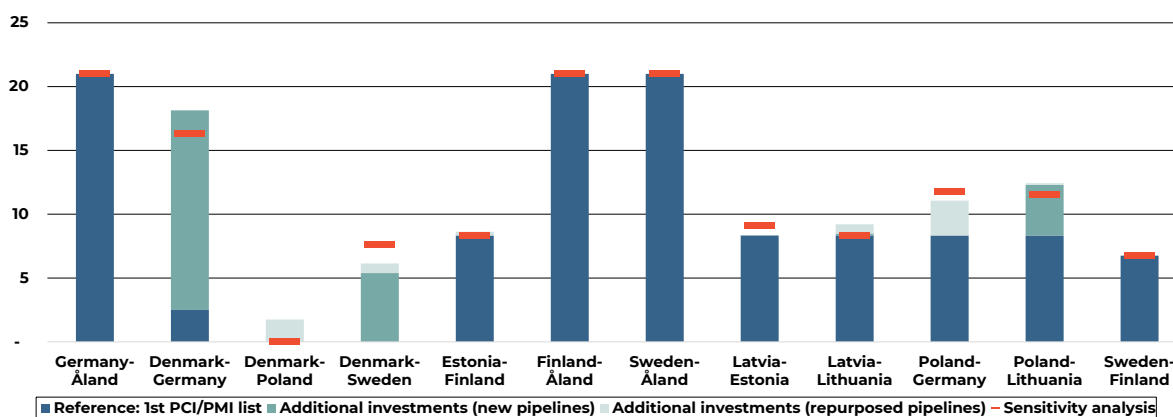
Aggregated cross-border methane transmission capacities in the baseline scenario



Note: Pipeline capacities displayed in the graph represent only cross-border capacities and do not include internal network capacities. As most pipelines are bidirectional, the graph displays the maximum capacity of the two directions of each pipeline.

Assessed **cross-border hydrogen transmission capacity** needs in 2050 are shown in the figure below for the baseline and sensitivity scenarios. In the baseline scenario by 2030 the model assumes the deployment of the projects in the 1st PCI/PMI list (i.e. the reference network) and foresees the need for investments in hydrogen storage, but not in further cross-border hydrogen pipelines in that horizon. Already in 2030, Germany appears as a major hydrogen transit hub, with imports to Germany from the rest of the EU and via import terminals being redistributed to other BEMIP MSs, and especially to Poland. By 2040, only modest additional investments in cross-border hydrogen pipelines are required compared to the reference PCIs from the first list, while investments in hydrogen storage increase significantly. Eventually, no further investments in hydrogen storage are anticipated beyond 2040, with total storage capacity remaining stable at 26 TWh. Moreover, the analysis indicates that by enabling a flexible operation of electrolyzers, hydrogen storage significantly contributes to the flexibility needs of the power system, allowing for a better integration of renewable power generation. In the baseline scenario, total investments required by 2050 according to the modelling conducted in this study amount to €14 billion for hydrogen storage and €31 billion for hydrogen cross-border capacities (including already planned PCIs). The sensitivity analysis shows that a delayed hydrogen transition under the selected assumptions would not affect hydrogen cross-border capacity needs much, but it would impact hydrogen storage needs.

Cross-border hydrogen capacities in 2050 in the baseline and sensitivity scenarios (GW)

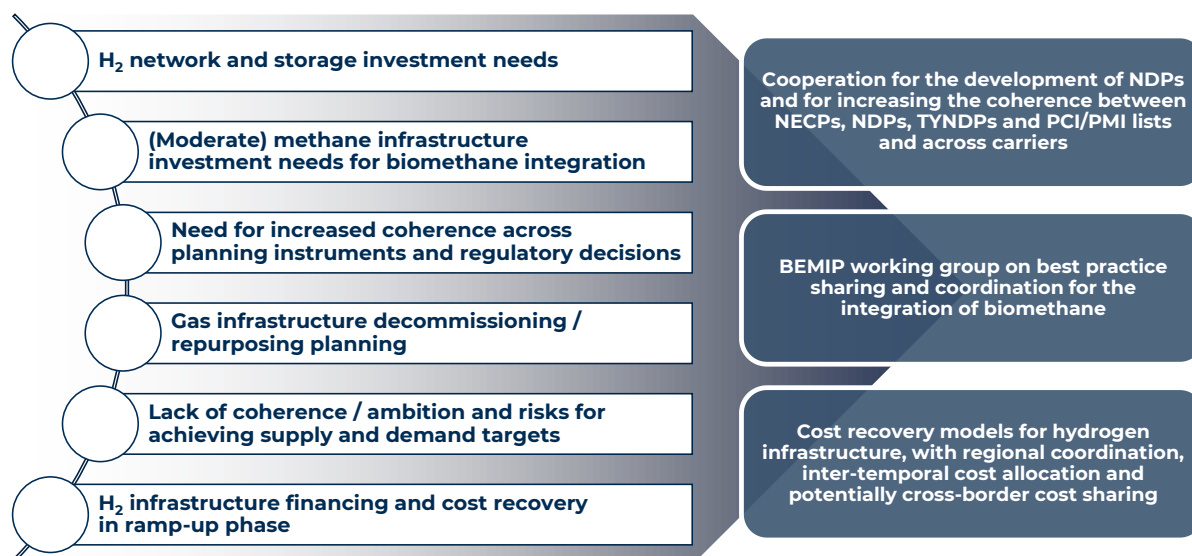


These results are to be interpreted within the context of the underlying scenario assumptions and modelling limitations. In particular, the spatial resolution of the model does not allow to assess the impact of internal congestions and may lead to an underestimation of hydrogen and methane storage needs in the long term, for example regarding domestic hydrogen network infrastructure. Besides, the model does not aim at performing a detailed analysis of methane security of supply, and the consideration of stress situations, such as supply shocks might result in higher capacity needs in the long term for methane infrastructure.

Infrastructure policy recommendations

Chapter 6 summarises the assessment of BEMIP infrastructure needs and presents **recommendations to address the identified cross-border infrastructure challenges** for the integration of biomethane and hydrogen in the region. Four recommendations are presented, aiming to complement measures already in place or under implementation, addressing main identified challenges as presented below. These recommendations are listed below, with further details on addressed challenges, implementation responsibility, timeline and barriers, and expected impacts presented in the report.

Infrastructure policy recommendations and associated challenges for the integration of biomethane and renewable and low-carbon hydrogen



1. Promote cooperation at the regional level for the development of NDPs and for increasing the coherence between NECPs, NDPs, TYNDPs and PCI/PMI lists and across carriers [biomethane/hydrogen]

Building on the ACER check on NDP/TYNDP coherence, national authorities within the BEMIP High Level Group and TSOs should further assess the coherence between the various energy infrastructure planning instruments listed, providing recommendations on addressing incoherences as well as improving the top-down planning processes, so that infrastructure needs identified at the regional level further drive the identification and development of infrastructure projects (and in the case of methane infrastructure, decommissioning or repurposing of existing assets). The overall process could further support the simplification of the TEN-E Regulation announced as part of the European Grid Package.

2. Establish a BEMIP working group on best practice sharing and coordination for the integration of biomethane [biomethane]

National authorities and network operators should establish an initiative for sharing of best practices and coordination across the region, building on already developed measures for the integration of biomethane in the gas grid in for example Denmark, Germany and non-BEMIP Member States such as France and Italy. The initiative should have a focus on sharing best practices for the integration of high shares of biomethane in the medium to long-term (i.e. not only considering 2030 projections/targets but also the 2040 and 2050 horizon). In addition to sharing best practices, the initiative could enhance coordination between NRAs on matters of cross-border relevance. Particularly, national authorities and TSOs should work towards harmonization of gas quality standards and associated measures when these constitute or will constitute a barrier to cross-border flows – for example in the case of the DK-DE border given the more stringent oxygen limits on the German side.

3. Consider cost recovery models for hydrogen infrastructure with regional coordination, inter-temporal cost allocation and potentially cross-border cost sharing [hydrogen]

National authorities and infrastructure operators should consider hybrid cost recovery models for hydrogen network infrastructure, with regional coordination and potentially cross-border cost sharing, pursuing cost reflectiveness while facilitating the development and growth of hydrogen supply and demand by containing the grid tariffs during the ramp-up phase at an 'affordable' level. Specific measures to be considered would include implementing progressive asset depreciation

rules, de-risking mechanisms to (partially) guarantee a market-based remuneration level of the assets in the long-term, and cross-border cost sharing of interconnection investment costs (bilaterally for the Member States of the relevant interconnection point, or at the regional level). Cost-sharing in large-scale hydrogen storage projects could also be considered as long as these projects contribute to cross-border hydrogen integration, trade, and security of supply.

Résumé

Introduction

Cette étude examine le déploiement des gaz renouvelables et à faible teneur en carbone et les besoins en infrastructures associés à l'horizon 2050 dans la région du Plan d'interconnexion des marchés énergétiques de la Baltique (BEMIP), en se concentrant sur les huit États membres du BEMIP : Danemark, Estonie, Finlande, Allemagne, Lettonie, Lituanie, Pologne et Suède.

Le BEMIP vise à créer un marché régional de l'énergie ouvert et intégré entre les pays de l'UE riverains de la mer Baltique. Les pays du BEMIP représentant environ 31 % de la demande de gaz naturel dans l'UE27 en 2023 et 23 % de la capacité installée de production d'électricité au gaz dans l'UE27, le gaz naturel occupe toujours une place centrale dans le système énergétique du BEMIP. Mais avec la forte expansion de l'électricité renouvelable et le potentiel de la biomasse durable (avec la nécessité de prendre en compte les limites et la concurrence potentielle avec d'autres utilisations), l'hydrogène renouvelable et à faible teneur en carbone ainsi que le biométhane (et potentiellement le méthane synthétique) décarboniseront les utilisations finales difficiles à électrifier, réduiront la dépendance à l'égard des combustibles fossiles importés, offriront de la flexibilité aux systèmes énergétiques et renforceront la sécurité énergétique.

Les infrastructures de méthane et d'hydrogène jouent un rôle important dans l'intégration des marchés régionaux. Des projets d'infrastructure récents, tels que l'interconnexion gazière renforcée entre l'Estonie et la Lettonie, achevée en janvier 2023, mettent en évidence les mesures prises pour intégrer les marchés du gaz et réduire la dépendance à l'égard du gaz russe. Avec le déploiement accru de l'hydrogène et du biométhane dans la région, les besoins en infrastructures et les flux évolueront, ce qui nécessitera des décisions coordonnées sur le développement des réseaux et du stockage de l'hydrogène, ainsi que sur la mise hors service et la réaffectation des infrastructures de méthane (associées à des investissements limités pour améliorer l'intégration du biométhane, en particulier au niveau national).

Les principaux objectifs de cette étude sont les suivants

1. Identifier les besoins en infrastructures pour l'hydrogène et le méthane afin de faciliter l'intégration des gaz renouvelables et à faible teneur en carbone dans la région, et
2. Fournir des recommandations pour des actions concrètes permettant l'intégration à grande échelle et avec un bon rapport coût/efficacité des gaz renouvelables et à faible teneur en carbone dans la région BEMIP.

Potentiel technique et évolution future de la production et de la demande de biométhane et d'hydrogène renouvelable et à faible teneur en carbone

Le chapitre 2 procède à un examen détaillé des **projections, du potentiel technique et des objectifs de développement de la production et de la demande d'hydrogène et de biométhane renouvelables et à faible teneur en carbone** dans la région BEMIP (avec, dans le cas du biométhane, une évaluation de la demande globale de gaz méthane). L'objectif est de fournir une vue d'ensemble et une compréhension approfondie du développement attendu dans les secteurs de l'hydrogène et du biométhane, qui servent de base à la définition du scénario de référence et de l'analyse de sensibilité pour la modélisation de l'infrastructure au chapitre 5.

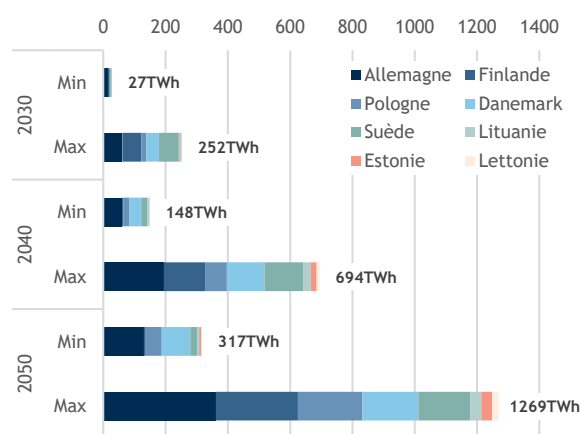
Dans le cadre de cette analyse, les scénarios du plan décennal de développement du réseau dans l'ensemble de l'Union (TYNDP) s'inscrivent dans la perspective des projections et des objectifs nationaux. En raison de leur rôle clé dans la planification des infrastructures européennes, les scénarios du TYNDP élaborés par les gestionnaires de réseau de transport européens sont considérés comme appropriés comme scénario de référence au chapitre 5. L'analyse détaillée fournie dans le

chapitre 2 révèle toutefois des écarts importants entre les scénarios TYNDP et les projections nationales (plus récentes) pour la montée en puissance de l'hydrogène et du biométhane :

- L'analyse confirme que les niveaux globaux de production de biométhane et d'hydrogène renouvelable augmentent de manière significative d'ici 2050 dans l'ensemble de la région BEMIP.
- Cependant, les résultats montrent également une grande variabilité dans les projections, ce qui indique le degré élevé d'incertitude pour les investissements dans les infrastructures.

Par conséquent, le déploiement réel des gaz renouvelables et à faible teneur en carbone dépendra largement du cadre politique et réglementaire établi dans chaque État membre du BEMIP. Cela concerne en particulier le calendrier et la vitesse de montée en puissance du marché de l'hydrogène, qui semble trop ambitieux dans les scénarios du TYNDP. En outre, le rôle du biométhane est - dans une large mesure - déterminé par les objectifs fixés, car les projections montrent que seule une petite partie du potentiel théorique sera exploitée jusqu'en 2050. Outre le cadre réglementaire, des limitations techniques peuvent également entraver l'introduction de l'hydrogène et du biométhane sur le marché. Les détails sont abordés au chapitre 4 et à l'annexe C.

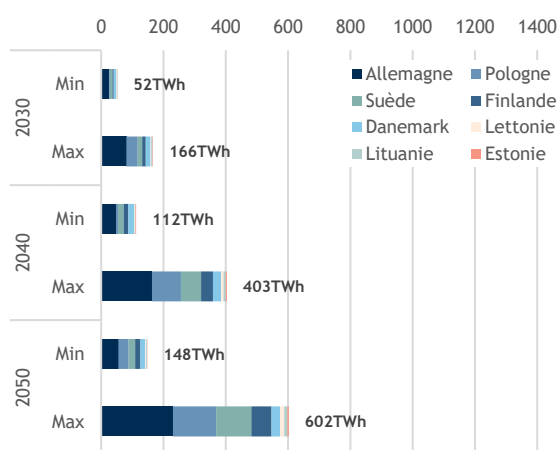
**Perspectives de production d'H2
renouvelable et à faible teneur en carbone
(TWh)***



* Données basées sur l'analyse de la littérature par LBST.

La production d'hydrogène existante (conventionnelle) n'est pas incluse.

**Perspectives de production de biométhane
(TWh)***



* Données basées sur l'analyse de la littérature par LBST.

Les valeurs maximales doivent être interprétées comme un potentiel de production, principalement basé sur les estimations de EBA & Guidehouse (2024).

Politiques et mesures relatives à l'offre, aux infrastructures et à la demande

Le chapitre 3 examine **le paysage des politiques publiques pour le déploiement du biométhane et de l'hydrogène renouvelable et à faible teneur en carbone**. Les politiques publiques d'offre et de demande ainsi que la planification et les mesures d'infrastructure pour l'hydrogène et le biométhane dans la région BEMIP varient considérablement, reflétant les caractéristiques distinctes et les priorités stratégiques de chaque vecteur énergétique. Bien que l'hydrogène et le biométhane soient tous deux essentiels à la transition vers une économie à faibles émissions de carbone, ils sont confrontés à des défis différents en matière de réglementation, d'infrastructure et de marché.

En ce qui concerne les politiques publiques relatives à l'hydrogène, la plupart des pays du BEMIP ont publié des stratégies nationales relatives à l'hydrogène, bien que le niveau de détail et d'ambition varie. Ces stratégies définissent des objectifs pour les capacités de production, en mettant souvent

l'accent sur l'hydrogène renouvelable. En outre, il existe de nombreux régimes de soutien, y compris des subventions CAPEX et OPEX, des incitations fiscales et des obligations de consommation spécifiques pour stimuler la production et l'utilisation de l'hydrogène - mais avec des différences importantes entre les États membres du BEMIP. Des efforts considérables sont mis en place pour planifier et développer l'infrastructure de l'hydrogène, y compris les pipelines et les installations de stockage. L'Allemagne, par exemple, dispose d'un plan détaillé de développement du réseau d'hydrogène et le Danemark a récemment finalisé un accord politique pour développer une dorsale nationale d'hydrogène jusqu'à la frontière allemande. Toutefois, les plans de développement des réseaux d'hydrogène des autres États membres du BEMIP sont moins avancés, même si la coopération des opérateurs de réseaux sur des projets régionaux tels que le corridor d'hydrogène nordique et baltique et le collecteur d'hydrogène de la mer Baltique est importante.

Les politiques publiques relatives au biométhane sont généralement encore moins uniformes dans la région BEMIP. Sept pays ont fixé des objectifs de production spécifiques. Des programmes de soutien à la production de biogaz existent, mais ils sont souvent axés sur la production d'électricité plutôt que sur la transformation du biogaz en biométhane et son injection dans les réseaux. Les politiques de soutien au développement de l'infrastructure pour l'intégration de l'infrastructure sont moins complètes que pour l'hydrogène. En outre, les politiques relatives au biométhane doivent relever des défis tels que la disponibilité des matières premières et la durabilité, la coordination des plans de développement des réseaux des gestionnaires de réseau de transport et de distribution, la planification de la mise hors service de (parties du) réseau gazier et la nécessité d'harmoniser les normes de qualité du gaz pour faciliter les échanges transfrontaliers.

Rôle de l'infrastructure gaz méthane et hydrogène, et liens et synergies potentiels entre les systèmes énergétiques

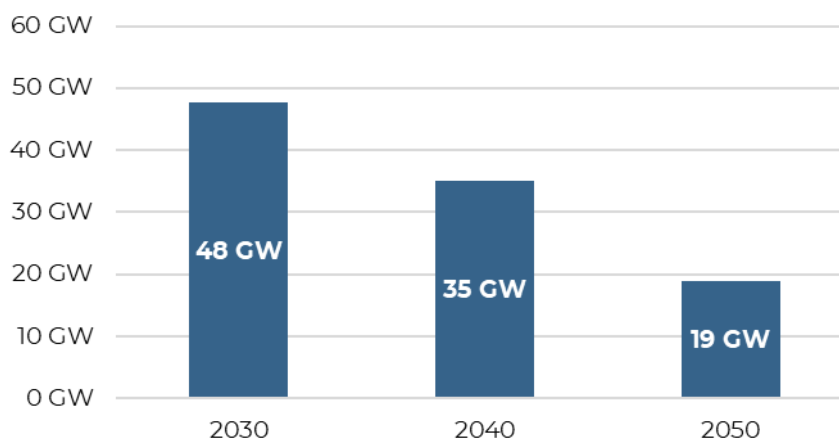
Le chapitre 4 analyse les **défis liés aux infrastructures pour l'intégration des gaz renouvelables et à faible teneur en carbone**. Le chapitre décrit d'abord l'état du réseau de gaz naturel existant dans la région BEMIP, en réfléchissant séparément à l'état de préparation et aux défis associés à la réaffectation de cette infrastructure en vue d'une utilisation future comme réseau de transport d'hydrogène/biométhane. Il donne ensuite un aperçu d'une étude de cas spécifique (Danemark) - y compris les défis et les mesures prises pour les résoudre - pour servir de bonne pratique dans l'intégration du biométhane dans l'infrastructure existante. Le chapitre fournit également une description détaillée des PCI hydrogène dans la région BEMIP.

Le chapitre 5 présente une **évaluation quantitative de la trajectoire optimale en termes de coûts pour le développement de l'infrastructure hydrogène et gaz méthane dans la région BEMIP** jusqu'en 2050, en mettant l'accent sur le stockage et le transport transfrontalier, en tenant compte de deux scénarios (base de référence et analyse de sensibilité).

La figure ci-dessous présente les capacités **agrégées de transport transfrontalier de méthane** pour les frontières du BEMIP à l'horizon de l'étude. Bien que les besoins en capacités transfrontalières de transport et de stockage du méthane diminuent, une partie des capacités de l'infrastructure méthane reste nécessaire en 2050 en raison de la demande résiduelle de méthane (renouvelable et à faible teneur en carbone) (principalement en Pologne et en Allemagne) et de l'injection importante de biométhane dans le réseau (en particulier au Danemark, en Suède et en Finlande, qui deviendront des exportateurs nets d'ici à 2050). Dans le scénario de base, d'ici 2050, 19 GW de capacités transfrontalières de méthane sont encore nécessaires le long des corridors allant de la Finlande à la Pologne via les États baltes et de la Suède et du Danemark à la Pologne et à l'Allemagne, ce qui représente une réduction de 45 % de la capacité transfrontalière totale dans la région BEMIP par rapport à 2025. En outre, au moins 18 TWh de capacités de stockage de méthane sont encore nécessaires, ce qui représente une réduction de 95 % par rapport aux niveaux de 2022. Dans le scénario d'analyse de sensibilité, qui suppose une transition retardée du méthane à l'hydrogène et donc une demande de méthane plus élevée, le modèle maintient 2 GW supplémentaires de capacité de transport de méthane et 2 TWh de stockage de méthane, tout en réaffectant moins d'actifs à

l'hydrogène. Par conséquent, l'intégration du méthane renouvelable et à faible teneur en carbone aura, à long terme, un impact sur la structure des flux de méthane dans le BEMIP, ce qui nécessitera le maintien d'une partie de l'infrastructure de méthane existante. Des investissements supplémentaires pourraient être nécessaires pour intégrer le biométhane dans les réseaux de gaz (non représentés dans le modèle).

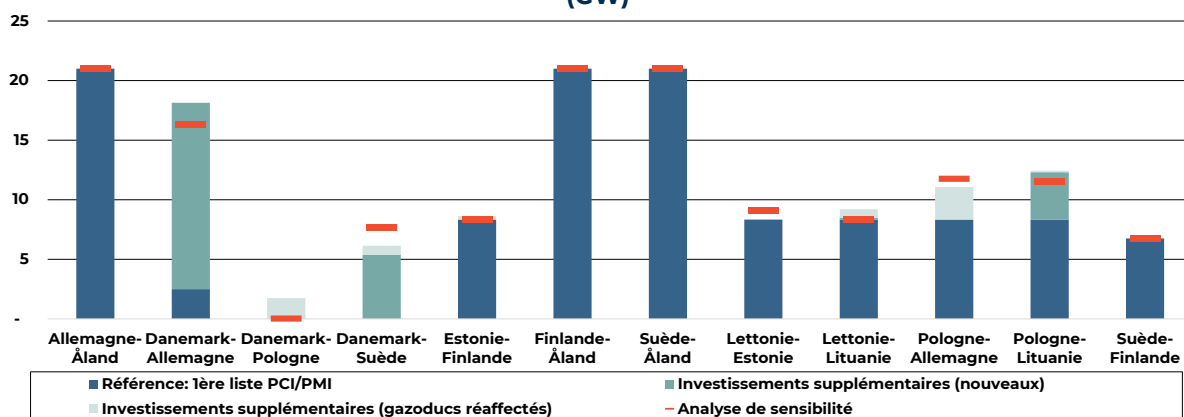
Capacités agrégées de transport transfrontalier de méthane dans le scénario de base



Remarque : les capacités des gazoducs figurant dans le graphique représentent uniquement les capacités transfrontalières et n'incluent pas les capacités internes du réseau. Comme la plupart des pipelines sont bidirectionnels, le graphique présente la capacité maximale dans les deux sens de chaque pipeline.

Les besoins évalués **en capacité de transport transfrontalier d'hydrogène** en 2050 sont présentés dans la figure ci-dessous pour le scénario de base et le scénario de sensibilité. Dans le scénario de base, d'ici à 2030, le modèle suppose le déploiement des projets figurant sur la première liste PCI/PMI (c'est-à-dire le réseau de référence) et prévoit la nécessité d'investir dans le stockage de l'hydrogène, mais pas dans d'autres canalisations transfrontalières pour l'hydrogène à cet horizon. Dès 2030, l'Allemagne apparaît comme une plaque tournante majeure pour le transit de l'hydrogène, les importations vers l'Allemagne en provenance du reste de l'UE et via les terminaux d'importation étant redistribuées vers d'autres pays du BEMIP, et en particulier vers la Pologne. D'ici à 2040, seuls de modestes investissements supplémentaires dans les conduites d'hydrogène transfrontalières sont nécessaires par rapport aux PCI de référence de la première liste, tandis que les investissements dans le stockage de l'hydrogène augmentent de manière significative. Finalement, aucun investissement supplémentaire dans le stockage de l'hydrogène n'est prévu au-delà de 2040, la capacité totale de stockage restant stable à 26 TWh. En outre, l'analyse indique qu'en permettant un fonctionnement flexible des électrolyseurs, le stockage de l'hydrogène contribue de manière significative aux besoins de flexibilité du système électrique, ce qui permet une meilleure intégration de la production d'électricité à partir de sources renouvelables. Dans le scénario de base, les investissements totaux requis d'ici 2050 selon la modélisation effectuée dans cette étude s'élèvent à 14 milliards d'euros pour le stockage de l'hydrogène et à 31 milliards d'euros pour les capacités transfrontalières d'hydrogène (y compris les PCI déjà planifiés). L'analyse de sensibilité montre qu'un retard dans la transition vers l'hydrogène selon les hypothèses retenues n'aurait pas beaucoup d'incidence sur les besoins en capacités transfrontalières d'hydrogène, mais qu'il en aurait sur les besoins en matière de stockage de l'hydrogène.

Capacités transfrontalières d'hydrogène en 2050 dans les scénarios de base et de sensibilité (GW)

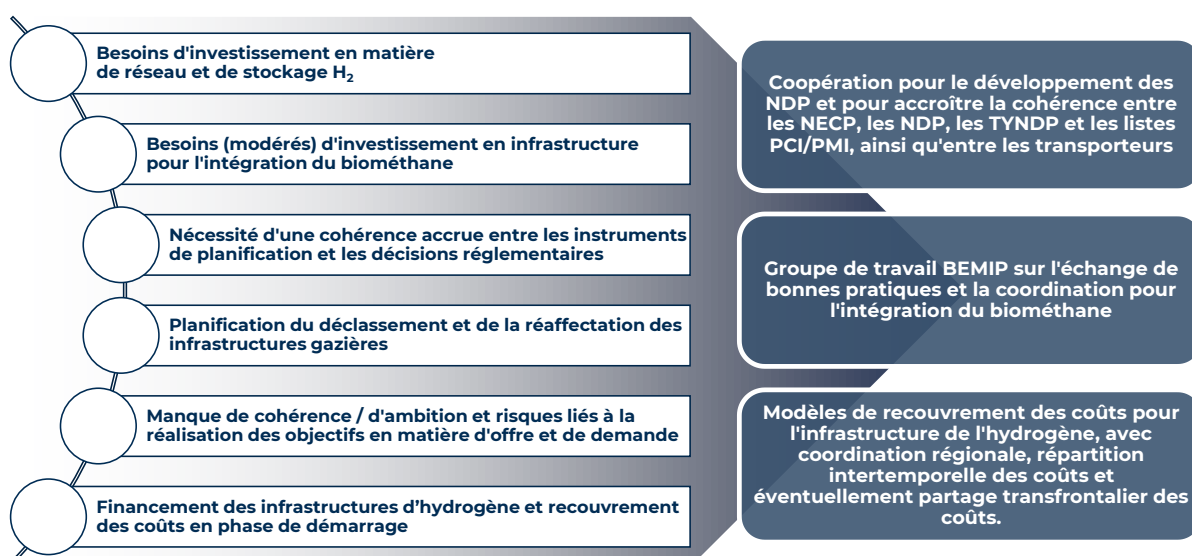


Ces résultats doivent être interprétés dans le contexte des hypothèses de scénario sous-jacentes et des limites de la modélisation. En particulier, la résolution spatiale du modèle ne permet pas d'évaluer l'impact des congestions internes et peut conduire à une sous-estimation des besoins de stockage d'hydrogène et de méthane à long terme, par exemple en ce qui concerne l'infrastructure du réseau domestique d'hydrogène. En outre, le modèle ne vise pas à réaliser une analyse détaillée de la sécurité d'approvisionnement en méthane, et la prise en compte de situations de stress, telles que des chocs d'approvisionnement, pourrait entraîner des besoins de capacité plus importants à long terme pour l'infrastructure méthane.

Recommandations en matière de politique d'infrastructure

Le chapitre 6 résume l'évaluation des besoins en infrastructures du BEMIP et présente des **recommandations pour relever les défis identifiés en matière d'infrastructures transfrontalières** pour l'intégration du biométhane et de l'hydrogène dans la région. Quatre recommandations sont présentées, visant à compléter les mesures déjà en place ou en cours de mise en œuvre, afin de relever les principaux défis identifiés, comme indiqué ci-dessous. Ces recommandations sont énumérées ci-dessous, avec plus de détails sur les défis abordés, la responsabilité de la mise en œuvre, le calendrier et les obstacles, et les impacts attendus présentés dans le rapport.

Recommandations en matière de politique d'infrastructure et défis associés pour l'intégration du biométhane et de l'hydrogène renouvelable et à faible teneur en carbone



1. Promouvoir la coopération au niveau régional pour l'élaboration des PND et pour accroître la cohérence entre les NECP, les NDP, les TYNDP et les listes PCI/PMI¹ et entre les vecteurs énergétiques [biométhane/hydrogène].

En s'appuyant sur le contrôle de l'ACER concernant la cohérence entre les NDP et le TYNDP, les autorités nationales au sein du groupe de haut niveau du BEMIP et les gestionnaires de réseau de transport devraient continuer à évaluer la cohérence entre les différents instruments de planification des infrastructures énergétiques énumérés, en formulant des recommandations pour remédier aux incohérences et améliorer les processus de planification descendants, de sorte que les besoins en infrastructures identifiés au niveau régional stimulent davantage l'identification et le développement de projets d'infrastructures (et, dans le cas des infrastructures méthane, la mise hors service ou la réaffectation d'actifs existants). Le processus global pourrait contribuer à la simplification du règlement pour les réseaux transeuropéens d'énergie annoncée dans le cadre du paquet "réseau européen".

2. Mettre en place un groupe de travail BEMIP sur le partage et la coordination des meilleures pratiques pour l'intégration du biométhane [biométhane].

Les autorités nationales et les opérateurs de réseaux devraient mettre en place une initiative pour le partage des meilleures pratiques et la coordination dans la région, en s'appuyant sur les mesures déjà développées pour l'intégration du biométhane dans le réseau de gaz, par exemple au Danemark, en Allemagne et dans les États non-membres du BEMIP tels que la France et l'Italie. L'initiative devrait se concentrer sur le partage des meilleures pratiques pour l'intégration de proportions élevées de biométhane à moyen et long terme (c'est-à-dire en considérant non seulement les projections/objectifs à l'horizon 2030, mais aussi aux horizons 2040 et 2050). Outre le partage des meilleures pratiques, l'initiative pourrait renforcer la coordination entre les autorités réglementaire nationales sur les questions d'intérêt transfrontalier. En particulier, les autorités nationales et les gestionnaires de réseau de transport devraient travailler à l'harmonisation des normes de qualité du gaz et des mesures associées lorsque celles-ci constituent ou constitueront un obstacle aux flux transfrontaliers - par exemple dans le cas de la frontière entre le Danemark et l'Allemagne, étant donné les limites d'oxygène plus strictes du côté allemand.

3. Envisager des modèles de recouvrement des coûts pour l'infrastructure hydrogène, avec une coordination régionale, une répartition intertemporelle des coûts et éventuellement un partage transfrontalier des coûts [hydrogène].

Les autorités nationales et les opérateurs d'infrastructures devraient envisager des modèles hybrides de recouvrement des coûts pour les infrastructures de réseaux d'hydrogène, avec une coordination régionale et éventuellement un partage transfrontalier des coûts, afin de refléter les coûts tout en facilitant le développement et la croissance de l'offre et de la demande d'hydrogène en maintenant les tarifs du réseau à un niveau "abordable" pendant la phase de montée en puissance. Parmi les mesures spécifiques à envisager figurent la mise en œuvre de règles d'amortissement progressif des actifs, des mécanismes de réduction des risques pour garantir (partiellement) un niveau de rémunération des actifs fondé sur le marché à long terme, et le partage transfrontalier des coûts d'investissement dans l'interconnexion (bilatéralement pour les États membres du point d'interconnexion concerné, ou au niveau régional). Le partage des coûts des projets de stockage d'hydrogène à grande échelle pourrait également être envisagé pour autant que ces projets contribuent à l'intégration transfrontalière de l'hydrogène, au commerce et à la sécurité de l'approvisionnement.

¹ En anglais: NECPs: National Energy and Climate Plans; NDP: Network Development Plan; TYNDP – Ten-Year NDP; PCI: Project of Common Interest; PMI: Project of Mutual Interest

1. Introduction

1.1. Background

This study focuses on the deployment of renewable and low-carbon gases in the Baltic Energy Market Interconnection Plan (BEMIP) region, focusing on the 8 BEMIP Member States (Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Poland, and Sweden). Renewable and low-carbon gases are expected to significantly contribute to the EU's decarbonization and energy independence ambitions, therefore provisions aimed at accelerating their deployment are increasingly reflected in the bloc's energy and climate policies.

Natural gas still plays a key role in the BEMIP region's energy supply, but renewable energy and decarbonization policies will result in a significant decline in natural gas demand. Biomethane as well as renewable and low carbon hydrogen can play a pivotal role in the decarbonization efforts of the BEMIP MSs, considering their large potential for renewable electricity generation and sustainable biomass. The geopolitical developments in 2022 prompted the EU to strive for decoupling its energy system from imported Russian electricity and fossil fuel sources. The BEMIP MSs were historically highly reliant on Russian energy imports; the Baltic countries had a reliance of 40-100% on Russian natural gas imports and their electricity systems used to be synchronized with Russia and Belarus rather than with continental Europe. A project to enhance the gas interconnection between Estonia and Latvia was recently finished (January 2023) as part of the BEMIP action plan, helping to ensure the integration of gas markets and decreased dependence on Russian gas. Further efforts are required to enhance production and use of biogas/biomethane and low-carbon/renewable hydrogen in the BEMIP MSs to cost-efficiently reach their energy and climate objectives, including by developing the required infrastructure

1.2. Objectives

The primary objective of this study is to promote the further integration of biomethane and hydrogen in the BEMIP region by supporting the development of the required infrastructure. The specific objectives of the study are to:

1. Assess the economic and technical potential supply for renewable and low-carbon gases in the BEMIP region, including domestic production and imports from Member States and non-EU countries.
2. Assess the potential demand for renewable and low-carbon gases in the region, including potential demand from other European countries to be met through gases produced in or transiting through the BEMIP region.
3. Identify the hydrogen and methane infrastructure needs to facilitate the integration of renewable and low-carbon gases in the region, to be met through repurposed/adapted or new methane or hydrogen infrastructure, and defining priority infrastructure projects.
4. Provide recommendations for concrete actions enabling the large-scale and cost-effective integration of renewable and low-carbon gases in the BEMIP region.

The study aims to provide a coherent pathway for the large-scale integration of renewable and low-carbon gases in the region along with the development of associated infrastructure needs. The recommendations aim to guide national authorities as well as network operators towards taking concrete actions to enable this integration, with particular attention to infrastructure development, market integration in the region and with other countries (Member States and non-EU countries) and system integration aspects (including holistic planning of energy infrastructure and sector coupling).

1.3. Reading guide

This report presents the final outputs for the project 'The potential for renewable and low-carbon gas deployment and impact on enabling infrastructure development for the Baltic Sea Region', covering all tasks of the study as outlined in the Terms of Reference.

The main report is structured as follows:

- **Chapter 2 provides an overview of the current and future role of renewable and low-carbon gases in the eight BEMIP MSs**, with a focus on quantitative supply and demand data. This serves both to understand the projected supply and demand pathways for the BEMIP MSs and region as a whole and to identify suitable data as input for the infrastructure modelling in chapter 5.
- **Chapter 3 presents the current policy landscape in the BEMIP region.** The Chapter briefly covers the key benefits and potential negative impacts of a fuel switch to renewable and low-carbon gases, and details both the existing supply and demand as well as infrastructure policies in place in the BEMIP region;
- **Chapter 4 discusses infrastructure readiness and challenges for integrating renewable and low-carbon gases in the region**, surveying the existing infrastructure and projects, as well as technical, safety and economic challenges. In addition, a detailed case study was performed, discussing the challenges and investment requirements related to the integration of biomethane production into the gas system based on the example of Denmark;
- **Chapter 5 conducts a quantitative assessment of the hydrogen and methane infrastructure needs and priorities** in the BEMIP region up to 2050 for the integration of biomethane and hydrogen, focusing on storage and cross-border network infrastructure. The assessment identifies cost-optimal pathways for development of hydrogen infrastructure as well as decommissioning/repurposing of methane gas infrastructure;
- **Chapter 6 presents the conclusions and recommendations**, discussing the role of gas infrastructure and potential energy system interlinkages, analysing how current infrastructure challenges will evolve in the light of the scenarios and infrastructure modelling results, and providing recommendations which complement policies and measures already in place or under development.

In addition, the annexes provide important supporting information to the main report:

- **Annex A** presents country fiches for renewable and low-carbon gases supply, demand and related infrastructure, and lists the key data sources for the analysis on hydrogen and biomethane supply and demand;
- **Annex B** analyses the benefits of and policies for the integration of biomethane and hydrogen in the BEMIP region;
- **Annex C** details the challenges of transitioning natural gas infrastructures in the region;
- **Annex D** presents the stakeholder engagement activities conducted in the project;
- **Annex E** details the modelling assumptions.

2. Renewable and low-carbon gases in BEMIP Member States

The following Chapter discusses the roles, natural gas, biomethane and hydrogen currently play in the BEMIP region, as well as key projections of future supply and demand of renewable and low-carbon gases in each BEMIP member state. The aim is to provide a comprehensive overview and thorough understanding of the expected developments in hydrogen and biomethane sectors, which serves as a basis for defining the baseline scenario and relevant sensitivities for the infrastructure modelling in chapter 5. The information collected in this chapter are based on a profound literature analysis, complemented by stakeholder input received via a survey.

As a starting point, chapter 2.1 presents an introduction on current natural gas market in the BEMIP region, by summarizing the energy supply and natural gas demand profile. Based on that, the following main part of the work focusses on a detailed discussion of current and future role of renewable and low-carbon gases in the eight BEMIP MSs. While chapter 2.2 covers hydrogen, chapter 2.3 presents the relevant topics around biomethane.

Both sections follow the same outline:

- 1) Current supply and demand in BEMIP MSs
- 2) Projections of future development and theoretical potential in BEMIP MSs, including aspects of production, demand, resulting import and export potentials.

Within this analysis, the scenarios from the Ten Year Network Development Plan (TYNDP)² are set within the perspective of national projections and targets. Due their key role in European infrastructure planning as being developed by European TSOs, the TYNDP scenarios are identified to being the most suited extensive and coherent dataset that should serve as baseline scenario in chapter 5.

The detailed analysis provided in this chapter, however, also reveals major deviations between TYNDP scenarios and national (more recent projections) for hydrogen and biomethane ramp-up:

- The analysis confirms that overall biomethane and renewable hydrogen production levels increase significantly by 2050 throughout the BEMIP region.
- The results, however, also show a high bandwidth in projections, which indicate the high degree of uncertainty for infrastructure investments.

Consequently, the actual deployment of renewable / low carbon gases will largely depend on the political and regulatory framework set in each BEMIP Member State. This especially includes the timeframe and speed of hydrogen market ramp-up, which seems overly ambitious in the TYNDP scenarios. In addition, the role of biomethane is – to a large extent – driven by political targets and projections show that only a minor share of theoretical potential will be exploited until 2050. Beside the regulatory framework, also technical limitations may hinder hydrogen and biomethane introduction into the market. Details are discussed in chapter 4 and Annex C (chapter 9).

As a result of this chapter, a suitable set of TYNDP scenarios for 2030, 2040 and 2050 was recommended to be used for the modelling (see modelling assumptions in chapter 11 (Annex E), Table 11-1). Furthermore, guidelines for adapting the assumptions in the context of a sensitivity are derived (see chapter 11 (Annex E) - Sensitivity analysis scenario assumptions).

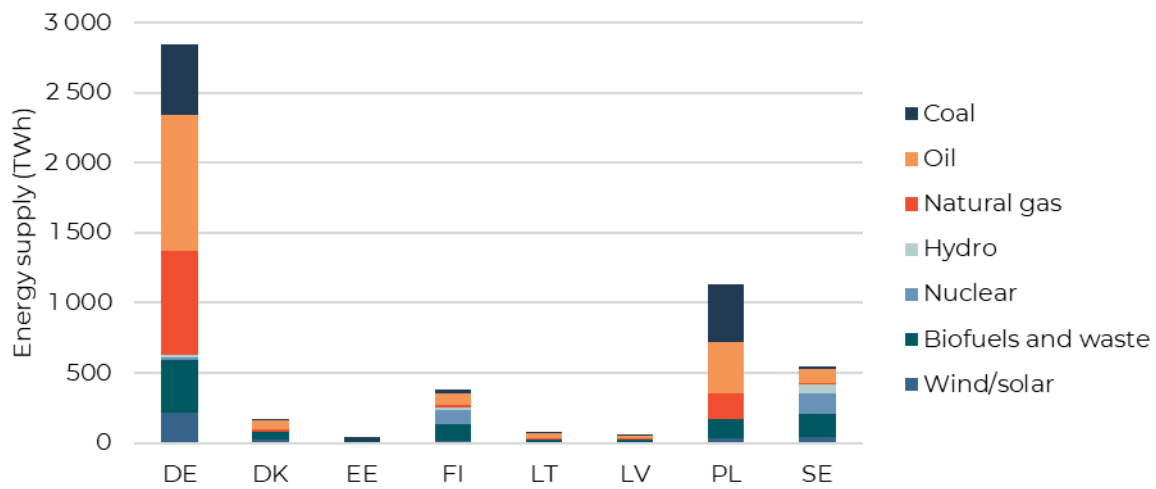
Please note: The data presented in this chapter are shown on an aggregated basis, summarising the detailed analysis on MS level that are presented in Annex A (chapter 7.1 regarding hydrogen supply and demand, and chapter 7.3 for biomethane production). Furthermore, key data sources identified

as being relevant for the analysis are presented in Annex A as well for hydrogen production and demand (chapter 7.2) and biomethane production (chapter 7.4).

2.1. Current role of natural gas in the BEMIP region

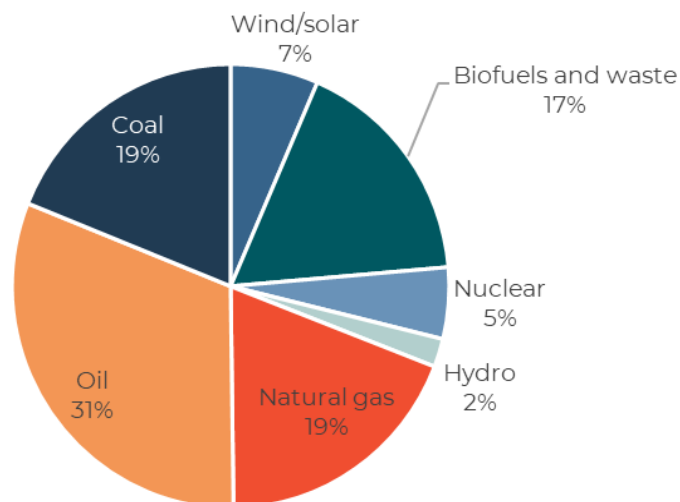
With BEMIP MSs representing approximately 31% of natural gas demand in EU27 in 2023³ and 23% of installed gas-fired capacity for power generation in EU27⁴, natural gas still holds a central place in the BEMIP's energy system. Natural gas accounted for 26% of primary energy supply in the BEMIP region in 2023 (see Figure 2-1). In particular, Germany and Poland are in the top 10 European countries consuming natural gas in 2022 and 2023⁵, and represent 78% and 16%, respectively, of the final natural gas consumption in the BEMIP region.

Figure 2-1 Energy supply in the BEMIP region in 2023



Source: International Energy Agency, based on World Energy Balances

Figure 2-2 Share of primary energy sources in the BEMIP region's energy supply in 2023



Source: International Energy Agency, based on World Energy Balances

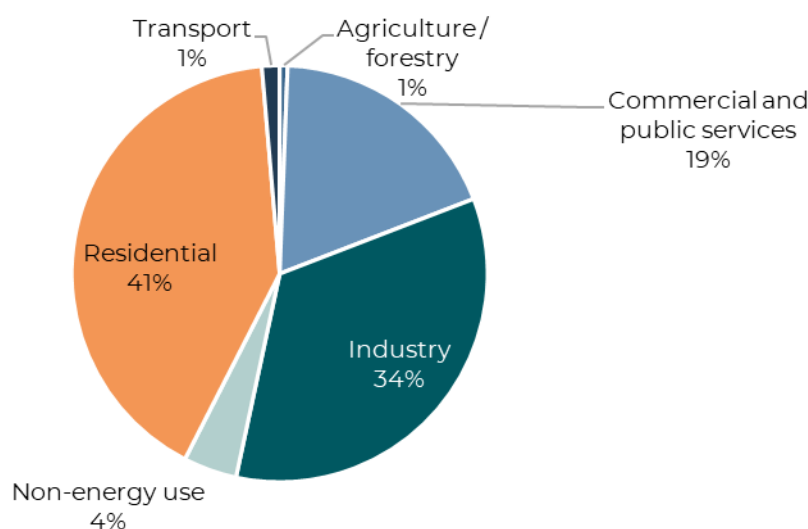
³ Eurostat (n.d.): [Natural gas supply statistics](#)

⁴ GIE (2025): [System Capacity Map](#)

⁵ Eurostat (n.d.): [Natural gas supply statistics](#)

The two sectors that consume the largest volumes of natural gas in the BEMIP region are residential end-users (around 41%) and industry (around 34%). In the Nordic countries, the industry sector represents most of the final gas demand, with more than 80% in Finland (around 5 TWh) and more than half in Sweden (around 2 TWh), while it was responsible for around 40% of the final natural gas demand in the two largest consumers of the region: Germany and Poland.

Figure 2-3 Final natural gas consumption by sector in BEMIP in 2023



Source: International Energy Agency, based on World Energy Balances

In Germany, natural gas represented 25% of final energy demand in 2023⁶ (Figure 2-4). Natural gas' role in power generation in Germany has increased over the past decades, as back-up for the increasing share of variable renewables and to enable the phase-out from coal and nuclear power generation. Hence, natural gas-fired plants' share in the power generation mix has grown by more than 70% between 2000 and 2023 and accounted for 17% of the German power generation in 2023.

In Poland, natural gas also holds a central place for power generation as the country is transitioning from coal to natural gas, to reduce the carbon emissions of its power sector. Hence, electricity generation from natural gas increased from less than 1 TWh in 2000, to more than 16 TWh in 2023. Yet, in 2023, coal still accounted for more than 60% of Poland's electricity generation. According to the country's latest NECP, electricity production from coal is expected to decrease to 22% by 2040 leading to a higher share of natural gas (16%) and renewables (40%). Otherwise, the Poland's phase out from coal would not be realised by 2040.

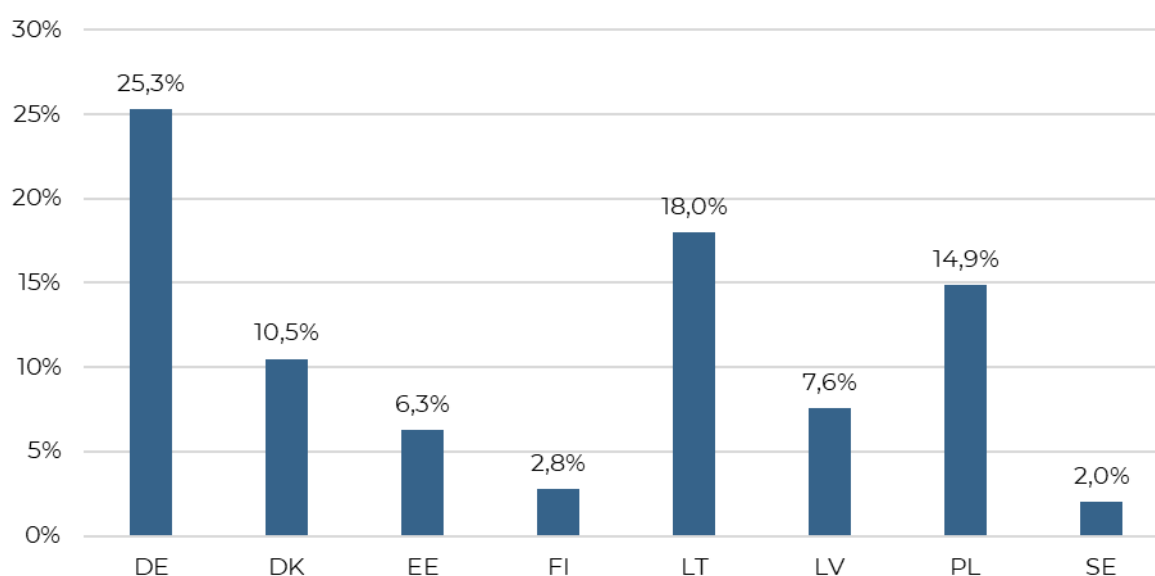
Natural gas has also become a transitional pillar of the Lithuanian energy system – especially after the country closed its last nuclear reactor for power production in 2009, which accounted for 70% of the country's power generation in 2005.⁷ In 2014 Lithuania commissioned its LNG import terminal in Klaipėda. Natural gas accounts for 18% of the country's energy supply in 2023 (see Figure 2-4) and remains the second most important primary energy fuel in the country, after oil. However, with increasing investments in renewable energies, natural gas is now mostly used by the industry and the fertilizer sector.

Other countries in the BEMIP region are progressively phasing out their natural gas use for electricity generation such as Denmark, Finland, or Estonia which have realised a 90% reduction of natural gas use in the power generation mix between 2000 and 2023. Natural gas fired power generation decreased from roughly 9 TWh in 2000 to 1 TWh in 2023 in Denmark, and similarly from 10 TWh in 2000 to 0.7 TWh in 2023 in Finland.

⁶ IEA (n.d.): [Germany](#)

⁷ International Atomic Energy Agency (n.d.): [Energy Supply Options for Lithuania](#)

Figure 2-4 Share of natural gas in the final energy demand (2023). Source: IEA



In terms of **natural gas supply**, some BEMIP MSs can rely to some extent on domestic natural gas production (Germany, Poland and Denmark). The production of the BEMIP MSs amounted to 94 TWh in 2022. However, all BEMIP MSs import large volumes of natural gas. Their strategic position close to, and, for some, directly connected to Russia made the region to heavily rely on Russian gas imports before 2022. Yet, the region has managed to transition away from Russian gas supplies while remaining one of the principal natural gas entry points of Europe, even after the invasion of Russia in Ukraine and the ensuing Russian supply disruptions. Indeed, the BEMIP region is main importer of natural gas from Norway –which now supplies more than half of the European natural gas demand– and covers 13% of LNG import capacity, with eight⁸ currently operational LNG terminals on its territory (as of January 2025)⁹. Since 2023, Germany supports this position with three active floating LNG terminals in operation since 2023 and two additional terminals planned to be in operation before 2030. Germany and Poland are major importers of natural gas from Norway.

While natural gas still plays a key role in the BEMIP region's energy supply today, decarbonization policies and targets as well as the increasing carbon emission cost will lead to a significant decline in natural gas demand within the next two decades. To continue the energy supply for hard-to abate industries, renewable and low-carbon gases like biomethane and (renewable or low-carbon) hydrogen thus must play a pivotal role in the decarbonization efforts of the BEMIP MSs. By optimally using the large potential for renewable electricity generation for the electrification of industry and the production of hydrogen as well as the sustainable biomass potential, BEMIP MSs can create economic and environmental benefits while also reducing their energy import dependency.

⁸ Wilhelmshaven (Germany), Brunsbüttel (Germany), Stade (Germany), Mukran (Germany), Świnoujście (Poland), Klaipėda (Lithuania), Inkoo (Finland), Hamina (Finland)

⁹ GIE (2025): [System Capacity Map](#)

2.2. Hydrogen in the BEMIP region

2.2.1. Current supply and demand

According to the IEA, global hydrogen production in 2022 was about 94 million tons, of which 74 million tons were produced in the form of pure hydrogen.¹⁰ Europe accounts for around 10% (9.9 million tons)¹¹, representing less than 2 % of its overall energy consumption. The hydrogen production currently mainly takes place in steam methane reformers (SMR) using natural gas to produce hydrogen for usage in chemical industries, like fertilizers (ammonia) or refineries.

While today's hydrogen production is (to the largest extent) limited to on-site hydrogen production at locations of use, transport of hydrogen is mainly done via H₂ trailers. Pipeline transport, however, only plays a small role at present and is limited to existing industrial pipeline systems in Germany within the BEMIP region. These privately operated networks are used to supply hydrogen within and between industrial sites. Examples include the network operated by the Air Liquide Group in the Ruhr region with a length of around 240 km, the network in the central German chemical area around Leuna (operated by Linde AG, approx. 140 km) and a network between Brunsbüttel and Heide in the north of Germany (approx. 30 km).¹²

The European Hydrogen Observatory includes data on hydrogen production¹³ and consumption¹⁴ in the EU Member States, including BEMIP MSs. Table 2-1 shows production figures (annual supply and production capacity) as well as national demand volumes in 2022. In total, around 102 TWh¹⁵ (or 3,050 kt) of hydrogen were produced in BEMIP MSs in 2022. This accounts for 40.1 % of total hydrogen production in EU27 (249 TWh, 7,484 kt). Compared to overall production capacity, 2022's production in BEMIP MSs represents a plant utilization of 76.3 % (in comparison: EU27 with 73.1 %).

Table 2-1: Status of hydrogen production and demand in BEMIP MSs in 2022
(Source: European Hydrogen Observatory 2024)

Country	Production		Production capacity		Demand	
	[TWh]	[kt]	[TWh/year]	[kt]	[TWh]	[kt]
Denmark	0.83	25.0	1.05	31.4	0.84	25.3
Estonia	0.00	0.0	0.00	0.0	0.00	0.0
Finland	5.88	176.4	6.64	199.1	5.88	176.4
Germany	58.11	1743.5	71.62	2148.9	57.88	1736.6
Latvia	0.00	0.0	0.00	0.0	0.00	0.1
Lithuania	4.79	143.7	8.90	266.9	4.79	143.7
Poland	26.15	784.6	36.82	1104.8	26.13	784.0
Sweden	5.85	175.4	8.08	242.3	5.82	174.7
BEMIP total	101.61	3048.6	133.10	3993.5	101.35	3040.7
EU27	249.44	7484.0	341.17	10236.0	248.11	7444.0

Includes existing H₂ production (SMR, by-product and electrolysis) and use (2022); original data in t/y; Conversion factor: 33.33 kWh/kg (= lower heating value, LHV).

Production volumes (differentiated by production technology, i.e. SMR, by-product and water electrolysis) and demand volumes (differentiated by end-use) are summarized in Figure 2-5 and Figure 2-6, respectively.

¹⁰ IEA (2022): [Global Hydrogen Review](#)

¹¹ Hydrogen Europe (2020): [Clean Hydrogen Monitor 2020](#)

¹² Fraunhofer ISI, Fraunhofer IEG, DVGW & DVGW EBI (2023): [Transformation der Gasinfrastruktur zum Klimaschutz, September 2023](#)

¹³ European Hydrogen Observatory (2022): [Hydrogen Production](#)

¹⁴ European Hydrogen Observatory (2022): [Hydrogen Demand](#)

¹⁵ Note: all energy values are based on lower heating value (LHV) in this study. A conversion factor of 33.33 kWh/kg hydrogen is used

Figure 2-5: Hydrogen production per technology (2022 data) (Source: European Hydrogen Observatory 2024)¹⁶

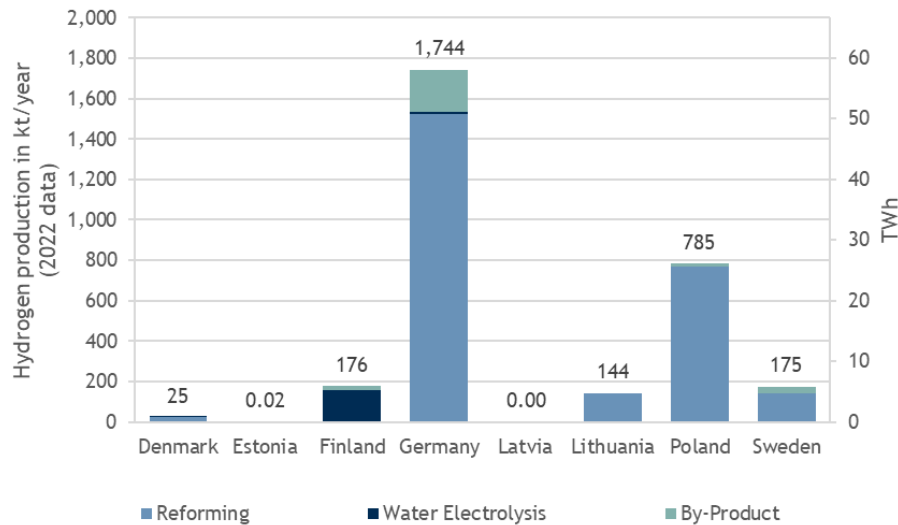
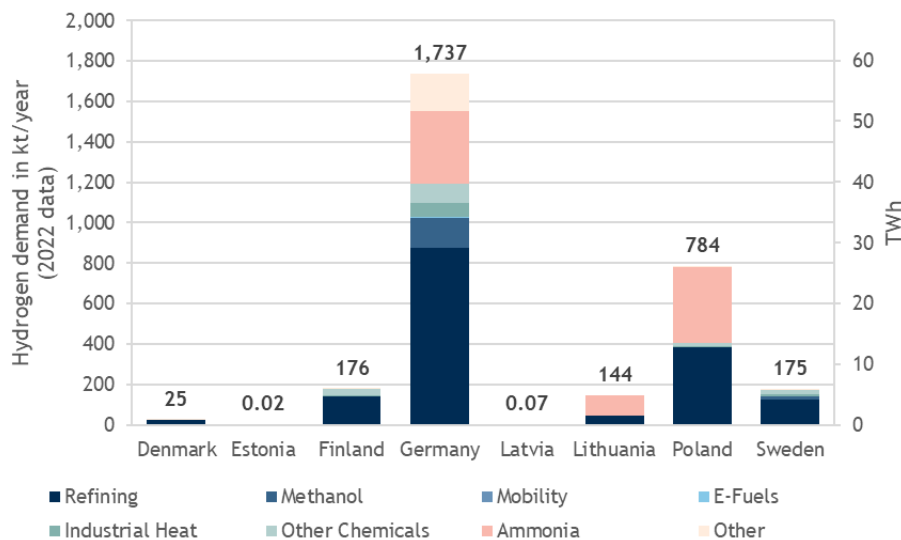


Figure 2-6: Hydrogen demand per technology and sector (2022 data) (Source: European Hydrogen Observatory 2024)



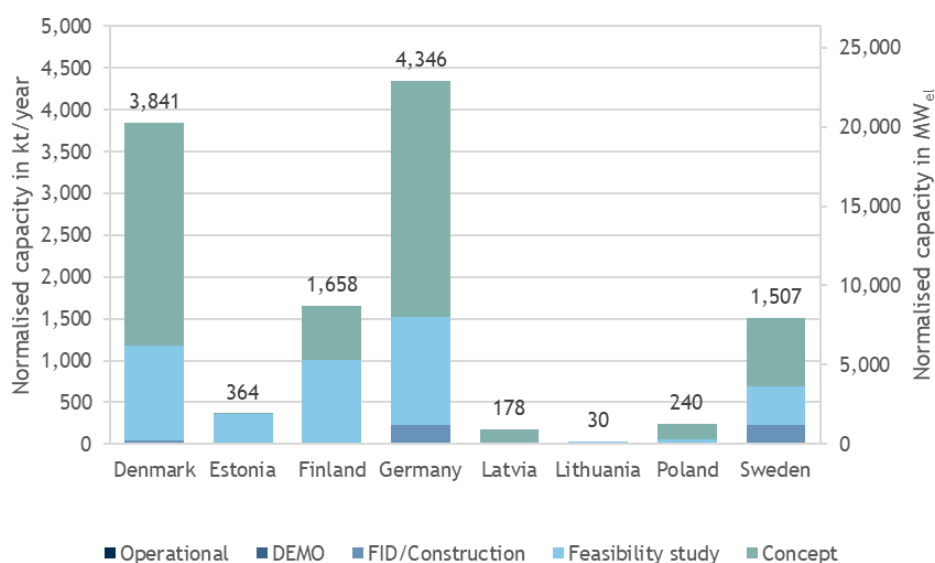
In contrast to the existing fossil-based hydrogen production, the renewable and low-carbon hydrogen production and market is still at a very early stage. Still, an increasing number of hydrogen production projects are announced across Europe. IEA's hydrogen production project database¹⁷ lists 405 announced projects in the eight BEMIP MSs (as of October 2024), with an overall targeted annual hydrogen production capacity of around 12.2 million tons (equivalent to 68.3 GW_e of (normalized) electrolyser capacity or around 12,164 kt/year) (see Figure 2-7)¹⁸. However, most of these projects are classified as 'concept' or 'feasibility study' and are concentrated in only some BEMIP MS. As of October 2024, only 196 MW_e of capacity are classified as 'operational' or 'DEMO' in the BEMIP MSs (equivalent to 0.3% of announced project capacity). Also, only a minor share of all announced projects has reached final investment decision (FID).

¹⁶ Unless stated otherwise, conversion from kt to TWh by using the lower heating value (LHV) and a conversion factor of 33.33 kWh/kg.

¹⁷ IEA (2024): [Hydrogen Production and Infrastructure Projects Database](#)

¹⁸ Capacity number for all announced projects (project start before 2035).

Figure 2-7 Capacity of announced renewable hydrogen projects by project status
(Source: IEA hydrogen project database)



2.2.2. Projections on future development and technical potential for renewable and low-carbon hydrogen – overview

The following analysis and discussion provides an overview over the whole BEMIP region. It is based on country-specific analysis for the eight BEMIP MSs which can be found in Annex A. (chapter 7.1)

Overview: outlook on future hydrogen production in the BEMIP region

In the last years, several studies have analysed the outlook of (renewable and low-carbon) hydrogen production in BEMIP MSs. Accordingly, there is a wide bandwidth between projections of several studies and scenarios on the future production of hydrogen in each country as well as the potential hydrogen production based on available renewable energy sources (for renewable hydrogen). Key literature sources which have been included in the analysis are listed in section 7.2.

It must be noted there is still uncertainty regarding the future levels of hydrogen production in the BEMIP region and Europe more broadly not only due to the wide bandwidth of projections, but also due to demand and the number of production projects taking final investment decisions (FID) tailing behind targets. This has been acknowledged among others by the latest State of the Energy Union report¹⁹, which notes that while the EU has the largest pipeline of hydrogen projects in the world, lower-than-anticipated demand for renewable hydrogen is holding back final investment decisions. Challenges in meeting the hydrogen targets has also been identified by ACER²⁰, the European Court of Auditors²¹, as well as a number of industry actors.²²

In the following analysis, the focus lies on renewable hydrogen from renewable electricity production produced via electrolysis. The reason is that – with the exception of Poland – all BEMIP MSs are favouring this production technology in their national strategies and plans. Only in Poland, domestic hydrogen production from natural gas using CCS was mentioned by stakeholders as relevant production technology as well.²³

¹⁹ European Commission (2024): [State of the Energy Union Report 2024](#)

²⁰ ACER (2024): [European hydrogen markets. 2024 Market Monitoring Report](#)

²¹ European Court of Auditors (2024): [Special report 11/2024: The EU's industrial policy on renewable hydrogen – Legal framework has been mostly adopted – time for a reality check](#)

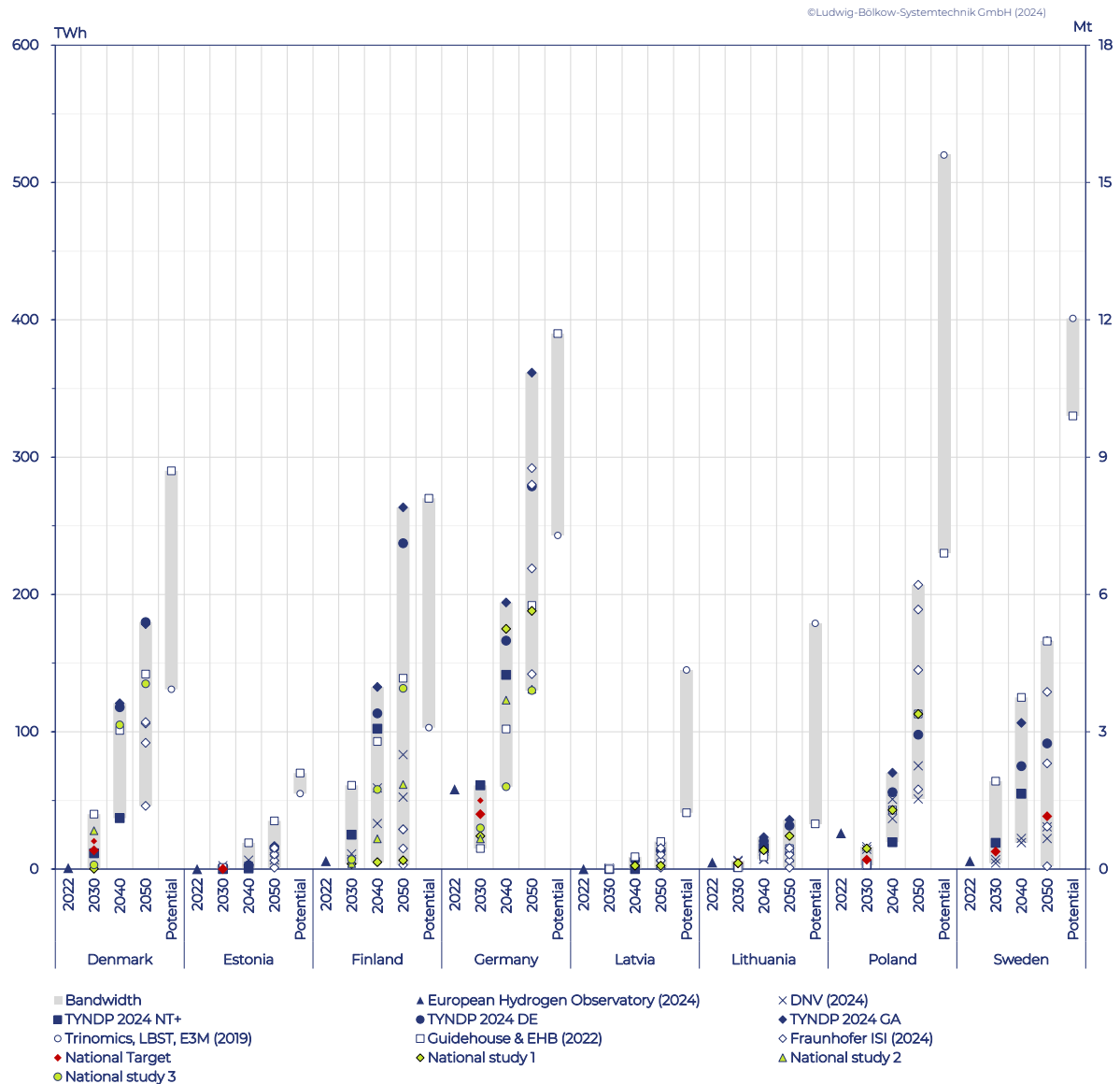
²² For example, see the [Joint statement on revision of European hydrogen policy](#)

²³ It should also be noted that, from a purely infrastructure perspective, a differentiation between renewable and low-carbon hydrogen is not required. Most relevant production technology in BEMIP region (based on e.g. announced projects in IEA project database (October 2024)) will be (water) electrolysis.

Figure 2-8 provides an overview of existing studies and projections, e.g. in the context of the (European) infrastructure planning activities like the Ten-Year Network Development Plan (TYNDP)²⁴ or the European Hydrogen Backbone (EHB) initiative. In addition, production targets (in red) and further studies on national level (in green) were considered in the analysis to allow for a comprehensive evaluation.

A detailed discussion at country level is included in the respective country fiches in section 7.1 (Annex A).

Figure 2-8: Overview of hydrogen production outlook and potential in BEMIP MSs
(Source: data analysis LBST)



²⁴ The Ten-Year Network Development Plan (2024) by ENTSOG and ENTSO-E includes three different scenarios: They mainly differ in variations in demand and supply patterns. The 'National Trends' (NT+) scenario is (largely) in line with national energy and climate policies derived from European targets and presented for 2030 to 2040-time horizons, while the two scenarios 'Distributed energy scenario' (DE) and 'Global ambition scenario' (GA) only covers the 2040-to-2050-time horizons. The DE scenario represents a pathway to achieving the carbon neutrality target of the EU-27 by 2050 driven by a behavioural shift of society and initiatives by citizens, communities and businesses, supported by authorities. In the GA scenario, achieving carbon neutrality by 2050 is driven by a fast and global move towards the Paris Agreement targets, supported by a wide range of technologies and global energy trade. (Source: ENTSOG / ENTSO-E (2024): Ten-Year Network Development Plan (TYNDP), Scenarios Storyline Report. Further information can be found here: <https://tyndp.entsoe.eu/explore/the-scenario-building-process>).

From an overarching perspective, already some first conclusions can be drawn: Several BEMIP MSs are projected to expand their hydrogen production significantly already by 2030. Germany, Finland, Denmark, Poland and Sweden plan to become major production countries. Studies by Guidehouse & EHB (2022) and Trinomics, LBST, E3M (2019) indicate a wide range in production potentials. Interestingly, the production potential according to Guidehouse & EHB (2022) is higher in Germany, Finland and Denmark, while Trinomics, LBST, E3M (2019) states higher potentials in Poland, Sweden, Latvia and Lithuania (compared to the other study, respectively).

An assessment of the scenarios in the TYNDP 2024 provides the following observations: In general, the NT+ scenario (blue squares in Figure 2-8 always presents a more conservative estimation of production values compared to DE scenario (blue circles) and the GA scenario (blue rhombus). NT+ fits – in most cases – rather good into the existing literature landscape. However, NT+ does not provide any data for 2050, also because the national targets are not sufficient to reach European and National long-term climate targets. A more ambitious ramp-up scenario of hydrogen production as implemented in the TYNDP DE and GA may, hence, be needed. Despite that, however, projections in DE and GA scenarios often are rather at the higher end of the bandwidth, indicating highly ambitious ramp-up pathways.

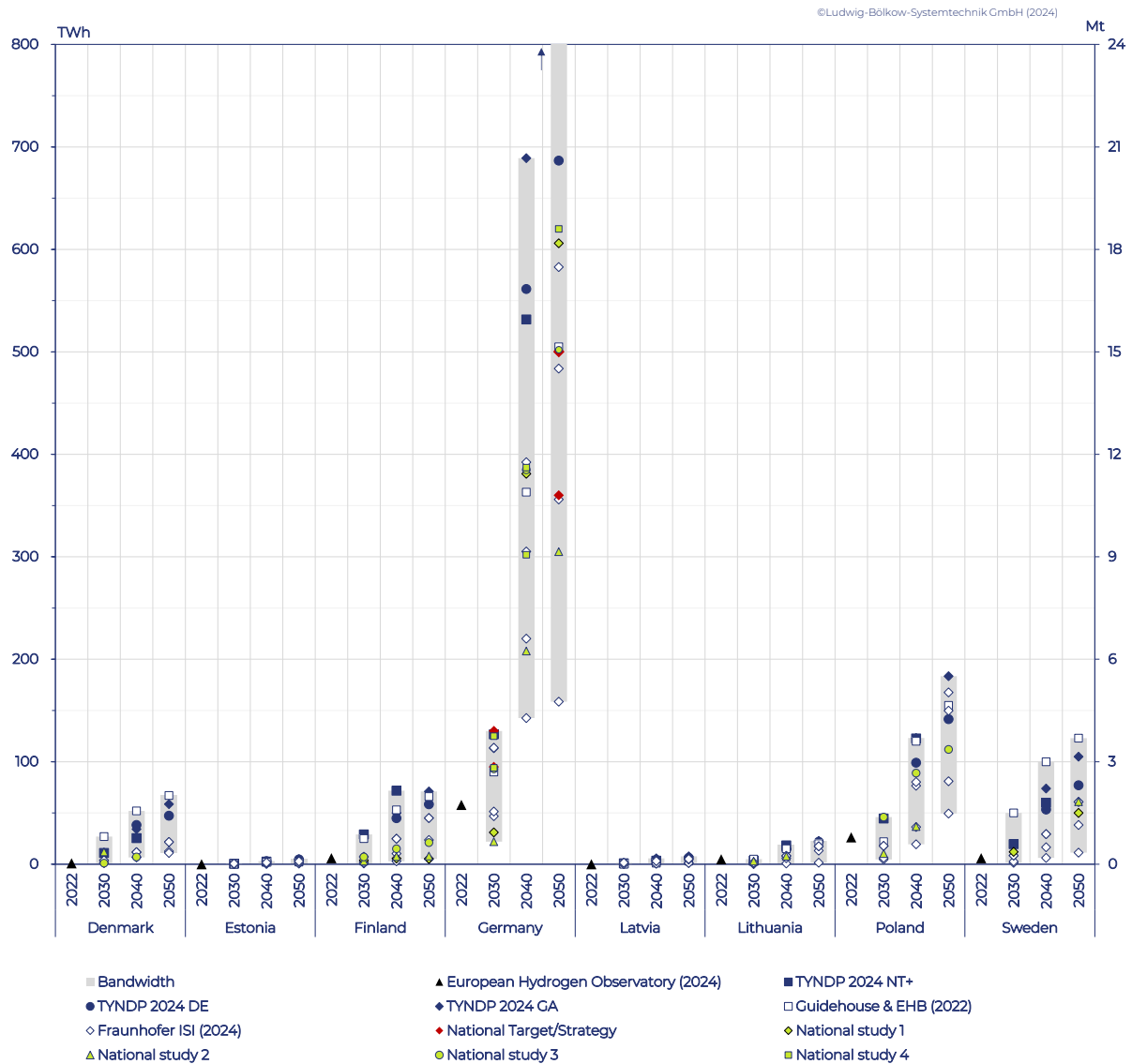
A comparison of the long-term projections until 2050 and the potential estimations also reveals some cases where production estimates are higher compared to the lower end of the bandwidth for production potential estimation. This is the case for Denmark, Finland, and Germany, indicating some uncertainty on whether the expected production volumes in these countries can be realized using domestic production potential.

Further discussions on the different scenarios and projections are included in section 7.1 on a country basis.

Overview: Expected Hydrogen demand in BEMIP region

As for the hydrogen production projections (and the theoretical production potential), also different demand scenarios were collected and compared based on literature. The result for all BEMIP MSs is presented in Figure 2-9. A detailed representation for hydrogen demand scenarios is also included in section 7.1 (Annex A) for each country.

Figure 2-9: Overview of hydrogen demand outlook (Source: data analysis LBST)



The data shows a strong concentration of hydrogen demand in Germany with the overall expectation of the German National Hydrogen Committee (Nationaler Wasserstoffrat) to mark the upper end of the bandwidth, with an estimation of between 620 and 1288 TWh by 2045 (here included as value for 2050).

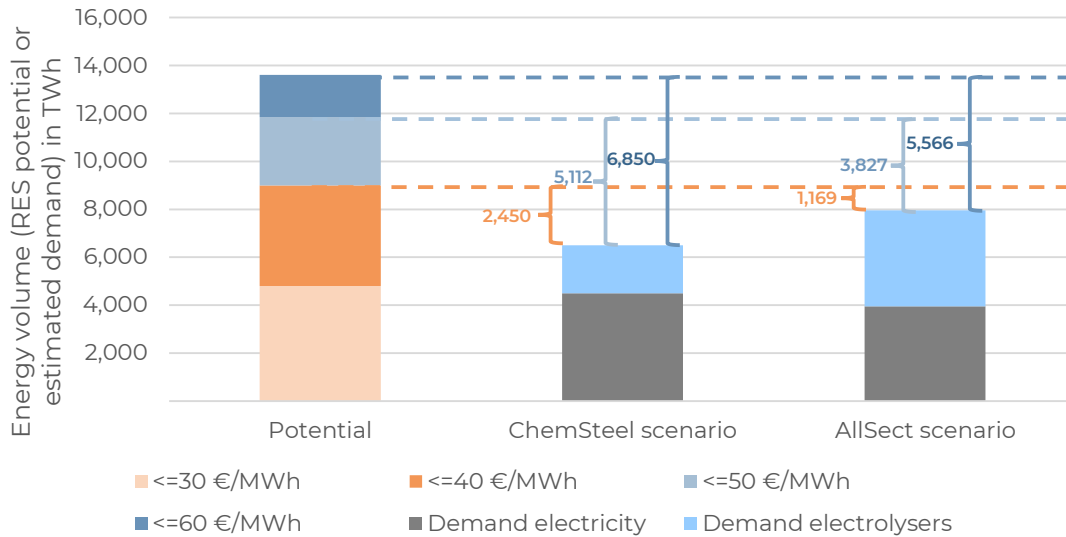
Imports vs. exports

The BEMIP MSs have very heterogeneous starting positions regarding potential production and demand of renewable hydrogen. An analysis by Fraunhofer ISI, RIFS Potsdam and Dena (2023)²⁵ comparing the technical renewable energy potential and demand (incl. electricity for hydrogen production) in Europe shows that even when looking at those renewable sources with levelized cost

²⁵ Fraunhofer, RIFS Potsdam, dena (2023): [Mobilizing Europe's Full Hydrogen Potential](#)

of electricity of €40 per MWh and below, the potential of renewable electricity production would exceed demand by 1,169 to 2,450 TWh in 2050, depending on the assumption on the role of hydrogen in the different sectors (see orange bars in Figure 2-10).

Figure 2-10: Technical renewable electricity potential vs. estimated demand (in TWh) in the EU, Norway, Switzerland, and the UK in 2050 (Source: LBST based on Fraunhofer ISI et al. (2023))



Under the assumption of taking all renewable electricity generation potentials using the five technologies (rooftop solar photovoltaics, utility-scale solar photovoltaics, onshore wind, offshore wind and concentrated solar power) with LCOE of 60 €/MWh and below and comparing these to expected domestic electricity and hydrogen demand (via electrolysis), the potential energy (in form of electricity) import needs are estimated. With this, the study shows that the BEMIP region (esp. Sweden, Finland and Poland) has a significant potential for producing surplus renewable electricity, part of which can be converted to hydrogen for supply to demand centres in central Europe. In contrast to that the demand in the industrial energy-intensive centres in Germany could potentially exceed domestic renewable electricity production by over 550 TWh (see Table 2-2). If hydrogen would not only be used in hard-to-abate sectors like steel but across all sectors, the German renewable electricity deficit, identified by the authors, may even increase to 883 TWh in 2050. Besides Germany, other main importers will likely be the Netherlands and Belgium, having lower renewable electricity potentials than demand (needed e.g. for hydrogen production) in 2050.

Table 2-2: Technical renewable electricity potential vs. demand (surplus (+) or deficit (-)) in BEMIP MSs, in 2050. (Source: Fraunhofer ISI et al. (2023))

BEMIP Country	ChemSteel scenario (S2)*	AllSect scenario (S5)
	in TWh	in TWh
Denmark	179	n/a
Estonia	105	n/a
Finland	494	n/a
Germany	-553	-883
Latvia	207	n/a
Lithuania	176	n/a
Poland	401	n/a
Sweden	702	n/a
Norway (BEMIP observer)	1,801	n/a
BEMIP total	1,310	
EU total	2,450	n/a

*ChemSteel scenario = Use of hydrogen hard-to-abates sectors like chemical and steel industry only.
AllSect scenario = hydrogen use across all energy sectors

Another approach to analyse potential hydrogen production and exports in the Baltic Sea region was chosen by DNV (2024),²⁶ which estimated the renewable hydrogen production potential for 2030, 2040 and 2050 based on the expected renewable electricity production ramp-up and the projected electricity demand per country.²⁷ By considering also the existing and future domestic hydrogen demand, the 'realistic' hydrogen export potential based on surplus electricity under the current policy framework and considering national plans was derived. Table 2-3 shows the results for the six analysed BEMIP MSs (Estonia, Finland, Latvia, Lithuania, Poland and Sweden).

In comparison to the data provided by Fraunhofer ISI et al. (2023), the DNV study results are significantly lower (also taking conversion losses for hydrogen production into account). The highest export potential for renewable hydrogen is identified for Finland (40 and 62 TWh by 2050 in the two scenarios, respectively). Other countries like, e.g. Lithuania are considered as an exporting country already in 2030, based on a rapid expansion of renewable electricity capacities. However, due to ongoing and ambitious national electrification targets across all sectors, the potential surplus for hydrogen production decreases over time. A similar trend can be observed for Sweden, with no surplus electricity being available in 2050 (due to industry electrification and domestic hydrogen use).

Surplus electricity production is mostly linked to onshore and offshore wind energy production, with onshore wind electricity expected to be the main source of surplus in the conservative scenario (share of about 40-50% in Sweden and 70-80% in Finland in 2030-2050). Electricity production surplus from offshore wind, on the contrary, accounts for around 10-20% only in Sweden (2050) and around 5% (2030) and 11% (2050) in Finland, respectively.

The DNV study also concludes that the hydrogen production potential strongly depends on national strategies and the decarbonisation pathways adopted in the individual countries. Overall, based on current policies, the study identifies significantly lower export potentials in the countries surrounding the Baltic Sea compared to the North Sea region. Thus, especially for countries like Sweden and Finland, a higher potential is expected in case more ambitious plans to produce renewable electricity and hydrogen for export are implemented. Especially Sweden possesses a strong (theoretical) potential due to the size of the country and available RES sources. Looking at the estimated hydrogen export potentials, however, it should be considered that also direct electricity exports from Nordic countries to central Europe may gain (further) relevance in the future, which was not considered in the study.

²⁶ DNV (2024): [Potential for a Baltic Hydrogen Offshore Backbone, March 2024](#)

²⁷ The analysis by DNV (2024) is based on the TYNDP (2022) and national energy targets.

Table 2-3: Renewable hydrogen export potential based on surplus electricity (in TWh) considering current policies (Source: DNV (2024))

Country	DNV (2024) – conservative in TWh (in kt)			DNV (2024) – optimistic in TWh (in kt)		
	2030	2040	2050	2030	2040	2050
Denmark	Not analysed					
Estonia	-	-	3.85 (116)	1.28 (38)	3.27 (98)	3.72 (112)
Finland	-	20.8 (624)	40.4 (1,212)	5.59 (168)	44.4 (1,332)	62.3 (1,869)
Germany	Not analysed					
Latvia	-	-	-	-	0.71 (21)	0.39 (12)
Lithuania	3.98 (119)	0.08 (2)	0.39 (12)	3.34 (100)	0.64 (19)	1.09 (33)
Poland	-	-	-	-	1.09 (33)	0.77 (23)
Sweden	2.59 (78)	4.75 (143)	-	-	7.90 (237)	8.54 (256)
Total	6.55 (197)	25.6 (768)	44.7 (1,341)	10.2 (306)	58.0 (1,740)	76.8 (2,304)

Selection of data input for modelling

Modelling of the BEMIP hydrogen infrastructure is performed in Chapter 5 of this study. A coherent data set among all BEMIP MSs is an essential element of an insightful analysis. Hence, European-wide modelling studies with homogeneous underlying assumptions are best suited to be selected as data input.

Based on the data presented above and the detailed analysis in section 7.1 (Annex A), it is suggested that the TYNDP 2024 National Trends (NT+) scenario serves as an appropriate data basis for hydrogen in 2030 and 2040. Compared to that, the other scenarios of TYNDP (Distributed Energy scenario, DE, and Global Ambition scenario, GA) are significantly more ambitious which (currently) seems not to be in line with most other studies analysed here. Especially for Germany, Finland and Denmark, the production ramp-up in the DE and GA scenarios are at the upper end of the bandwidth identified.

For 2050, however, the TYNDP 2024 NT+ scenario does not provide any data forecast. The other scenarios DE and GA could serve as a reasonable, although ambitious data basis, with projections for hydrogen production and demand in DE being lower than in GA.

Under the assumption that the NT+ scenario is used as a basis for 2030 and 2040 hydrogen production and demand data and the DE scenario for 2050, the following graphs on national hydrogen surplus or deficit are obtained (please note: numbers provided in the figures refer to surplus and deficit volumes only). The graphs show that while in 2030, main deficit is observed in Germany and Poland with 66 and 41 TWh hydrogen, respectively, none of the other BEMIP MSs achieves a significant surplus for export. The situation changes until 2050 (under the assumptions taken). Germany will remain the main demand centre with around 408 TWh import demand. However, most of the other BEMIP MSs (except Poland) would have a surplus hydrogen production, with Finland and Denmark showing the highest values with 179 and 133 TWh, respectively.

Figure 2-11: Hydrogen surplus and deficit balance for TYNDP2024 National Trends (NT+) scenario 2030
(Source: LBST based on TYNDP2024)

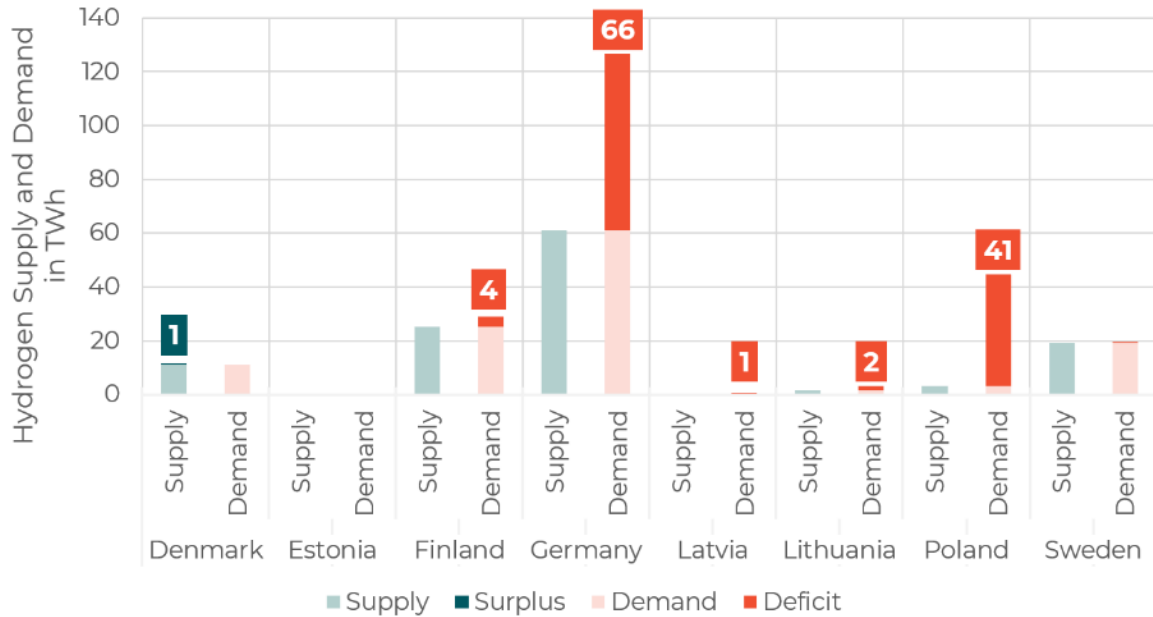


Figure 2-12: Hydrogen surplus and deficit balance for TYNDP2024 National Trends (NT+) scenario 2040
(Source: LBST based on TYNDP2024)

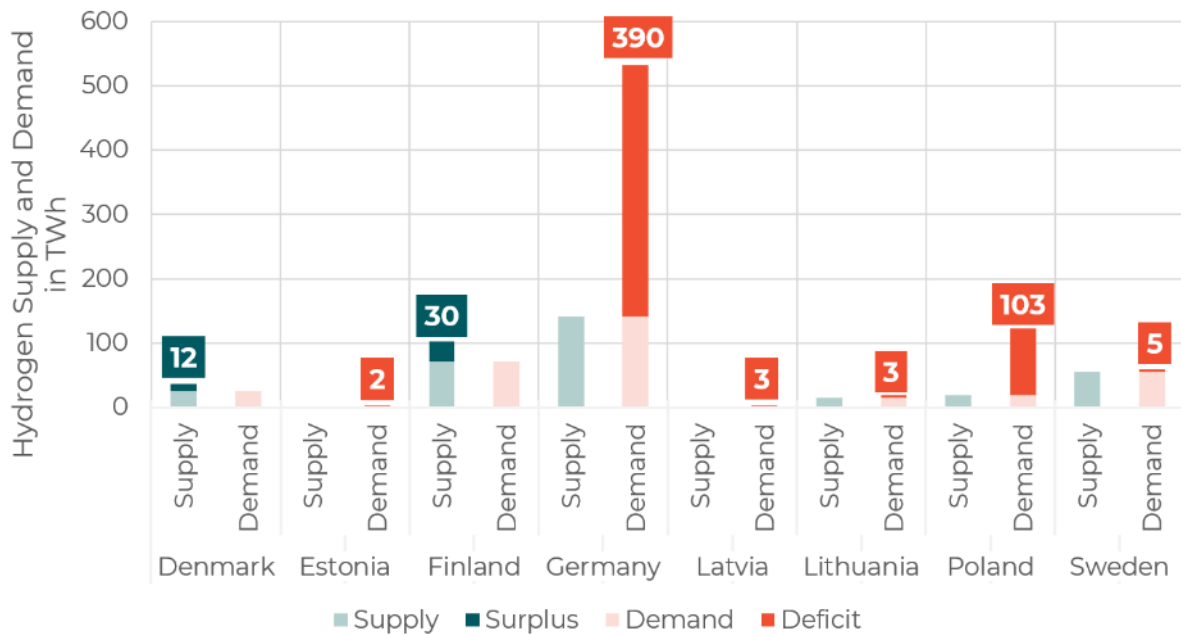
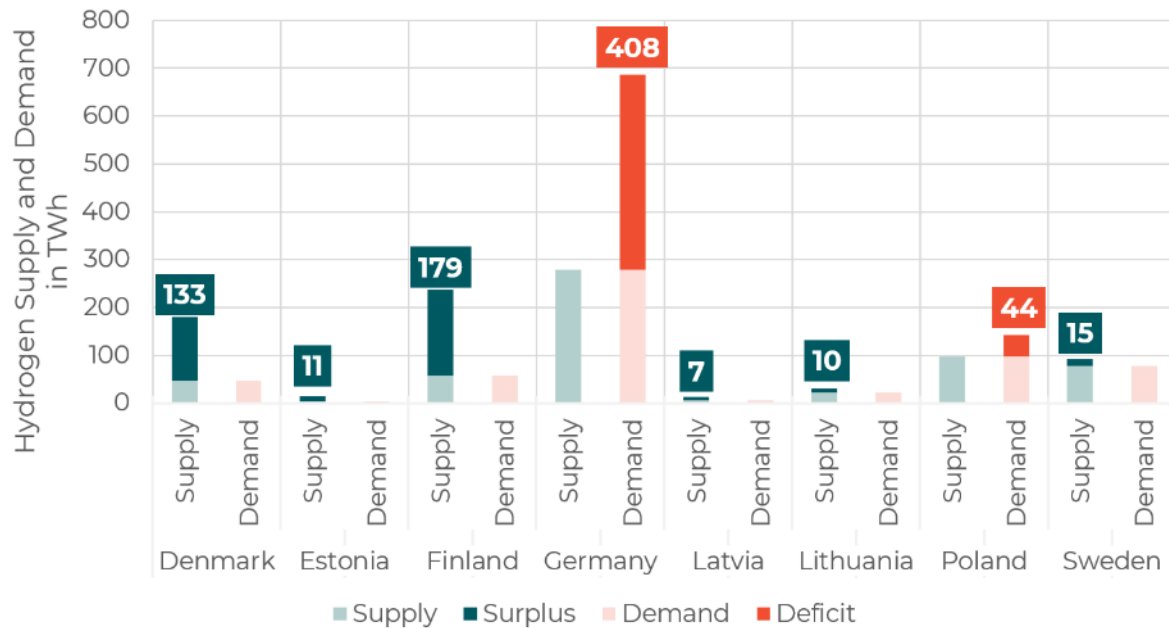


Figure 2-13: Hydrogen surplus and deficit balance for TYNDP2024 Distributed Energy (DE) scenario 2050 (Source: LBST based on TYNDP2024)



2.3. Biomethane in the BEMIP region

Background on biomethane production

Biomethane can be generated via anaerobic digestion of moist biomass and downstream upgrading of the biogas to gas with high methane content and similar characteristics like natural gas. Agricultural residues, food waste, and moist biomass from energy crops such as maize or grass silage can be used as feedstock. Biogas consists of 50 to 70% methane, 30 to 50% CO₂, and traces of hydrogen and hydrogen sulphide (H₂S). For biogas upgrading to biomethane with a methane content of above 98% various technologies are available such as pressurized water scrubbing, pressure swing adsorption, membranes, and scrubbing with amines. Today, most biogas is directly converted to electricity and heat via gas engines. Only a limited part of the biogas is upgraded to biomethane with sufficient methane content for injection into the natural gas grid.

Another production pathway is to directly produce biomethane via gasification of solid biomass and downstream methanation. Some sources, therefore, also refer to this product as synthetic natural gas (SNG) instead of biomethane. In the following – however – the potential for gasification is considered under the (theoretical) biomethane production as well. It should however be noted that, until now, only a few pilot and demonstration plants for the gasification of solid biomass with downstream methanation exist, e. g. Gothenburg Biomass Gasification (GoBiGas) plant which was operated between 2015 and 2018 and meanwhile has been closed²⁸. The capacity of the GoBiGas plant was 20 MW of biomethane. In contrast to that, SNG production from renewable hydrogen and CO₂ is not considered as biomethane and not part of this study.

Table 2-4 lists different (potential) feedstocks and technology scopes for both technologies.

²⁸ Göteborg Energi (2024): [The GoBiGas plant](#)

Table 2-4: Feedstock and technology scope (Source: based on EBA & Guidehouse 2024²⁹)

Anaerobic Digestion	Thermal Gasification
Agricultural residues Left-over materials after harvesting of the main crop (e.g. cereal straw).	Forestry residues Residues from (pre-commercial) thinnings, final fellings and logging.
Animal manure Liquid and solid animal waste from livestock in stables or barns.	Landscape care wood For example: trees from management operations in urban areas, roadsides, railways and private gardens.
Biowaste Food and vegetal waste (from households or industry).	Municipal solid waste (organic fraction only) Waste material that has not been separately collected for recycling, composting or anaerobic digestion (mainly from households, also industry).
Industrial wastewater Wastewaters from industry sectors in which anaerobic digestion could be implemented as a pre-treatment method.	Prunings Biomass residues after cutting, mulching and chipping activities.
Sequential crops Cultivation of a second crop on the same agricultural land.	Wood waste Secondary woody biomass, e.g. from wood processing, demolition wood, etc.
Permanent grassland (Germany only) Grass from grassland which does not compromise animal husbandry.	
Roadside verge grass Collected during maintenance operations in urban areas.	
Sewage sludge Semi-solid or liquid material that is produced as a result of sewage treatment of municipal wastewater.	

Please note: Most sources provide data for biogas and biomethane production in billion cubic meters (bcm) or Peta Joule (PJ). For a higher transparency, the original values are cited in the following and – for a better comparison – recalculated into TWh.

Biomethane in Europe

The number of biomethane plants in Europe has continuously increased over the past years. In the framework of the REPowerEU Plan³⁰ published in 2022, the European Commission has set the ambition to scale-up the biomethane production to 35 bcm by 2030 (around 366 TWh³¹), while the production in 2022 amounted to 4.2 bcm (around 44 TWh) (for comparison: total biogas (= biogas + biomethane) production was around 21.0 bcm). The related investment needs until 2030 would amount to around €37 billion.

The biomethane development is also driven by an increasing number of biogas plants changing their business model from direct electricity (and heat) production to biomethane upgrading (purification) for injection into the natural gas grid and/or use in the transport sector. However, biomethane production still represents a limited share of less than 20% of the overall biogas production in Europe.

According to the 'Biomethane Map 2024'³², 1,548 bio-methane production facilities were in operation in Europe as of June 2024 (EU, Iceland, Norway, Switzerland, Ukraine). Of the existing biomethane plants, around 58% are connected to the distribution grid, 17% to the transmission grid and 9% do not have a grid connection. For 16% of the plants, the European Biogas Association (EBA) database did not provide information.³³

²⁹ European Biogas Associations / Guidehouse (2024): [Biogas towards 2040 and beyond - a realistic and resilient path to climate neutrality](#)

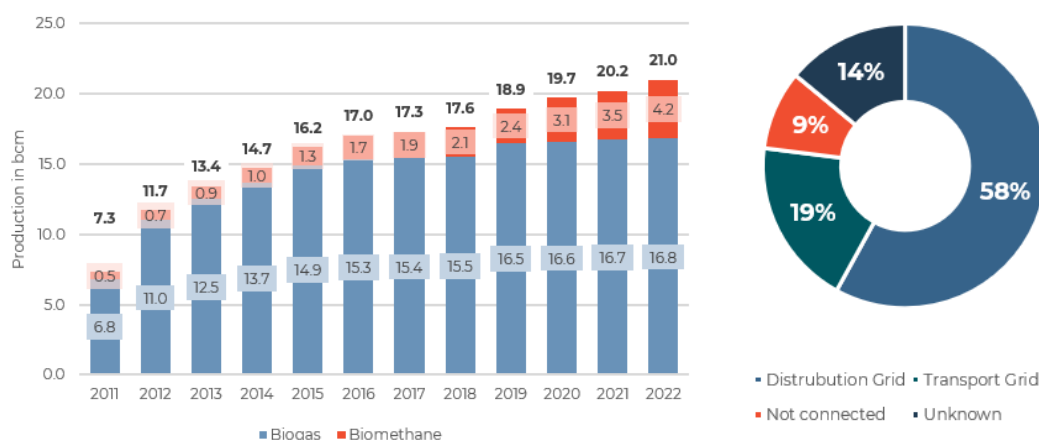
³⁰ EC (n.d.) [Biomethane](#)

³¹ Conversion factor: 1 billion m³ (bcm) = 10.467 TWh or 1 TWh = 0.09554 bcm based on ifeu (2022): [Biomethane in Europe](#)

³² GIE, European Biogas Association (2024): [European Biomethane Map 2024](#)

³³ European Biogas Association, EBA Statistical Report 2023; GIE, European Biogas Association (2024): [Biomethane Map 2024](#)

Figure 2-14: Development of European biogas and biomethane production (Source: EBA 2024)³⁴ (left) and percentage and status of biomethane plants connected to the natural gas grid (right) (Source: GIE and EBA 2024)³⁵



2.3.1. Current biomethane supply and demand in BEMIP Member States

The current biomethane market situation is highly heterogeneous among the eight BEMIP MSs. While Germany, Denmark, and Sweden have a significant number of facilities for the upgrading of biogas to biomethane, other countries like the Baltic States or Poland are just beginning to build biomethane plants. Furthermore, especially Nordic countries like Finland and Sweden, but also the Baltic states use the upgraded biogas primarily as transport fuel (in the form of compressed natural gas (CNG) or liquified natural gas (LNG) / liquified biogas (LBG)), while Denmark and especially Germany inject a significant share into the gas grid. Overall biomethane production in BEMIP MSs is estimated to reach around 25 TWh from 424 biomethane plants in 2024, while in 2022, the production was around 21.6 TWh (see Table 2-5).

Table 2-5: Overview of existing biomethane production as well as natural gas and biogases (biogas and biomethane) demand (as gross inland consumption) in BEMIP MSs

	Production of biomethane [TWh] (2022)	No of biomethane plants (2024)	Estimated average plant production [m³/h]	Gross inland consumption Natural gas [TWh] (2022)	Gross inland consumption of biogases* [TWh] (2022)
Denmark	6.50 7.35 (2023), ~8.00 (2024)	58	1339	16.7	8.0
Estonia	0.21 (2023)	8	315	3.4	0.2
Finland	0.36	24	177	12.8	2.1
Germany	12.80	254	704	776.5	94.5
Latvia	0.10	4	299	8.0	0.6
Lithuania	0.12	2	717	14.9	0.5
Poland	0.00	-	-	175.0	4.1
Sweden	1.50	74	242	7.5	0.0
BEMIP total	21.6	424	-	1,014.8	110.1
Source	See country fiches	GIE, EBA (2024): European Biomethane Map 2024	Calculated based on production and No. of plants	Eurostat nrg_bal_c	Eurostat nrg_bal_c

* Biogases includes biogas and biomethane.

Table 2-5 also lists the value of 2022 overall biogases consumption (which is mainly covered by domestic production). The figures include both, biogas and biomethane and can thus also serve as a

³⁴ European Biogas Association, EBA (2024): [Decoding Biogases – Made in Europe, Sustainable, Affordable](#)

³⁵ GIE, European Biogas Association (2024): [European Biomethane Map 2024](#)

first proxy on the actual biomethane production in case all biogas plants are converted to upgrade biogas to biomethane in the future.

Figure 2-15 compares the national biomethane production volumes, while Figure 2-16 shows the number of plants per country as well as the average plant production capacity.³⁶ Denmark is the only country where a significant increase in production capacity can be observed since 2022.

Figure 2-15: Overview of annual biomethane production per country in 2023/2024.

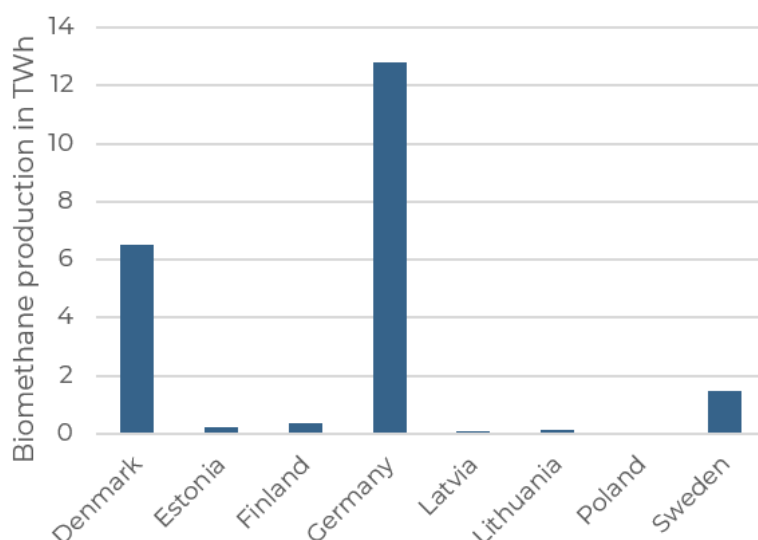
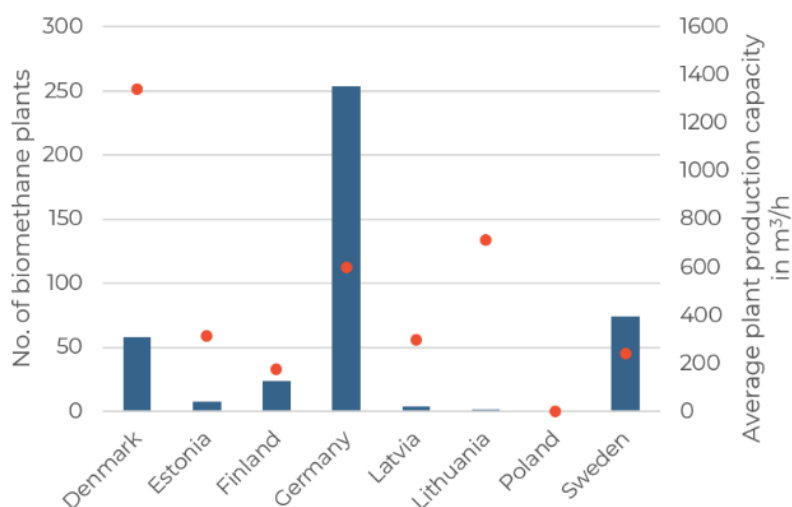


Figure 2-16: Overview of the number of biomethane plants (blue columns; left scale) and average plant capacity (red dots; right scale)



The current biomethane production characteristics as well as its use are also driven by existing gas demand patterns, which significantly differ among the BEMIP MSs. Significant natural gas consumption can only be observed in Germany and Poland – both countries with a dense gas grid and high presence of energy-intensive industries (see section 2.1).

³⁶ Conversion factor: 1 billion m³ (bcm) = 10.467 TWh or 1 TWh = 0.09554 bcm based on ifeu (2022): [Biomethane in Europe](#)

2.3.2. Projections on future development and technical potential for biomethane production and gas demand - overview

Overview: Development of biomethane production and gas demand in BEMIP region

As with the projections of (renewable) hydrogen, relevant scenarios in different sources were collected and compared. Besides the National Energy and Climate Plans (NECPs), biomethane potential data from EBA & Guidehouse (2024)³⁷ and three different scenarios from TYNDP 2024³⁸ by ENTSG / ENTSO-E were used for comparison and identification of relevant input data used for infrastructure modelling in Chapter 5.

The TYNDP presents three scenarios for biomethane supply and demand in the future European energy system. These scenarios differ mainly in possible variations in demand and supply patterns and are therefore technology, source and energy carrier-neutral. The scenario 'NT+ scenario' is largely in line with national energy and climate policies derived from European targets and presented for 2030 to 2040-time horizons, while the two scenarios 'Distributed energy scenario' (DA) and 'Global ambition scenario' (GA) only cover the 2040 to 2050 time horizons. The DA scenario represents a pathway to achieving the carbon neutrality target of the EU-27 by 2050 driven by a behavioural shift of society and initiatives by citizens, communities and businesses, supported by authorities. In the GA scenario, achieving carbon neutrality by 2050 is driven by a fast and global move towards the Paris Agreement targets, supported by a wide range of technologies and global energy trade.³⁹

ENTSG applied a biomethane tool and numbers used in REPowerEU by the EU Commission and numbers from the study 'Biomethane production potential in the EU' by Guidehouse⁴⁰ to calculate the biomethane potentials. While the data from the EU Commission is slightly lower than those from ENTSG's biomethane tool, the numbers from the Guidehouse report are slightly higher. These values were then updated or verified by the TSOs.⁴¹ For 2040, the biggest increase in the biomass supply (and utilization) compared to the status quo is observed for the NT+ scenario, while the other two scenarios present lower numbers (see Figure 2-19). A clear trend is seen in all three scenarios, that more biomass feedstock will be used in the future for biomethane production, and less directly for electricity (and heat) generation. The role of biofuels in transport is very dominant in NT+ scenario by 2040 compared to DE and GA.⁴²

EBA & Guidehouse (2024)⁴³ calculate the total biomethane potential per country that could potentially be tapped if all the available sustainable feedstock was utilised for biomethane production, which is a hypothetical approach. It considers technical and environmental constraints to derive a sustainable potential. The potential projections for the years 2030, 2040 and 2050 are shown in Figure 2-17.

For the report, similar calculation methodologies were applied as in Gas for Climate 2022⁴⁴ with updated data, and the resulting estimates were reviewed with regard to the strengthened sustainability criteria for woody biomass under the Directive 2023/2413. Also, a ramp-up of biomethane from 2030 to 2040 is estimated, reflecting the European Commission's intention to reduce the EU's net greenhouse gas emissions by 90% by 2040 relative to 1990. Still, the potential estimated are significantly higher than estimates included e.g. in the TYNDP 2024 scenarios above. To what extent this so-called sustainable potential can be achieved strongly depends on both policy and economic factors.

³⁷ European Biogas Association & Guidehouse (2024): [Biogases towards 2040 and beyond](#)

³⁸ ENTSG / ENTSO-E (2024): [Ten-Year Network Development Plan](#) (TYNDP)

³⁹ ENTSG / ENTSO-E (2024): Ten-Year Network Development Plan (TYNDP), [Scenarios Storyline Report](#)

⁴⁰ Guidehouse & Gas for Climate (2022): [Biomethane production potentials in the EU](#)

⁴¹ ENTSG / ENTSO-E (2024): Ten-Year Network Development Plan (TYNDP), [Scenarios Methodology Report](#)

⁴² ENTSG / ENTSO-E (2024): Ten-Year Network Development Plan (TYNDP), [Draft Scenarios Report](#)

⁴³ European Biogas Association & Guidehouse (2024): [Biogases towards 2040 and beyond](#)

⁴⁴ Guidehouse & Gas for Climate (2022): [Biomethane production potentials in the EU](#)

Figure 2-17: Existing biomethane production in 2022 (blue) and potential biomethane production (orange) (Source: European Biogas Association & Guidehouse (2024))⁴⁵

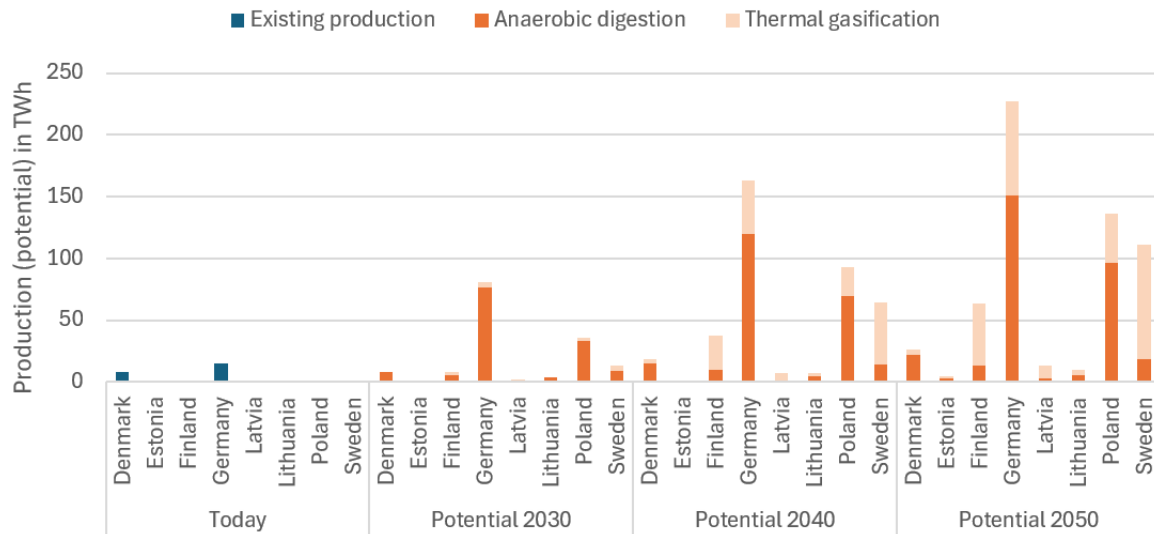
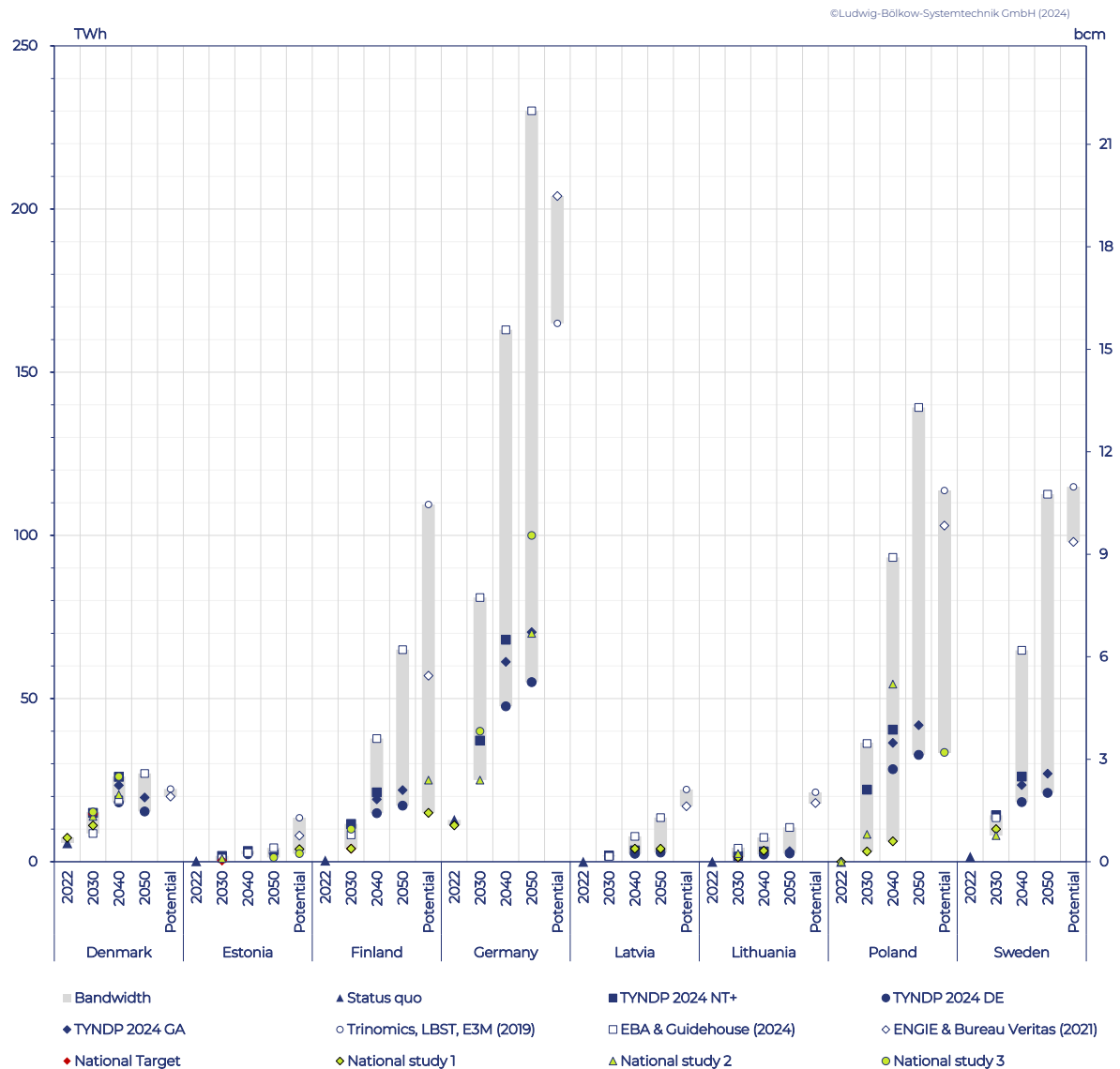


Figure 2-18 provides an overview of the biomethane production outlook (projection and potential) for all BEMIP MSs. It should be noted that some scenarios include a shift from biogas to biomethane production, and more generally a shift from other uses of biogas to the production of biomethane. As such, not all future production quantities shown in the graph require additional resources. Detailed discussions for each BEMIP country can be found in section 7.2.

The future (potential) biomethane demand is, on the contrary, mainly determined by the development of the natural gas consumption and infrastructure in BEMIP MSs. It is, hence, determined by the general transition pathway each country follows to reach climate neutrality of the energy system. Accordingly, no analysis on the expected gas demand is included here. Relevant input data based on TYNDP scenarios used for modelling are discussed below.

⁴⁵ The potential bars are differentiated between Anaerobic Digestion (AD (feedstocks mainly agricultural residues, crops, manure) and Gasification (mainly wood waste, forestry residues, landscape care wood, municipal solid waste and prunings).

Figure 2-18: Overview biomethane production outlook and potential in BEMIP MSs (Source: data analysis LBST)



Selection of data input for modelling

Modelling of the BEMIP gas infrastructure is performed in Chapter 5 of this study. A coherent data set among all BEMIP MSs is an essential element of an insightful analysis. Hence, European-wide modelling studies with homogeneous underlying assumptions are best suited to be selected as data input.

Based on the data presented above and the detailed analysis in section 7.3 (Annex A – biomethane country fiches), it is suggested that the TYNDP 2024 National Trends (NT)+ scenario serves as an appropriate data basis for biomethane production in 2030. Compared to that, the other TYNDP 2024 scenarios (DE and GA) are showing significantly lower increases in biomethane production for the 2040 and 2050 timeframe – which is in line with the analysis of the projections in BEMIP MSs. In contrast to that, potential estimations by most studies seem to represent rather the theoretical potential than what can really be expected to be deployed – even in the long term.

In summary, the recommendation is to use specific TYNDP 2024 scenarios as basis for modelling in the baseline scenario of the different time steps: the NT+ scenario serves as input for the biomethane supply in 2030 and the (less ambitious) DE scenario for 2040 and 2050. The natural gas demand, on the contrary, is based on TYNDP 2024 NT+ scenario for 2030 and 2040, representing a slower natural gas phase out. Only for 2050, the DE scenario is applied for all input parameters (see also Table 11-1).

For the sensitivity analysis, the assumptions for projected biomethane production are adapted taking country-specific analyses and projections into account (see section 5.2.2). The detailed country analyses in section 7.3 (Annex A – biomethane country fiches) also shows that all BEMIP MSs are expected to only exploit a limited share of the overall theoretical biomethane production potential described e.g. by the European Biogas Association & Guidehouse (2024) (see Figure 2-17).

Import vs. export of biomethane

The final step of the analysis is the comparison of the supply and demand situation in each country. For this purpose, the respective data are compared based on TYNDP 2024 scenarios that were selected as potential basis for the modelling exercise.

Figure 2-19 and Figure 2-20 compare the development of biomethane production and (natural) gas demand in BEMIP MSs for the years 2030, 2040 and 2050, respectively.

Figure 2-19: Biomethane production projections in TYNDP 2024 scenarios (Source: LBST based on TYNDP2024)

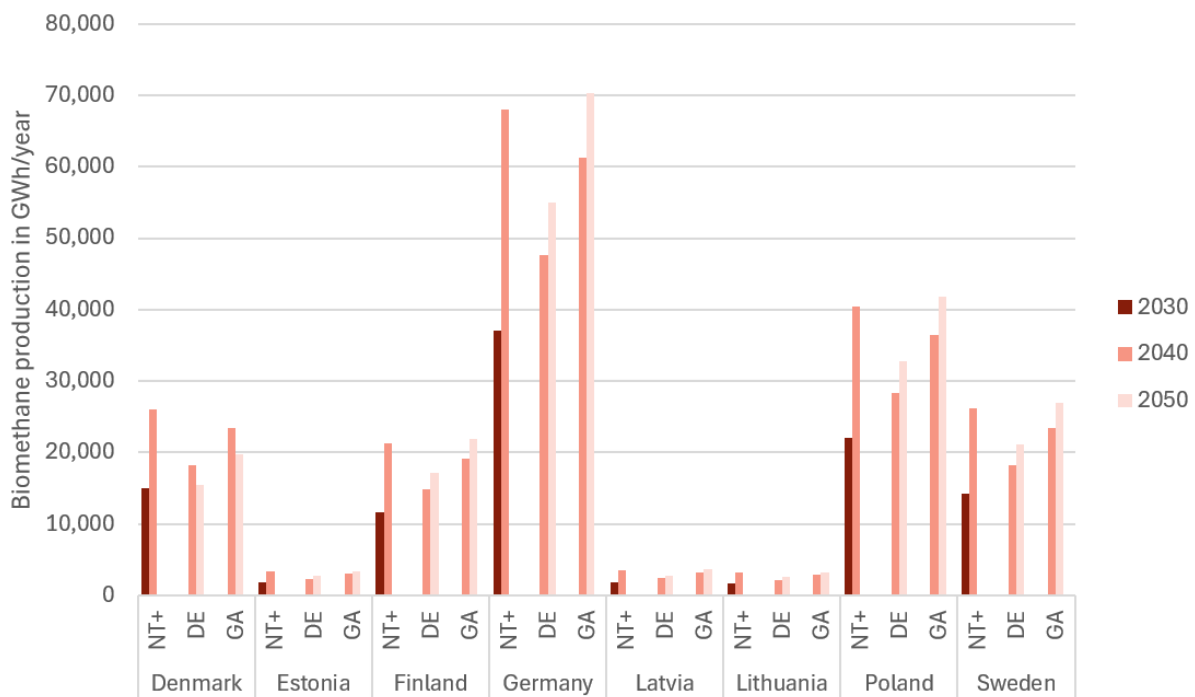
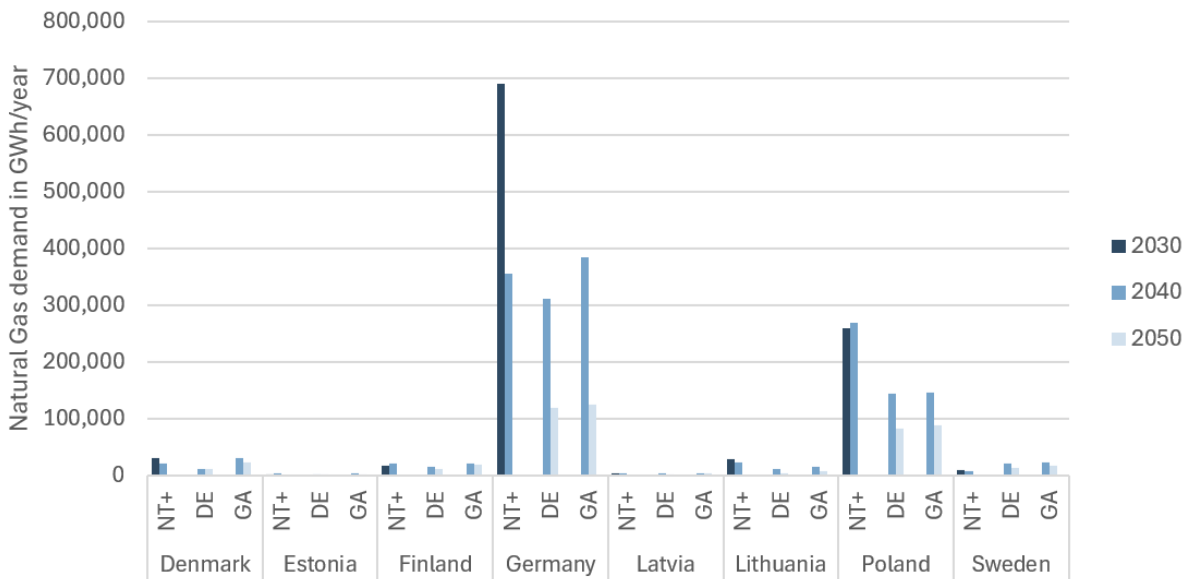


Figure 2-20: Methane demand in TYNDP 2024 scenarios (Source: LBST based on TYNDP2024)



In a second step, biomethane surplus and deficit are derived comparing projected biomethane production in those TYNDP scenarios that were selected for the baseline scenario with the overall methane demand for BEMIP MSs for the years, 2022, 2030, 2040 and 2050, respectively (see Figure 2-21 to Figure 2-24).

It should be noted that potential production of e-methane (also synthetic methane) based on renewable hydrogen and carbon dioxide are not included in this comparison. Based on assumptions in the TYNDP, e-methane is, however, projected to also contribute to domestic methane production in the future (see Table 5-1 to Table 5-3 for assumptions used for modelling).

The comparison shows that while in 2022, biomethane production is (significantly) lower than overall methane demand, this changes over time due to increasing production capacities for biomethane and continuously shrinking methane demand in all BEMIP MSs. With that, some countries like Denmark, Finland and Sweden even show small surpluses of biomethane production from 2030 onwards (for Sweden) and in 2050 (for Finland). These methane surpluses could be exported to neighbouring countries via the (natural) gas infrastructure. It should be noted, that for some countries like Denmark, more ambitious national targets have recently been formulated, indicating an export potential already from 2030 onwards (see country fiche in section 7.2). These ambitions, however, were not included in the TYNDP 2024 scenarios (yet).

In contrast to hydrogen (see section 2.2.2), the overall energy amounts for (bio-)methane needed to be imported or produced via alternative pathways (e.g. e-methane) are, however, expected to be very low, especially in the long-term until 2050 – with highest projected methane import needs for Germany (around 65 TWh) and Poland (around 50 TWh).

Figure 2-21 Biomethane surplus and deficit balance (compared to methane demand) for 2022.

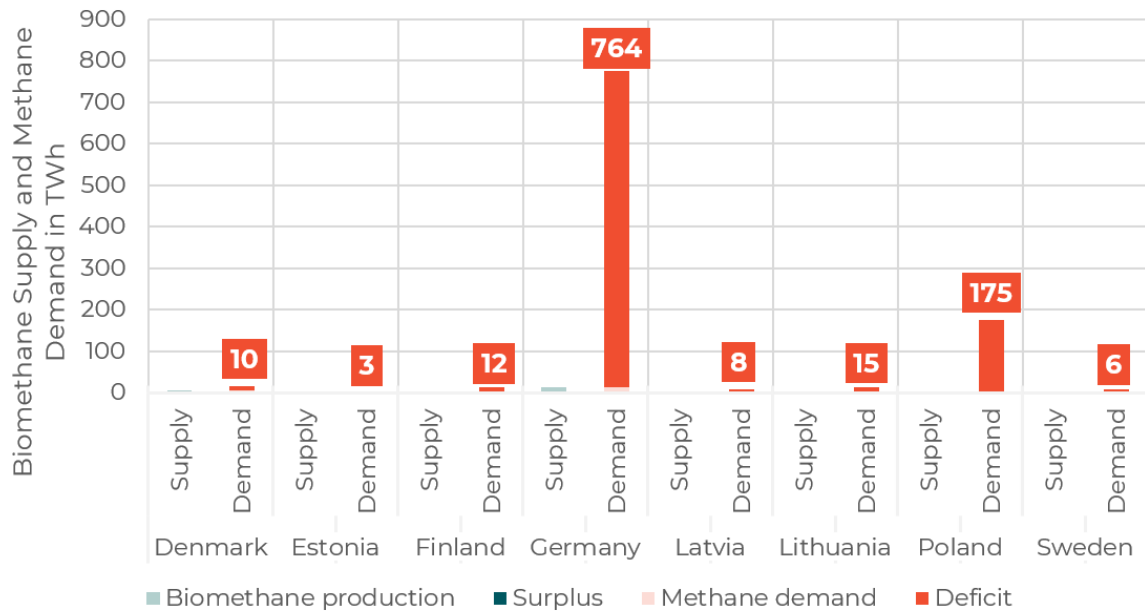


Figure 2-22: Biomethane surplus and deficit balance (compared to methane demand) for 2030 (Data source: TYNDP2024 National Trends (NT+) scenario).

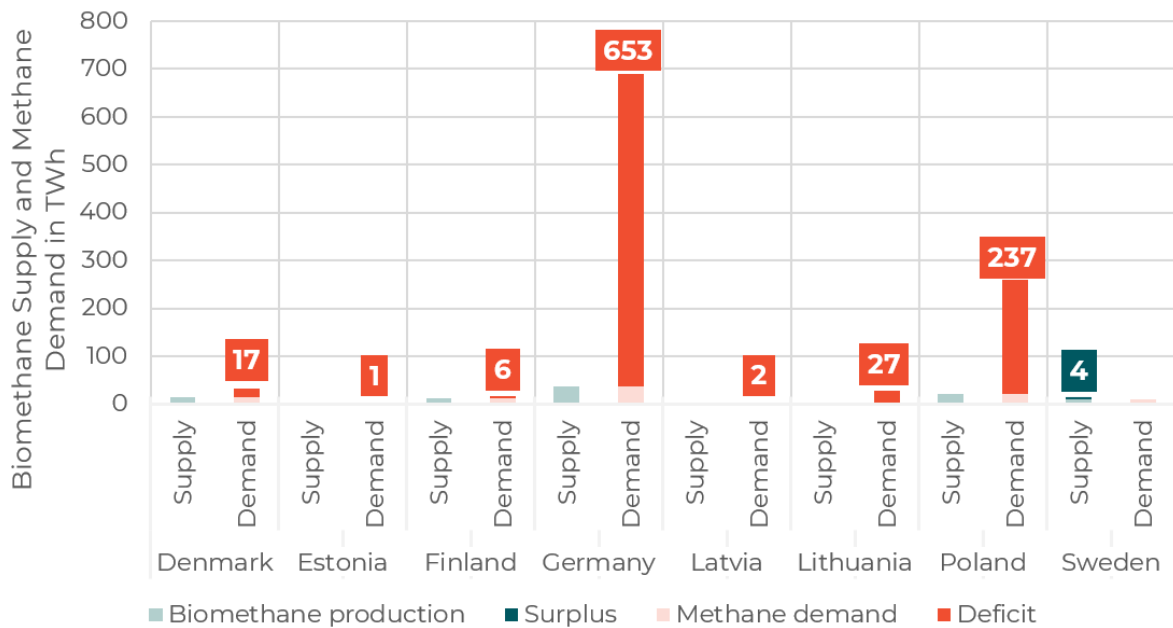


Figure 2-23: Biomethane surplus and deficit balance for 2040 (Data source: TYNDP2024 National Trends (NT+) scenario for methane demand and TYNDP2024 Distributed Energy Scenario (DE) scenario for biomethane supply).

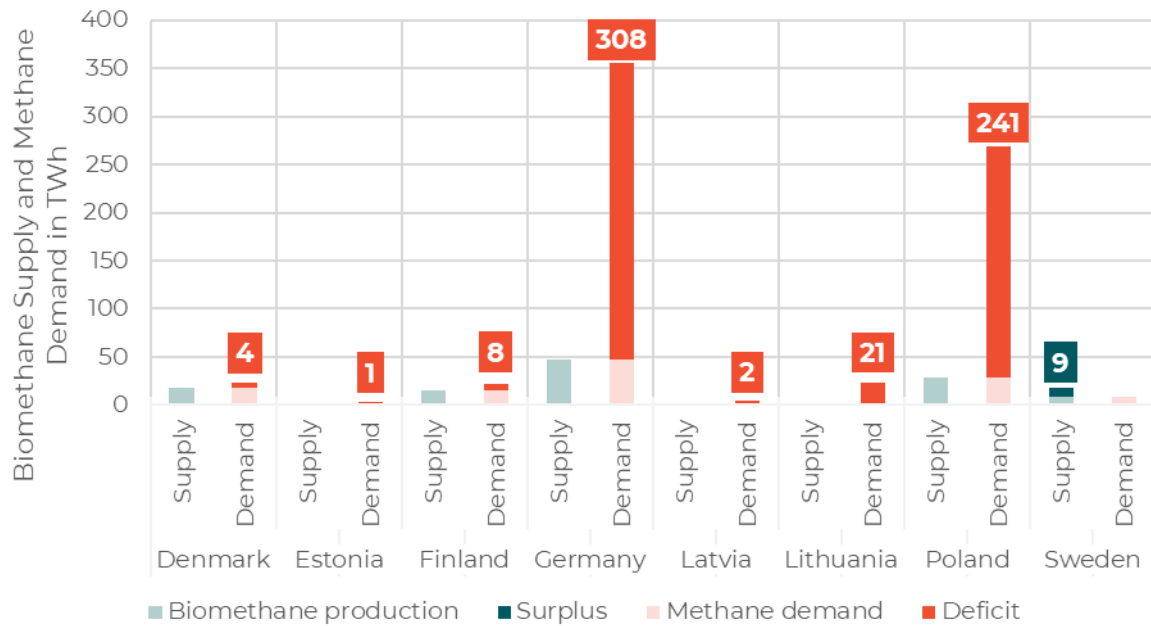
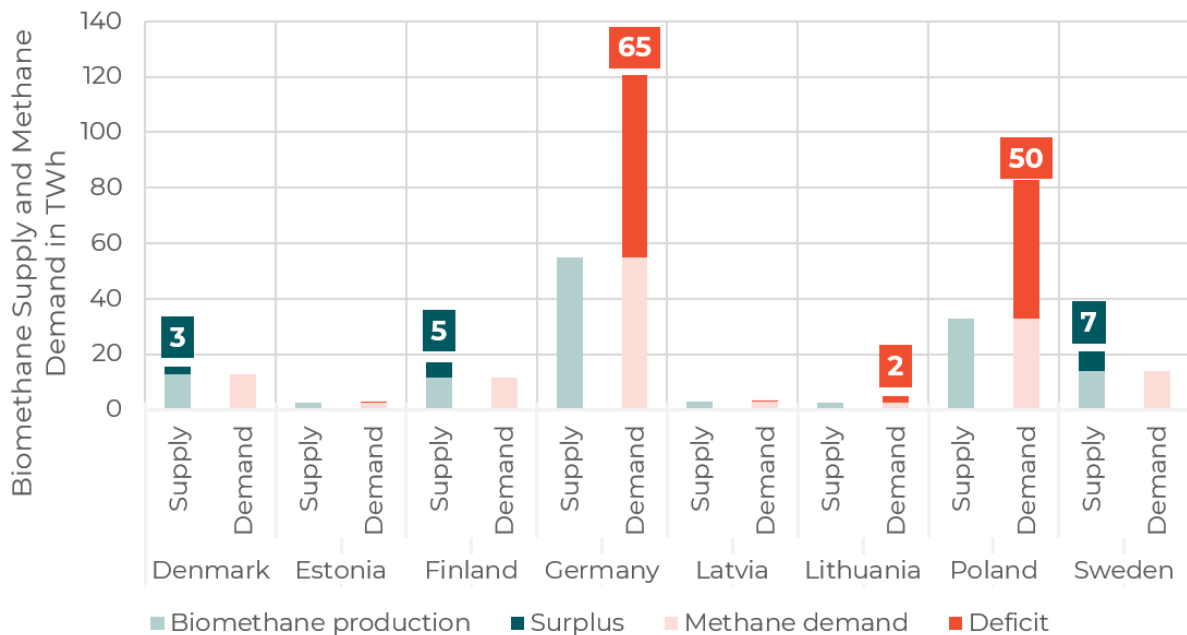


Figure 2-24: Biomethane surplus and deficit balance (compared to methane demand) for 2050 (Data source: TYNDP2024 Distributed Energy Scenario (DE) scenario).



3. Policies, measures and infrastructure plans in the BEMIP region

The BEMIP region has a complex history with natural gas, heavily influenced by its geographical and historical context. During the Soviet era, the Baltic States — Estonia, Latvia, and Lithuania — developed gas infrastructures that were deeply integrated with the Soviet system. This dependency on natural gas from Russia became visible after these nations regained independence in the early 1990s, as the existing infrastructure continued to tie them to Russian gas imports, and has gradually driven efforts to diversify gas supply routes. The opening of LNG terminals in Lithuania (Klaipėda in 2014) and Poland (Świnoujście in 2016), along with projects like new LNG terminals in Poland, Latvia, and Finland, and the Baltic Pipe project to transport Norwegian gas to Poland via Denmark (partially completed by the end of 2022), were helping the Baltic Sea region to gradually reduce its reliance on Russian gas⁴⁶.

Figure 3-1 presents the current gas transmission infrastructure in the BEMIP region. The geographic and demographic characteristics of the BEMIP MSs have significantly influenced their gas infrastructure development. Lithuania, for instance, has a relatively small but well-integrated gas network, connected to Latvia, Poland, and supported by an LNG terminal in Klaipėda⁴⁷. The country's low population density combined with strong district heating systems and energy efficiency policies, has curbed the expansion of gas infrastructure. Finland's gas grid is relatively short and primarily serves major population centres, leaving large rural areas unconnected. In Sweden, the gas infrastructure is sparse, a reflection of both geographic dispersion and a national energy strategy that favours alternatives to natural gas. Similarly, Latvia and Estonia possess less developed gas transmission networks, consistent with their smaller demand bases.

In response to the challenges posed by the reliance on Russian gas and the need for energy security, the BEMIP region has undertaken significant efforts to diversify energy sources and enhance interconnectivity. Projects like the Gas Interconnection Poland–Lithuania (GIPL)⁴⁸, which began commercial operations in May 2022, exemplify these efforts by linking the Lithuanian and Polish gas systems, thereby integrating the Baltic States into the broader European gas network.

Looking ahead, the BEMIP region is actively pursuing an integrated and decarbonized energy system. The focus is on enhancing cross-border energy infrastructure, promoting renewable energy sources, and developing strategies for decarbonizing the gas market, including the increased use of hydrogen and biomethane. The key benefits of this energy transition are discussed in the following Chapter, where the current policy landscape in the BEMIP region is presented.

First, the following Chapter discusses the rationale for the development of renewable and low-carbon gases in the BEMIP region, covering the rationale for a fuel switch from fossil gas in section 3.1 and the main policies and measures that support this fuel switch (for supply and demand in section 3.2, and for infrastructure development in 3.3). In section 9.2 of Annex C the perspectives for future regional cross-border flows of biomethane and hydrogen are discussed.

⁴⁶ DIIS (2021): [New energy technology will make the Baltic Sea Region more crisis-resilient | DIIS](#)

⁴⁷ As well as a transit line between Belarus and Kaliningrad. See at [Amber Grid's website](#)

⁴⁸ EC (2022): [Inauguration of gas interconnection between Poland and Lithuania](#)

Figure 3-1 Gas transmission infrastructure in the BEMIP region (Source: ENTSOG Transparency Platform)⁴⁹



⁴⁹ ENTSOG (2025): [Transparency Platform](#)

3.1. Key benefits and potential negative impacts of a fuel switch from fossil gas to renewable and low-carbon gases

Section 8.1 under Annex B analyses the key benefits as well potential negative impacts of biomethane and hydrogen deployment, with a focus on grid-connected supply and consumption facilities.

The presentation of key benefits provides the main arguments for the adaptation and development of methane and hydrogen networks in the BEMIP region to integrate biomethane and renewable and low-carbon hydrogen, respectively. **Key benefits of a fuel switch** to biomethane and hydrogen include:

- **Market Self-Reliance and Market Coupling:** Regional production of biomethane and hydrogen can shift the import-oriented methane market to a market, which is increasingly self-reliant. Challenges include realising the necessary infrastructure investments to integrate these gases, harmonizing gas quality, and ensuring mutual recognition of guarantees of origin.
- **Competitiveness and Affordability:** Domestic production stabilizes energy prices, increases liquidity, and reduces external dependence. However, renewable and low-carbon gases are more expensive than fossil gas, potentially impacting industrial competitiveness and household affordability.
- **Energy System Integration:** Methane and hydrogen storage provide flexibility to the power system, especially during peak demand periods. Electrolysers offer short-term demand-side flexibility, and biomethane can be used in hybrid heat pumps as a transitory solution. Finally, biomethane can allow for the continued utilisation of (part of) the methane gas infrastructure, while hydrogen can enable its repurposing.
- **Sustainability:** Substituting fossil fuels with biomethane and hydrogen reduces GHG emissions in hard-to-electrify end-uses. Biomethane use also reduces emissions of air pollutants. Sustainability benefits depend on the type of feedstock used and management practices.
- **Security of Energy Supply:** Domestic production of renewable and low-carbon gases enhances energy security by reducing import dependency and improving storage capabilities. This can mitigate risks associated with insufficient domestic supply of renewable and low-carbon gases as well as of electricity during the energy transition.

A number of **sectors can specifically benefit** from the integration of biomethane and hydrogen:

Supply side

- **Agriculture and Waste Processing:** Biogas production and local consumption offers environmental and economic benefits for farmers and waste collectors. Upgraded biomethane can substitute natural gas or be used in transportation, while by-products can substitute chemical fertilisers.
- **Equipment Suppliers:** Domestic production of renewable gases provides opportunities for companies producing and maintaining relevant equipment.
- **Methane and Hydrogen DSOs/TSOs:** The deployment of biomethane and hydrogen allows network operators to continue utilising or repurpose part of the existing infrastructure.
- **Electricity Producers:** Electrolysers using flexible electricity can improve the business case for renewable electricity production.

Demand side:

- **Industry:** Renewable gases enable industry to decarbonize processes requiring gas molecules as feedstock.
- **Transport Sector:** Biomethane and hydrogen can replace fossil fuels in transportation, though direct electrification remains more efficient for certain applications, and the optimal solution depends on many factors.

- Tertiary and Residential Users: Biomethane can decarbonize heating in buildings as a transitional solution, while hydrogen is less suitable compared to direct electrification.

The **potential negative impacts of biomethane and hydrogen integration** should also be considered as gas infrastructure development is a complex but also capital and time-intensive process, which should take place in view of concrete benefits and accompanied by appropriate policies and measures to mitigate any potential negative impacts. These potential negative impacts include the following:

- Local production could hinder market coupling if gas quality is not harmonized at the regional level.
- Regional trade could be hindered in case guarantees of origin (GOs) are not mutually recognised.
- Renewable and low-carbon gases are still more expensive than fossil gas, which could negatively affect industrial competitiveness and household affordability.
- Renewable electrolytic H₂ production can pressure electricity prices and crowd-out the direct electrification if regulation and price signals are not adequate.
- Hydrogen risks across the value chain may lead to stranded assets and compromise decarbonization efforts.
- Actual sustainability benefits depend on the feedstock type, production process and management practices for mitigating methane and hydrogen emissions.
- There is a large uncertainty regarding the future availability (and sustainability) of import sources.

There are therefore clear benefits arising from a fuel switch to biomethane and hydrogen (where energy efficiency and direct electrification are not appropriate solutions). Moreover, the potential negative impacts of such a switch can be managed with adequate policies and market design, as well as careful consideration on how biomethane and hydrogen is produced (or imported), transported, stored and used. Therefore, the EU, Member States and infrastructure operators have already adopted or are in the process of adopting a number of measures to foster the integration of biomethane and hydrogen. The following section discusses these supply, infrastructure and demand policies.

3.2. Supply and demand policies and measures

This section maps existing and planned policies, support schemes and targets for the production, import and consumption of renewable and low-carbon gases in the BEMIP region. The goal of this mapping is to identify the general trends and to draw qualitative conclusions regarding the current state and outlook of the relevant regulatory framework. This will inform the analysis of the infrastructure needs for the region, helping to gauge potential risks for specific BEMIP MSs or the region as a whole not meeting their renewable and low-carbon gas supply and demand targets. The review covers information available during the literature review of this study conducted in Q1 2024, including selected posterior developments identified by the project team or stakeholders.

The mapping includes both national initiatives (if they already exist) as well as regional ones. The policy initiatives aiming at fostering biomethane and hydrogen deployment are discussed in separate sections – with the exception of policies with a transversal scope, affecting these and possibly other carriers. These measures are listed and discussed in both sections.

The investigated policy instruments include subsidies for investment and operational expenditures (CAPEX, OPEX), supply or consumption obligations, binding and non-binding targets, tax incentives, network access conditions and tariff discounts, as well as other (indirect) measures not fitting into those categories.

Based on the analysis of the national targets, policies and measures, the following main insights can be drawn:

- With regard to its biogas/biomethane ambitions, **Denmark stands out in the BEMIP region**, while Poland also has considerable biomethane potential which however requires further policies for its exploitation.
- Regarding hydrogen targets, **Germany has the highest ambitions** in absolute terms, but Lithuania's ambitions surpass them on a per GDP basis,
- Latvia is the only BEMIP MS **without a hydrogen strategy/roadmap or targets at the moment** – the revised NECP sets the deadline for the development of an action plan for 2025,
- Most BEMIP MS have **well-defined biogas/biomethane** targets – Germany being an exemption because of its already well-developed biogas sector,
- BEMIP MS employ a **wide range of support schemes** to promote the biogas/biomethane/hydrogen value chain, including CAPEX and OPEX support, supply and consumption obligations, tariff and tax incentives,
- The targets in place with regard to renewable and low-carbon gases on the 2030 horizon in some BEMIP MS are limited to the transport sector's consumption (i.e. in Finland), which **does not necessitate a network infrastructure**,
- **Not all BEMIP MS matched their ambitions with concrete measures** so far – although further measures are announced in the latest NECPs (e.g. Sweden).

3.2.1. Supply and demand policies for biomethane

Table 3-1 below provides the biomethane targets or projections (extracted from NECPs) determined by the BEMIP MS. Germany seems to have no recently-defined biomethane production/consumption target for the 2030-time horizon – having an already well-developed biogas sector with the largest number of operational biogas plants in Europe (electricity output of 31.7 TWh/year of which 2.9 TWh/year is biomethane).

Table 3-1 Biomethane production and consumption targets or projections

BEMIP Member State	2030 production target [bcm]	2030 consumption target [bcm]
Denmark	1.8	-
Estonia	0.04	-
Finland	0.38	-
Germany	.. ⁵⁰	-
Latvia	0.09	-
Lithuania	0.13	-
Poland	0.99	-
Sweden	0.94	-
Total for the BEMIP region	4.37	

The sum of the national targets or projections for biomethane production in the BEMIP region for 2030 add up to 4.37 bcm (or 43 TWh) (without a value for Germany), compared to a biomethane production of 21.6 TWh in 2022 (see section 2.3.1)

Denmark has the most ambitious biomethane targets in the 2030-time horizon based on the published and reviewed policy documents, and the aim to replace all fossil gas with biomethane by 2030 (38% share in the grid in 2024). The government promotes biogas as a mean to achieve not only carbon-neutrality but also energy independence from Russian gas supplies. To fulfil this ambition, the Danish government introduced a number of additional schemes in 2023, aimed at (1) the incentivisation of suppliers of biomethane to the natural gas grid in a bidding scheme (where

⁵⁰ The German updated 2024 National Energy and Climate Plan indicates that while “every year, 600 MW of installed biomethane capacity is put out to tender. The Renewable Energy Sources Act does not provide for a specific expansion target for biomethane alone.”
Federal Ministry for Economic Affairs and Climate Action (2024): [Update of the Integrated National Energy and Climate Plan](#)

suppliers bidding for the lowest unit amount of subsidy win, the programme running until 2029)⁵¹, (2) a more gradual lowering of the energy crops limit in biogas production⁵², and (3) increasing the use of straws in biogas production instead⁵³. Furthermore, it introduced a mapping of the potential for the decommissioning of (sections of) the natural gas distribution network⁵⁴.

As an efficiency measure, in 2023 the Danish Energy Agency also issued a regulation⁵⁵, containing requirements for the annual review of biogas production plants in view of limiting methane leakages (estimated at 2.5% of the biomethane produced⁵⁶).

As an indirect support measure, the government also specified its ambition to phase out natural gas boilers in households by 2035. Part of this measure includes support for municipalities in developing their heating plans, and in reaching out to their residents who, according to official data sources, use fossil fuel-based technologies for meeting their heating needs.

The Danish Climate Agreement on Green Power and Heat from 2022 set the ambition for the country to completely phase out fossil gas use by 2030⁵⁷. This ambition has been reiterated in the recent revision of Denmark's NECP⁵⁸. These projections are also in line with the Danish Climate Status and Projection (KF) by the Danish Energy Agency for 2024,⁵⁹ expecting biomethane production to match gas demand by 2029 already (aided by production side support measures, delivering 1.4 billion m³ of biogas, according to the latest NECP).

As **Germany** has an already well-developed biogas/biomethane sector (producing about 1/3 of the EU-27's biomethane output⁶⁰), the government does not seem to focus on further development through dedicated governmental subsidies and policy measures⁶¹. The German Renewable Energy Sources Act has been in force since 1 April 2000, offering feed-in tariffs for the suppliers of renewable electricity – including biogas producers⁶². Due to the termination of this support after 20 years, a shift from electricity production to biomethane injection could become interesting for several plants in the coming years.

Poland, having one of the largest sustainable biomethane potential, has a guaranteed feed-in tariff scheme similar to that of Germany's, promoting all renewable electricity sources – among them biogas/biomethane⁶³. Apart from this, in 2021 the government initiated and accepted an agreement for cooperation in the development of the biogas and biomethane sectors with interested stakeholders⁶⁴ and in its most recent NECP it pledges CAPEX support for the establishment of agricultural biogas plants of up to 50 kW.⁶⁵ Furthermore, from 2025 onwards, for all renewable generators – including biogas –, a new fixed revenue support scheme will be introduced.

In **Sweden** – already a frontrunner in biomethane implementation in the transport sector – while the set target is relatively ambitious, there is only one support scheme announced by the government, available for the upgrading of biogas to biomethane, and for the production of biogas itself from 2024 onwards.

Estonia had a biomethane production subsidy in force since 2018 – the scheme was scheduled to end in 2024. In its draft updated NECP, the government announced additional support measures,

⁵¹ ENS (n.d.): [Støtteudbud til biogas og andre grønne gasser](#)

⁵² KEFM (2023): [Ny aftale understøtter produktion af dansk biogas](#)

⁵³ ENS (2023): [Ny rapport undersøger udfordringerne ved øget brug af halm i biogasproduktion](#)

⁵⁴ Evida (2023): [Indledende screening af gasdistributionssystemet](#)

⁵⁵ Danish Energy Agency (n.d.): [Metantab fra biogasanlæg](#)

⁵⁶ Danish Energy Agency (2021): [MÅLRETTET INDSATS FOR AT MINDSKE METANTAB FRA DANSKE BIOGASANLÆG](#)

⁵⁷ Government of Denmark (2022): [Klimaaftale om grøn strøm og varme 2022](#)

⁵⁸ European Commission (2024): [Final update of Denmark's National Energy and Climate Plan for the period 2021-2030](#)

⁵⁹ Danish Ministry of Climate, Energy and Utilities (2024): [Climate Status and Projections 2024](#)

⁶⁰ European Commission (n.d.): [Biomethane fiche - Germany \(2021\)](#)

⁶¹ Sesini et al. (2024): [Unlocking European biogas and biomethane: Policy insights from comparative analysis](#)

⁶² IEA (2014): [Renewable Energy Sources Act \(Erneuerbare-Energien-Gesetz EEG\)](#)

⁶³ European Biogas Association (s.d.): [Renewable Energy Act approved by the Polish parliament](#)

⁶⁴ Ministry of Climate and Environment Republic of Poland (2021): ['Agreement on cooperation for the development of the biogas and biomethane sectors' has been signed](#)

⁶⁵ Ministry of Climate and Environment Republic of Poland (2024): [National Plan in the field of Energy and Climate by 2030](#)

including (1) an exemption for biogas from excise duties, and (2) funding from the EU's RRF for investment support in biogas production and uptake outside the transport sector.

Finland has a state-funded infrastructure support programme for alternative fuels infrastructure (electricity, biomethane, hydrogen). A total of approximately € 35 million was allocated to subsidies for 2022–2023 and a total of € 10 million has been reserved for 2024 for the same purpose.

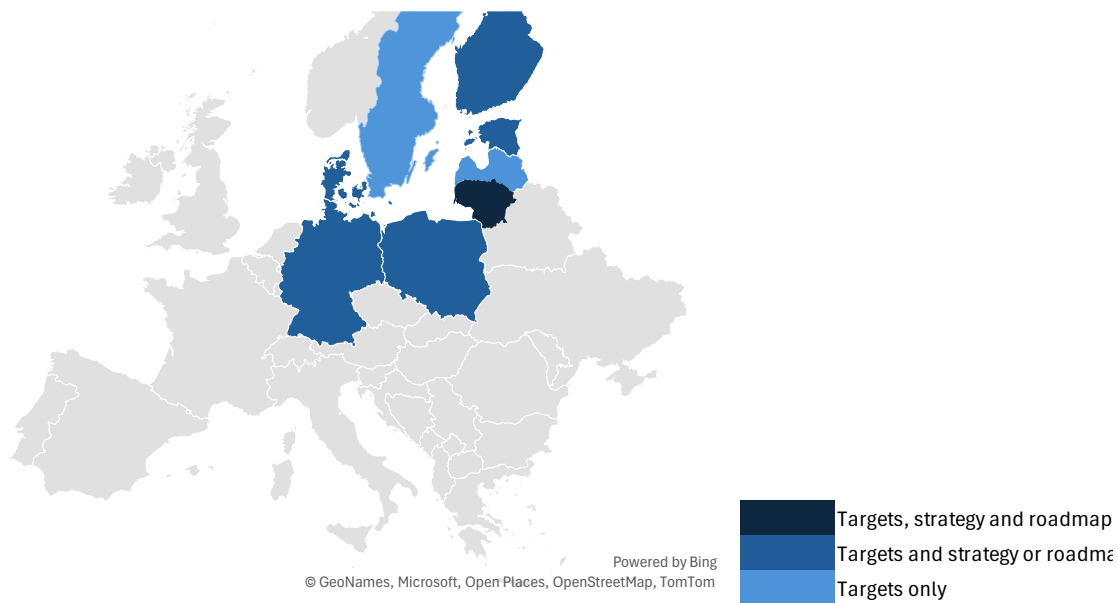
In **Lithuania**, the country having a significant sustainable biomethane potential, the government introduced a supply obligation (increasing share from 4% in 2025 to 16.8% in 2030) for natural gas retailers to include biomethane in their supplied natural gas. There also exists an investment support scheme for biomethane production facilities and a scheme aimed at municipalities to replace their public transport vehicles with vehicles using alternative fuels.

In **Latvia**, the updated National Energy and Climate Plan lists a measure targeting the installation of at least 7 new biomethane producers and also connection of at least 7 to the gas grid, as well as the production of at least 210 GWh of biomethane. It also indicates the aim to promote biogas and biomethane use in agricultural production, ensure the extraction of biogas/biomethane in wastewater treatment plants, and designate renewable acceleration areas, including for biomethane production.⁶⁶

3.2.2. Supply and demand policies for hydrogen

Figure 3-2 below summarises the state of specific hydrogen policy documents within the BEMIP MSs based on the existence of a (1) comprehensive **strategy**, (2) implementation **roadmap**, and/or (3) specific **targets**, published or endorsed by the respective national governments. The BEMIP MSs are all highlighted, and the Member States with a darker shade are most advanced in terms of specific hydrogen policy documents. Seven out of eight BEMIP MS fit at least two criteria, with Lithuania having all; a strategy, a roadmap and well-defined targets. Six BEMIP MS had in 2024 already published a national hydrogen strategy (Lithuania's strategy being the most recent) – the exceptions are Latvia, and Sweden, the Latvian government having announced that such initiative will be taken before the end of 2025, and Sweden having proposed but never officially adopted a comprehensive hydrogen strategy.

Figure 3-2 State of specific national hydrogen strategies, roadmaps and targets in BEMIP MSs



⁶⁶ Climate and Energy Ministry (2024): [Final Updated National Energy and Climate Plan](#).

Table 3-2 contains the summary of targets set by BEMIP MSs in their publicly available documents (hydrogen strategies, latest updates of their National Energy and Climate Plans). Few of the BEMIP MSs have published a hydrogen target beyond 2030 in their NECPs, with the exception of Lithuania (which indicates a need of up to 24.16 TWh in that year). Nonetheless, they may have published national targets or forecasts in other documents – however, even forecasts reported by Member States are in many cases derived from scenarios developed by network operators, rather than from analysis and targets developed by policymakers.⁶⁷

Furthermore, some Member States specify targets regarding installed electrolyser capacities, but not renewable and low-carbon hydrogen produced – in these cases, the targets in the table are calculated based on specific assumptions (detailed below). Also, the definition of renewable hydrogen as used by BEMIP MSs is not necessarily fully in line with the delegated act on a methodology for renewable fuels of non-biological origin (RFNBOs), and therefore the targets are hard to compare.⁶⁸

Table 3-2 Renewable and low-carbon hydrogen production and consumption as specified in the national hydrogen strategy targets or in the updated NECPs

Member State	2030 production [TWh]	2030 consumption [TWh]
Denmark	11.0-24.3*	-
Estonia	1.332	0.033
Finland	-	-
Germany	26.8-40.5*	130
Latvia	-	-
Lithuania	4.3	2.9
Poland	-	10
Sweden	12.12-18.15**	-

*Calculated target numbers based on 68% electrolyser efficiency and a load factor of 46-68%.

**The share of renewable and low-carbon hydrogen within the target is dependent on the share of renewable electricity used – often not explicitly specified within the strategic documents (ACER, 2024)

Finland is the only BEMIP MS that – despite having a national hydrogen strategy (published in 2023) – has no general hydrogen production nor consumption target. The Finnish strategy rather limits itself to a specific e-fuels target (3% share of renewable hydrogen in transport fuels by 2030).

The **German** government has the highest ambitions in absolute terms regarding the future hydrogen economy reflected both in the production and consumption targets mentioned in the published documents. This ambition is backed by the highest number of State aid schemes within the EU (and consequently the BEMIP region) – 18 of them approved as of September 2024.

Sweden and **Denmark**, building on the Baltic Sea's offshore wind energy potential, also set high (renewable) hydrogen production targets already by 2030 – without specifying consumption targets. The Danish government's ambition is backed by three approved State aid schemes, whereas Sweden recently announced a number of policy measures, including two tax incentive schemes in its updated NECP, aimed at hydrogen mobility applications (use of hybrid and hydrogen cars, and refuelling infrastructure), investment subsidies in the hydrogen value chain (production, storage, transport and applications) and the Industrial Leap action to decarbonise industrial processes. However, the development of its offshore wind potential has been halted by security/national defence concerns of the Swedish government (end of 2024).

The **Danish** Climate Agreement on Green Power and Heat from 2022 set the ambition for the country to be 100 % fossil gas free by 2030⁶⁹. This ambition has been reiterated in the recent revision of

⁶⁷ See for example European Commission (2024): [Hydrogen and electrolyzers cross-regional meeting](#)

⁶⁸ ACER (2024): [Market monitoring report 2024 - European hydrogen markets](#)

⁶⁹ Government of Denmark (2022): [Klimaafale om grøn strøm og varme 2022](#)

Denmark's NECP⁷⁰. It must be noted that the largest potential for offshore wind in Denmark lies in the North Sea, although the potential of Baltic waters is still significant.

Within the BEMIP region, **Estonia** is relying mostly on CAPEX support in kick-starting its future hydrogen economy – with eight existing schemes mainly aimed at the transport sector (purchasing of hydrogen fuelled vehicles and investments in refuelling stations) and the chemical industry.

Finland employs a wider variety of schemes – three involving OPEX support, a (non-binding) target of 200 MW electrolysis capacity by 2025 and 1000 MW by 2030 paired with CAPEX support, and a consumption obligation for e-fuels – apart from four other schemes involving some CAPEX support. The recently launched Clean Industrial Investment Support Programme provides tax breaks for industrial investments in low-carbon industrial production processes via electrification or the use of hydrogen. Altogether, seven such policies exist currently aimed at the market development of renewable and low-carbon hydrogen/gases.

Furthermore, in 2022 Finland introduced the Energy Investment Aid scheme to award funding from the EU Recovery and Resilience Facility (RRF). The scheme provides around € 540 million in funding for energy investments, including energy infrastructure, the deployment of new energy technology, hydrogen, CCU and the electrification of industries. The funding is granted in 2021–2024 and the funded projects must be finished by 2026.

Similarly to Estonia, **Lithuania** also relies mostly on CAPEX support schemes and targets its transportation sector in the development of a local hydrogen economy (a scheme aimed at municipalities to replace their public transport vehicles with vehicles using alternative fuels, i.e. hydrogen), with three schemes dedicated to investments in refuelling and airport infrastructures, and one scheme for the uptake of hydrogen production capacities. Furthermore, as part of the European Hydrogen Bank's Auction-as-a-Service scheme, Lithuania is dedicating € 36 million in the form of a production subsidy, to help developing additional electrolyser capacities, backed by the Innovation Fund⁷¹.

The **Polish** government provides R&D support to prepare for the deployment of renewable hydrogen in the Polish heating sector. In its updated NECP, the government also announced a contracts for differences (CfD) scheme for hydrogen producers, and CAPEX support for the development of hydrogen infrastructure (including production, transmission and storage). Like in Lithuania, the government also provides support to the municipalities in replacing their rolling stock with hydrogen fuelled vehicles.

Few specific policies and measures aimed at the deployment of the hydrogen economy have been identified in **Latvia**. The updated 2024 National Energy and Climate Plan lists several measures targeted on the transport sector, but also for example a measure for setting up pilot projects for hydrogen and e-methanol production.

3.2.3. Summary of supply and demand policies and gaps

Several gaps can be identified in the supply and demand side policies when it comes to renewable hydrogen and biomethane within the BEMIP region.

For biomethane, up until the start of the energy crisis in 2022 a general lack of government support (especially for deployment beyond electricity production, and in comparison to other RES), and a lack of a harmonised European regulatory framework⁷² made the competition with much cheaper natural gas detrimental for the more general adoption in the past decades. The government policies on biomethane also lacked the scope and neglected to focus on the entire value chain – subsidising mainly production (and successfully offsetting investment costs) but ignoring the end-use and feed-

⁷⁰ European Commission (2024): [Final update of Denmark's National Energy and Climate Plan for the period 2021-2030](#)

⁷¹ European Commission (2024): [Joint press release by the Commission, Spain, Lithuania and Austria on the European Hydrogen Bank's 'Auctions-as-a-Service' scheme, increasing the funding for clean investments](#)

⁷² Sesini et al (2024): [Unlocking European biogas and biomethane: Policy insights from comparative analysis](#)

stock availability⁷³. Sweden and Lithuania both have significant targets in biomethane (and in renewable hydrogen) production, yet no specific support schemes have been announced until September 2024⁷⁴.

For hydrogen, the diverging methodologies in the target-setting make it difficult to compare even the existing targets (which are already lacking beyond the 2030 time-frame) among BEMIP MS. Some only set production capacity targets (i.e. Denmark and Germany), others do not make a clear distinction between renewable and non-renewable hydrogen in their target numbers, nor do they set clear pathways for the decarbonisation of (future) hydrogen production (i.e. Sweden). These practices make it challenging to track and measure the governmental ambition against either the collective EU targets for renewable gases, or the estimated/projected needs of the BEMIP region as a whole, increasing the uncertainty in collaborative and integrated market planning across the region. Strategic coordination beyond 2030 would allow avoiding temporal mismatches between the emerging demand of BEMIP MS and the supply to meet this demand with intraregional (BEMIP) production, as demonstrated in Chapter 2 of this report – this would also avoid potential negative impacts on the emerging transmission infrastructure and its utilisation.

While a wide variety of support schemes in BEMIP MS exist to promote the renewable and low-carbon hydrogen economy along its entire value chain (including CAPEX and OPEX support, consumption obligations and schemes to encourage the switch to RFNBO fuelled vehicles) within the region, the amount of support made available via these schemes does not always seem to match the declared governmental ambitions. In Germany, a recent study commissioned by the Association of Water and Energy Industries (BDEW) revealed that the uncertainty regarding the demand for and profitability of hydrogen investment options (in this case, storage specifically) still plays a major role in the (delayed) decision-making of market participants. According to the BDEW, the current level of state support in Germany would be insufficient and new financing mechanisms would be necessary to enable a timely ramp-up of hydrogen storage capacities⁷⁵.

Similarly, the Finnish government recently (in 2023) accepted a resolution asserting the country's potential to become a 'European leader' in the hydrogen economy via producing up to 10% of the EU's renewable hydrogen in 2030 already⁷⁶, yet the government does not seem to have any binding production or consumption targets/obligations, beyond the transportation sector (3% share in supplied fuels). Some of these MS have been announcing the roll-out of new support schemes only recently, in their latest NECPs, making the feasibility of their 2030 targets questionable. Furthermore, while Germany and Poland both emerge as large hydrogen importers of the region based on projections and decarbonisation targets (both MS having a significant, hard-to-decarbonise industry), only Germany has a clearly defined import target and an import strategy to meet its future hydrogen needs. Finally, as of now, six out of the eight BEMIP MS (Denmark, Estonia, Finland, Germany, Latvia and Lithuania) have designated issuing bodies of guarantees of origin for renewable gases in accordance with the Renewable Energy Directive Art. 19 of the EU⁷⁷.

3.3. Network infrastructure-related policies and measures

This section introduces the existing and planned policies and support schemes for the deployment and development of network infrastructure to transport renewable and low-carbon gases in the BEMIP region.

First, the section provides an overview of the countries' strategic documents as the main source of information. Strategic documents encompass the latest available NECPs, national hydrogen strategies, and National Network Development Plans (NDPs). The thematic scope of this section

⁷³ *idem*

⁷⁴ ACER (2024): [European Hydrogen Markets - 2024 Market Monitoring Report](#)

⁷⁵ BDEW (2024): [Aufbau von Wasserstoffspeichern gelingt nur mit maßgeschneidertem Finanzierungsmechanismus](#)

⁷⁶ Finnish Government (2023): [Government adopts resolution on hydrogen – Finland could produce 10% of EU's green hydrogen in 2030](#)

⁷⁷ S&P Global Commodity Insights (2024): [Renewable gas tracking systems – Value of biomethane/RNG certificates](#)

concentrates on the planning and support instruments that target infrastructural development (therefore excluding demand and supply-side measures, which are addressed in Section 2.3).

3.3.1. Hydrogen network development

The BEMIP MS exhibit varying degrees of development in their biomethane and hydrogen infrastructure network planning. Cross-border cooperation and infrastructure planning are central to the region, with a number of initiatives aimed at enhancing system integration between Member States. Key developments include agreements and planning frameworks that prioritize both carriers, albeit with different levels of progress across the countries.

Network planning processes

While the overall regulatory framework for the planning of hydrogen infrastructure is defined at the EU level, most BEMIP MSs lack such a national framework, with the exception of Germany and Denmark (which will have to adapt their frameworks in line with the respective approved EU legislation). Moreover, Poland has proposed in May 2024 amendments to its Energy Law to create a regulatory framework, which were expected to be adopted by the end of the same year.

The BEMIP MS are also at different stages regarding the development of a vision for creating an overall hydrogen strategy, which of course affects the development of an infrastructure planning framework.

The table below summarises the information available for Germany, Denmark and Poland, and the subsequent text provides further identified information for the BEMIP region. A number of main insights can be drawn from this information:

- Germany is most advanced regarding network planning, with a regulatory framework in place (which will need to be adapted to comply with the new EU rules), financing and risk-sharing mechanisms for the development of a hydrogen core network in place, as well as a detailed submitted hydrogen network development plan⁷⁸;
- Denmark and Poland seemingly aim to implement a fairly straightforward regulated framework for their transmission hydrogen network operators (HNO), although the specific financing and risk-sharing mechanisms need to be further specified in the case of Poland;
- In Germany, Denmark, Finland and Poland existing natural gas TSOs play a central and for the latter three Member States even an exclusive role in developing the hydrogen backbone. The German planning framework is more complex due to the existence of multiple transmission HNOs, which coordinate their network planning in one coordinating entity;
- Regulatory frameworks address cross-border cooperation through the issuance of mandates for cooperation to the transmission HNOs. Of course, the European Network of Network Operators for Hydrogen (ENNOH) and the development of the 2026 integrated Ten-Year Network Development Plan will constitute the main channel for regional planning of the European hydrogen network. Denmark conditions the final investment decision on its West Backbone on capacity bookings.

⁷⁸ FNB (n.d.): [Hydrogen core network - FNB Gas](#)

Table 3-3 Planned/existing H₂ network planning framework in Germany, Denmark and Poland

Aspect	Description
Germany⁷⁹	
Applicability	Operators of hydrogen networks can declare to the NRA (Federal Network Agency / BNetzA) that their hydrogen networks should be subject to regulation (called ' opt-in declaration '). Hydrogen core network operators will automatically be subject to respective hydrogen network regulation in the future
Transmission HNO designation	Multiple HNOs with one coordinating entity (FNB Gas)
Horizontal unbundling	Ownership unbundling from H ₂ terminals, storage and distribution
Third party access (TPA) rules in transition phase	Negotiated TPA
Network planning and build-up	Integrated gas and H ₂ network planning set in law. Electricity and Gas TSOs develop 2025 scenario frameworks to be approved by BNetzA. The scenario frameworks support a bi-annual integrated gas, electricity and hydrogen network development plan to be approved by the NRA, based on a single network model.
Network planning oversight	NRA approves NDP. Ad-hoc, needs-based assessment process in place for approving new hydrogen network infrastructure applications. Repurposed gas pipelines are preferred to newly built ones.
Repurposing of natural gas assets	About 60% of core network will consist of repurposed natural gas pipelines.
Tariff setting	Conditions for determining the allowed recoverable costs, including depreciation, are regulated by the Hydrogen Network Tariffs Ordinance .
De-risking	During the ramp-up phase, there will be an intertemporal cost allocation mechanism in place to provide financial certainty for investors and operators. This includes capping network fees to make up for initial lower demand, and an amortisation account to compensate these operators for the difference between their actual costs and the revenues obtained from the capped fees.
Considerations for distribution networks	Most provisions in place or proposed refer only to hydrogen TSOs. Hydrogen DSOs are nonetheless required to prepare network development plans and contribute to the joint network development plan, and negotiated TPA also applies to hydrogen distribution networks.
Denmark^{80,81,82}	
Applicability	Applicable to all HNOs (mainly Energinet and Evida)
Transmission HNO designation	Energinet to be certified as transmission HNO
Horizontal unbundling	Legal unbundling, with Energinet establishing a subsidiary.
TPA rules in transition phase	Regulated TPA
Network planning and build-up	Investment decision on Jutland network to be taken based on future business case. Depending on lack of robustness of business case (committed capacity bookings) network development could be broken down in phases/areas. Investment decision depends on network users committing financially and legally for a minimum of 10-15 years to purchase a minimum of 1.4 GW (0.5 GW in the case of the German interconnector 'The Seven') of hydrogen capacity annually in a pipe with a hydrogen capacity of 3 GW. Energinet reached an agreement with the German HNO Gasunie Deutschland in early 2025 for the interconnection with Germany (see text below)
Network planning oversight	To be defined
Repurposing of natural gas assets	Southern part of Danish Hydrogen Backbone should be composed of repurposed pipeline but there is no specific national regulatory framework in place for this yet.

⁷⁹ Trinomics and LBST (2024): [Current status of the hydrogen markets and their regulation in France, the Netherlands and Germany](#)

⁸⁰ Danish Ministry of Climate, Energy and Utilities (2025): [Bred politisk aftale om milliarder til brintør til Tyskland](#)

⁸¹ Danish Ministry of Climate, Energy and Utilities (2024): [New hydrogen agreement paves the way for a new, green export adventure and local growth](#)

⁸² [Gas supply act](#) of 2023

Tariff setting	Revenues defined using revenue cap methodology, approved by regulator. Revenue framework developed in cooperation with the Danish Energy Agency and industry. Two-year regulatory period without efficiency requirements initially.
De-risking	Inter-temporal cost allocation mechanism approved by regulator to allocate risks between State, Energinet and network users, five conditions laid out for state funding ⁸³ . For the hydrogen pipeline from Esbjerg to the German border: DKK 7.4 billion (€991 million) in investment loan Up to DKK 8.3 billion (€1.11 billion) in operational subsidies over a 30-year period Up to DKK 0.4 billion (€54 million) coverage of stranded costs in case of political decision to cancel project in case of insufficient demand in 2026 capacity sale Simplification of procedures for permitting and obtention of right of way
Considerations for distribution networks	Evida planning to be certified as distribution HNO.
Poland⁸⁴	
Applicability	Applies to the single hydrogen/combined network operator and all distribution HNOs. New or repurposed hydrogen networks with operating pressure not exceeding 5 bar and hydrogen connections and purification devices with capacity not exceeding 250 kgH ₂ /day require only notification. Specific derogations also possible for geographically confined hydrogen networks. ⁸⁵
Transmission HNO designation	A single hydrogen or combined system operator will be designated
Horizontal unbundling	Legal unbundling
TPA rules in transition phase	Regulated TPA
Network planning and build-up	10-year NDP developed every 2 years Hydrogen Authority draws up development plan for meeting current and future hydrogen demand for at least 4 years
Network planning oversight	NDP approved by regulator
Repurposing of natural gas assets	Includes process for eventual transfer of assets from gas to hydrogen network operator, based on a cost-benefit analysis and impact assessment of the measures
De-risking	No specific provisions identified

Sources: own data collection on sources indicated and ACER (2024) Market monitoring report 2024— European hydrogen markets

In addition to the adopted or proposed regulatory frameworks in Germany, Denmark and Poland, the following further developments should be noted:

- **Denmark and Germany** signed a Joint Declaration of Intent in March 2023, in which the parties commit to support the deployment of hydrogen infrastructure between Denmark and Germany with a view to establishing a border-crossing hydrogen infrastructure linking Danish green hydrogen producers with German consumers. A renewed political agreement from February 2025⁸⁶, backed by a state loan and operational subsidies from the Danish government, will provide DKK 7.4 billion (€ 991 million) and up to DKK 8.3 billion (€ 1.11 billion) in operational subsidies over a 30-year period for the a hydrogen pipeline from Esbjerg to the German border ('The Seven') to enable the transport of green hydrogen by 2030.
- **Nine TSOs from the BEMIP MSs** signed in June 2024 a Memorandum of Understanding aiming to coordinate and facilitate hydrogen infrastructure and market development in the Baltic Sea region⁸⁷.

⁸³ *Five conditions* have been named for Energinet to access state funding as of February 2025, which we also introduce below.

⁸⁴ Polish Ministry of Climate (2024): *Draft act amending the Energy Law and certain other Acts*

⁸⁵ CMS Law-now (2024): *Poland to create regulatory environment for development of hydrogen market*

⁸⁶ Danish Ministry of Climate, Energy and Utilities (2025) *Bred politisk aftale om milliarder til brintør til Tyskland*

⁸⁷ Gaz-system (2024) *Gas transmission system operators from the Baltic Sea region have signed a Memorandum of Understanding to accelerate the development of hydrogen infrastructure*

- **Germany** focusses in the 2024-2030 period on building import infrastructure directly into Germany and encourages the planning and establishment of EU-wide hydrogen networks, including interconnections from outside of the EU into EU MS, e.g. from Algeria via Tunisia to Italy, eventually reaching Germany via Austria (and Switzerland)⁸⁸.
- The **Finnish TSO** Gasgrid Finland has been tasked with developing a national hydrogen network, cooperating on international infrastructure and supporting the development of the Baltic Sea hydrogen market⁸⁹.
- **Lithuania** has adopted Hydrogen Roadmap and Action Plan with an outlook to 2050 in 2024⁹⁰ with the participation of its TSO. The implementation plan has been published for public consultation, and a strategic environmental impact assessment of the plan has been carried out. The Roadmap sets out to establish a legal framework for the production, transport storage and use of H₂, with no concrete date. Lithuania's gas NDP also includes dedicated hydrogen pipeline projects - as well as **Latvia's**⁹¹.
- **Sweden** does not have an extensive natural gas grid that can be repurposed for hydrogen transport, however, plans are underway for a northern hydrogen pipeline to support industrial decarbonization in the steel sector, and feasibility studies are being conducted for a national hydrogen grid, though no formal timeline has been set⁹². The Swedish Energy Agency has already called for the development of a dedicated hydrogen regulatory framework by 2030⁹³.

It is interesting to note that a requirement is proposed in the political agreement that conditions the FID of the Danish Hydrogen Backbone on Energinet and the German TSO Gasunie achieving an agreement.⁹⁴ **Specifically, the 2nd economic framework conditions for hydrogen infrastructure indicates the following five conditions for Energinet having access to State financing:**

- Before Energinet's final investment decision, users contractually commit financially and legally for a minimum of 10-15 years to purchase a minimum of 0.5 GW of hydrogen capacity annually in a pipe with a hydrogen capacity of 3 GW
- Energinet establishes a wholly owned and legally and financially separate subsidiary, without a parent company
- Energinet and Gasunie sign a contract for a hydrogen interconnection between Denmark and Germany, which is mutually binding for both parties
- The state financing contribution must be assessed as financially responsible and not compromise other expenses from the state budget
- In the case of flexible tariffs, the Danish energy regulatory approves a revenue model for hydrogen infrastructure that allows inter-temporal cost allocation, with under-recovery of revenues in the early stages of deployment compensated by over-recovery in later stages

Finally, the Danish TSO Energinet has recently postponed the roll-out of the interconnector from 2028 to 2030 because 'several activities on the critical path have proven to be more extensive and time-consuming than originally anticipated'^{95,96}.

Repurposing existing methane infrastructure

Repurposing existing natural gas infrastructure to transport hydrogen is a key strategic direction in the national strategies for developing a hydrogen network in many EU Member States. In the BEMIP

⁸⁸ Federal Ministry for Economic Affairs and Climate Action (2023): [National Hydrogen Strategy Update - NHS 2023](#)

⁸⁹ European Hydrogen Observatory (2024): [The European hydrogen policy landscape- April 2024 \(Report 02\)](#)

⁹⁰ Amber Grid, EPSO-G (2022): [Lithuanian Hydrogen Sector Development Roadmap and Action Plan for its Implementation](#)

⁹¹ ACER (2024): [Opinion on the review of gas and hydrogen national Network Development Plans to assess their consistency with the EU Ten-Year Network Development Plan](#)

⁹² IVL Swedish Environmental Research Institute et al. (2024): [The Potential of Hydrogen in a Swedish Context](#)

⁹³ Swedish Energy Agency (2024): [Hydrogen and Hydrogen Infrastructure in the Swedish Energy System](#)

⁹⁴ Danish Ministry for Climate, Energy and Utilities (2024): [New hydrogen agreement paves the way for a new, green export adventure and local growth \(kefm.dk\)](#)

⁹⁵ Energinet (2024): [Energinet's market dialogue on hydrogen infrastructure has been closed, the booking requirement recalculated, and the schedule updated](#)

⁹⁶ Reuters (2024): [Denmark postpones green hydrogen transmission roll-out to Germany to 2031](#)

region, concrete plans to repurpose natural gas pipelines for hydrogen transport are limited to Germany (where the approved core hydrogen network⁹⁷ comprises a majority of sections from repurposed natural gas pipelines), Poland (section connecting the NBHC with Gdansk-Kosakowo) and Denmark (where the southern end of the West backbone should be developed with repurposed pipelines)⁹⁸.

In Poland, repurposing forms an important element of the future network development (with specific mechanisms proposed in legislation to regulate the transfer of assets), and Lithuania also plans to adapt their existing natural gas infrastructure to hydrogen transport in several stages, starting with further assessing the technical parameters for the economic feasibility of repurposing pipelines⁹⁹. This will include assessing technical solutions for integrating the Klaipėda LNG terminal into the hydrogen value chain, possibly making it an industrial hydrogen hub. Information on repurposing is not available from other BEMIP MS.

Appropriate planning for repurposing or eventual decommissioning of gas infrastructure, on both transmission and distribution levels, needs proper consideration of competing uses of the infrastructure for the integration of biomethane or pure hydrogen. Section 3.3.2 below details concerns of biomethane stakeholders in Germany to the repurposing of part of the gas distribution system for the integration of hydrogen.

Financing and cost recovery

The future of European hydrogen infrastructure will largely depend on availability of funding and the funding mechanisms¹⁰⁰, with significant public finance needed due to market immaturity and high upfront costs. Some key market risks impacting hydrogen infrastructure projects at the present time include uncertainties regarding the pricing and volume of capacity bookings for pipelines, terminals, reconversion, and storage facilities. In conventional infrastructure projects, price risks are usually managed by regulatory authorities through established and regulated network tariffs. However, in the emerging hydrogen economy, uncertainty about future capacity bookings and overall utilisation—particularly during the ramp-up phase—remains a significant risk. Containing network tariffs in the ramp-up phase in order to attract further network users and thus increase network utilisation (thereby distributing network costs across a larger user base) is a central challenge. Besides market risks, there are further political, regulatory, permitting and technological risks that affect the enabling environment for infrastructure projects¹⁰¹. Countries have developed different ways to deal with this financial challenges.

A recent study by Trinomics, Artelys and LBST on the investment needs of European energy infrastructure¹⁰² tried to estimate investment needs into hydrogen infrastructure using a combination of bottom-up and top-down approaches, using project-based planning data, risk and maturity assessments, and financial viability studies. The study shows that hydrogen infrastructure shows substantial investment needs EU-wide, with planned investments equalling to approx. €170 billion between 2024-2040, the majority of which is dedicated to pipelines (€105.2 billion) built in the period 2024-2034¹⁰³. Funding sources include EU funds, national support schemes, private investments, loans, and guarantees. The BEMIP region's planned and estimated investments according to the study total to approximately €55 billion in this timeframe, as shown on Figure 3-3.

⁹⁷ FNB (n.d.): [Hydrogen core network - FNB Gas](#)

⁹⁸ Energinet (2024): [Information Package 1 - Danish Hydrogen Backbone](#)

⁹⁹ Roadmap for Hydrogen Development in Lithuania 2024-2025

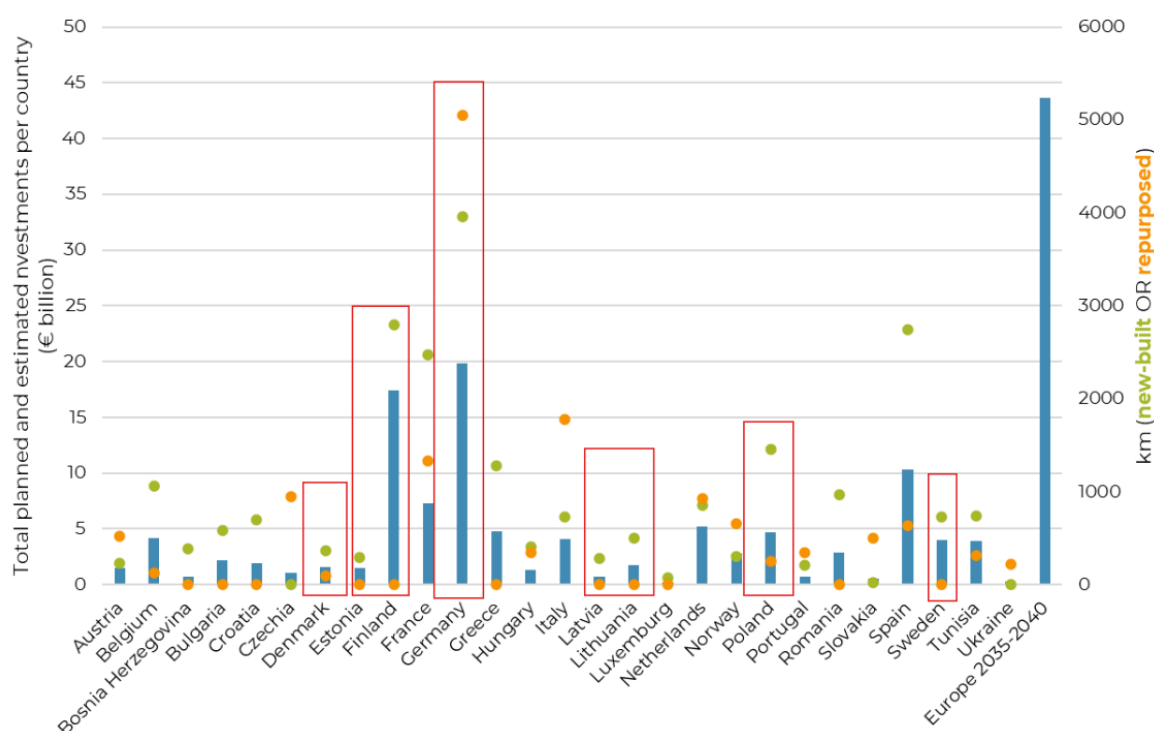
¹⁰⁰ Hydrogen Europe (2024): [Hydrogen Infrastructure report](#)

¹⁰¹ H2Global (2024): [Bridging the gap: Mobilizing investments in hydrogen infrastructure](#)

¹⁰² Trinomics, Artelys and LBST (2025): [Investment needs of European energy infrastructure to enable a decarbonised economy](#)

¹⁰³ Please note that the methodology for the referenced study differs from the methodological basis of this current study, as it includes internal pipelines; whereas our assessment for pipeline needs in BEMIP for 2030, 2040 and 2050 only cover cross-border pipelines.

Figure 3-3 Cumulated investment needs (planned per country until 2034, estimated (Source: Trinomics, Artelys and LBST)



Up until now, only a few BEMIP MSs have defined to some extent the framework for financing the development of hydrogen networks.

At the EU/regional level, there are multiple funding sources available that generally apply to specific both hydrogen and biomethane projects, which we detail in the next section. Furthermore, the **IPCEI Hy2Infra programme** (Important Projects of Common European Interest) as part of the Recovery and Resilience Facility provided a framework allowing the provision of State aid by Member States to hydrogen infrastructure projects.

Of the BEMIP MSs, **Germany** has nine approved IPCEIs (while Poland has one electrolyser project approved). In Germany, hydrogen IPCEIs representing 2,700 km (about 27% of the proposed core hydrogen network) are co-financed by the government (handed out through the Federal Ministry for Economic Affairs and Climate Action (BMWK) and the Federal Ministry for Digital and Transport (BMDV) and the Bundesländer, with 70% of funding from the federal government and 30% from Bundesländer (regional) governments.¹⁰⁴

The **German hydrogen core network** that has been approved by the NRA¹⁰⁵ consists of a 9,040 km pipeline system, transports hydrogen from interconnection points and production plants to industrial and urban centres. About 60% of the network will consist of repurposed natural gas pipelines. The total German hydrogen core transmission network is estimated to cost € 20 billion in its current shape, with commissioning starting in 2025 and intended completion planned by 2032 (but with some flexibility to achieve completion by 2037). To address potential mismatches between transported volumes and costs, an intertemporal cost allocation mechanism has been developed. This mechanism includes a “ramp-up” tariff, which starts below cost-reflective levels and gradually increases as the transported volumes grow. If the demand lags, the German government and network operators will share the risks of uncovered costs, with the state covering up to 76% of any deficit by 2055 if demand projections and respective cost recovery through tariffs are not met. The

¹⁰⁴ Federal Ministry for Economic Affairs and Climate Action(2024): [European Commission gives the go-ahead for the funding of 24 German IPCEI hydrogen projects](#)

¹⁰⁵ FNB (n.d.): [Hydrogen core network - FNB Gas](#)

mechanism also includes an amortisation account, which records the gap between revenues generated by the ramp-up fee and approved costs. The mechanism is supposed to provide financial certainty for early-stage investments while distributing costs over a longer timeline, reducing risks for both investors and operators. The first payments from this account have successfully been rounded up in early 2025¹⁰⁶.

As indicated above, in the case of **Denmark**, the February 2025 political agreement further details the specific model for the state's risk coverage of Energinet's investment in a hydrogen backbone, with both an investment loan and an operational subsidy foreseen for the Esbjerg to Germany section, as well as a guarantee for covering any stranded costs in case of a political decision to cancel the project if no sufficient capacity is booked in 2026¹⁰⁷.

Finland has allocated funding for instruments which support among other activities also capital expenditures of hydrogen and biomethane projects and related network infrastructure. The Energy Investment Aid scheme allocated € 540 million for clean energy investments with projects being commissioned by 2026 (financed from EU Recovery and Resilience Facility (RRF) funds)¹⁰⁸. A support program for alternative fuels infrastructure also allocated approximately € 35 million to subsidies to these carriers between 2022-2023. Tax breaks are also granted for large-scale investments (min. € 30 million) in the form of tax breaks, valid for investments made before end 2025¹⁰⁹.

No dedicated financing framework has been identified for the other BEMIP MSs.

3.3.2. Methane gas network development for the integration of biomethane

Network planning processes

Country-specific insights

Network planning approaches and the regulatory landscape across the BEMIP region is highly varied, with different levels of depth and maturity in supporting network planning for biomethane integration. While the REPowerEU Biomethane Action Plan¹¹⁰ defines multiple actions and the broader EU legislative framework (e.g., revised Gas and Hydrogen Directive and Regulation) includes provisions which should promote the integration of sustainable biomethane, national regulations vary significantly, including on infrastructure aspects. Achieving the 35 bcm biomethane production target by 2030 of the REPowerEU Plan¹¹¹ requires clear, streamlined national regulations, particularly in areas such as grid access, injection and grid quality standards, and support mechanisms. Below is an analysis of key regulatory frameworks specific to biomethane infrastructure in the BEMIP MSs.

Denmark has a clear strategy to phase out gas from space heating, with related network decommissioning ongoing, which makes them lead among the BEMIP MSs in network planning for biomethane integration. Policies and investments announced will support the country's NECP target to cover 100% of gas in the Danish gas system with green gases in 2030, and enable exports after this date¹¹². This involves upgrading existing methane pipelines and constructing new sections to ensure efficient biomethane transport.¹¹³ Other investments focus on grid upgrades, reverse flow¹¹⁴ capabilities to allow flows from the distribution to the transmission level, and direct injection from local production sites into the gas grid.

¹⁰⁶ BMWK (2025): [Finanzierung des Wasserstoff-Kernnetzes: Die erste Auszahlung an die Wasserstoff-Kernnetzbetreiber aus dem Amortisationskonto ist erfolgt](#)

¹⁰⁷ Danish Ministry of Climate, Energy and Utilities (2025): [Bred politisk aftale om milliarder til brintør til Tyskland](#)

¹⁰⁸ European H₂ observatory (2024): [The European hydrogen policy landscape](#)

¹⁰⁹ Finnish Ministry of Economic Affairs and Employment (2024): [Government Decree - Support Programme for Industrial Investments in the Clean Transition](#)

¹¹⁰ European Commission (2022): [Commission Staff working document on implementing the REPowerEU Plan : Investment needs, Hydrogen Accelerator and achieving the biomethane targets](#)

¹¹¹ Biomethane - European Commission (europa.eu)

¹¹² Energinet (2024): [Long-Term Development Plan 2024 towards 2050](#)

¹¹³ Biogas Danmark (2023): [Biogas Outlook 2023](#)

¹¹⁴ DSO to TSO level flows

Denmark has set transparent frameworks for infrastructure development, including TSO-DSO cooperation, a legal right for producers to inject biomethane¹¹⁵, and cost-sharing mechanisms. The Danish Energy Agency issued methane loss regulations in 2023 to identify and avoid methane emissions from biomethane plants, requiring annual reviews and a self-monitoring program to minimize methane leaks during production.

With its 'legal right to inject' policy for biomethane, producers have guaranteed access to the gas grid. Standardized connection terms and a transparent cost-sharing framework further incentivize biomethane production. Furthermore, according to Denmark's NECP, the TSO has reserved a virtual entry point for biomethane in order to enable its participation in wholesale markets.

Germany's TSOs are required by the Energy Industry Act to draw up a joint Network Development Plan (NDP)¹¹⁶ for methane gas and hydrogen¹¹⁷. For now, biomethane is integrated into the broader methane gas network planning of the gas TSOs. Biomethane, hydrogen and synthetic gas are taken into account in the modelling of the current German gas NDP of 2022.¹¹⁸ Integrated planning of hydrogen pipelines with the methane gas network development planning is important, as any repurposing of methane pipelines for hydrogen transport requires integrated and iterative modelling of the transmission networks. This planning process will support a hydrogen ramp-up in parallel to the supply and transit of methane, and help networks to adapt to an increasing supply of biomethane, synthetic methane and LNG in the future.

Finland's National Energy and Climate Plan (NECP) supports biomethane production¹¹⁹ primarily for use in the transport sector and includes measures to support biomethane production and its integration into the gas network. Infrastructure planning seems to focus on expanding bio-CNG and bio-LNG networks.¹²⁰ The national biogas roadmap aims for 4 TWh per year of biogas production by 2030, with most of it upgraded to biomethane¹²¹.

Latvia emphasizes in its NECP the role of biomethane in energy and transport systems¹²², particularly as transport fuel and for the substitution of natural gas. The NECP aims to modernize the Latvian transmission infrastructure to accommodate renewable gases and support the integration of biomethane into the gas system through infrastructure development and bio-CNG transport. However, long-term plans for biomethane integration beyond 2030 remain less well-defined.

Lithuania's NECP refers to the planned revision of the regulatory framework to enable public biomethane access points¹²³, which would connect producers located far from gas networks to inject biomethane without the need for direct pipeline connections. This measure is intended to reduce infrastructure costs, because the development of dedicated pipelines for biomethane has been assessed as too expensive. The Law on Alternative Fuels¹²⁴ mandates 5.2% renewable gases in the transport sector by 2030, and imposes gas suppliers to support biomethane in transport, which is a key regulatory step to encourage its use.

Poland already has applicable regulation¹²⁵ in place for the definition of biomethane and its production activities, administrative procedures for production authorisations, and gas grid quality requirements. Ongoing amendments to its NECP¹²⁶ and the Polish Energy Policy (PEP) will likely result in updated assumptions and principles for network planning. Regarding cross-border networks, agreements made with the Danish and Ukrainian TSOs aim at promoting biomethane as

¹¹⁵ 'Right to inject' policy: upgrading plants have the right to be connected and to inject into the gas grid. Terms of connection are standardized.

¹¹⁶ FNB (2022): [Network Development Plan 2022 - FNB Gas](#)

¹¹⁷ BNetzA (n.d.): [Network development plan gas/hydrogen](#)

¹¹⁸ FNB (2022): [Network Development Plan 2022 - FNB Gas](#)

¹¹⁹ European Commission (2024): [Finland- Final updated NECP 2021-2030](#)

¹²⁰ Gasum (2020): [Finland's national biogas programme strengthens the role of biogas in transport emission reduction effort](#)

¹²¹ Finnish Biocycle and Biogas Association (Biokertu) (2022): [National Biogas Roadmap Finland](#)

¹²² Latvian Ministry of Economy (2021): [National Energy and Climate Plan for 2021-2030](#)

¹²³ Ministry of Energy (2023) [Updated National Energy and Climate Plan](#)

¹²⁴ OECD (2021): [Lithuania's Law on Alternative Fuels](#)

¹²⁵ Gas System Regulation update as of 2022

¹²⁶ As of early June 2025, Poland has not submitted their final updated NECP yet

means of decarbonization. The operational Poland-Lithuania Gas Interconnector (GIPL) does enable potential cross-border biomethane trade, but dedicated policies to fully facilitate this trade are not yet properly developed.

Sweden currently lacks policies or measures specifically targeting network planning for biomethane, despite its interest in green gases.

Challenges of decommissioning gas infrastructure

The decommissioning of natural gas infrastructure, as planned due to the gradual phase-out of fossil natural gas, presents a significant challenge to biomethane integration, considering the reliance of its transport on existing gas distribution (and partly transmission) networks. Therefore, paradoxically, the phasing out of these networks without establishing alternative solutions could hinder the deployment of biomethane and impact RES targets. The necessity for gas distribution grids varies geographically, depending on factors such as the availability of biological feedstock for biomethane production, existing alternative infrastructure, and regional energy demand. Areas with substantial agricultural activity or waste resources may have higher potential for biomethane production, making the retention or adaptation of gas distribution networks more critical in these regions, while demand is anticipated to decrease due to the transition to electrified heating. Conversely, urban areas transitioning to electrified heating solutions and/or district heating systems may find the decommissioning of gas grids more feasible. As part of the EU Gas and Hydrogen Package, Directive (EU) 2024/1788 obliges gas grid operators to draw up decommissioning plans by 2026¹²⁷.

Germany has initiated plans for the gradual decommissioning of its gas distribution network to facilitate a transition to climate-neutral heating. On the municipal level, cities like Mannheim have announced plans to decommission their gas grids by as early as 2035¹²⁸, encouraging residents to adopt alternative heating systems such as heat pumps. The local utility recommends that customers begin exploring alternative heating options early to avoid increased costs associated with a dwindling user base and rising CO₂ emission expenses. A green paper on gas grid decommissioning¹²⁹ released by the German Federal Ministry for Economic Affairs and Climate Action (BMWK) emphasizes the need to ensure a continuous, affordable energy supply during this transformation and acknowledges the necessity of protecting grid operators from financial losses during this transition. The German Biogas Association has expressed significant concerns regarding the BMWK's proposed strategy to decommission parts of the gas distribution network and reallocate sections from methane to hydrogen, claiming that the chances of Germany switching from fossil methane to renewable methane are not being practically considered. They stress that decisions on replacing natural gas with renewable methane should be made locally within municipal heat planning frameworks and aligned with broader network planning. Preserving existing transmission networks is deemed essential to meet supra-regional demand, facilitate imports and transits, and utilize the gas network's storage capacity.

After having decommissioned most of its gas distribution grid for residential use, Denmark maintains its gas infrastructure for larger consumers. Developments suggest that the country is focusing on adjusting and expanding its gas infrastructure to accommodate biomethane: in regions like Lolland-Falster, Energinet and Evida have initiated projects to establish a green gas grid to enable local biomethane production and offer industrial consumers a more climate-friendly production source. The project connects Lolland-Falster to the existing gas grid on Zealand via a new pipeline, facilitating the distribution of green gas to end consumers¹³⁰.

Reverse/cross-border flows and other aspects

¹²⁷ European Union (2024): [Directive \(EU\) 2024/1788 on common rules for the internal markets in renewable and natural gases and in hydrogen](#)

¹²⁸ Clean Energy Wire (2024): [German city announces decommissioning of gas grid by 2035, encourages heat pump purchases](#)

¹²⁹ BMWK (2024): [Green Paper on the Transformation of Gas and Hydrogen Distribution Networks](#)

¹³⁰ Energinet (2024): [Green Gas Lolland-Falster](#)

Biomethane's integration into existing gas transmission grids is increasingly favoured, as it is fully compatible with existing natural gas transmission infrastructure and end-use equipment and thus can serve as direct substitute for natural gas without any repurposing or adaptation costs, if it meets the applicable gas quality standards. Several studies also mention the ease of upgrading biogas from various feedstocks into biomethane for injection into grids, which is considered a cost-effective method for biomethane production, including in countries like Poland¹³¹. Countries like Denmark and Germany have well established biomethane injection practices¹³², while other BEMIP MS are in the process of developing the necessary regulatory framework to integrate biomethane.

Managing **oxygen levels from biomethane injection into methane transmission networks** is important. At present, managing gas quality across international borders with different national oxygen level requirements is a resource-intensive task. The existing gas quality standards were established when only natural gas was transported in the European gas network. The increasing injection of biomethane (and in some BEMIP MSs also synthetic methane) into this system can alter the quality of the gas that is transported and consumed across Europe. To ensure biomethane meets the required gas quality standards, sulphur must be eliminated, which in many cases is achieved through the addition of oxygen, resulting in higher oxygen levels in biomethane compared to natural gas. Differing national gas quality specifications levels (e.g. in terms of maximum oxygen level) can hinder cross-border trade of gas. This and other technical bottlenecks to biomethane integration are further detailed in section 9.5.

Denmark has observed significant increases in biomethane production, with a 52% rise between 2019 and 2020. This penetration of biomethane is supported by the comprehensive regulatory framework described above, however properly planning the investments to enable reverse flows is still a challenge, and the unpredictability of biomethane projects' timelines makes it difficult for Energinet to prioritize between projects. The text box below illustrates the challenge of handling different oxygen levels at interconnection points, and solutions implemented by Energinet, as they have reported to ENTSG¹³³.

Germany has a well-developed network to accommodate biomethane integration, including arrangements to enable reverse flows between distribution and transmission networks where required. However, technical challenges remain, particularly in harmonizing gas quality standards with neighbouring networks (specifically Denmark's) to enable cross-border flows. Despite these challenges, Germany's infrastructure is capable of managing large volumes of biomethane, with regulatory frameworks supporting grid injection. A key issue according to German stakeholders is the cost-sharing between producers and grid operators, as grid upgrades and injection points require significant investments.

Latvia is advancing in biomethane injection, with Conexus Baltic Grid developing biomethane injection points for producers far from the transmission network. This coordinated approach allows producers to inject biomethane at designated points¹³⁴, enabling its integration into the grid. Despite expectations from the TSO that all produced biomethane could be injected in the grid, Latvia lacks a legal framework for off-grid biogas/biomethane accounting and use. Latvia plans to implement further regulations under the Law on Energy, facilitating biomethane use in transport and gas networks.

Poland is still in the early stages of biomethane integration. Biomethane connections to either TSO or DSO networks do not yet exist, and the primary challenge is the uncertainty around the scale of production and its potential, and the high assumed cost of connecting production sites to the gas network, which is considered as a barrier preventing integration of biomethane into the natural gas system. GAZ-SYSTEM, the Polish TSO, is working on solutions to overcome these barriers.

¹³¹ EBA (2024): *Biogases towards 2040 and beyond*

¹³² Bioenergy Europe (2022): *Statistical Report 2022*

¹³³ ENTSG(2022): [Oxygen handling at Interconnection Points](#)

¹³⁴ Conexus (n.d.): [Biomethane injection points](#)

Managing oxygen levels at interconnection points: Energinet's approach

Danish TSO Energinet has reported on the challenges faced in handling varying oxygen levels at interconnection points where Denmark's gas grid connects with those of neighbouring countries. These variations arise due to the increasing share of biomethane injected into the grid, which has a higher oxygen content than conventional natural gas. The need to balance free gas flow across borders while maintaining independent, green gas supplies presents a regulatory and technical challenge.

Energinet operates six interconnection points, with entry points from Norway, the North Sea, and Germany, and exit points to Sweden, Poland, Germany, and to the Danish DSO. The oxygen content in gas at these points varies:

- **Norwegian gas:** ~0.001% oxygen
- **Danish North Sea gas:** <0.1% (effectively close to 0%)
- **Germany:** 0.001%
- **Sweden:** 0.5%
- **Poland:** 0.2%
- **Storage facilities:** peaks of 0.5%, averaging 0.1% annually
- **Danish DSO:** 0.5%

To accommodate biomethane injection, the TSO has had to install four reverse flow stations to manage supply while preventing excessive oxygen content from affecting transmission system operation. To address these challenges, Energinet has implemented specific infrastructure solutions at different interconnection points:

- **Germany:** given its strict oxygen threshold, Energinet has developed targeted infrastructure adaptations to ensure compliance with German regulations.
- **Poland:** Energinet has integrated additional operational tools in case a "biomethane pocket" would enter the Baltic Pipe system from Poland.
- **Sweden:** through collaboration between Swedish TSOs and end-users, Sweden has been able to increase its oxygen acceptance level, accommodating the rise in biomethane use.

Sweden's biomethane integration into the methane network is nascent and involves the need to install compressors to enable reverse gas flows (from DSO to TSO level) in locations where biomethane injection exceeds local usage in the DSO network. As Sweden does not have an extensive gas network, the potential to value its biomethane production via the gas grid is limited.

Financing and cost recovery

Similarly to hydrogen, biomethane infrastructure deployment largely depends on the availability of financing, with anticipatory investments and the right support mechanisms serving as a crucial factor. Currently, the BEMIP MSs are at different stages of developing funding mechanisms to support the infrastructure deployment and integration of biomethane (and hydrogen). BEMIP MSs have a number of available mechanisms, often relying on a combination of public and private investments, while EU funds also play a critical role.

EU-level funding

EU-level funding mechanisms focus on financing projects that contribute to the decarbonization of energy systems, including biogas production, upgrading to biomethane quality, and integration into existing gas networks.

➤ Connecting Europe Facility (CEF) – Energy¹³⁵

CEF generally supports cross-border energy infrastructure projects that contribute to the EU's energy policy objectives. It provides funding for Projects of Common Interest (PCIs), which include smart gas grid projects that aim to enable and facilitate the integration of renewable and low carbon gases, including biomethane, into existing gas networks. Biomethane projects that have received the PCI status can apply for CEF funding. This is especially relevant for cross-border biomethane infrastructure or investments to facilitate reverse flows in gas networks.

➤ Innovation Fund (IF)¹³⁶

Managed by the European Commission, this fund is one of the largest EU funding programs for innovative low-carbon technologies, which is financed through revenues from the EU Emissions Trading System (ETS). The fund supports projects aimed at decarbonizing heavy industries and fostering renewable and low-carbon hydrogen and biomethane production. The Innovation Fund can support the construction and upgrading of biomethane production facilities (including from waste¹³⁷), integrating biomethane into energy networks, and scaling up technologies related to renewable gases.

➤ European Regional Development Fund (ERDF)¹³⁸

ERDF helps finance projects that boost economic and social cohesion across Europe. It allocates funds to regional projects, including renewable energy infrastructure such as biomethane plants and networks, with a focus on promoting the sustainable energy transition at local and regional levels. ERDF can co-finance biomethane infrastructure, particularly in regions with high renewable potential. This includes technologies for upgrading biogas, systems for the injection of biomethane into gas networks, and pipeline extensions to facilitate biomethane integration.

➤ Recovery and Resilience Facility (RRF)

The RRF is an instrument of the NextGenerationEU plan, which provides financial support to EU Member States for sustainable recovery from the COVID-19 pandemic. RRF funding is tied to National Recovery and Resilience Plans (NRRPs), many of which include renewable energy targets such as biomethane production and integration. Biomethane infrastructure, including upgrading plants and injection into national gas grids, can be financed through the RRF if included in the NRRPs.¹³⁹ RRF funds have a fixed spending timeframe however and thus do not provide continuous financial support.

Latvia is set to receive €134.4 million from the REPowerEU plan, which will be invested in improving energy security and, among others, supporting biomethane production. This funding is part of broader efforts under the RRF and aims to enhance Latvia's renewable energy capabilities, particularly in developing the biomethane sector¹⁴⁰.

➤ Horizon Europe¹⁴¹

Horizon Europe, the EU's research and innovation funding program, includes a focus on energy transformation. It supports research and demonstration projects that promote new technologies and solutions for biomethane production, storage, and integration into existing networks. Horizon Europe funds innovation projects related to biomethane, including upgrading biogas to biomethane, enhancing injection systems, and developing new business models for cost recovery of biomethane infrastructure.

¹³⁵ European Commission (2024): CEF Guidelines [Energy Infrastructure - European Commission](#)

¹³⁶ European Commission (2024): [Innovation Fund projects - European Commission](#)

¹³⁷ See Spanish grid-compliant landfill gas project supported by the IF by European Commission / CINEA (2024): [W4W: upgrading landfill gas into grid-compliant biomethane](#)

¹³⁸ EUR-LEX (2024): [Summaries of EU Legislation - European Regional Development and Cohesion Funds \(2021–2027\)](#)

¹³⁹ European Commission (2024): [Recovery and Resilience Facility](#)

¹⁴⁰ Ministry of Economics of the Republic of Latvia (2024): [Latvia to invest EUR 134.4 million in energy security and biomethane production](#)

¹⁴¹ European Commission (2024): Horizon Europe [Cluster 5: Climate, Energy and Mobility](#)

➤ Just Transition Fund (JTF)¹⁴²

The goal of the JTF is to finance green transition projects, including renewable energy projects, such as biomethane plants. JTF can fund biomethane projects in transition regions, focusing on helping regions shift from fossil fuels to renewable gases and creating the necessary infrastructure to inject biomethane into gas networks.

National financing mechanisms

Governments and system operators have different ways of supporting network development and de-risk investments into infrastructure projects.

Finland's Infrastructure Support Programme for Alternative Fuels allocates state funding for biomethane, hydrogen, and electricity infrastructure. The program, which provided € 35 million in subsidies for 2022–2023 and € 10 million for 2024, supports the expansion of biomethane production and its use in transport, particularly bio-CNG and bio-LNG infrastructure.¹⁴³

Estonia has passed legislation to support large investments in biomethane infrastructure, particularly focusing on advancing biomethane production and building a network of filling stations. The government is also promoting the use of biomethane in public transport, demonstrating a strategic approach to integrating biomethane across multiple sectors.¹⁴⁴

Denmark used to operate a super shallow¹⁴⁵ cost-sharing framework to facilitate biomethane injection into the grid. Producers financed the cost of upgrading biogas to biomethane and the connection of the plant to the network, while grid reinforcement investments, such as reverse flow and compression, were financed by DSOs and TSOs and recovered through the tariff system. In 2025, an access tariff for producers has been introduced which does recover some of the system-related costs.

Poland currently uses a deep cost recovery¹⁴⁶ model, where the high cost of connecting biomethane production facilities to the grid is primarily recovered from producers. This has been a major barrier to biomethane integration, and efforts are underway to address this issue through updated regulatory and financial frameworks¹⁴⁷.

3.3.3. Summary of infrastructure-related policies and gaps

The BEMIP region faces a range of challenges in network planning for the integration of biomethane and developing hydrogen infrastructure, incl. for example harmonised standards, supply and demand uncertainties but also a heterogeneous regulatory environment. Regulatory uncertainty is a challenge, especially around cross-border infrastructure for both biomethane and hydrogen. Varied national priorities, differing tax policies, and unaligned regulatory frameworks impede progress on large-scale integration and cross-border trade of biomethane, and development of dedicated hydrogen infrastructure.

Below we summarize the identified gaps for both hydrogen and biomethane, including cost sharing aspects applicable to both carriers.

Hydrogen

Various regional initiatives on hydrogen are under development besides the BEMIP High-Level Group, including the Nordic Council of Ministers of 2021¹⁴⁸ and the cooperation between BEMIP gas/

¹⁴² EC (2023): [Approaches for biomass projects \(europa.eu\)](#)

¹⁴³ European Commission (2024): [Finland- Final updated NECP 2021-2030](#)

¹⁴⁴ European Biogas Association (n.d.): [Estonia: Public transport turns to biomethane | European Biogas Association](#)

¹⁴⁵ Shallow cost sharing frameworks make new network users/producers only pay for the direct connection to the existing grid, while broader system upgrades are funded by the network operator or socialized across all users

¹⁴⁶ Deep cost sharing means that the network user/producer is responsible for both the direct connection and any necessary upstream network reinforcements caused by their connection

¹⁴⁷ Polish Biomethane Organization (2023): [The Polish Biomethane Organization's position on the draft act on the amendment to the Renewable Energy Sources Act and certain other acts](#)

¹⁴⁸ Nordic Cooperation(2021): [Nordic Co-operation Programme on Energy Policy 2022–2024](#)

hydrogen TSO. Nonetheless, specific coordinated infrastructure plans for hydrogen storage or transport in the BEMIP region are still underdeveloped and the current fragmentation in planning efforts, especially between different energy carriers like electricity, hydrogen and (bio)methane, could hinder the progress. The lack of integrated cross-border hydrogen infrastructure between the Baltic and Nordic regions is highlighted as an ongoing challenge by stakeholders, to which the Nordic-Baltic Hydrogen Corridor and Nordic Hydrogen Route plans will bring partial relief, however most countries in the BEMIP region do not even have any kind of domestic hydrogen infrastructure yet.

Although the report acknowledges the availability of financial tools like the EU's Innovation Fund and Hydrogen Bank for financing, it also indicates that the funding mechanisms are insufficient for the scale of infrastructure needed. Large-scale investments in hydrogen and storage infrastructure are still lacking, which slow down deployment efforts in the BEMIP MSs.

While some countries, such as Denmark and Germany, have included hydrogen transport infrastructure in their NDPs, others, like Poland, are still in the process of developing dedicated policies and regulatory frameworks. Others have not yet published any concrete strategies or legislative initiatives. Danish TSO Energinet has pointed out that further market dialogue and maturation are needed before final decisions can be made regarding large-scale hydrogen infrastructure investments. Denmark has also identified the need for a state-backed risk coverage model to support Energinet's investments in a hydrogen backbone. Currently, only Germany so far has implemented a framework for state capital contributions to de-risk investments in its national hydrogen infrastructure.

Biomethane

None of the BEMIP MSs have **biomethane consumption targets** (binding or not) for 2030 or beyond. But all BEMIP MSs except Germany provide a projection of biomethane development towards 2030 in the NECPs, and several include specific targets, such as Sweden with a 10 TWh target for 2030, and Denmark who aims to fully decarbonise gas supply through biomethane by 2030. Stakeholders have called for long-term, legally binding targets to foster investment and drive sector growth. However, other stakeholders call for stopping the expansion of biogas/biomethane, and even reducing production, because of feedstock constraints and competition with food and feed crops.

Differences in **gas quality standards** across BEMIP MSs present major barriers to cross-border biomethane transport. For example, Denmark has increased the admissible oxygen content in its gas grid to 0.5% to facilitate biomethane integration, but is now facing challenges in complying with the gas quality standards of the European Committee for Standardization (CEN) at points of the network where a lower oxygen content required, typically where a storage facility is located (0.001%). This restricts the flow of biomethane towards Central Europe – and thus implies additional operational costs to be recovered from the network users.

Lack of investments in methane grid expansion: several stakeholders, particularly in Latvia, Lithuania, and Poland (where the gas grids are underdeveloped, or parts of the country are not connected to a grid at all) note that there is insufficient funding allocated for the expansion of gas grids to accommodate biomethane.

Reverse flows: while Denmark and Sweden are exploring reverse flow options from distribution to transmission systems, many countries in the BEMIP region lack the necessary compressors and other equipment to facilitate reverse flows. This restricts biomethane transport, especially in cross-border contexts.

Grid integration: In some countries, such as Estonia, (bio)methane infrastructure is still at a nascent stage, and although there is significant potential in sectors like agriculture and waste, this has not yet been fully tapped. Latvia and Lithuania both report gaps in biomethane grid integration strategies, particularly regarding funding commitments and infrastructure development. In Lithuania and Poland, biomethane producers face challenges in **connecting to the gas system**, particularly in identifying an optimal connection point and navigating complex permission processes.

An important finding is the absence of **infrastructure for biomethane refuelling stations**, particularly for bio-CNG and bio-LNG vehicles for many countries. Thus, infrastructure planning for biomethane seems to focus on expanding bio-CNG and bio-LNG networks in multiple BEMIP MSs. Particularly in Lithuania, Latvia, and Poland, limited availability of gas refuelling infrastructure hampers the adoption of biomethane-fuelled transport. Biomethane used for transport purposes not injected in gas networks is, however, not in scope of the present study.

Financing and cost recovery for infrastructure integrating renewable and low-carbon gases

The scale of the potential financial challenge faced by hydrogen (and to a more limited extent methane infrastructure) largely depends on the level of public funding allocated to infrastructure, the proportion of existing infrastructure that needs to be decommissioned (for methane gases), or developed (for hydrogen, including through repurposing methane gas infrastructure), and the specific locations of supply and demand centres, which vary significantly between BEMIP MSs.

The choice of cost recovery methods and tariff policy has significant impacts on the financial stability of system operators, who must consider the maturity and nature of the energy carrier:

- **Hydrogen** infrastructure development is in its infancy, requiring massive investment in pipelines, storages, grid components and retrofitting of existing networks. For hydrogen, intertemporal cost allocation to later stages may be necessary to attract early-stage investments, but these may need to be paired with robust public funding or alternative revenue streams to avoid overburdening system operators. As the most advanced countries in this regard, the approach taken in Germany and recently agreed in Denmark can provide inspiration for other BEMIP MSs.
- **Methane networks** enabling the integration of biomethane already exist and are currently used for methane transport, thus investment needs differ. When deciding about cost-sharing, policymakers must strike a careful balance between incentivizing biomethane production, considering the impacts of a potentially shrinking network user base, and ensuring that tariffs and any tariff discounts secure the financial sustainability of the grid.

4. Infrastructure readiness and challenges for renewable and low-carbon gas integration

The present Chapter describes the state of the existing natural gas network in the BEMIP region, reflecting separately on the associated challenges with repurposing this infrastructure for the future utilisation as a hydrogen/biomethane transmission network instead. It then provides an overview of a specific case study (Denmark) – including challenges and measures taken to solve them – to serve as a good-practice in the integration of biomethane in the existing infrastructure. The Chapter also provides a detailed description of hydrogen PCIs in the BEMIP region.

4.1. Overview of the current natural gas system in the BEMIP region

As underlined in section 2.1, natural gas still plays a key role in the BEMIP region's energy supply. In that context, over the last decade, several infrastructure projects have focused on reinforcing gas interconnections in BEMIP as well as diversifying sources of supply. These most notably include:

- Klaipeda LNG terminal in Lithuania (in operation since December 2014)
- Baltic connector pipeline (Finland-Estonia, commissioned in 2020)
- The Gas Interconnection Poland-Lithuania (GIPL), commissioned in 2022, which now enables the Baltics and Finland to trade natural gas with central Europe
- The Baltic Pipe project which connects Poland to Norway via Denmark (2022)

More recently, following the disruption of natural gas supply from Russia, several LNG terminals have been commissioned in BEMIP region. These include three floating storage and regasification units (FSRUs) in Germany and a second LNG terminal in Finland. Further developments are still ongoing, with additional projects in e.g. Estonia and Latvia, as well as extensions in Poland and Germany.

Further details on the current state of the natural gas system in the BEMIP region are provided in the review of underground gas storage capacities and hydrogen storage potential in the region in section 9.2.3, and the country fiches on infrastructure in sections 9.3 (Annex C).

4.2. Challenges of transitioning the current BEMIP natural gas infrastructures to accommodate renewable and low-carbon gases

4.2.1. Dedicated hydrogen infrastructure challenges

Scaling up hydrogen production requires significant investment in infrastructure for importing, transporting, and storing hydrogen. This infrastructure could either be newly built or based on repurposed natural gas assets. Repurposing offers a cost-effective solution for both transport and storage but comes with challenges, particularly regarding capacity constraints due to hydrogen's lower volumetric energy density compared to methane, as well as purity concerns.

More broadly, many technical challenges related to hydrogen storage and transport stem from its low volumetric energy density, necessitating higher compression levels in gas pipeline infrastructure or conversion into alternative carriers, such as ammonia for shipping. Additionally, the small molecular size of hydrogen increases the risk of leaks, posing further challenges for infrastructure development.

The following technologies are considered for future hydrogen transport and storage and are discussed in detail in section 9.4 (Annex C):

- A) Hydrogen transport network (pipeline) – onshore
- B) Hydrogen transport network (pipeline) – offshore
- C) Underground hydrogen storage – Salt caverns
- D) Underground hydrogen storage – Porous media storage (i.e. depleted oil and gas reservoirs, aquifers)
- E) Above ground hydrogen storage – Pressurised tanks
- F) Hydrogen maritime imports in the form of ammonia

A summary of challenges and technology readiness level (TRL)¹⁴⁹ for each technology is presented in Table 4-1 below.

Table 4-1 Summary of hydrogen infrastructure technologies – Technology readiness level (TRL) and main challenges

Technology	TRL	Main challenges
Onshore hydrogen pipeline	8 - 9	Embrittlement, leakages, higher compression needs, expertise in repurposing gas pipelines still under development, coordination needs, cost uncertainty.
Offshore hydrogen pipeline	4 - 5	Same as onshore + no existing offshore hydrogen pipeline (contrary to onshore), (geopolitical) vulnerability.
Underground hydrogen storage – Salt caverns	8 - 9	Limited geographical availability, salt creeping / subsidence, lack of experience for fast cycling, purity issues, reduced storage capacity compared to gas as well as supply, demand and costs uncertainty.
Underground hydrogen storage – Porous media	3 - 4	Losses, purity issues (e.g. microbiological activity), limited operational experience, reduced storage capacity compared to gas as well as supply, demand and costs uncertainty.
Above ground hydrogen storage – Pressurised tanks	9	High investment and pressurisation costs, mostly suitable for small scale storage.
Hydrogen maritime imports in the form of ammonia	4	Ammonia cracking not yet mature, safety issues in case of large-scale shipping and storage close to populated areas.

4.2.2. Methane infrastructure challenges for the integration of biomethane

Challenges for the integration of biomethane in the BEMIP region

A number of challenges for the integration of biomethane in natural gas networks (which are detailed further in section 9.5.1 in Annex C), include:

- Defining the optimal location of new production facilities and injection points, cost allocation among stakeholders, and technical issues related to grid connection, pressure requirements, and gas quality. In countries with limited gas networks, high costs for grid connection are significant barriers. Harmonized rules and cost-sharing models are essential to facilitate biogas upgrading and injection while ensuring gas quality standards. Countries like Denmark, Germany, and Sweden have already begun direct biomethane injection into their transmission systems, whereas others still face challenges related to permissions, land use, and regulatory frameworks.
- The process of upgrading biogas to biomethane is essential due to its **differing composition** from natural gas, necessitating removal of components like sulphur and oxygen to prevent issues such as corrosion and microbiological growth. Different countries have varying limits on acceptable contaminants' limits (e.g. oxygen content), which can impact cross-border biomethane trade. Moreover, the most cost-effective method for oxygen removal varies by

¹⁴⁹ The TRL scale is presented in detail in the Annex.

country, with central purification being more efficient at higher biomethane shares. **Cost allocation between producers and grid operators**, as well as responsibilities for gas quality measurement and metering, also varies and impacts market integration. Harmonised rules and standardisation efforts by CEN or other standardization organisations are crucial for addressing the issues regarding gas quality and facilitating the integration of biomethane into the gas grid. Financial support for small facilities and improved sulphur cleaning technologies can help reduce costs and enhance biomethane integration into the gas grid.

- **Reverse flow measures** can be required for the injection of biomethane into the natural gas grid in scenarios where regional biomethane supply exceeds regional demand. This requires the implementation of additional compressor stations and other measures. Challenges include cost, as grid operators bear the costs for additional compressor stations and other reverse flow measures, with timing and optimal locations complicated by uncertainties in the ramp-up of biomethane injection. **Equipment limitations** also pose a problem, as many countries in the BEMIP region lack the necessary compressor stations and equipment, restricting biomethane transport to individual distribution systems level and limiting cross-border trading. **Odorization practices** differ between countries, potentially creating barriers to cross-border flows and necessitating deodorization plants where odorization is only present at the distribution level. Strong cooperation between grid operators (TSOs and DSOs) and biomethane producers is essential, particularly for cost division and ensuring efficient operation. Additionally, the regulatory environment, lack of political support, and difficulties meeting the TEN-E regulation criteria for eligibility to obtain PCI status can hinder the implementation and efficiency of reverse flow measures.

Case study on the integration of biomethane in Denmark

Denmark's gas market is notable for its high share of biomethane, reaching around 40% by the end of 2023 with plans to reach complete coverage of own gas demand by 2029. Section 9.5.2 in Annex C details the infrastructure measures and challenges Denmark faces in integrating biomethane into its natural gas system, offering insights applicable to other BEMIP MSs.

Key challenges faced for the integration of biomethane in Denmark include:

- **Gas supply and demand:** Rapid decline in gas consumption from around 20.9 TWh in the 2023 to 10-12.5 TWh in the long-term, driven by household gas consumption reduction.
- **Biogas pockets:** Local surpluses in biomethane production necessitate reverse flow facilities to manage gas flow direction changes at interconnection points.
- **Integrating large production sites:** Central biogas facilities, mainly straw-based, face challenges in integrating into the gas distribution system due to high production capacities.
- **Additional grid measures:** Connecting existing grid parts at distribution levels to minimize the need for reverse flow stations.
- **M/R stations:** Changes in demand and supply patterns impact capacity requirements of metering and regulation stations, necessitating modifications or decommissioning.
- **Oxygen limit:** High biomethane shares lead to oxygen concentration issues, impacting cross-border gas trade and requiring deoxidation measures.

A **number of measures** were undertaken or are being undertaken in Denmark in order to facilitate the integration of biomethane and adapt to the falling overall methane gas demand:

- **Reverse Flow Facilities:** Installation of additional compressor and deodorization units at metering and regulation stations to allow gas flow reversion.
- **Grid Expansion:** Five new pipelines are constructed or planned to interconnect distribution grids and minimize the need for reverse flow stations.
- **Oxygen management:** Blending of methane gas sources as well as sectioning of network parts (e.g. by not allowing biomethane injections in certain segments) are used to maintain oxygen levels within specifications. Centralized deoxidation measures at cross-border interconnection points could be necessary in the future to manage high oxygen.

- **Tariff structure review:** Access (i.e. injection) tariffs were introduced for biomethane producers (which did not face such tariffs before), and tariffs were also harmonised between distribution companies.

The Danish experience underscores the importance of coordinated planning, investment in infrastructure, and regulatory support in facilitating the integration of biomethane into existing gas grids. In particular the following **practices could be considered for other Member States** (with the relevance varying according to the state of development of biomethane):

- Development of reference supply and demand scenarios by national authorities to be used in network development planning;
- Coordinated TSO/DSO network development planning with recurrent coordination meetings as well as informal exchanges;
- Development of (modular) reverse flow facilities by either TSO or DSO but not both whenever possible, to enhance learning effects and economies of scale;
- Interconnection of distribution grids to enable decommissioning of specific metering & regulation stations;
- Review of quality standards regarding oxygen concentration and other contaminants and network management to maintain quality standards within limits;
- Introduction of injection tariffs and harmonisation of tariffs across network operators/grids.

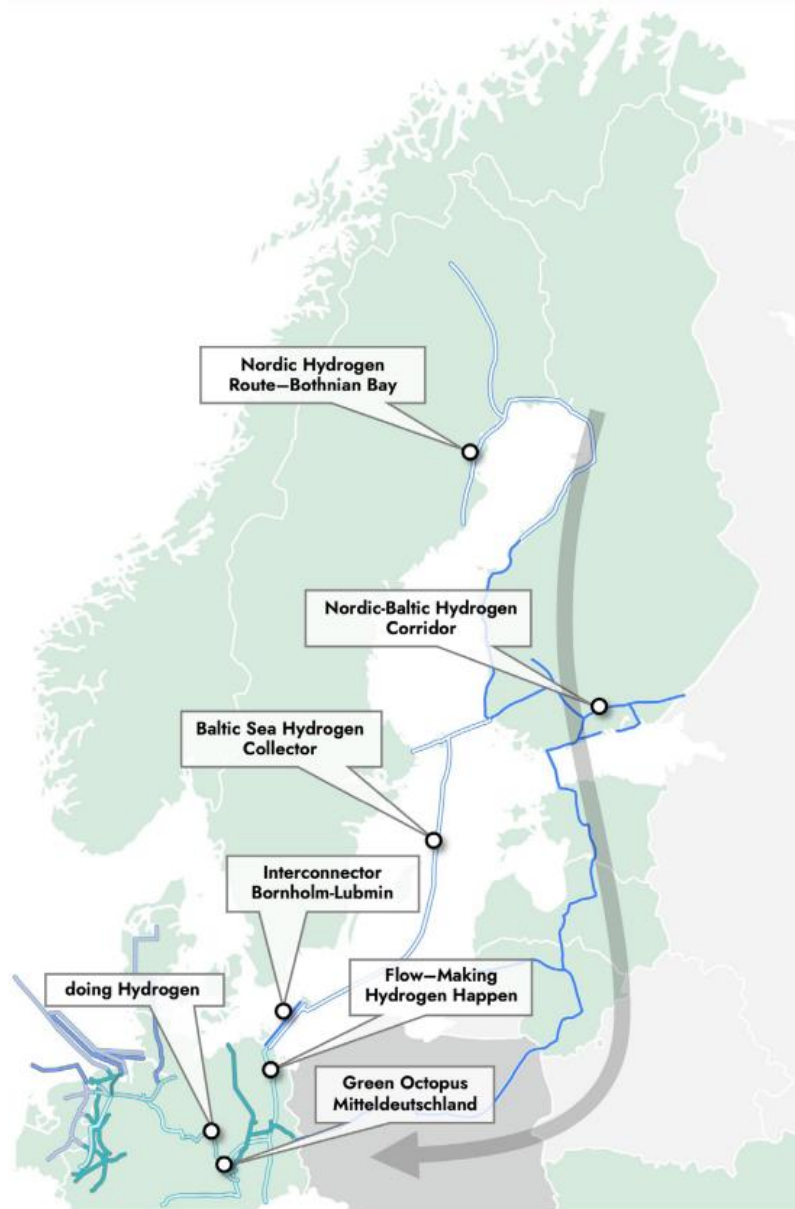
4.3. Supporting the developing hydrogen corridor between Sweden/Finland onshore and offshore via the Baltic countries and Poland to Germany

As highlighted in sections 2.2.2 (for hydrogen) and 2.3.2 (for biomethane), the BEMIP region has significant renewable energy potential, both onshore and offshore, availability of land and easy access to water, especially in the Bothnian Bay and the Baltic Sea: the first being one of the earliest greenfield hydrogen production projects in Europe; the other, being ideal for wind farm installations as the Baltic Sea has relatively shallow waters and abundant winds. The wind energy potential in the Baltic Sea is estimated at 93 GW, while the currently installed capacity is only around 3 GW. On the other hand, the main hydrogen demand centres will be located in the southern part of the region, primarily in Germany and Poland, as well as in other European countries. This supply-demand dynamic is expected to drive north-to-south hydrogen flows within the BEMIP region. Current projects reflect this trend, featuring laying out two major hydrogen supply routes:

- An onshore hydrogen supply route, connecting the Bothnian Bay production potential to demand centres by crossing most of BEMIP MSs onshore. The route's lay-out is built along the Nordic Hydrogen Route and the Nordic-Baltic Hydrogen Corridor (see below for details on the projects);
- An offshore hydrogen supply route, fostering the very high offshore energy production potentials in the Baltic Sea, which would build upon the ambitious new-built offshore Baltic Sea Hydrogen Collector project and connect mainland Sweden, Finland and Germany. Additionally, Denmark, along with the Åland, Gotland and Bornholm islands, could potentially be connected to this pipeline too. The Interconnector Bornholm-Lubmin, promoted by GASCADE and Energinet, would bring further connection between large-scale hydrogen production in the Bornholm area to demand centres in Germany and central Europe¹⁵⁰.

¹⁵⁰ Gascade (2024): [Gas transmission system operators around the Baltic Sea have signed a MoU to accelerate the development of hydrogen infrastructure](#); ENTSOE, GUE, EUROGAS, CEDEC, GD4S & GEODE (2024): [Hydrogen Infrastructure Map](#)

Figure 4-1 The future of the hydrogen transmission system in the BEMIP region, envisioned by the EHB.)



Source: EHB – Implementation Roadmap, 2023

Besides, twelve projects located in the BEMIP region – comprising hydrogen pipelines, storage facilities, and terminals – were included in the first list of Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs)¹⁵¹. The list was published in November 2023. Details on these projects were gathered based on the ENTSOG TYNDP 2024 Project Tables¹⁵² and the PCI-PMI Transparency Platform¹⁵³. Note that this list is not exhaustive as it focuses on projects on the first PCI/PMI list, there are additional transmission and storage projects in planning in BEMIP, which may later apply for the PCI/PMI status or national support schemes.

¹⁵¹ European Commission (2023): [Commission delegated regulation \(EU\) 2024/1041 of 28 November 2023](#)

¹⁵² ENTSOG (2024): [Ten-year Network Development Plan](#)

¹⁵³ EC (2025): [PCI-PMI Transparency Platform](#)

PCI-PMI – projects for hydrogen pipelines

Hydrogen interconnector Denmark – Germany: The Danish section of the project, *Danish Backbone West*, is led by Energinet, while the German section, known as *Hyperlink 3*, is promoted by Gasunie Deutschland. This project involves repurposing part of the existing interconnection for hydrogen, as well as building new hydrogen pipelines. Its purpose is to connect renewable hydrogen producers in Denmark with industrial clusters in Germany, while linking them to large-scale storage facilities such as Lille Torup in Denmark and Harsefeld in Germany and enhancing export opportunities. The feasibility study¹⁵⁴ results for this project were published in 2023. The project was originally scheduled for commissioning in 2028. However, after further political discussions in early 2025, state loans and operational subsidies shall enable transport of green hydrogen only by 2030. At the same time, minimum booking requirements of the pipelines were reduced to 0.5 GW in order to facilitate market access for producers.

Clean Hydrogen for Europe Pipeline (CHP): promoted by Gassco and Equinor, this PMI aimed to develop a dedicated high-pressure hydrogen pipeline from Norway's west coast to Northern Germany. The design of the hydrogen transport infrastructure has evaluated three potential options: (1) a combination of new and repurposed offshore pipelines, (2) a completely new offshore pipeline, and (3) a new pipeline that is connected to the AquaDuctus pipeline in the German exclusive economic zone. This infrastructure would have enabled the direct transport of low-carbon and renewable hydrogen produced in the North Sea and Norwegian Sea Basin. In September 2024, the main promoters of the project announced to halt plans for a hydrogen pipeline from Norway to Germany, citing the absence of a regulatory framework and the immaturity of the current market.¹⁵⁵

Nordic Hydrogen Route – Bothnian Bay: a 1,000 km initiative of new dedicated hydrogen pipelines, supported by Gasgrid Finland and Nordion Energi. The project would connect the Northern parts of Finland and Sweden to build upon the strong renewable potential in the Bothnian Bay, as it is one of the key regions of Europe for renewable hydrogen production. A re-application was submitted in November 2024 to include an additional section connecting to the great industrial hydrogen demand area of Gällivare and Kiruna in Sweden which will account for 70% of total projected hydrogen demand by 2040. Overall, the region covered by the NHR is projected to see large scale hydrogen production as well as demand. In 2030 regional demand is estimated at 24TWh with production expected to be 67 TWh, increasing to 56 TWh and 111 TWh respectively by 2040. Thus, the Nordic Hydrogen Route would allow sector integration on a large scale in the Nordic region, leading to benefits in terms of infrastructure co-optimization as well as energy system resilience and security, supporting the European energy independence in the long run. As of March 2025, the project was in the design phase, with construction expected to begin in 2028¹⁵⁶.

Nordic-Baltic Hydrogen Corridor: supported by Amber Grid, Conexus Baltic Grid, Elering, Gasgrid Finland, Ontras and Gaz System Poland, would then endorse the prolongation of this supply route up to Germany and Central Europe. As highlighted by the different project partners, this opportunity could support the integration of the Nordic, Baltic, Polish and German hydrogen markets, thus fostering the emergence of an open hydrogen market in the BEMIP region and the development of hydrogen dedicated infrastructures in the countries crossed by the corridor. The project's pre-feasibility study was launched in January 2024. High-level results were published in late summer 2024.¹⁵⁷ As of May 2025, the project is in its feasibility phase.

Baltic Sea Hydrogen Collector (BHC) is an offshore hydrogen pipeline connecting Finland and Sweden to central Europe promoted by Nordion Energi and Gasgrid Finland together with Copenhagen Infrastructure Partners. The newly built, bi-directional pipeline system will be approximately 1,250 km in length, consisting of 2 sections: Section A from Finland to Germany, and

¹⁵⁴ Energinet (n.d.): [Feasibility study - Hydrogen Transmission Infrastructure in Jutland](#)

¹⁵⁵ Montel News (2024): [Gassco becomes 3rd firm to ditch H2 project](#)

¹⁵⁶ Direct communication with Nordion Energi; Nordic Hydrogen Route (n.d.): [About the project](#)

¹⁵⁷ Gasgrid (2024): [Nordic-Baltic Hydrogen Corridor](#)

Section B from Sweden to Finland, as well as the islands of Åland and Gotland. There is significant potential for Northern Scandinavia to produce competitive green hydrogen from an estimated 350GW off and onshore wind. According to the most recent market consultation in Finland, demand for hydrogen will be 20TWh and supply 95TWh, thus the BHC will serve as a diversified dispatch of large energy volumes to demand centres either in central Europe or in Finland and Sweden. The pre-feasibility study for the BHC was completed in 2024.¹⁵⁸

PCIs – projects for hydrogen storage

Danish Hydrogen Storage: promoted by Gas Storage Denmark, this project aims to convert existing natural gas salt caverns at Lille Torup to hydrogen storage facilities. Strategically located near the North Sea's wind energy resources, it supports the expansion of renewable energy. The project is developed in collaboration with Danish hydrogen infrastructure and the multi-purpose Green Hydrogen Hub Denmark project. The preliminary timeline considers the permitting phase to start between 2024 and 2025.

SaltHy hydrogen storage Harsefeld: promoted by Storengy, this project involves the creation of a new salt cavern along with the construction of dedicated surface facilities for hydrogen storage. The facility will connect to Gasunie's hydrogen network, which will extend from the Netherlands to Denmark via Hamburg where a hydrogen distribution network is planned. The Harsefeld salt dome has the potential for the development of multiple caverns, offering additional storage capacity. As of March 2025, the project was in the planning phase¹⁵⁹. Construction work is scheduled to begin in 2026 with the sinking of the first boreholes. Depending on the size of the cavern, the work should be completed between 2030 and 2032 and the SaltHy hydrogen storage facility put into operation¹⁶⁰.

Hydrogen Storage Gronau-Epe: promoted by RWE Gas Storage West, this project will include the repurposing of two existing salt caverns that were previously used for natural gas storage. The project is currently in the permitting phase (as of March 2025).¹⁶¹

PCI projects – Hydrogen terminals

Ammonia reception facility terminal Brunsbüttel (RWE Supply & Trading): This project aims to facilitate the import of substantial quantities of renewable ammonia. The ammonia terminal will include an ammonia cracker to convert the imported ammonia into hydrogen for delivery to Germany.

Ammonia reception facility Wilhelmshaven (BP): The project involves developing a renewable hydrogen import facility at the German port of Wilhelmshaven. It aims to develop renewable hydrogen supply by first converting it to ammonia for transportation, then shipping it to the new terminal site in Wilhelmshaven, where it will be cracked back into hydrogen for distribution to industrial demand centres.

Ammonia reception facility Wilhelmshaven (Uniper): The project involves constructing an import terminal at Wilhelmshaven to facilitate the import of low-carbon ammonia, including a large-scale ammonia cracking plant for hydrogen production. Up to 20% of the imported ammonia will be redistributed directly by rail, while the majority will be converted into hydrogen and injected into the German hydrogen core network, which is planned to run alongside the terminal site.

¹⁵⁸ Direct communication with Nordion Energi

¹⁵⁹ EC (2025): [PCI Fiche - SaltHy hydrogen storage Harsefeld](#)

¹⁶⁰ Storengy (n.d.): [SaltHy](#)

¹⁶¹ EC (2025): [PCI Fiche - RWE H2 Storage expansion Gronau-Epe](#)

5. Assessment of the infrastructure development and adaptation needs

This Chapter provides an overview of the identified needs in infrastructure development for integration of renewable and low-carbon gases in the BEMIP region, starting with a methodological note on the modelling – including the description of the model used, base assumptions, the modelling scenarios and the sensitivity analyses. It then provides a detailed description of the results per scenario, and an explanation of what these mean in terms of infrastructural priorities, beyond the baseline of the already existing PCIs/PMIs.

5.1. Cost-effective methods for hydrogen transportation and storage

This study provides a quantitative assessment of the cost-optimal pathway for the development of hydrogen and methane infrastructure in the BEMIP region up to 2050, focusing on storage and cross-border transport. The analysis is performed using the Artelys Crystal Super Grid modelling software solution, a platform dedicated to the modelling of energy systems, considering techno-economic and environmental constraints.

Artelys Crystal Super Grid can jointly optimise the hourly generation dispatch, in order to meet energy demands, as well as investments in energy infrastructures. The solution can simulate several energy vectors and their interactions: electricity, gas, heat, etc., to identify synergies between sectors. Pathway optimisation in Artelys Crystal Super Grid consists in the dynamic optimisation of investment and decommissioning plans over a series of coupled time periods (2030, 2040 and 2050 in this study).

The modelling scope in this study covers hydrogen, gas and electricity, representing all BEMIP MSs. A pathway multi-energy optimisation is carried out, with the objective to minimise the total system costs, including both operating costs and the costs of investments in hydrogen storage and cross-border transmission infrastructure, for years 2030, 2040 and 2050. Each BEMIP country is represented as a single node, meaning that only cross-border transport capacities are modelled, while internal networks are not represented.

The analysis includes a baseline scenario and a sensitivity analysis. In the baseline scenario, main assumptions regarding the power system as well as hydrogen and methane supply and demand¹⁶² are based on TYNDP 2024 scenarios developed by ENTSO-E and ENTSG. National Trends+ (NT+) scenario is used for years 2030 and 2040¹⁶³ and Distributed Energy is used for year 2050. In the sensitivity analysis scenario, the impact of a delayed integration of hydrogen in BEMIP energy system is investigated. Details about the main scenario assumptions are provided in Chapter 11 (Annex E).

Hydrogen infrastructure is optimised by the model, including underground hydrogen storage in salt caverns and porous media¹⁶⁴ and above-ground hydrogen storage, as well as cross-border pipeline capacities. The model has two options, investing in new hydrogen pipelines (resp. storages) or repurposing existing natural gas pipelines (resp. storages). The joint modelling of gas and hydrogen infrastructure allows to reflect the trade-off between repurposing gas infrastructure or using the gas infrastructure for e.g., natural gas, biomethane or synthetic gases. The model can also decommission some capacities if they are no longer required for the operation of the system, which brings the opportunity to decrease the fixed operating costs of the energy system.

¹⁶² It is to be noted that, as the model explicitly represents sector coupling, part of the energy demand is endogenously determined by the model and may slightly differ from TYNDP scenario results. This is the case for, e.g., the electricity consumption of electrolyzers, or methane consumption of power plants.

¹⁶³ Except for biomethane production in 2040 which is based on Distributed Energy scenario, see Annex.

¹⁶⁴ Hydrogen storage in porous media is not assumed to be available until 2040 only due to lower Technology Readiness Level.

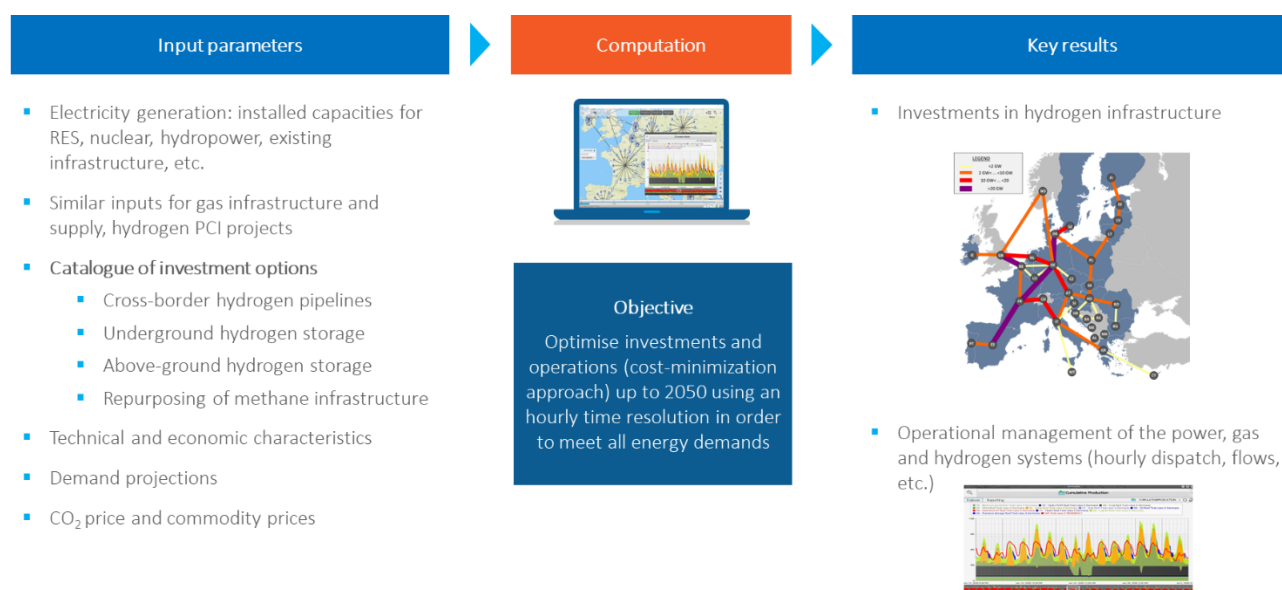
The model does not represent pipeline and storage assets individually; capacities are aggregated at the country or border level. These aggregated capacities are determined endogenously by the model, with the objective to minimise the sum of investment costs and system operation costs up to 2050. In order to identify the infrastructure needs, no limitations on potentials have been considered for pipeline and hydrogen storage. Economic assumptions regarding investment and operational costs used in the modelling are detailed in Chapter 11 (Annex E). In addition, the capacities corresponding to hydrogen infrastructure projects from the first PCI-PMI¹⁶⁵ list are enforced as minimum infrastructure levels in the model, following this rule:

- Projects expected to be commissioned before 2030 are included in the modelling for the years 2030, 2040 and 2050.
- Projects with a commissioning date after 2030 are included in the 2040 and 2050 modelling years.

In the model, hydrogen can be supplied via electrolysis, via Steam Methane Reforming (potentially with CCS), and via imports. Potentials for hydrogen imports include pipeline imports from the rest of EU (including both hydrogen produced domestically and imports from outside of EU transiting through non modelled neighbouring countries), shipped imports into Germany, as well as, from 2040, pipeline imports from Norway¹⁶⁶.

Regarding the power system on the other hand, installed capacities of generation and transmission technologies are a fixed assumption based on the TYNDP scenarios. The dispatch of power generation technologies is optimized by the model, considering installed capacities and availability constraints. Figure 5-1 presents a synthetic overview of the modelling methodology.

Figure 5-1 Overview of the modelling methodology



The modelling exercise focuses on cross-border hydrogen transmission capacity needs while internal transmission constraints are neglected, it is assumed that internal transmission capacities allow to connect production and consumption sites as well as storage infrastructure within a country. The model does thus not identify internal network development needs, for which levels of maturity vary significantly between BEMIP MSs. In Germany in particular, the [hydrogen core network](#) is planned to be mostly operational by 2032, with already significant capacities commissioned by 2030. Overall, the model may therefore underestimate hydrogen and methane storage needs, and the consideration

¹⁶⁵ European Commission (2023): [Commission delegated regulation \(EU\) 2024/1041 of 28 November 2023](#)

¹⁶⁶ It is to be noted that the TYNDP 2024 scenarios were designed before the Norway-Germany pipeline project was abandoned. Potential imports from Norway are removed in the sensitivity analysis.

of internal congestions and physical constraints like speed of gas flows might result in higher storage capacities.

5.2. Infrastructure needs in the mid- and long-term perspective

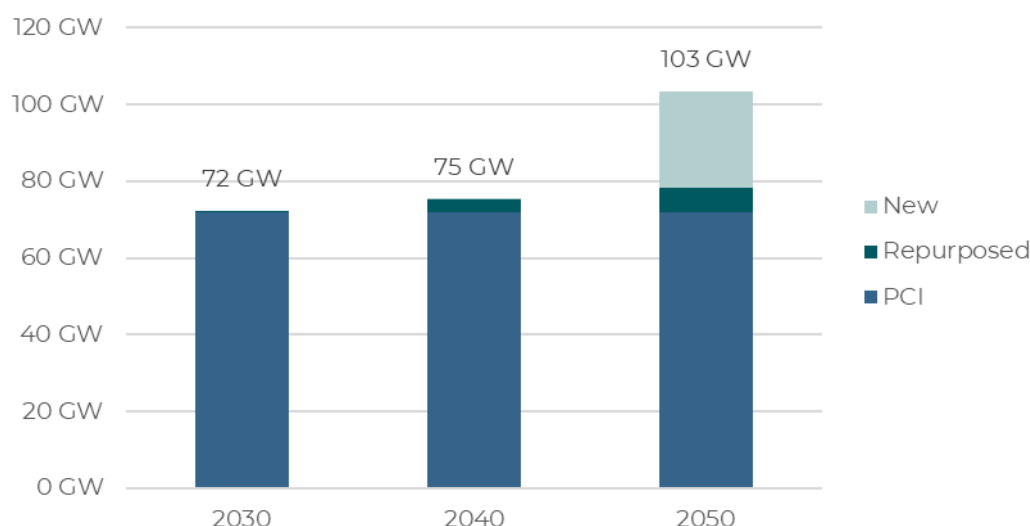
The following sections describe the main modelling results and conclusions in terms of investments in energy infrastructure and energy system operation, focusing first on hydrogen and then on methane infrastructure, considering the baseline and sensitivity analysis scenarios.

5.2.1. Baseline scenario

Hydrogen infrastructure

Figure 5-2 illustrates the aggregated cross-border hydrogen capacities between BEMIP MSs obtained from the model capacity optimisation for the years 2030, 2040 and 2050.

Figure 5-2 Cross-border hydrogen transmission capacities

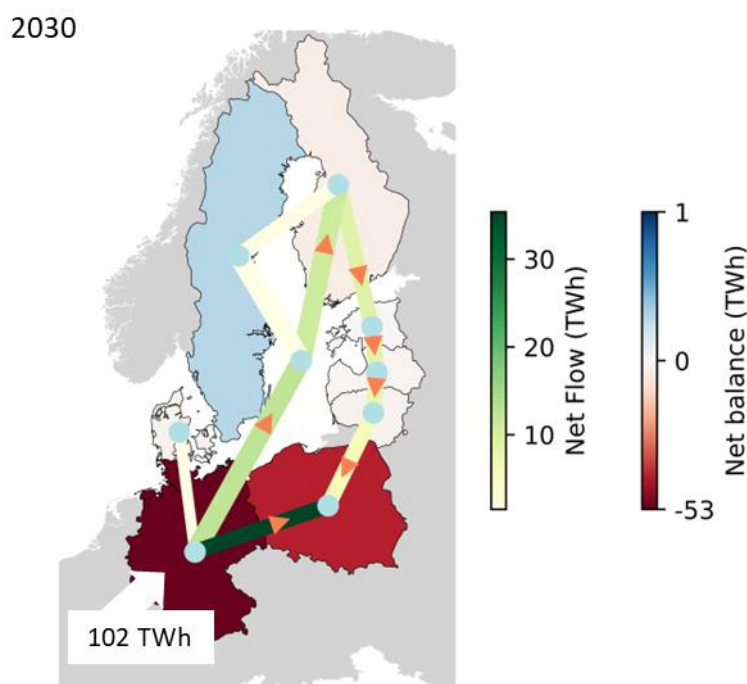


Source: Artelys modelling

Note: Pipeline capacities displayed represent only cross-border capacities and do not include internal network capacities. In case of asymmetric capacities at a given border, the maximum capacity of both directions is reported. The 'PCI' bar represents the projects from the first PCI/PMI list of 2024 that are scenarized in the model, 'new' and 'repurposed' bars represent additional capacities that are endogenously determined by the model. The PCIs includes both new pipelines and repurposing of existing pipelines.

In 2030, the capacity expansion does not lead to additional investments beyond the PCIs of the first PCI/PMI list of 2024. By 2040, only a few additional investments are expected to be required. Note that this result is to be considered keeping in mind that the model focuses on cross-border transmission. Most additional investments in cross-border capacity occur by 2050, with 25 GW of newbuild pipelines and an additional 6 GW from the repurposing of existing gas pipelines, all complementing the baseline PCIs of 2024. Figure 5-3 below displays a map showing hydrogen flows in the system in 2030, as well as capacities and usage of the network.

Figure 5-3: Member States' net hydrogen balance, net hydrogen flows and cross-border transmission usage in the BEMIP region for the year 2030.



2030	Transmission capacity (GW H2)			Flows (TWWh)			
Border	PCI/PMI level	Newbuild	Repurposed	Direct	Reverse	Net	Pipeline usage (%)
DK-DE	2.5	0.0	0.0	3.2	4.9	- 1.7	37%
IBFI-DE	21.0	0.0	0.0	6.9	19.3	- 12.4	14%
PL-DE	8.3	0.0	0.0	0.0	35.4	- 35.4	48%
FI-EE	8.3	0.0	0.3	9.0	0.0	9.0	12%
LV-EE	8.3	0.0	0.0	0.0	8.6	- 8.6	12%
IBFI-FI	21.0	0.0	0.0	14.3	3.4	10.9	10%
SE-FI	6.8	0.0	0.0	2.8	1.0	1.8	6%
SE-IBFI	21.0	0.0	0.0	3.5	5.0	- 1.5	5%
LV-LT	8.3	0.0	0.0	7.8	0.0	7.8	11%
PL-LT	8.3	0.0	0.0	0.0	6.0	- 6.0	8%
FI-DE	0.0	0.0	0.0	0.0	0.0	- 0.0	0%
PL-DK	0.0	0.0	0.0	0.0	0.0	- 0.0	0%
SE-DK	0.0	0.0	0.0	0.0	0.0	- 0.0	0%
IBFI-EE	0.0	0.0	0.0	0.0	0.0	0.0	0%

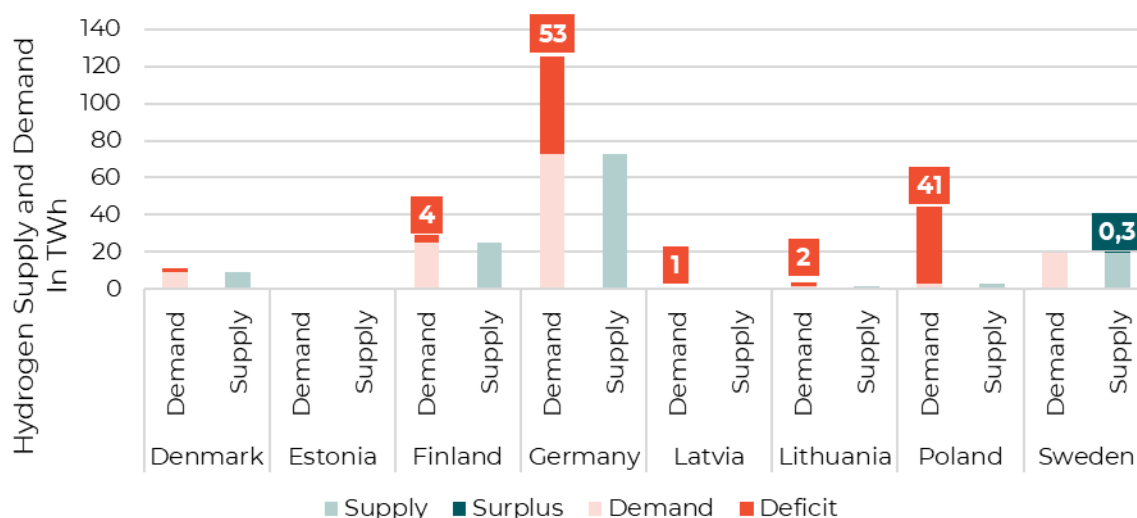
Source: Artelys modelling

Note: The map background displays each Member State net balance (hydrogen domestic production – consumption). Line colours indicate net flows on each border and arrows indicate the direction of the net flow (for net flow values above 2 TWWh). The table indicates the pipeline capacities, flows in both directions (for instance, for DK-DE border, direct flow represents the yearly flow from Denmark to Germany) and pipelines usage (pipeline usage is computed considering the sum of yearly flows in both directions). It is thus to be noted that low net flows do not necessarily translate a low level of pipeline usage and can also translate flows in each direction cancelling each other (see detailed figures in the table). The IBFI node represents the junction point of both branches of the Baltic Hydrogen Collector pipeline project. The FI-DE pipeline represents the option for repurposing Nord Stream pipelines which is implemented in the model. The white arrow indicates net imports from outside of BEMIP into Germany (in TWWh). In 2030 in the baseline scenario, Germany is the only country exchanging hydrogen outside the BEMIP region.

The map shows that in 2030, almost all Member States rely on imports from outside the BEMIP region to meet their hydrogen demand, these imports are mostly needed in Germany and Poland while Finland and the Baltic states import smaller volumes of hydrogen. According to the scenario assumptions, Germany is the only entry point of imports from outside BEMIP in 2030, with the map

showing that Germany acts as a transit hub redistributing hydrogen imports to other Member States. This is particularly noticeable at the Germany-Poland border. The modelling results also show a bidirectional hydrogen flows pattern at the Denmark-Germany border¹⁶⁷. A pattern of hydrogen flows from Finland to Poland via the Baltic states also appears in the map, showing that depending on situation, Finland may need to import hydrogen from Germany or export hydrogen. This result can be interpreted considering that there is no significant potential for underground hydrogen storage in Finland due to geological considerations. Pipelines also show a low level of infrastructure usage, with load factors of hydrogen pipelines ranging from 5% to 48% and an average of only 13%. This illustrates that in 2030, the hydrogen network appears to be oversized (in terms of maximum flows) compared to hydrogen flow needs seen by the model, which can be explained since ongoing projects are dimensioned considering an anticipation of future needs for up until 2050.

Figure 5-4: Hydrogen supply-demand balances in BEMIP MSs in 2030.



Source: Artelys modelling

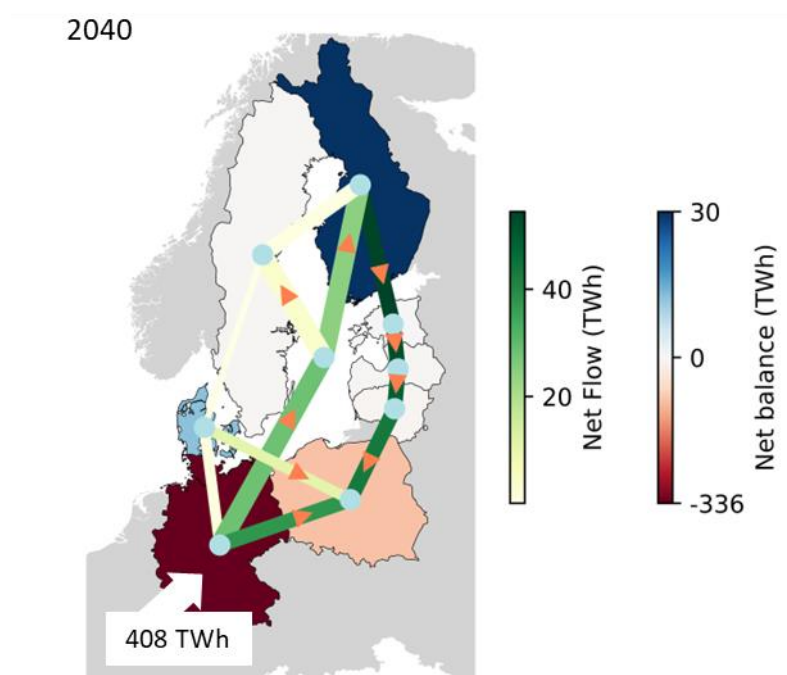
The Figures below show similar outputs for 2040, where flow patterns are similar to 2030. Germany still imports high volumes of hydrogen, of which part is redistributed towards Poland and Finland. The pattern of hydrogen flows from Finland to Poland via the Baltic states is still observed. In 2040, the share of domestic hydrogen generation increases significantly in Denmark and Finland, which become net exporters with 12 TWh and 30 TWh of hydrogen exports, respectively (see Figure 5-5 and Figure 5-6). Therefore, the net flow between Denmark and Germany is reversed compared to 2030. While becoming a net hydrogen exporter, Finland still needs to import hydrogen at some times. Meanwhile, Germany and Poland remain hydrogen importers, with 335 TWh and 98 TWh of net hydrogen imports, respectively. Overall, transmission usage significantly increases compared to 2030, the average load factor of hydrogen transmissions¹⁶⁸ increases by a factor 3 to reach 38%. The increase of infrastructure usage is accompanied by investment in a few additional repurposed transmission capacities on the Denmark-Poland¹⁶⁹, Germany-Poland, Sweden-Denmark, and Estonia-Finland borders.

¹⁶⁷ It is noticeable that while Denmark plans to export hydrogen towards Germany, the flows are rather bidirectional in the modelling. This result is consistent with the TYNDP 2024 NT+ scenario which foresees a higher hydrogen consumption in Denmark compared to national plans (see annex 7.1 country fiche on hydrogen demand and supply).

¹⁶⁸ That is, the average load factor of all hydrogen pipelines, weighted by their transmission capacities in MW.

¹⁶⁹ As of May 2025, no projects are planned to repurpose the pipeline between Denmark and Poland considering that Poland's methane consumption is expected to increase in the short to mid-term. This result reflects the cost-optimisation approach, it is to be noted that the model does not aim at performing a detailed security of supply analysis for methane, considering supply risk, notably regarding Polish LNG infrastructure might lead to different results.

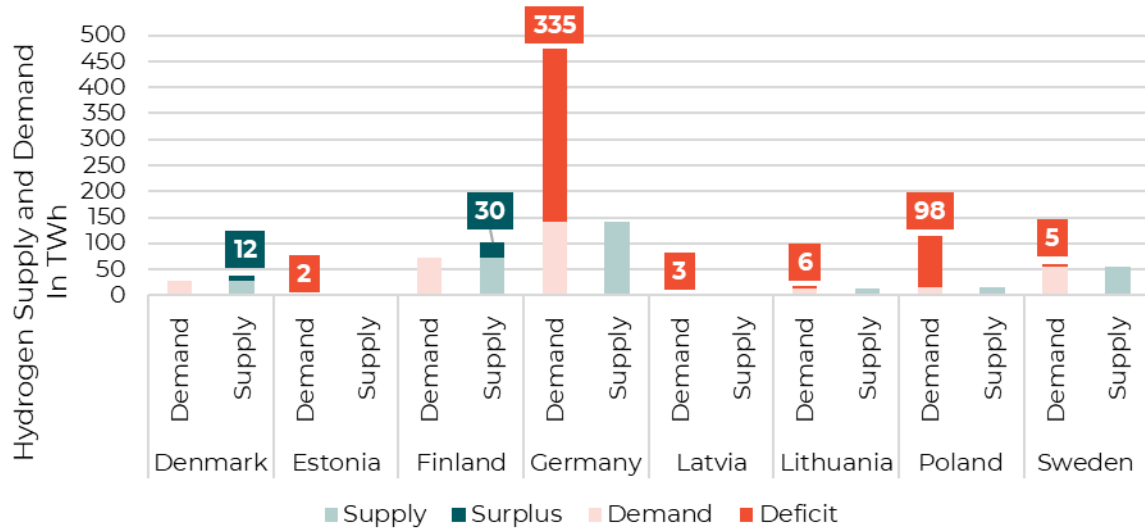
Figure 5-5: Member States' net hydrogen balance, net hydrogen flows and cross-border transmission usage in the BEMIP region for the year 2040.



2040	Transmission capacity (GW H2)			Flows (TWh)			
Border	PCI/PMI level	Newbuild	Repurposed	Direct	Reverse	Net	Pipeline usage (%)
DK-DE	2.5	0.0	0.0	3.8	2.5	1.3	29%
IBFI-DE	21.0	0.0	0.0	20.0	48.5	- 28.4	37%
PL-DE	8.3	0.0	0.5	0.0	37.6	- 37.6	48%
FI-EE	8.3	0.0	0.3	54.5	0.0	54.4	72%
LV-EE	8.3	0.0	0.0	0.1	52.3	- 52.3	72%
IBFI-FI	21.0	0.0	0.0	38.9	14.4	24.5	29%
SE-FI	6.8	0.0	0.0	1.2	1.8	- 0.6	5%
SE-IBFI	21.0	0.0	0.0	5.7	9.6	- 3.9	8%
LV-LT	8.3	0.0	0.0	48.8	0.0	48.8	67%
PL-LT	8.3	0.0	0.0	0.0	43.3	- 43.3	59%
FI-DE	0.0	0.0	0.0	0.0	0.0	- 0.0	0%
PL-DK	0.0	0.0	1.7	0.0	11.0	- 11.0	72%
SE-DK	0.0	0.0	0.7	0.0	0.1	- 0.1	2%
IBFI-EE	0.0	0.0	0.0	0.0	0.0	0.0	0%

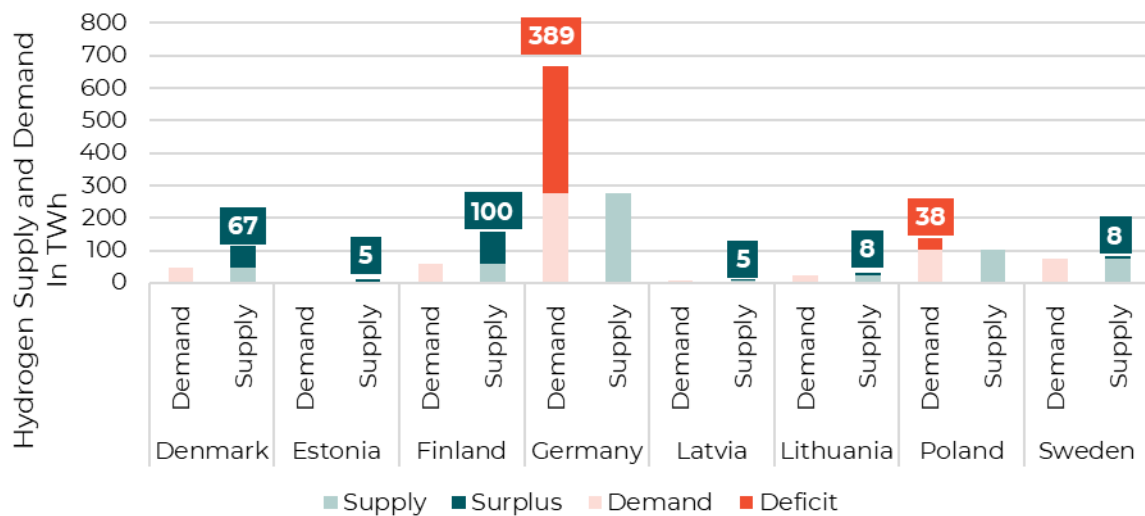
Source: Artelys modelling

Figure 5-6: Hydrogen supply-demand balances in BEMIP MSs in 2040.



Source: Artelys modelling

Figure 5-7: Hydrogen supply-demand balances in BEMIP MSs in 2050.



Source: Artelys modelling

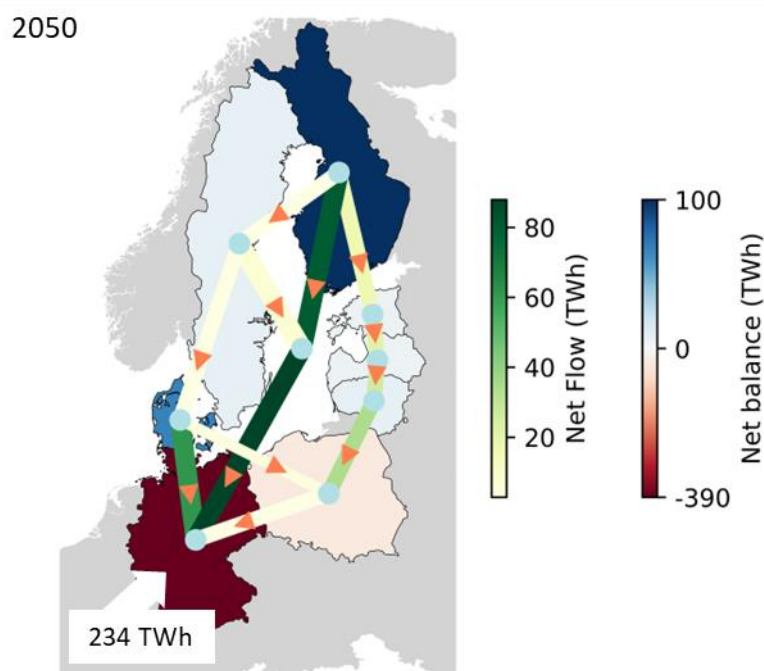
In 2050, as illustrated in Figure 5-7 and Figure 5-8, Denmark and Finland remain the main net hydrogen exporters, with 67 TWh and 100 TWh of hydrogen exports, respectively. Conversely, Germany and Poland remain the primary net importers, with 389 TWh and 38 TWh of hydrogen imports, respectively. As a result, most significant additional investments are needed in pipeline capacities located at the Denmark-Germany, Germany-Poland and Lithuania-Poland borders. Approximately 20% of these additional capacities correspond to repurposed methane pipelines. The capacity-weighted average level of hydrogen transmission usage is 33%. This marginal decrease in transmission capacity average load factor in 2050 indicates that the further investment in hydrogen pipelines allows additional flexibility in the system. This illustrates that a somewhat limited number of full load hours may not necessarily translate an infrastructure underutilisation and can reflect a provision of flexibility to the system.

It is also noticeable that the model does not foresee the repurposing of Nord Stream Pipelines as cost optimal¹⁷⁰. Indeed, the model allows for the option to reinforce the hydrogen corridor stretching from Finland to Germany via repairing and retrofitting the Nord Stream pipelines to transport hydrogen. Still, it appears that to increase export capacity from Finland, the model rather opts for reinforcement of the onshore corridor from Finland to Lithuania. These reinforcements, in the range of 700-1000 MW, are rather marginal compared to the pre-existing PCI level. Rather, the most significant investments are seen for the Sweden-Denmark-Germany corridor, and at the Germany-Poland border.

Overall, the BEMIP region imports 105 TWh of hydrogen in 2030, 405 TWh in 2040, and 276 TWh in 2050.

¹⁷⁰ The Nord Stream pipelines are modelled as an aggregated transmission capacity connecting Finland and Germany (refer to modelling annex for detailed economic assumptions), given its proximity to the Finnish coast. No additional penalties for repairing the pipelines have been applied compared to other repurposed pipelines. The repurposing of the Nord Stream pipeline is not included in the model's minimum infrastructure level, which only accounts for PCIs. From the model perspective, repurposing of Nord Stream is thus an additional option, not an alternative to the base PCI infrastructure level.

Figure 5-8: Member States' net hydrogen balance, net hydrogen flows and cross-border transmission usage in the BEMIP region for the year 2050.



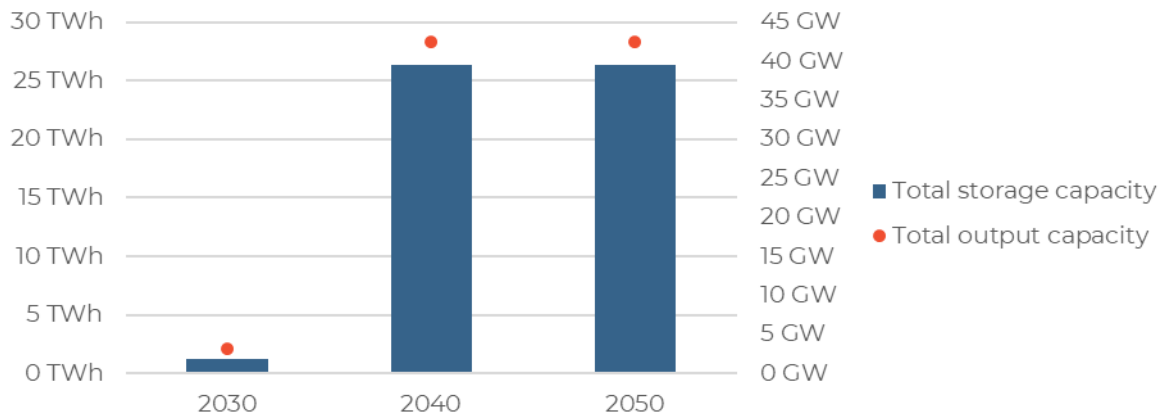
2050	Transmission capacity (GW H2)			Flows (TWh)			Pipeline usage (%)
Border	PCI/PMI level	Newbuild	Repurposed	Direct	Reverse	Net	
DK-DE	2.5	15.6	0.0	61.5	0.0	61.5	39%
IBFI-DE	21.0	0.0	0.0	92.1	4.2	87.9	52%
PL-DE	8.3	0.0	2.7	18.6	15.7	2.8	35%
FI-EE	8.3	0.0	0.3	18.9	3.1	15.8	29%
LV-EE	8.3	0.0	0.0	0.7	21.9	- 21.2	31%
IBFI-FI	21.0	0.0	0.0	3.3	83.9	- 80.6	47%
SE-FI	6.8	0.0	0.0	3.3	6.3	- 3.1	16%
SE-IBFI	21.0	0.0	0.0	8.2	1.0	7.2	5%
LV-LT	8.3	0.2	0.7	26.8	0.4	26.4	34%
PL-LT	8.3	4.0	0.1	0.9	35.5	- 34.5	33%
FI-DE	0.0	0.0	0.0	0.0	0.0	0.0	0%
PL-DK	0.0	0.0	1.7	0.5	5.5	- 5.0	39%
SE-DK	0.0	5.4	0.8	9.0	5.3	3.7	27%
IBFI-EE	0.0	0.0	0.0	0.0	0.0	- 0.0	0%

Source: Artelys modelling

Regarding storage infrastructure capacities, only minor additional investments (1 TWh) are required by 2030, beyond hydrogen storage PCIs in the BEMIP region (exclusively located in Germany). The majority of storage investments are needed by 2040, as shown in Figure 5-9. By 2050, the model foresees no additional storage investment need compared to 2040, the total capacity remaining stable at 26 TWh¹⁷¹.

¹⁷¹ The model assumes no limitations on underground hydrogen storage potential.

Figure 5-9: Hydrogen storage capacities.

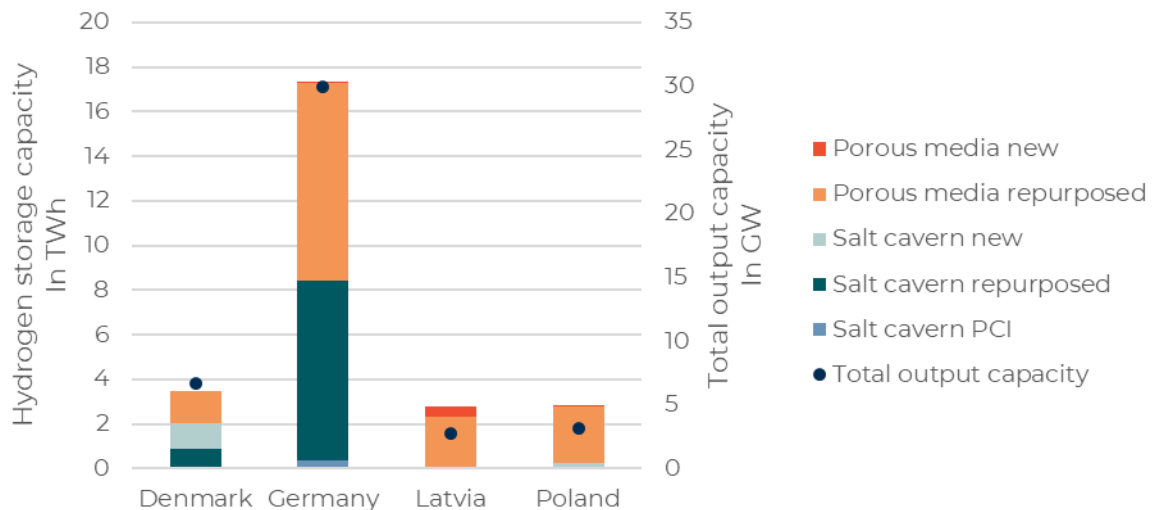


Source: Artelys modelling

Note: The left axis represents storage capacities in TWh, the right axis represents total output capacity in GW (i.e. capacity for withdrawal from storage to the network, supposed to be equal to injection capacities). It is to be noted that the model does not represent internal networks, the consideration of internal congestions constraints may result in higher storage needs.

In 2050, salt caverns account for 40% of the total hydrogen storage capacity, while depleted fields and aquifers make up the remaining 60%. No investments are made in above-ground hydrogen storage (pressurised tanks)¹⁷² or new porous media storage. Consequently, hydrogen storage assets are located in four countries (Denmark, Germany, Poland and Latvia) where there is potential to develop or repurpose salt caverns, and to repurpose depleted fields or aquifers (see Figure 5-10). A large share of these capacities is located in Germany, consistent with Germany's high hydrogen consumption and production as well as function as a hydrogen re-distribution hub. Moreover, by 2050, 93% of the total added hydrogen storage capacity (i.e., excluding PCIs) consists of retrofitted infrastructure.

Figure 5-10: Hydrogen storage capacities in 2050 broken down by technology and by country.



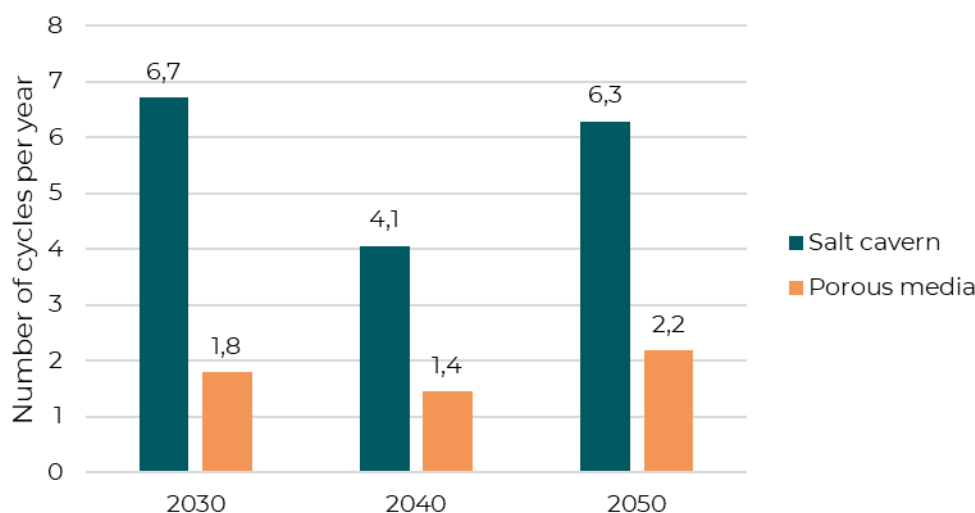
Source: Artelys modelling

Note: The left axis represents storage capacities in TWh, the right axis represents total output capacity in GW (i.e. capacity for withdrawal from storage to the network, supposed to be equal to injection capacities). Porous media category includes depleted fields and aquifers.

¹⁷² This result can be linked to the significantly higher CAPEX of pressurized tanks compared to underground storage, given the cost minimisation approach of the model. Hydrogen storage in tanks is however expected to be needed, e.g. at the distribution level, which is not captured in the model (truck transportation, onsite storage).

Figure 5-11 displays the number of yearly cycles performed by storage assets in the BEMIP region (i.e. the total yearly output divided by available storage volume).

Figure 5-11: Hydrogen storage cycles in the BEMIP region.



Source: Artelys modelling

Aquifers and depleted fields show lower cycling rates compared to salt caverns due to their longer discharge time¹⁷³. The average storage usage decreases in 2040 as a result of the increase in hydrogen storage capacity between 2030 and 2040. However, since the total storage capacity remains unchanged between 2040 and 2050, storage assets are more used in 2050 compared to 2040. This can be explained by the fact that electrolysis production – which may display hourly variability due to the link with renewable electricity generation – increases during this period, while steam methane reforming is completely phased out by 2050.

Methane infrastructure

In the baseline scenario assumptions, overall methane final demand in the BEMIP region decreases¹⁷⁴ from 785 TWh in 2030 to 249 TWh in 2050 (excluding demand for power generation and for SMR)¹⁷⁵ according to the NT+ and DE scenarios. While some methane demand remains in 2050, it is supplied via biomethane and synthetic methane, and no fossil gas remains in the 2050 energy system.

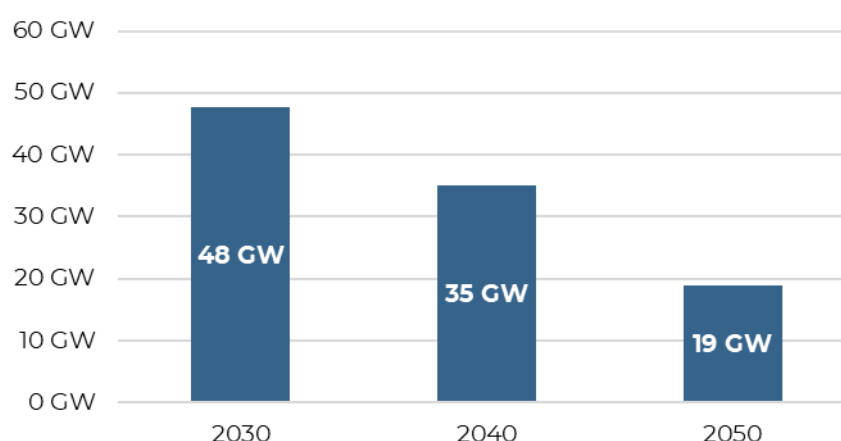
As methane demand in the BEMIP region declines, the need for methane storage and cross-border transport also diminishes, providing opportunities to decommission or to repurpose to hydrogen part of the existing methane infrastructure. According to the capacity optimisation, aggregated cross-border gas pipeline transmission capacities decrease from 48 GW in 2030 to 19 GW by 2050, as shown in Figure 5-12.

¹⁷³ The model defines the storage capacity of an asset (in MWh) by multiplying its withdrawal capacity (in MW) by the discharge time (in hours, input in the model). Thus, the discharge time corresponds to the time theoretically required for the storage to be completely emptied.

¹⁷⁴ Overall methane demand in the BEMIP region decreases, although in the short term it increases in some countries, such as Poland.

¹⁷⁵ See Figure 11-2 in annex

Figure 5-12: Aggregated cross-border methane transmission capacities.



Source: Artelys modelling

Note: Pipeline capacities displayed in the figure represent only cross-border capacities and do not include internal network capacities. As most pipelines are bidirectional, the graph displays the maximum capacity of the two directions of each pipeline.

Table 5-1 Methane supply-demand balances in BEMIP MSs in 2030

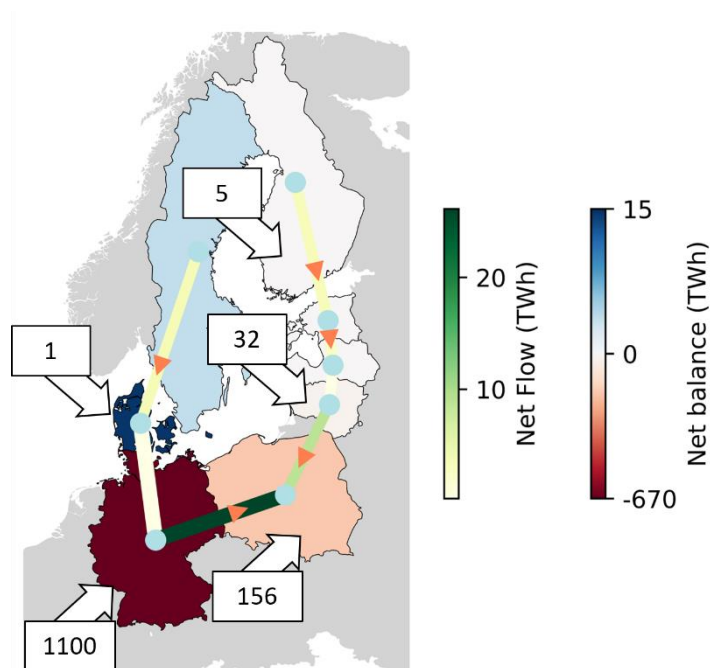
2030	Supply (TWh LHV)				Demand (TWh LHV)
	Domestic natural gas	Synthetic methane	Biomethane	Total supply	Total demand
Denmark	33	0	15	48	33
Estonia	0	0	2	2	3
Finland	0	2	12	14	15
Germany	0	0	37	37	706
Latvia	0	0	2	2	4
Lithuania	0	0	2	2	26
Poland	42	0	22	64	244
Sweden	0	0	14	14	11
Total	75	2	105	183	1042

Source: Artelys modelling

Note: In green, countries where the methane local production is higher than demand. In red, countries where the methane local production is lower than methane demand.

In 2030, the BEMIP region remains heavily dependent on natural gas imports, with Germany and Poland being the main importers, accounting for 669 TWh and 180 TWh of net gas imports, respectively. Conversely, two countries are net gas exporters due to their biomethane production and their low gas demand: Denmark, which exports 15 TWh in 2030, and Sweden, which exports 3 TWh. Consequently, and with Germany and Poland also importing LNG through Finland and Lithuania, methane flows from the north of the BEMIP region to the south, converging in Germany and Poland, as illustrated in Figure 5-13. Besides, Germany redistributes part of its imports from outside the BEMIP region to other BEMIP MSs, in particular Poland. In 2030, methane flows are mostly driven by the location of import capacities and therefore are mostly monodirectional, contrary to hydrogen flows.

Figure 5-13: Member States' net methane balance and net methane cross-border flows in the BEMIP region for the year 2030.



2030		Flows (TWh)		
Border	Transmission capacity (GW)	Direct	Reverse	Net
DK-DE	5.2	0.2	0	0.2
PL-DE	13.6	0	26.1	26.1
FI-EE	2.7	3.5	0	3.5
LV-EE	3.1	0	2.6	2.6
LV-LT	3.7	0.3	0.1	0.2
PL-LT	2.4	0	8.8	8.8
PL-DK	13.4	0	0	0
SE-DK	3.7	4.6	1.0	3.7

Source: Artelys modelling

Note: The map background displays each Member State's net balance (methane domestic production including biomethane, synthetic methane and residual natural gas production – consumption). Line colours indicate net flows on each border; arrows indicate the direction of the net flow. White arrows indicate imports from outside of BEMIP in TWh.

In 2040, the BEMIP region continues to be a net gas importer, although local biomethane production increases significantly. Germany and Poland remain the largest importers, with 316 TWh and 172 TWh of gas imports respectively. Meanwhile, Denmark and Sweden remain the region's only net gas exporters, with 7 and 9 TWh of gas exports respectively (see Table 5-2). Flows are similar to 2030 flows and are illustrated in Figure 5-14.

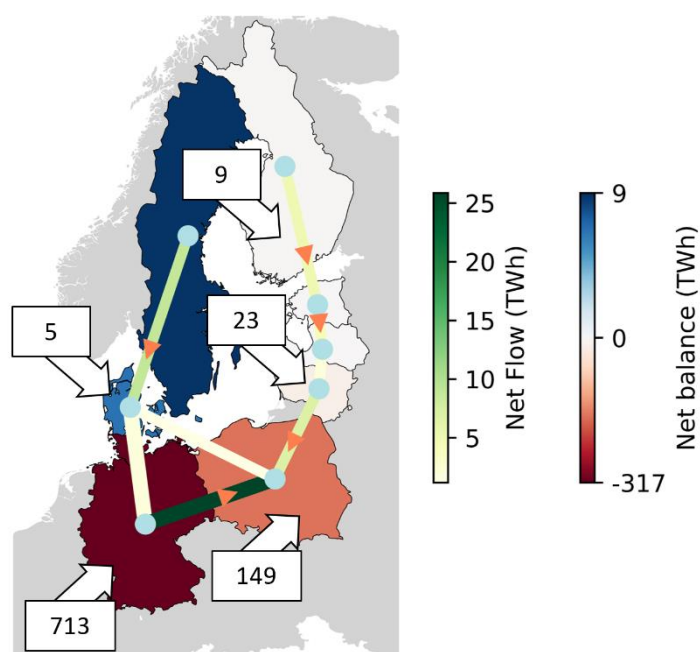
Table 5-2: Methane supply-demand balances in BEMIP MSs in 2040.

2040	Supply (TWh LHV)				Demand (TWh LHV)	
	Domestic natural gas	Synthetic methane	Biomethane	Total supply	Total demand	
Denmark	11	1	18	30	23	
Estonia	0	0	2	2	3	
Finland	0	3	15	18	21	
Germany	0	16	48	64	380	
Latvia	0	0	2	3	5	
Lithuania	0	0	2	2	20	
Poland	43	6	28	77	249	
Sweden	0	0	18	19	10	
Total	53	27	134	214	712	

Source: Artelys modelling

Note: In green, countries where the methane local production is higher than demand. In red, countries, where the methane local production is lower than methane demand.

Figure 5-14: Member States' net methane balance and net methane cross-border flows in the BEMIP region for the year 2040.



2040	Transmission capacity (GW)	Flows (TWh)		
		Direct	Reverse	Net
DK-DE	5.2	1.9	0	1.9
PL-DE	12.6	0	25.9	25.9
FI-EE	2.7	5.0	0	5.0
LV-EE	2.1	0	4.3	4.3
LV-LT	3.7	2.5	0.6	2.0
PL-LT	2.4	0	6.9	6.9
PL-DK	4.2	0	1.2	1.2
SE-DK	2.2	8.8	0.0	8.8

Source: Artelys modelling

In 2050, methane demand in the BEMIP region declines significantly, while biomethane and synthetic methane production increases in most Member States¹⁷⁶. As a result, the region becomes a

¹⁷⁶ There is no more domestic natural gas production by 2050 according to the TYNDP 2024 Distributed Energy scenario.

net gas exporter, with a net export of 33 TWh outside the BEMIP region, as described in Table 5-3¹⁷⁷. While methane consumption remains in the 2050 energy system, it is supplied via biomethane and synthetic methane according to European and national carbon neutrality goals. Germany becomes the largest gas exporter, with 27 TWh of net exports, due to a high synthetic methane and biomethane production, while Poland remains a net importer, importing 32 TWh of gas. Consequently, flows within the BEMIP region converge towards Poland or are directed to the rest of the EU through Germany.

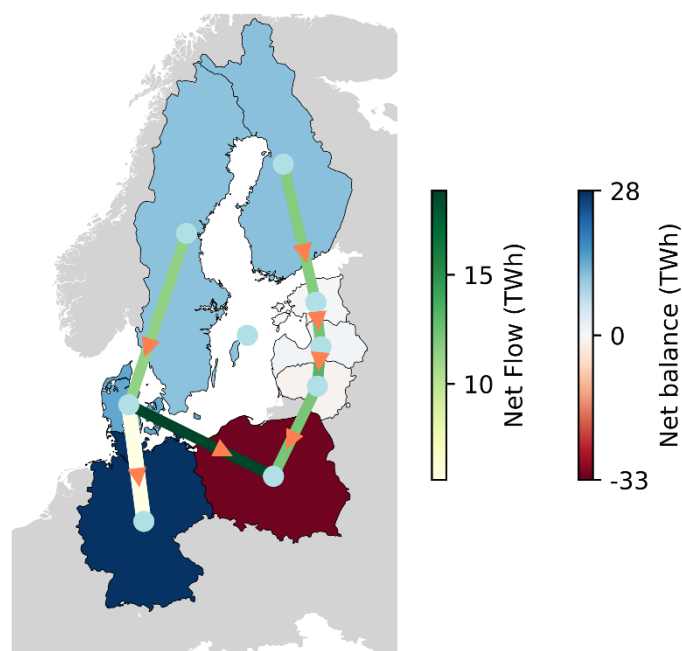
Table 5-3: Methane supply-demand balances in BEMIP MSs in 2050.

2050	Supply (TWh LHV)		Demand (TWh LHV)	
	Synthetic methane	Biomethane	Total supply	Total demand
Denmark	12	15	27	13
Estonia	1	3	3	3
Finland	6	17	24	12
Germany	93	55	148	121
Latvia	1	3	4	3
Lithuania	1	3	4	5
Poland	19	33	52	84
Sweden	4	21	25	14
Total	138	149	287	254

Source: Artelys modelling

Note: In green, countries where the methane local production is higher than demand. In red, countries where the methane local production is lower than methane demand.

Figure 5-15: Member States' net methane balance and net cross-border flows in the BEMIP region for the year 2050.



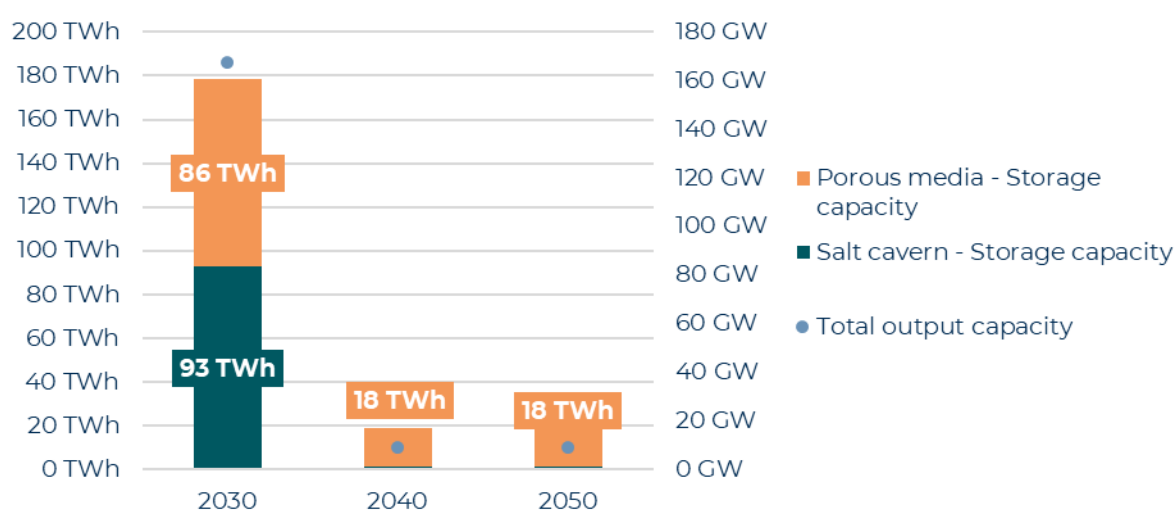
¹⁷⁷ In 2050, BEMIP region has a positive methane balance (net exporting) in the TYNDP 2024 DE scenario, with exports towards the rest of Europe.

2050		Flows (TWh)		
Border	Transmission capacity (GW)	Direct	Reverse	Net
DK-DE	5.2	5.6	0	5.6
PL-DE	0	0	0	0
FI-EE	1.9	11.8	0	11.8
LV-EE	2.1	0	12.3	12.3
LV-LT	2.3	13.4	0	13.4
PL-LT	2.2	0	12.2	12.2
PL-DK	3.2	0	18.8	18.8
SE-DK	2.2	11.5	0.1	11.4

Source: Artelys modelling

As there are remaining flows in the BEMIP region in 2050, due to a residual gas demand in Poland and due to biomethane and synthetic methane production, methane infrastructure capacities are still needed in 2050. As a result, the model does not repurpose or decommission all methane pipelines and storages (as shown for storages in Figure 5-16). It is to be noted that the model developed in this study does not aim at performing a methane Security of Supply analysis. In particular, the results regarding repurposing are to be interpreted in light of the scenario assumptions regarding the gradual reduction of methane consumption. Scenarios with a slower decrease of methane consumption and considerations of the ability of the system to withstand security of supply risks could result in lower potentials for the repurposing of methane infrastructure. This appears in the sensitivity analysis scenario which assesses the impact of a slower decrease in methane consumption.

Figure 5-16 Methane storage capacities in the BEMIP region in the baseline scenario



Source: Artelys modelling

5.2.2. Sensitivity analysis scenario

A sensitivity analysis is performed to assess the robustness of the modelling results relative to the main scenario assumptions. In particular, the sensitivity analysis investigates the impact of the total hydrogen consumption, which is a key driver of uncertainty. The sensitivity scenario is built according to the following narrative:

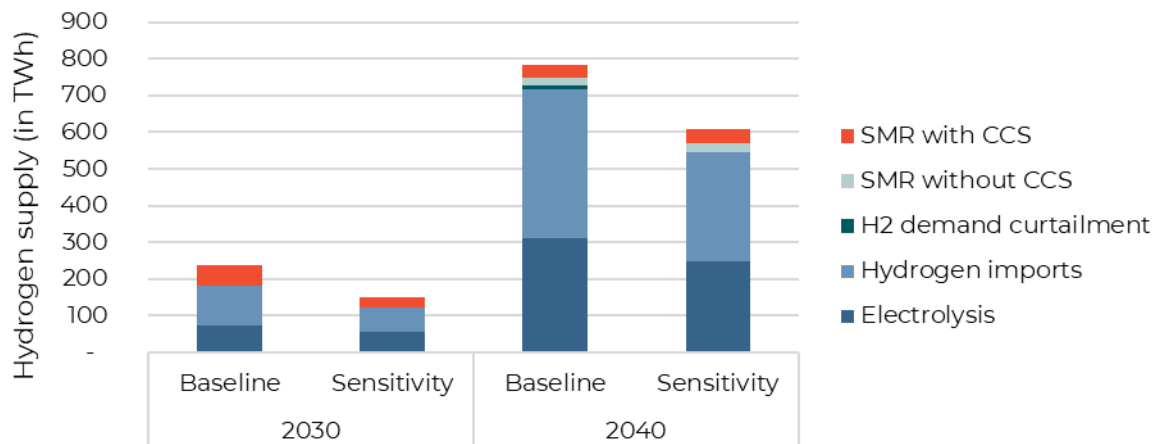
- A slower development of hydrogen demand, particularly for end-uses in the residential and tertiary sectors, as well as power generation¹⁷⁸. The delayed adoption of hydrogen in certain applications leads to higher methane consumption.

¹⁷⁸ In the TYNDP NT+ scenario, hydrogen demand is considered in the residential and tertiary sectors and reaches 7 TWh in 2030 and increases to 48 TWh by 2040 in the BEMIP region. Given the lack of consensus on these end-uses, the sensitivity scenario assumes no hydrogen demand in the residential and tertiary sectors.

- A delayed development of offshore wind and electrolysis.
- Reduced hydrogen imports from outside the BEMIP region.
- Member State-specific adjustments to biomethane supply.

The 2050 horizon is not modified and remains aligned with the TYNDP DE scenario, only 2030 and 2040 intermediate points of the trajectory are affected. Detailed sensitivity analysis assumptions are described in the dedicated modelling annex E. Hydrogen supply differences between baseline and sensitivity scenarios are shown in Figure 5-17.

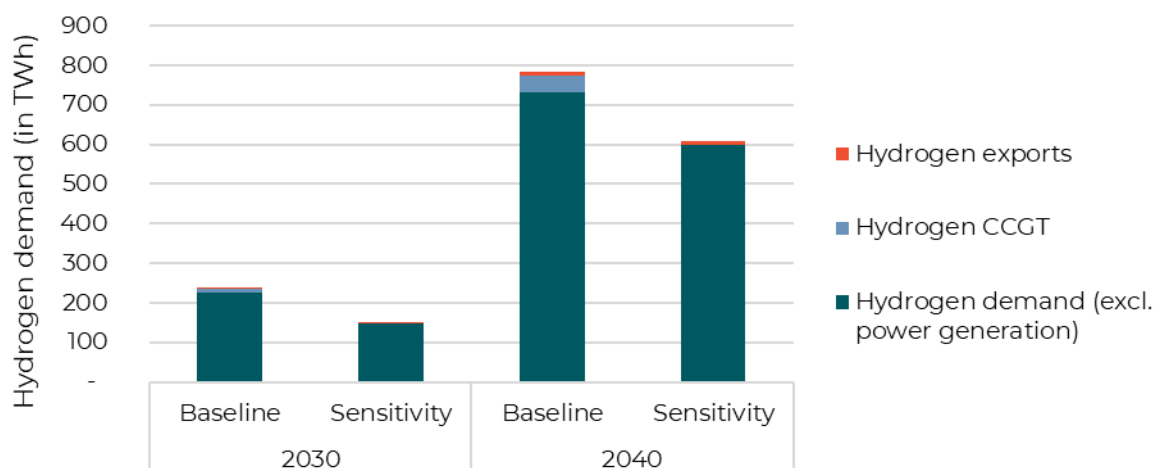
Figure 5-17 Hydrogen supply in the baseline and sensitivity scenarios



Source: Artelys modelling

As a result, hydrogen consumption decreases to 150 TWh in 2030 (instead of 234 TWh in the baseline scenario) and to 600 TWh in 2040 (instead of 774 TWh in the baseline scenario), as shown in Figure 5-18. Besides, hydrogen-fired power plants from the baseline scenario are assumed to remain methane power plants in 2030 and 2040. Since hydrogen consumption in the residential and tertiary sectors is not considered in the sensitivity scenario for 2030/2040 (unlike in the baseline scenario), hydrogen consumption profiles have been adjusted accordingly, affecting the seasonality of hydrogen demand.

Figure 5-18 Hydrogen demand in the baseline and sensitivity scenarios



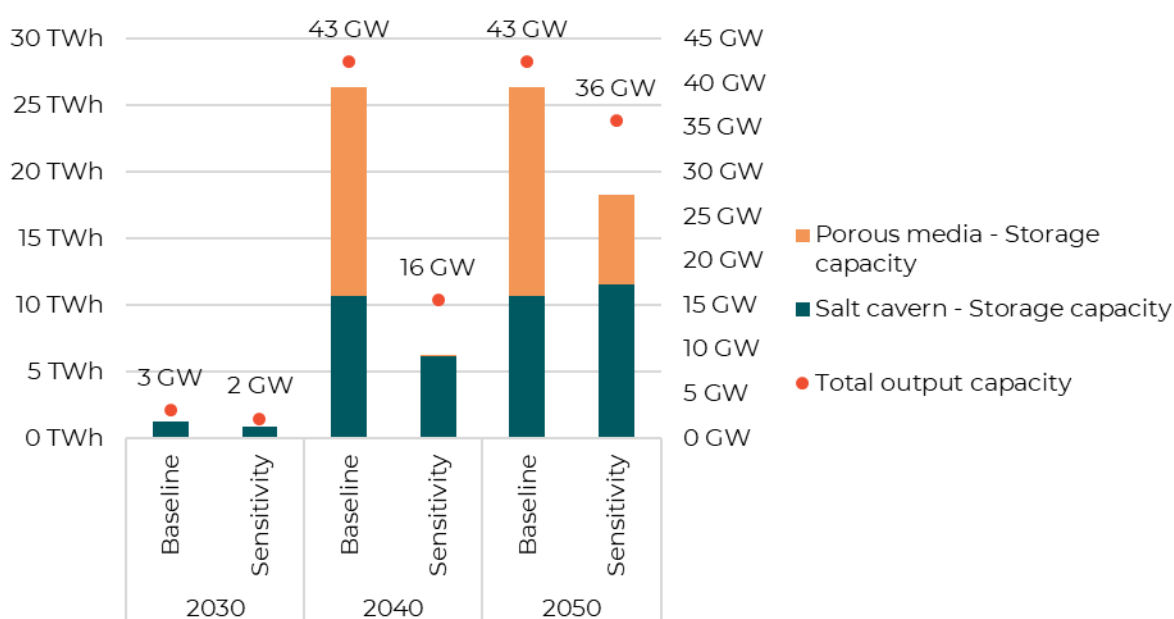
Source: Artelys modelling.

Note: Marginal volumes of hydrogen are exported from Germany to neighbouring countries, following the results of the TYNDP scenarios.

Sensitivity assumptions mainly impact hydrogen storage needs, especially from 2040 onward (see Figure 5-19). In 2030, hydrogen storage capacity installed by the model decreases from 1.3 TWh in the baseline scenario to 0.9 TWh in the sensitivity scenario. In 2040, the hydrogen storage need is significantly reduced, decreasing from 26 TWh to 6.2 TWh. In 2050, storage capacity remains lower in the sensitivity scenario (19 TWh), despite hydrogen demand being the same as in the baseline scenario. This indicates that in the reference modelling run, storage needs peak in 2040 rather than in 2050. It also highlights the impact of hydrogen-fired power generation on hydrogen storage needs, since in the baseline scenario, hydrogen power plants are mostly used in 2040.

The distribution of hydrogen storage capacities across BEMIP MSs is detailed in Figure 5-20. It is worth noting that the hydrogen storage capacity need is mostly impacted in Germany, where hydrogen consumption is mostly impacted by the sensitivity analysis (consumption of hydrogen in buildings and for power generation are most significant in Germany in the baseline scenario, according to NT+ scenario). This figure also highlights that in 2050, most of the hydrogen storage capacities in the sensitivity scenario are newly built infrastructure, whereas in the baseline scenario, they are primarily repurposed from existing natural gas storage facilities. Indeed, in the baseline scenario, the model repurposes significant methane storage capacities to hydrogen in 2040. In the sensitivity analysis, since the hydrogen storage need is much lower in 2040, these methane storage capacities are rather decommissioned than repurposed. As a consequence, the model needs to invest more in new storage capacities when the hydrogen storage capacity need increases in 2050¹⁷⁹.

Figure 5-19 Hydrogen storage capacities in the baseline and sensitivity scenarios

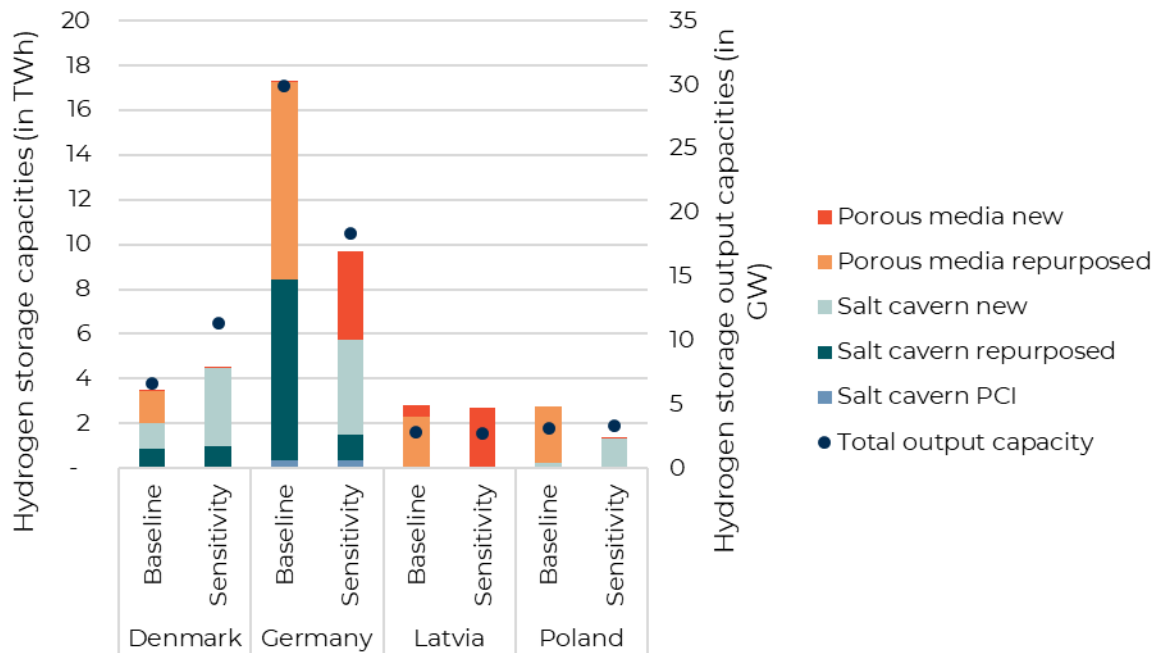


Source: Artelys modelling

Note: The left axis represents storage capacities in TWh, the right axis represents total output capacity in GW (i.e. capacity for withdrawal from storage to the network, supposed to be equal to injection capacities).

¹⁷⁹ This illustrates a conservative assumption in the model: decommissioned capacities cannot be repurposed, while maintaining a capacity to repurpose it later incurs additional fixed operating costs. Overall, this assumption has little impact on total storage capacity and rather influences the shares of new and repurposed storage infrastructures.

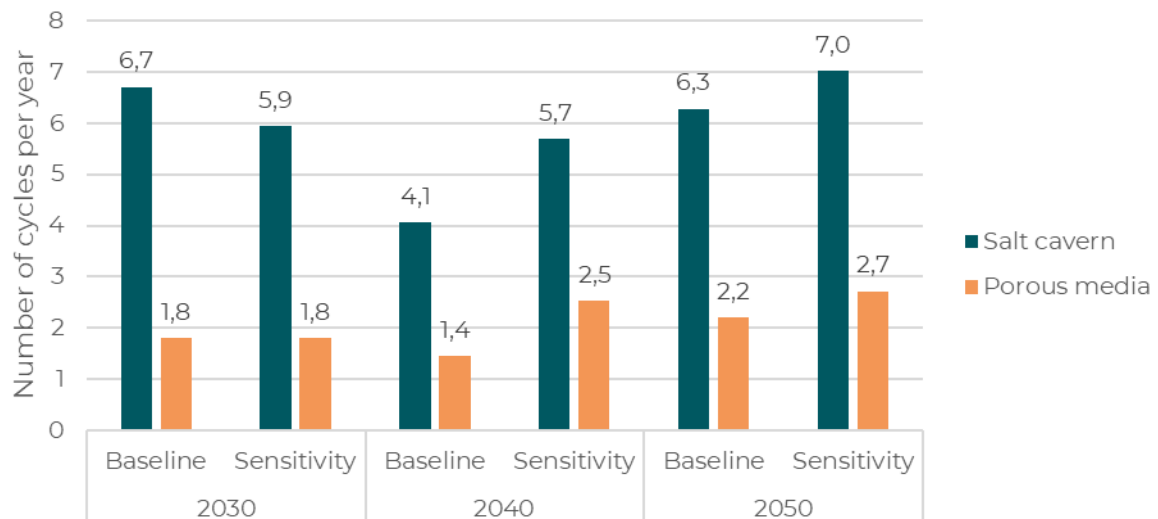
Figure 5-20 Hydrogen storage capacities in 2050 in the baseline and sensitivity scenarios, detailed by technology and by country



Source: Artelys modelling

Due to significantly lower storage capacity in the sensitivity scenario, hydrogen storage facilities show higher cycling rates in the sensitivity scenario compared to the baseline scenario in 2040 and 2050, as shown in Figure 5-21. In 2030, the storage cycle rate is slightly lower in the sensitivity scenario compared to the baseline scenario since storage capacities remain relatively unchanged between the baseline and sensitivity scenarios, while hydrogen demand and production decrease significantly.

Figure 5-21 Hydrogen storage cycling rates in the baseline and sensitivity scenarios (in cycles per year)



Source: Artelys modelling

In 2040, the seasonality of hydrogen storage is also affected (see Figure 5-22 and Figure 5-23). In the baseline scenario, the storage level curve shows strong seasonal variations, looking like typical natural gas storage level curves, with storage level peaking after summer and reaching its minimum after winter. However, this seasonality disappears in the sensitivity scenario. This change is primarily due

to the removal of seasonal variations from hydrogen demand¹⁸⁰ profiles and the absence of hydrogen-fuelled power generation in 2040 in the sensitivity scenario. In the baseline scenario, the storage usage is rather driven by the seasonal variations in demand, while in the sensitivity analysis it is rather driven by short-term variations in hydrogen production of electrolyzers (in correlation to the variations of renewable power generation).

Figure 5-22 Hydrogen storage levels in 2040 in the baseline scenario



Source: Artelys modelling

Figure 5-23 Hydrogen storage levels in 2040 in the sensitivity scenario

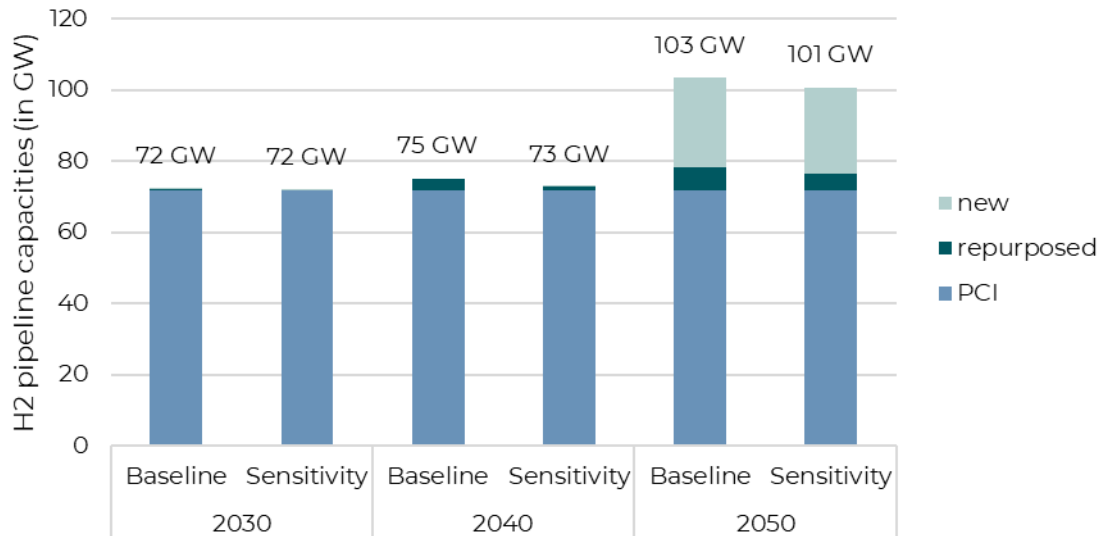


Source: Artelys modelling

The impact of the sensitivity assumptions on hydrogen pipeline capacities remains moderate, primarily due to the high share of already planned PCIs in transmission capacity needs identified by the model in 2030 and 2040. As a result, hydrogen pipeline capacities remain almost unchanged in 2030. In 2040, the impact is marginal, with slightly less repurposing of methane pipeline infrastructure for hydrogen transport. In 2040, the average hydrogen pipeline capacity factor decreases from 38% to 34%. In 2050, hydrogen cross-border capacities are marginally lower in the sensitivity scenario than in the baseline scenario (3%).

¹⁸⁰ As a reminder, the sensitivity analysis assumes no hydrogen consumption in residential and tertiary in 2030 and 2040.

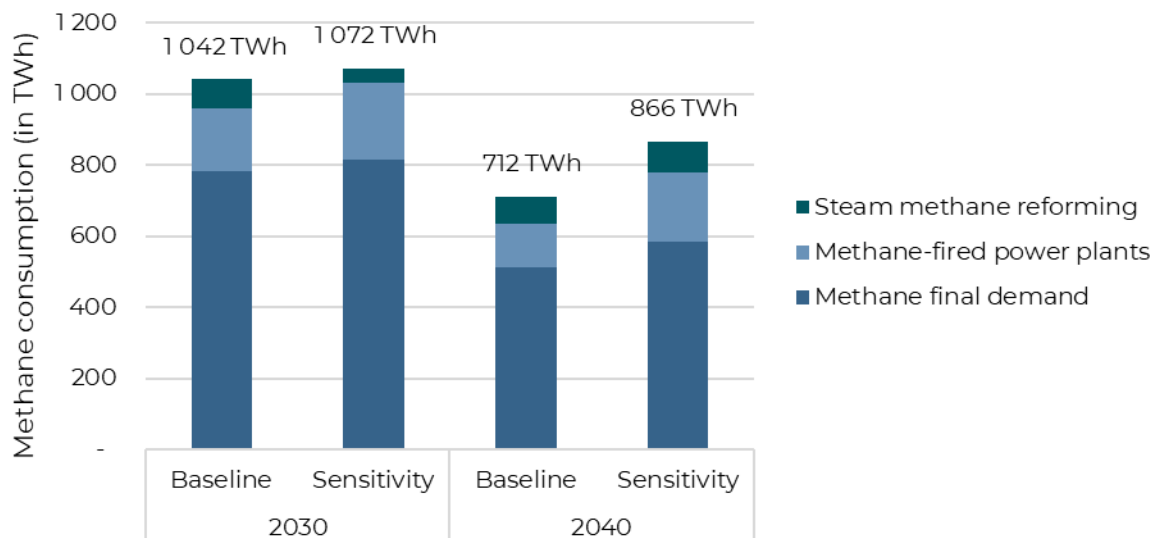
Figure 5-24 Aggregated hydrogen pipeline cross-border capacities in the baseline and sensitivity scenarios



Source: Artelys modelling

Since part of methane consumption is no longer replaced by hydrogen for some end-uses in the sensitivity scenario, final methane demand increases by 32 TWh in 2030 and 72 TWh in 2040. Moreover, gas-fired CCGTs¹⁸¹ replace hydrogen-fired CCGTs, and their gas consumption increases by 40 TWh in 2030 and 76 TWh in 2040. As a result, gas imports rise, and the model keeps an additional 2 GW of methane pipeline capacity (37 GW in the sensitivity scenario vs. 35 GW in the baseline, as shown in Figure 5-26) and 2 TWh more of methane storage (21 TWh in the sensitivity scenario vs. 19 TWh in the baseline, as shown in Figure 5-27) in 2040.

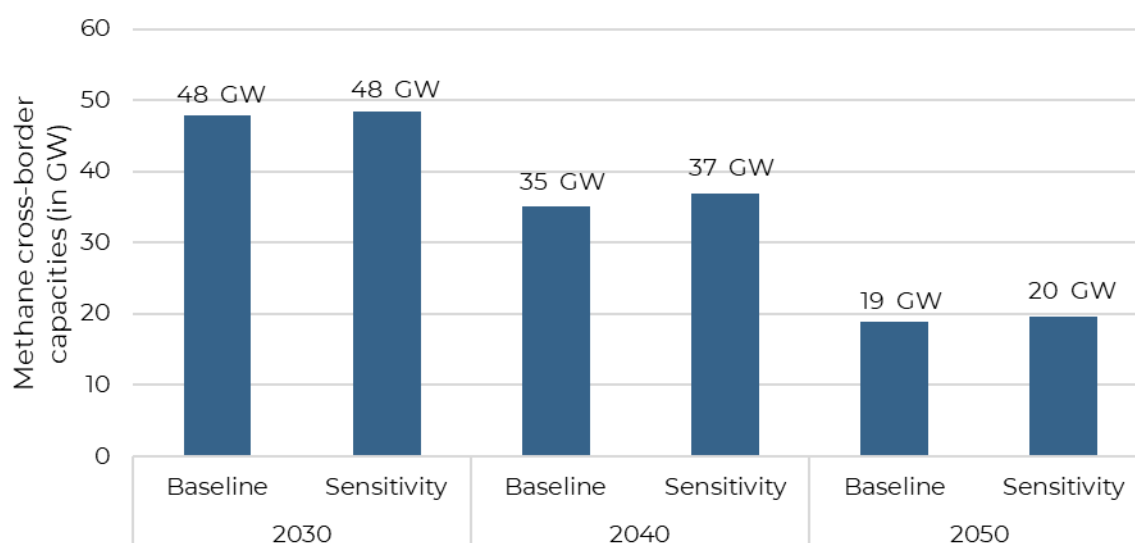
Figure 5-25 Methane consumption in the baseline and sensitivity scenarios



Source: Artelys modelling

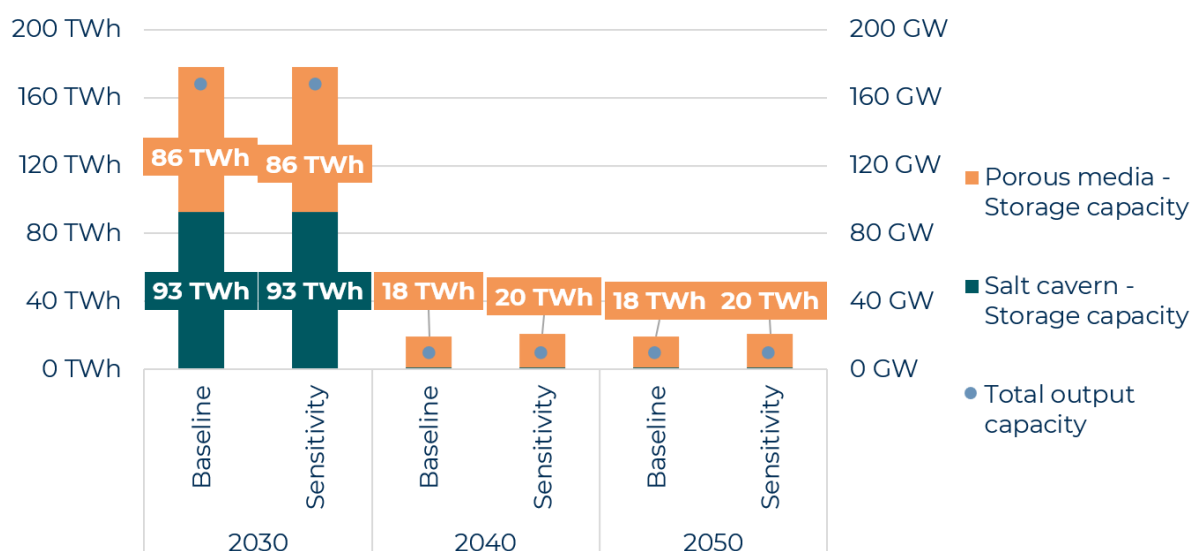
¹⁸¹ CCGT: Combined-cycle gas turbine

Figure 5-26 Methane cross-border capacities in the baseline and sensitivity scenarios



Source: Artelys modelling

Figure 5-27 Methane storage capacities in the baseline and sensitivity scenarios



Source: Artelys modelling

5.2.3. Sector integration/coupling and impacts

The term sector coupling originally refers to connecting the methane and electricity sectors¹⁸². Sector integration, also known as energy system integration, is a broader term - **referring to the interconnection of various energy carriers and sectors - specifically methane, hydrogen, electricity, and heat systems - encompassing both markets and infrastructure**¹⁸³. Integrated system planning is essential for the effective integration of hydrogen, biomethane and electricity in the EU and within the BEMIP MSs. The EU's Energy System Integration Strategy^{184,185} describes sector

¹⁸² Florence School of Regulation (2020): [Sector Coupling and Energy System Integration](#)

¹⁸³ Hydrogen Europe (2024): [Hydrogen Infrastructure: The Recipe for a Hydrogen Grid Plan](#)

¹⁸⁴ COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS [Powering a climate-neutral economy: An EU Strategy for Energy System Integration](#)

¹⁸⁵ Trinomics, LBST et. al (2024): [Study on promoting energy system integration through the increased role of renewable electricity, decentralised assets and hydrogen](#)

integration as the **interlinkage of various energy carriers** — not limited to electricity and gas but also heat, cold, and solid and liquid fuels — across end-use sectors including heating, transport, and industrial production. The six pillars of this strategy are:

1. Circular energy system with energy efficiency first
2. Direct electrification of end-uses
3. **Renewable and low-carbon fuels to decarbonise hard-to-electrify sectors**
4. Integrated energy markets and distributed resources
5. **Integrated energy infrastructure**
6. Energy system digitalization and innovation.

The boundaries between sector coupling and sector integration often fade, as they both impact each other bi-directionally and are linked by energy infrastructure that adds technical, geographical, and economical layers to the system. This section briefly reviews the relevant EU regulatory framework for cross-sectoral infrastructure planning, before analysing the current state and challenges for energy system integration and integrated infrastructure planning in the BEMIP region.

EU regulatory frameworks for cross-sectoral infrastructure planning

The development of **renewable and low-carbon gas infrastructure** faces several challenges, which arise in parallel to challenges observed in electricity networks. The widespread deployment of these gases will pose new challenges to the EU energy system as a whole and will lead to the emergence of new and repurposed infrastructure assets - but **these assets must be able to interact not only with each other, but with electricity and heat/cold networks, too**. For this, firstly (as discussed above), regulators and the energy sector **must transition from siloed planning to a cross-sectoral network planning approach**. This has been called for by multiple agencies and stakeholders, and has been recognized in the EU Strategy for Energy System Integration¹⁸⁶ as well as in several legislative and strategic documents.

The **TEN-E Regulation**¹⁸⁷ lays down the rules for the timely development and interoperability of trans-EU energy networks and calls for the integration of renewables and new clean energy technologies into the energy system. Some of the main changes in comparison to the previous version of the TEN-E Regulation are: the exclusion of natural gas infrastructure projects, the inclusion of electrolyser and hydrogen infrastructure projects, smart gas grid projects, a stronger focus on offshore wind development, and a new category of projects with third countries, namely PMIs (Projects of Mutual Interest).

The **EU Hydrogen Strategy** emphasizes the importance of coordinated infrastructure planning across electricity, (bio)methane, and hydrogen networks, and the **Hydrogen and Decarbonised Gas Market Package**¹⁸⁸ imposes the development of joint scenarios for these carriers at national level in network planning. In a 2024 opinion, ACER welcomes some progress in joint gas and electricity scenarios already, but notes that the majority of MS still need to make progress towards integrated planning, as sector-integrated modelling of electricity and gas sectors is not common yet - with only three NRAs using it in their gas Network Development Plans.¹⁸⁹

For more coordinated **cross-border infrastructure planning**, the TYNDP 2024 supports the process at the European and regional level, as it is the first TYNDP introducing specific hydrogen project

¹⁸⁶ EC (2020): [COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Powering a climate-neutral economy: An EU Strategy for Energy System Integration](#)

¹⁸⁷ EC (2022): [Regulation \(EU\) 2022/869 to the European Parliament and the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations \(EC\) No 715/2009, \(EU\) 2019/942 and \(EU\) 2019/943 and Directives 2009/73/EC and \(EU\) 2019/944, and repealing Regulation \(EU\) No 347/2013; OJ L 152, 3.6.2022, p. 45\]](#)

¹⁸⁸ European Commission (2024): [Hydrogen and decarbonised gas market](#)

¹⁸⁹ ACER (2024): [Opinion on the review of gas and hydrogen national Network Development Plans to assess their consistency with the EU Ten-Year Network Development Plan](#)

categories. ENTSOG is applying system integration principles in its various methodologies used in gas network planning: for scenario development, infrastructure needs assessments and for the cost-benefit allocations (CBAs) assessing the contribution of specific projects. The integration of energy carriers is captured in two dual models, which examine interactions between the electric and hydrogen systems, and between the hydrogen and natural gas systems¹⁹⁰. **In the future, ENTSO-E, ENTSOG and ENNOH will develop infrastructure scenarios jointly to ensure that system planning takes into account all carriers and vectors of the future energy system.**

Beneficial investments for sector integration, sector coupling and main policy objectives

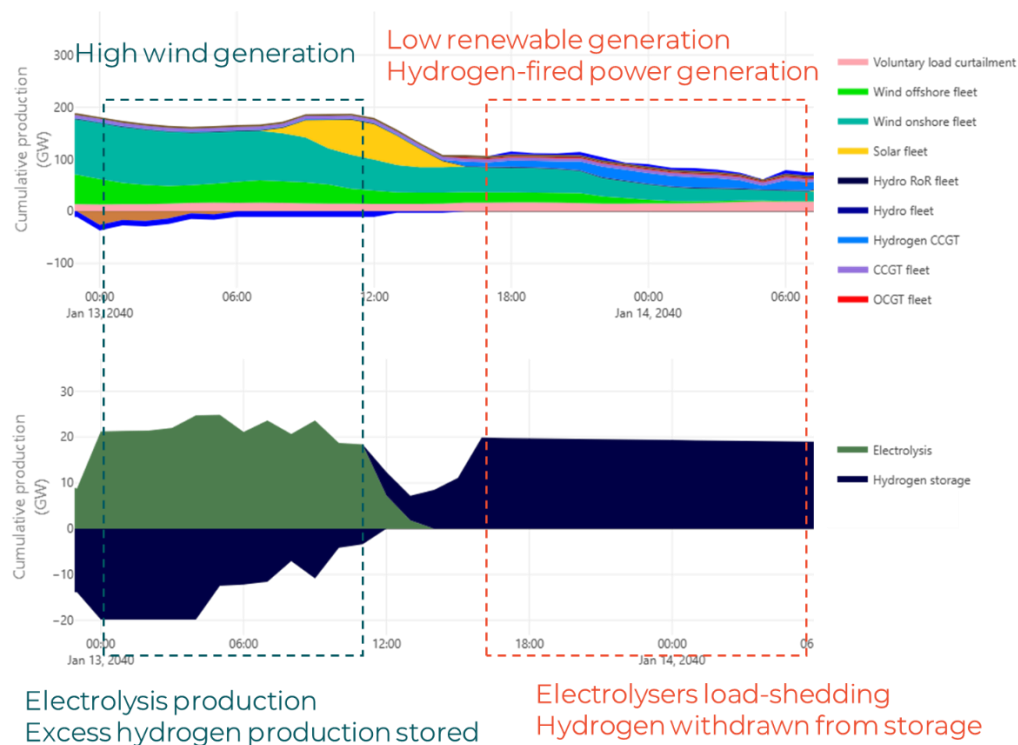
As described in section 5.1, the model developed in this study explicitly represents sector coupling by integrating key interlinkages between hydrogen, gas and electricity systems:

- Electrolysis
- Hydrogen-to-power assets
- Gas-to-power assets
- Steam methane reforming

This integration highlights the potential of hydrogen to provide flexibility, particularly by alleviating constraints in the power system. For instance, electrolyzers may produce hydrogen during periods of high renewable energy generation, enabling hydrogen to be stored and later used for final consumption or in hydrogen turbines when renewable electricity generation is low, as shown in Figure 5-28. In this example, on January 13th, renewable generation peaks between 00:00 and 12:00, resulting in significant hydrogen production via electrolysis and subsequent storage. From 18:00, wind generation decreases significantly, electrolyzers ramp down while hydrogen CCGTs start to produce electricity, and hydrogen is withdrawn from storages to meet the increased hydrogen demand.

¹⁹⁰ Based on ENTSOG presentation on integrated energy system planning, 04 November 2024

Figure 5-28: Power generation (top), electrolysis and hydrogen storage production in Germany (bottom), in January 2040 (Source: Artelys)



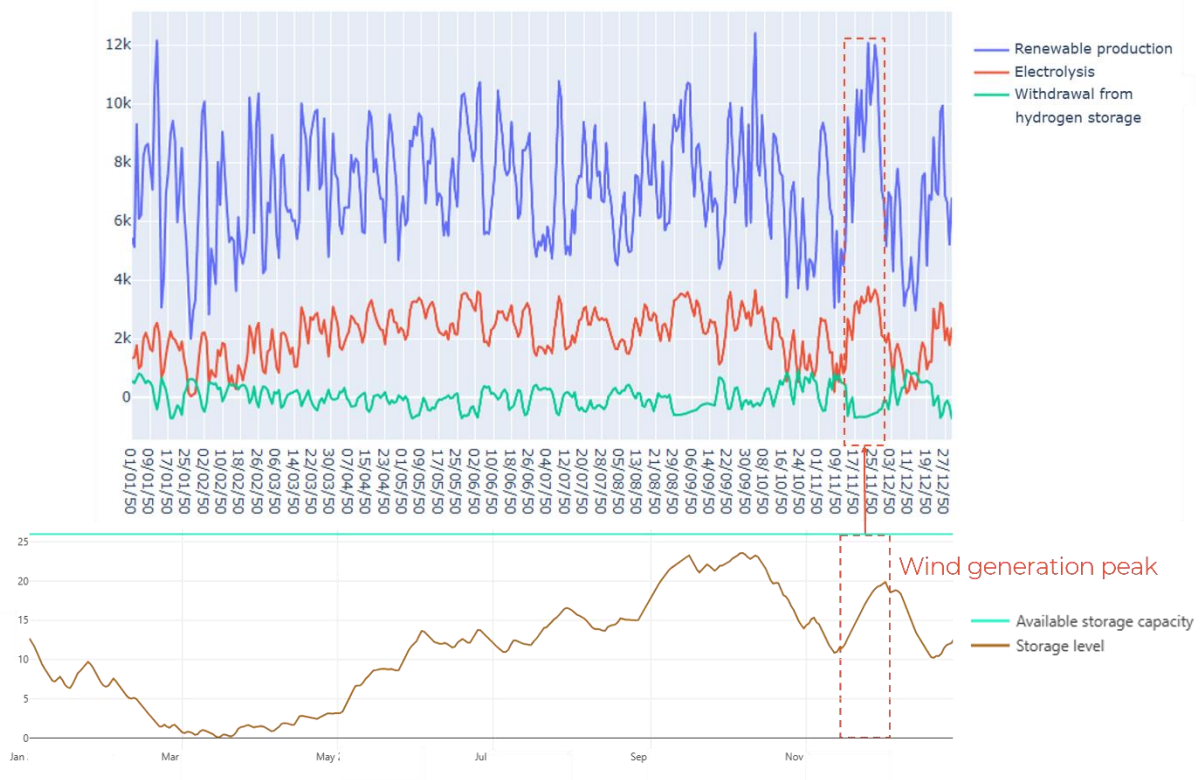
Source: Artelys modelling

Note: Negative hydrogen storage production corresponds to hydrogen consumption by storage assets. Hydro RoR fleet refers to run-of-river hydroelectric power generation assets.

Hydrogen production through electrolysis is thus correlated with variable renewable electricity generation all year long, as shown in Figure 5-29. Hydrogen storage further enhances system flexibility by storing surplus hydrogen during periods of high renewable generation and releasing it during lower production periods. In Figure 5-29, the storage levels show seasonal variations and tend to increase during summer. In the displayed example, a period of high wind generation in November leads to a fast filling of hydrogen storage assets.

Adequate hydrogen storage capacity thus enables greater hydrogen production and storage during peak renewable generation, thereby improving the overall flexibility and efficiency of the energy system. This flexibility results in a load factor for electrolyzers averaging around 54% in 2050.

Figure 5-29 Daily renewable electricity generation, generation of hydrogen, and withdrawal from hydrogen storages (top, in GWh/d) and aggregated hydrogen storage level in BEMIP region across the year (bottom, in TWh).



Source: Artelys modelling

Note: In the first figure, a negative withdrawal from hydrogen storage correspond to hydrogen injection into storage assets.

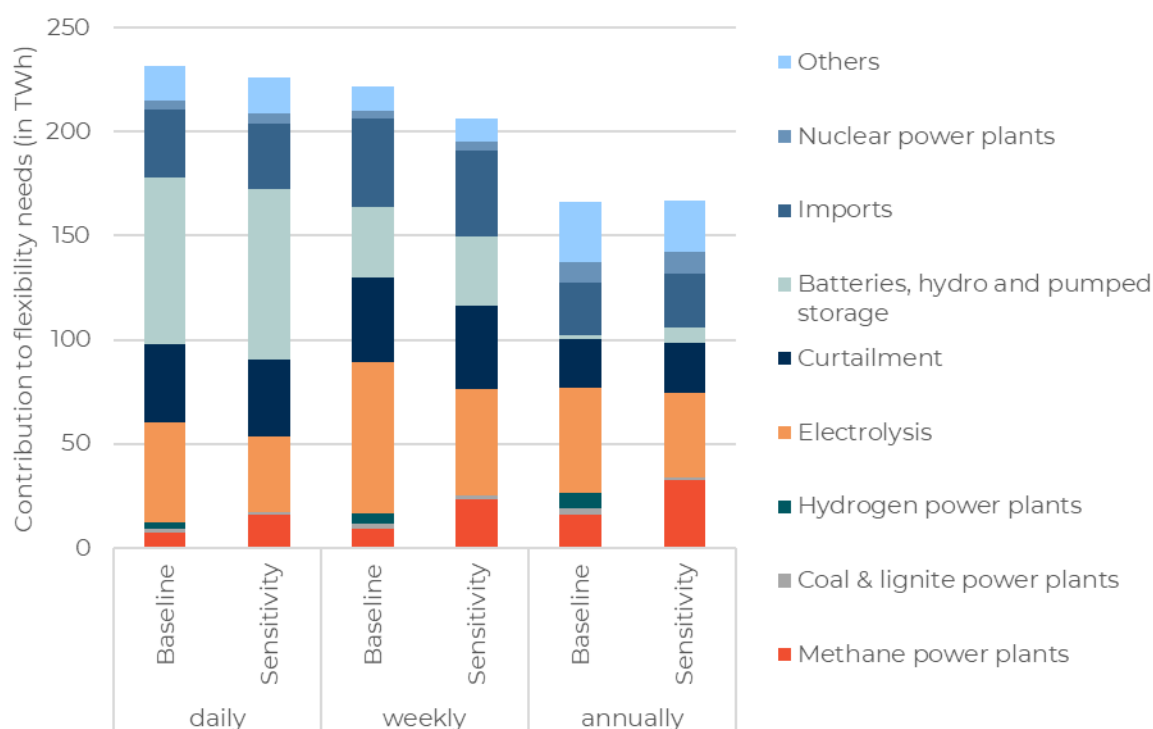
These results illustrate that electrolysis is a source of flexibility for the power system. Figure 5-30 below details the contribution of each technology to power system flexibility needs in 2040 comparing both the baseline and sensitivity scenarios.

Flexibility needs are a metric that captures the dynamics in the residual load¹⁹¹ on daily, weekly, and yearly timescales. For instance, the daily flexibility needs measure to which extent the residual load tends to deviate from its daily average, and similarly for other timescales. For instance, the integration of solar PV mostly increases daily flexibility needs, due to the daily variations in solar irradiation, while wind power mostly impacts weekly and seasonal flexibility needs. The contribution of a given technology to flexibility needs, on the other hand, measures to which extent an asset tends to vary its generation and/or consumption in a direction that adapts to the variations of the residual load, on

¹⁹¹ The residual load is defined as the load that has to be served by dispatchable technologies (e.g. thermal, hydro, storage, demand-response, interconnectors, etc.), it is computed by subtracting the wind, solar and must-run generation from the non-flexible demand.

the same timescale. Similarly, it is calculated based on the variations of the asset production/consumption compared to its average¹⁹².

Figure 5-30 Contribution to flexibility per technologies in 2040, in the baseline and sensitivity scenarios



Source: Artelys modelling

Figure 5-30 shows that battery storage primarily addresses daily-scale flexibility needs, while electrolyzers contribute to flexibility across all timescales, with a somewhat stronger role at the weekly level. Daily and weekly flexibility needs are reduced in the sensitivity scenario compared to the baseline scenario, by 3% and 7% respectively. This is consistent with the lower renewable production from wind offshore in the sensitivity scenario, it is noticeable that the most significant decrease in flexibility needs occurs at the weekly scale, since offshore wind production patterns typically fluctuate on a weekly scale.

Across all timescales, methane power plants play a greater role in flexibility in the sensitivity scenario compared to the baseline, notably compensating for the removal of hydrogen power plants. Conventional flexibility sources - such as batteries, hydropower and pumped storage - are marginally impacted, as well as imports, intra-BEMIP exchanges, nuclear generation and curtailment.

Considering the decrease in hydrogen consumption and electrolysis capacity, the contribution of electrolyzers decreases significantly in the sensitivity scenario, particularly at weekly scale. This drives an increase in the contribution of thermal generation to flexibility needs. Besides, while the contribution of curtailment to flexibility need is not significantly impacted, its share in the total flexibility needs is also slightly higher in the sensitivity analysis.

In summary, electrolyzers provide less flexibility in the sensitivity scenario compared to the baseline scenario, while thermal power plants' overall contribution increases. The flexibility role previously held by hydrogen power plants is instead fulfilled by methane power plants. This illustrates the benefits of

¹⁹² More information on the methodology used to compute these metrics can be found in [Mainstreaming RES](#) study report.

sector coupling, and particularly the benefits of flexible operation of electrolyzers, coupled with underground hydrogen storage.

5.3. Infrastructure priorities for the higher uptake of renewable and low-carbon gases for the BEMIP region

The key results and conclusions drawn from the modelling exercise are presented in this section.

In the baseline scenario, in the 2030 horizon, the BEMIP region remains a hydrogen and methane importer. The hydrogen network is mostly used to redistribute imports from outside of the BEMIP region and presents a low level of usage. No investment in cross-border transmission capacities is foreseen by the model, apart from the base PCI layer which is to be implemented as minimum capacity, and marginal investment in storage is observed compared to the PCI layer. The low level of usage of the infrastructure illustrates the anticipation of higher volumes of hydrogen transiting through the networks in the medium- to long-term.

In the 2040 horizon, Denmark and Finland become net exporters of hydrogen while Germany and Poland remain the main importers. Overall usage of the hydrogen network significantly increases compared to 2030. The model mainly foresees significant investment needs in hydrogen storage, with a storage capacity reaching 26 TWh compared to 1.3 TWh in 2030. This reflects the low relative share of hydrogen storage projects in the BEMIP region on the first PCI/PMI list of 2024 compared to hydrogen transmission projects (only three hydrogen storage projects in the BEMIP region on the list).

In the 2050 horizon, Germany and Poland remain the only net hydrogen importers while exports from Finland and Denmark significantly increase; the other BEMIP MSs are self-sufficient. Hydrogen storage capacity remains stable while investment in new hydrogen transmission capacities occur, mostly in the corridors ranging from Sweden to Germany through Denmark and from Finland to Poland.

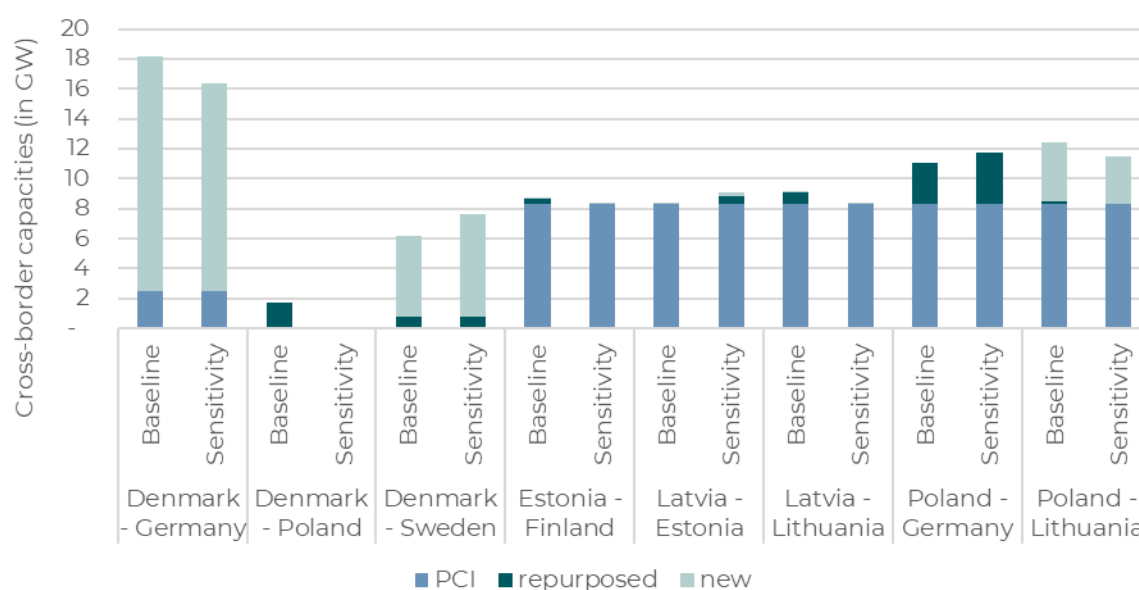
In the sensitivity analysis scenario, cross-border hydrogen transmission capacity needs are little impacted. However, the slower development of hydrogen demand strongly impacts the identified storage capacity need in 2040 (decreasing from 26 TWh to 6 TWh), but the impact is less marked in 2050 (from 26 TWh to 19 TWh). Based on the DE scenario assumptions for 2050, the modelled scenarios identify hydrogen storage capacity needs in the range of 19-26 TWh for BEMIP MSs in 2050, with an intermediate capacity need in 2040 which is strongly impacted by the rate of development of hydrogen demand. Considering the timeline for the implementation of such infrastructure projects (typically in the range of 5-10 years), the development of hydrogen storage appears as an infrastructure priority, even in the case of delayed development in hydrogen demand. Indeed, while the model identifies increased hydrogen storage capacity needs in Denmark, Germany, Latvia and Poland, planned projects are mostly concentrated in Germany. Indeed, based on the TYNDP 2024 projects list¹⁹³, there is currently no planned project in Latvia, and only one project each in Denmark and Poland.

Besides, comparing the baseline and sensitivity scenarios, some no-regret investments in hydrogen pipelines can be identified beyond the already planned PCIs (see Figure 5-31). These notably include cross-border capacity expansion between Denmark and Germany (16 to 18 GW needed by 2050), due to the high hydrogen production in Denmark, as well as between Sweden and Denmark (6 to 8 GW needed by 2050), where the current PCI level is less developed. Additionally, transmission capacities between Poland and Germany, as well as Poland and Lithuania, require reinforcement in both scenarios¹⁹⁴.

¹⁹³ *ENTSOG (2024): TYNDP 2024 Annex-A, Projects*

¹⁹⁴ *Conversely, the model does not foresee the repurposing of Denmark-Poland pipeline in the sensitivity analysis, which is compensated by an increase of the capacity between Germany and Poland.*

Figure 5-31 Cross-border hydrogen capacities in 2050 in the baseline and sensitivity scenarios



Source: Artelys modelling

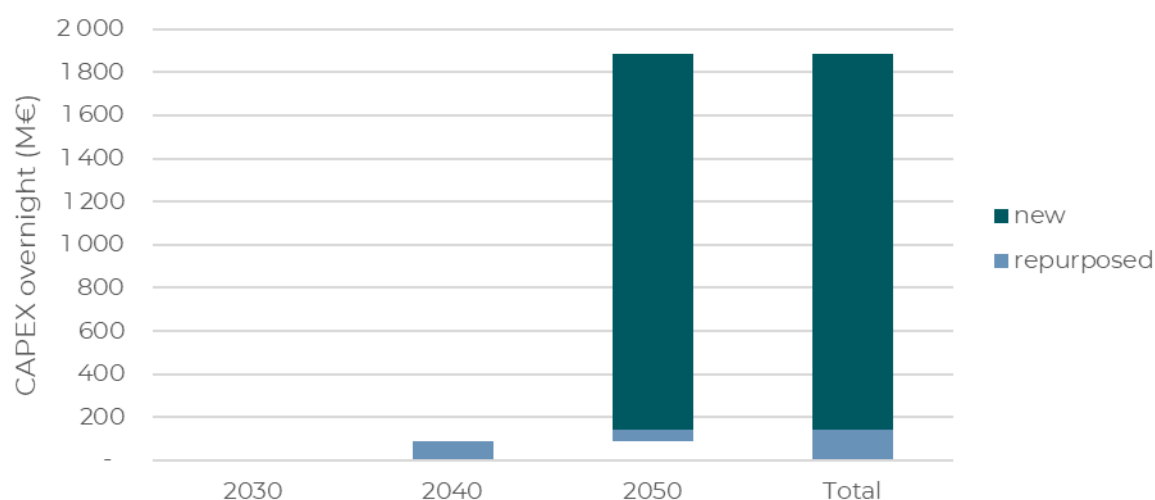
Note: In none of the scenarios does the model see the need for additional cross-border capacity beyond the PCI projects on the Sweden-Finland border and on the BHC route. Therefore, capacities associated to these projects are not presented on this figure.

In the baseline scenario, total investments required by 2050 amount to €14 billion for hydrogen storage and €31 billion for hydrogen cross-border capacities (including already planned PCIs)¹⁹⁵. Regarding cross-border capacities, only €1.9 billion of additional CAPEX investment is foreseen by the model (see details on Figure 5-32), with most occurring by 2050. The remaining €29.1 billion correspond to estimated CAPEX costs for PCI projects. It is to be noted that these figures exclude the costs related to internal hydrogen networks which are not represented in the model.

Conversely, investments in storage PCIs represent only a marginal share of the total identified hydrogen storage CAPEX, as illustrated in Figure 5-33. The majority of hydrogen storage investments occur by 2040 in the baseline scenario, with no additional investments foreseen in 2050. In the sensitivity scenario, total overnight CAPEX for hydrogen storage increases slightly from €14 billion to €14.5 billion, reflecting a shift toward more new storage capacities and fewer repurposed ones. CAPEX for hydrogen pipelines remains nearly unchanged in the sensitivity analysis.

¹⁹⁵ These costs represent total CAPEX and do not include operational costs.

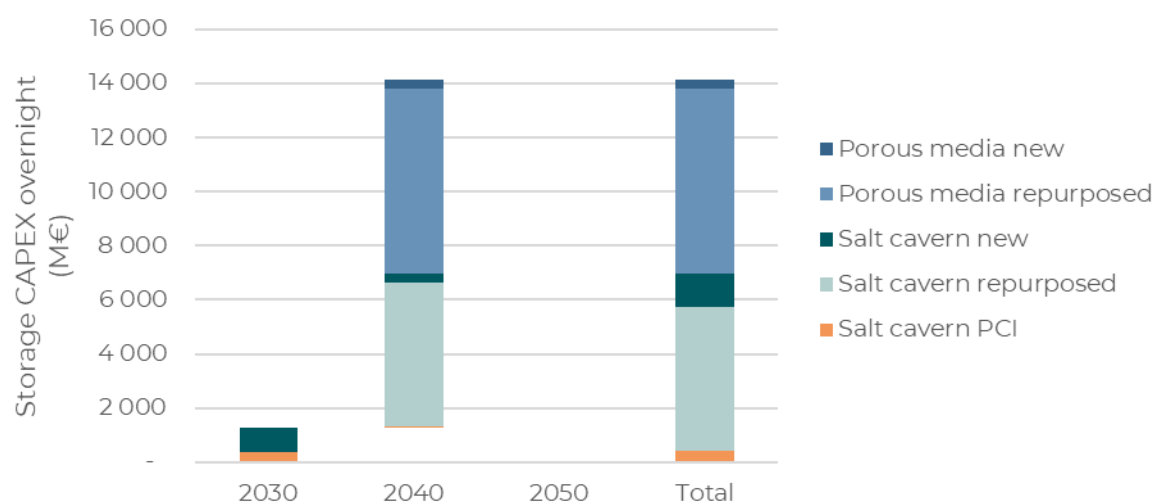
Figure 5-32 Distribution of hydrogen pipeline overnight CAPEX in the baseline scenario (excluding PCI costs)



Source: Artelys modelling

Note: This graph displays investments made by the model at each time horizon. The "Total" column represents cumulated investments over the whole period (2030 to 2050). Only the investments identified by the model beyond the already planned PCIs are represented in this figure, investment costs corresponding to PCIs projects represent €29.1 billion.

Figure 5-33 Distribution of hydrogen storage overnight CAPEX in the baseline scenario



Source: Artelys modelling

The scenarios considered in the analysis foresee a decrease of methane consumption, which is eventually supplied in 2050 only by domestic production of biomethane and synthetic methane, consistent with climate neutrality goals. Therefore, methane flow patterns are expected to vary, with the apparition of two corridors converging towards Poland and Germany, with Finland, Sweden and Denmark becoming main exporters of biomethane and synthetic methane.¹⁹⁶ A consequence is that certain methane infrastructure remains necessary in the 2050 BEMIP energy system, all along the corridors ranging from Finland to Poland via the Baltic states and from Sweden and Denmark to Poland and Germany. In the scenarios, BEMIP domestic biomethane production increases from

¹⁹⁶ According to the DE scenario assumptions for 2050, Germany also produces more biomethane/synthetic methane than domestic consumption, these volumes are exported towards the rest of Europe.

around 70-100 TWh in 2030 to around 150 TWh in 2050. As discussed in section 4.2.2, the integration of these volumes of biomethane in methane networks also poses several infrastructure challenges.

The sensitivity analysis eventually shows that, besides technical considerations, the potential for repurposing or decommissioning methane storage and transport infrastructure will also depend on the rate of decrease of methane consumption. It is noteworthy that the modelling exercise does not aim at performing a detailed methane Security of Supply analysis, and considering the ability of the system to withstand security of supply risks might also result in lower potentials for the repurposing of methane infrastructure.

6. Conclusions and recommendations

This Chapter provides the conclusions regarding the integration of renewable and low-carbon gases in the existing infrastructure, as well as the necessity of additional investments beyond the existing plans (in terms of upgrades and on top of the PCIs of the first Union list of 2024) based on the results of the literature review and the modelling exercise. The Chapter also reflects on the main challenges of infrastructure development, both for biomethane and for renewable and low-carbon hydrogen in terms of integration, standardization, safety, etc. It then concludes with the recommendations to address these challenges including an advisable timeline, also reflecting on any additional barriers the problem-owners might face in the implementation.

6.1. Role of methane gases and hydrogen infrastructure and potential energy system interlinkages and synergies

This section provides an overview of the key insights from the modelling described in the previous Chapter. As a reminder, the modelling exercise includes a baseline scenario, aligned with the assumptions of the TYNDP 2024 NT+ (for 2030 and 2040) and DE (for 2050) scenarios, as well as a sensitivity analysis scenario assessing the impact of a delayed development of hydrogen.

Role of gas infrastructure for the integration of biomethane

In the baseline scenario considered in this study (which reflects external scenarios and targets reviewed in Chapter 2), between 2030 and 2050, overall BEMIP methane demand decreases as it is progressively replaced by hydrogen and electricity for several end-uses¹⁹⁷. Simultaneously, natural gas supply is phased out, partially replaced by biomethane (and to some extent synthetic methane) production. Those changes in methane supply and demand modify the methane infrastructure needs in the BEMIP region.

Although methane cross-border pipeline and storage capacity needs decrease, part of the methane infrastructure capacities remain necessary in 2050 due to residual methane demand (primarily in Poland and Germany) and due to high biomethane injection into the grid. According to the TYNDP 2024 DE scenario, this residual methane demand is supplied via biomethane and synthetic methane, consistently with the EU and national carbon neutrality objectives. Consequently, the model does not fully repurpose or decommission all methane pipelines and storage facilities. By 2050, 19 GW of methane cross-border capacities are still necessary along the corridors ranging from Finland to Poland via the Baltic states and from Sweden and Denmark to Poland and Germany, representing a 45% reduction in total cross-border capacity in the BEMIP region compared to 2025. Additionally, 18 TWh of methane storage capacities are still necessary, marking a 95% reduction from 2022 levels.

Besides, the integration of significant volumes of biomethane in BEMIP comes with several challenges and the need for adaptations, not only for cross-border but also domestic transmission and distribution grids,¹⁹⁸ which are discussed in sections 4.2.2 and 9.5 (Annex C).

In the sensitivity analysis scenario, which assumes a delayed transition from methane to hydrogen and consequently higher methane demand, the model maintains an additional 2 GW of methane transmission capacity and 2 TWh of methane storage, while repurposing fewer assets to hydrogen. These results highlight that the potential for repurposing and decommissioning methane infrastructure will depend on the rate of decrease of methane consumption. Overall, the repurposing potential might be overestimated, since the model developed for this study does not aim at performing a detailed methane Security of Supply analysis and does not consider internal networks congestion constraints. The results regarding repurposing should therefore be interpreted in light of

¹⁹⁷ Note that methane demand first increases in Poland in the short to mid-term, but total demand decreases in BEMIP.

¹⁹⁸ As discussed in the methodology, adaptations needed to integrate biomethane in gas networks are not captured by the model.

the scenario assumptions, particularly those regarding the gradual decrease of methane consumption¹⁹⁹.

Role of infrastructure for the integration of renewable and low-carbon hydrogen

In the baseline scenario, between 2030 and 2050, hydrogen demand grows from 234 TWh to more than 1 000 TWh in BEMIP and electrolysis develops rapidly. In the 2030 horizon, the model foresees no additional investments in cross-border hydrogen pipelines beyond the projects with current PCI status, with only minimal investments in hydrogen storage. It is to be noted that the model does not represent internal hydrogen networks which are necessary to connect production sites to consumption sites and storage infrastructure within a country. While national hydrogen network development plans already include an extensive network in Germany in 2030, further investments might be required in other BEMIP MSs where internal hydrogen network development plans are less mature. Cross-border pipeline infrastructure shows in 2030 a low utilisation rate, with a capacity-weighted load factor of only 13%. It appears that the hydrogen network intended for 2030 (in terms of PCIs from the first list of 2024) might be oversized in terms of cross-border capacities, relative to the respective consumption and flows in the system. However, this can be explained as ongoing projects are designed to anticipate future needs in the coming decades and there remains a risk of projects not being realized for a variety of reasons. Besides, by 2030 and particularly during the ramp-up phase of the hydrogen market, Germany appears as a major hydrogen transit hub, with imports to Germany from the rest of EU and via import terminals being redistributed to other BEMIP MSs, and especially to Poland. This result originates from the scenario assumptions in terms of available infrastructure allowing to import hydrogen from outside of BEMIP and could be impacted by different assumptions. Still, the expected impact would be limited to infrastructure in Poland and Germany as other BEMIP MSs are net exporters in the long term.

According to the modelling, by 2040, only modest additional investments in cross-border hydrogen pipelines are required compared to the PCIs from the first list of 2024, while investments in hydrogen storage increase significantly. The capacity utilisation of cross-border pipelines rises significantly compared to 2030, with the capacity-weighted load factor of hydrogen transmission PCIs almost tripling to reach 38% along increasing uptake of hydrogen. Particularly the development of hydrogen storage allows synergies between power and hydrogen, with electrolyzers contributing to the flexibility of the electricity system.

Most investments in hydrogen pipelines in addition to the first PCI/PMI list occur between 2040 and 2050, with 32 GW of additional capacities required to complement the PCIs, mostly located at the borders of Sweden-Denmark, Denmark-Germany and Germany-Poland. In terms of cross-border hydrogen transmission infrastructure needs, PCIs on the first Union list of 2024 thus significantly contribute to the needs identified by the model, considering that they are all implemented as planned. The increase in transmission capacities in 2050 provides additional flexibility, and the capacity-weighted average level of hydrogen transmission usage in 2050 slightly decreases to reach 34%.

Eventually, no further investments in hydrogen storage are anticipated beyond 2040, with total storage capacity remaining stable at 26 TWh. The low utilisation rates of hydrogen transmission before 2040 could raise a challenge for the operation of the infrastructure – however, this challenge need to be overcome to enable the respective hydrogen flows.

By 2040-2050 however, hydrogen flows and demand increase across all BEMIP MSs, increasing the infrastructure usage. The two main corridors – *Baltic Sea Hydrogen Collector* and the *Nordic Hydrogen Route/Nordic-Baltic Hydrogen Corridor* – are complementary rather than in competition to each other. Indeed, the offshore *Baltic Sea Hydrogen Collector* allows to connect hydrogen production in Sweden and Finland to Germany, the main hydrogen importer and transit country in

¹⁹⁹ This model limitation is mitigated by the sensitivity analysis which notably assumes a delayed decrease in methane demand.

the BEMIP region, while the onshore *Nordic-Baltic Hydrogen Corridor* facilitates the collection and (re-)distribution of hydrogen across most BEMIP MSs.

Regarding hydrogen storage, however, ongoing PCIs contribute only marginally to the needs identified by the model in 2050. As of 2040, the hydrogen storage capacity in BEMIP increases to 26 TWh, located in Denmark, Germany, Poland and Latvia, while PCIs only represent 0.459 TWh in Germany and Denmark.

The sensitivity analysis shows that a delayed hydrogen transition under the selected assumptions would not affect much overall hydrogen cross-border capacity needs, and allows to identify some no-regret investments beyond PCI level, such as between Denmark and Germany or between Denmark and Sweden, as detailed in Figure 5-31. However, it would impact hydrogen storage needs, reducing them to 6 TWh in 2040 (instead of 26 TWh in the baseline scenario), and to 19 TWh in 2050 (compared to 26 TWh in the baseline scenario). This highlights that storage needs peak in 2040 in the baseline scenario, when the system relies the most on hydrogen-fired power generation to balance electricity demand and production. Although the intermediate hydrogen storage need in 2040 is strongly affected by the rate of increase in hydrogen demand, even the 6 TWh hydrogen storage need identified in the sensitivity analysis represents more than 10 times the capacity of planned PCIs from the 2024 list. Moreover, the list of candidate PCIs for the next PCI process includes eleven new hydrogen storage projects in the BEMIP region (including extensions of existing projects), of which one project is located in Poland, the remaining projects being all located in (the Western part of) Germany (and thus probably serving Western European markets).

Energy system interlinkages and synergies

The modelling results show that the integration of hydrogen in the BEMIP energy system and sector coupling provide benefits to the operation of the power system. In particular, provided that hydrogen storage capacity is available, hydrogen production by electrolysis improves the flexibility of the power system. Hydrogen produced by electrolysis during periods of high renewable generation can be stored and consumed later, potentially in hydrogen power plants during peak demand, partially replacing methane power plants. Sufficient hydrogen storage capacity enables greater production and storage during peak renewable generation and load shifting during periods of high electricity demand and lower renewable generation.

Besides, the flexible operation of hydrogen networks, through bi-directional flows, provides benefits for supply security and helps compensate for renewable production variations between different states. The flexible operation of the networks also reflects the limited availability of underground hydrogen storage (limited to Denmark, Germany, Poland and Latvia). Some countries which are net exporters, like Sweden and Finland, might, in some situations, still require to import hydrogen from south of BEMIP, considering the unavailability of large-scale hydrogen storage. This improves system flexibility and efficiency. Conversely, in the sensitivity scenario where hydrogen consumption and production are delayed, the provision of flexibility through electrolysis decreases, and the system relies more on methane-fired power plants to handle fluctuations in net power demand.

Finally, the role of hydrogen storage will also be impacted by the potential intraseasonal variations of hydrogen demand. While hydrogen storage levels show seasonal variations driven by the consumption of hydrogen in buildings and for power generation in the baseline scenario, they are rather driven by short-term variations of hydrogen production by electrolyzers (driven by variations in renewables generation) in the sensitivity analysis scenario.

Key conclusions

- The integration of renewable and low-carbon methane gases will, in the long term, impact the structure of methane flows in BEMIP, thus requiring maintaining part of existing methane infrastructure

- Additional investments might be necessary to integrate biomethane in the gas networks (not represented in the model)
- Existing cross-border hydrogen pipeline PCIs, if all commissioned, will significantly contribute to the needs identified by the model up to 2040, with additional needs identified by 2040-2050, mostly in the corridor ranging from Sweden and Denmark to Poland and Germany
- While a national hydrogen network development plan is already mature in Germany, investments and concrete plans are required in other BEMIP MSs to connect hydrogen production and consumption sites to the cross-border infrastructure (not represented in the model)
- Additional investment needs are identified for hydrogen storage by 2040 and 2050, with a trajectory sensitive to the pace of development of hydrogen consumption
- In particular, the technological choice to rely on hydrogen-fired power plants to balance the power system increases hydrogen storage capacity need
- By enabling a flexible operation of electrolyzers, hydrogen storage significantly contributes to the flexibility needs of the power system, allowing for a better integration of renewable power generation
- A delayed development of the hydrogen sector and phase out of methane consumption would delay the opportunity to repurpose or decommission methane infrastructure

These results are to be interpreted within the context of the underlying scenarios assumptions (particularly stemming from ENTSG TYNDP scenarios) and modelling limitations; and taking into account that there are no additional delays or non-investments of the PCIs of the first Union list of 2024. In particular the spatial resolution of the model developed in this study does not allow to assess the impact of internal congestions and may lead to an underestimation of hydrogen and methane storage needs in the long term. Besides, the model does not aim at performing a detailed analysis of methane security of supply, and the consideration of stress situations, such as supply shocks might result in higher capacity needs in the long term for methane infrastructure.

6.2. Regional infrastructure challenges for the integration of renewable and low-carbon gases

This section analyses how the current main infrastructure challenges for the further integration of hydrogen and biomethane will evolve throughout the horizon of the study, considering the scenarios for development of biomethane and hydrogen and the associated infrastructure detailed in Chapter 5. The challenges cover those described in previous sections of the report, especially the analysis summarised on section 4.2 (and detailed in Annex C, on technical, safety, economic and regulatory challenges) as well as Chapter 3 (regulatory challenges).

Both biomethane and hydrogen still face significant uncertainty regarding future supply and demand levels. Considering the results of Chapter 2 and the current status of hydrogen supply projects, we identified the risk of supply and demand levels falling short of current targets/forecasts, potentially leading to relatively low utilisation of hydrogen infrastructure, particularly in the 2030 horizon. Similarly for biomethane, future production strongly depends on policy targets and support mechanisms, resulting in a high overall uncertainty on national supply volumes. The available data doesn't provide a clear trend for the region, and with developments in Denmark, Germany and Poland being central to regional supply and demand.

Infrastructure challenges for the integration of biomethane²⁰⁰

²⁰⁰ A detailed analysis on bottlenecks regarding the integration of biomethane into the current natural gas infrastructure, including a Case Study for Denmark is provided in Chapter 9.5.

According to the TYNDP 2024 DE scenario, biomethane will represent a significant share of grid-connected methane gas demand by 2040, not only in Denmark but also Finland and Sweden (even if overall volumes are limited). Moving on to 2050, biomethane could represent over 40% of methane supply in Germany and Poland (compared to synthetic gas supply), the two BEMIP MSs expected to remain with the highest methane gas demand by 2050. In light of the climate protection targets, the scenario considers synthetic methane production and imports to complement the national biomethane supply. Hence many of the issues faced by Denmark for the network integration of biomethane could at a later stage occur throughout the BEMIP region. For instance, an increasing number of domestic networks will have to enable **reverse flows**. **Changes in cross-border flow patterns** should also be observed, however with the EU phase out of Russian gas, the EU gas system has already seen an important shift in gas flows.

At higher biomethane penetration levels, locally or at system-level, the composition of the methane gas mix can differ significantly from that of natural gas and possibly exceed current limits set in (national) standards and grid codes. This may require actions by network operators to **manage gas quality**, redirect gas flows or curtail injection by biomethane producers in case of so-called biomethane pockets. This challenge may be observed in any BEMIP Member State in the future, as it will depend on biomethane plants connected to specific network segments.

Moreover, **national gas quality standards differ across the BEMIP region**, which can act as a barrier to cross-border flows. Oxygen concentrations in biomethane is currently the main issue, as gas storages and some end-users may be sensitive to higher oxygen concentrations, and to a lesser there may also be an impact on (high-pressure) methane networks. This issue already hinders cross-border flows from Denmark to Germany, as the latter's standard has a lower tolerance limit for oxygen. Modelling results indicate that in the future flows could be significant, but would require addressing this gas quality issue. Further detailed analysis will be necessary regarding other interconnection points, as the modelling does not indicate significant future flows from other BEMIP MSs to Germany in the 2030-2050 horizon – but this is dependent on assumptions, and gas quality issues might arise in other interconnection points. Furthermore, in the future, other gas components might play a larger role, in case e.g. of hydrogen contamination or active blending in gas networks (although hydrogen blending is out of the scope of this specific study).

While it is preferred to connect small and medium-scale biomethane production plants to distribution networks, in particular to obviate the need for further compression, injection volumes may exceed local demand (usually during summer) and require **investments in reverse flow stations, deodorisation or interconnection of different distribution networks**. Therefore, in some cases, the connection of the producer directly to the transmission network may be a more appropriate option. This will be an issue faced particularly by Poland as it could see a significant development of the biomethane sector in the future although, up to today, no biomethane injection into the gas grid exists.

The higher penetration of biomethane in gas networks will also alter the calorific value of the gas mix, which can have **consequences for the metering and billing systems and processes**, as gas meters measure flow volumes rather than calorific value. Hence, systems may be needed to simulate gas flows and monitor calorific values in different network points, to account for temporal and geographical variations. This will affect all BEMIP MSs to different extents, depending on the biomethane penetration levels.

While the technical challenges can in general be adequately addressed by network operators, the **economic and regulatory challenges in the context of this study require more attention, in particular** on how to ensure that appropriate investments for the integration of biomethane are timely realised and costs adequately allocated. The main economic and regulatory challenges identified comprise:

- The **need for integrated methane system planning** between TSOs and DSOs, to connect biomethane producers at the optimal level from a system perspective, as well as regarding

the repurposing or decommissioning of gas pipelines. The new provisions in the recast EU Gas Directive and Regulation regarding network development plans (at the transmission and distribution levels) and the consideration of decommissioning needs should drive the regulatory framework in this regard, but BEMIP MSs will still have significant leeway in specifying how this coordination should take place.

- The **financing and cost allocation** of investments in solutions such as reverse flow stations, interconnection of distribution networks, biomethane injection stations, and control and metering/billing systems. While the associated costs can be limited compared to the overall costs to produce and integrate biomethane, the competent national authorities should decide whether to recover them via the general grid tariffs or from the concerned producers. Denmark has for instance moved towards charging biomethane producers access tariffs to recover the costs of such specific investments. Nonetheless, in a context of diminishing gas demand, network operators and regulators will need to review connection and access tariff methodologies and charges, striking a balance between cost-reflectivity, cost recovery of network operators, and the facilitation of biomethane integration (although the latter may not be in the specific remit of regulators).
- Another important decision will be **whether and when to decommission or repurpose certain cross-border methane network segments**. Security of supply considerations might warrant maintaining a certain back-up capacity, in which case gas quality issues will remain important not only in the DK-DE and DK-PL interconnection points, but also the DE-PL and other IPs in the region. At the same time, the new supply situation in Europe with a significant role of LNG imports and significantly decreased imports from Russia needs to be considered. Challenges may also arise at the distribution level, especially for Nordic and Baltic Member States, with remaining network users or limited opportunities to e.g. interconnect distribution grids potentially limiting the decommissioning potential.

Infrastructure challenges for the integration of renewable and low-carbon hydrogen

For hydrogen, **there are a number of specific technical and safety challenges** which require further technological development, as detailed in section 4.2.1 and further details in Chapter 9 (Annex C). These challenges are related to both more mature technologies such as onshore hydrogen pipelines and long-term storage in salt caverns, as well as less mature but relevant ones such as repurposed and offshore hydrogen pipelines, development of repurposed or porous-reservoir storages, and fast cycling of salt cavern storage. However, it is expected that adequate solutions will be developed that address these challenges, albeit they may require additional investments for infrastructure deployment. Hence, the remainder of the analysis focuses on economic/financial and regulatory challenges.

While renewable and low-carbon hydrogen supply is expected to significantly increase throughout the BEMIP region, there is still significant uncertainty given the current economic challenges faced by production projects. While according to our modelling and underlying assumptions Sweden, Finland and Denmark would in the long run have a supply surplus of hydrogen which could be transported to Poland and especially Germany for consumption, **overall the BEMIP region is expected to run a hydrogen deficit**, which would need to be covered by supply from other EU Member States, or imported from outside the EU. Moreover, in the shorter-term until 2040, hydrogen would flow towards rather than from Northern Member States for a significant number of hours. While by 2050 net flows will be from northern hydrogen producing Member States to Germany and Poland, **bidirectional flows** will remain (and illustrate the specific need for cross-border integration), given differences in renewable energy generation profiles and the geographical distribution of hydrogen storage capacity.

An important finding from the modelling exercise presented in Chapter 5 is the **need for significant investments in hydrogen networks and storages**, including beyond the PCIs of the first Union list of 2024 by 2040 for hydrogen storage (concentrated in DK, DE and PL) and 2050 for networks (concentrated in DK-DE, PL-DE, PL-LT and SE-DK, but actually with non-trivial investments in most

borders). As the model does not take potential grid congestions on national level into account, the capacity needs presented here may even underestimate the actual storage needs. Therefore, during the next cycle for adopting a PCI list, particular attention could be given to **providing PCI status and facilitating hydrogen gas storage projects** (as long as justified by an appropriate cost-benefit analysis taking into account supply uncertainties), also considering the long lead time for commissioning such projects.

However, the effective **commissioning of all hydrogen infrastructure projects with PCI status should not be considered as a certainty**, given it is natural that certain projects are cancelled and considering the risks for meeting EU hydrogen targets identified by actors such as the European Commission and ACER. On the national level, while Germany decided to roll out a core hydrogen network and Denmark achieved a political agreement to develop and finance a hydrogen backbone to Germany, other BEMIP MSs are in earlier planning stages. Therefore, the business case for building hydrogen infrastructure should as much as possible rely on a **modular/incremental approach for setting up infrastructure and reasonably certain demand for transport capacity**. However, timely development of transport and storage infrastructure development can also have a catalyst effect in developing supply and demand, and **too strict criteria for assessing infrastructure needs can lead to delays in industrial projects and/or under-dimensioning of the transport infrastructure, and hence anticipatory investments** should also be considered to enable the development of a larger regional network.

This is compounded by the fact that the modelling indicates utilisation of hydrogen networks would still be comparatively low in 2030, with several pipelines having less than 20% utilisation (although they investments may be socio-economically optimal even then). A financing mechanism like the so-called “amortization account” implemented for the German core grid may also be considered for other countries as well to limit financial risks for grid operators in the early market phase. Nonetheless, it's important to stress that, under the present modelling assumptions, utilisation for these pipelines increase towards 2040/2050, and overall they present a positive net benefit for the whole modelling horizon.

The significant investment volumes will also lead to **financing challenges for hydrogen infrastructure operators**, also taking into account the low utilisation in the ramp-up phase, as discussed in section 3.3.3. At present, in the BEMIP region only Germany has defined the subsidy, cost recovery and de-risking mechanisms for the roll-out of the core hydrogen network. Policymakers and regulators are now dedicating attention to this financing challenge for hydrogen network infrastructure. Governments will likely need to (partially) de-risk such investments of their mostly state-owned hydrogen TSOs and bridge the ramp-up costs until the infrastructure user base develops. For cross-border projects the concerned governments will need to agree on their respective contributions. For hydrogen storage, the problem could be compounded by the difficulty in demonstrating cross-border benefits of such projects, although they may be justified exclusively on the basis of national benefits to producers, suppliers, off-takers and network operators. The limited experience with cross-border cost allocation for electricity and gas interconnectors indicates this can be a difficult issue, and the heightened uncertainties regarding the exact benefits of hydrogen interconnectors will further complicate (but not make impossible) cost allocation agreements between NRAs.

In general, the challenges discussed above highlight the importance of **infrastructure development and (national) regulation coordination in the region**, which can significantly alleviate some of the infrastructure risks and improve the business case for specific projects. Gas TSOs/HNOs are cooperating at the regional level, particularly around the Baltic Sea Hydrogen Collector and the Nordic-Baltic Hydrogen Corridor, but these projects are now moving into detailed feasibility studies, and there is much work necessary until final investment decisions are taken. Regional NRAs are also cooperating in among other platforms within the BEMIP High-Level Group, with the present analysis highlighting a number of aspects where continued (and intensified) coordination is beneficial.

6.3. Recommendations to address regional infrastructure challenges

This section presents recommendations to address the identified cross-border infrastructure challenges for the integration of biomethane and hydrogen in the BEMIP region. Table 6-1 summarises the recommendations, their applicability for biomethane or hydrogen, and the implementation responsibility. The recommendations are further detailed after the table, including expected impacts, barriers and tentative schedule for implementation. It must be noted that when the BEMIP High-Level Group is indicated as having the responsibility for implementation, the analytical work would be conducted by the HLG technical level, with outputs and recommendations being approved by the HGL's operational and political levels.²⁰¹

The recommendations aim to complement measures already in place or under implementation. Other potential measures could have an important impact on the integration of biomethane and hydrogen in the region, but are out of scope of this study given the focus on infrastructural aspects. Possible measures which are not detailed here include particularly further work on establishing gas/hydrogen guarantees of origin and proofs of sustainability (as major element of RFNBO certification), and ensuring their cross-border recognition.

Table 6-1 Recommendations to address infrastructure challenges for integration of biomethane and hydrogen in the BEMIP region

Recommendation	Biomethane/ Hydrogen	Responsibility
1. Promote cooperation at the regional level for the development of NDPs and for increasing the coherence between NECPs, NDPs, TYNDPs and PCI/PMI lists and across carriers	Biomethane / hydrogen	BEMIP HLG, NRAs, TSOs
2. Establish a BEMIP working group on best practice sharing and coordination for the integration of biomethane	Biomethane	BEMIP HLG, NRAs, TSOs, DSOs
3. Consider cost recovery models for hydrogen infrastructure with regional coordination, inter-temporal cost allocation and potentially cross-border cost sharing	Hydrogen	BEMIP HLG, NRAs, TSOs, SSOs

²⁰¹ For further information see the [2015 BEMIP Memorandum of Understanding](#).

1. Promote cooperation at the regional level for the development of NDPs and for increasing the coherence between NECPs, NDPs, TYNDPs and PCI/PMI lists and across carriers [biomethane/ hydrogen]

Context

Our analysis has identified significant investment needs in cross-border hydrogen network infrastructure as well as decommissioning or repurposing of cross-border methane gas infrastructure (with differences in the time horizon for development or decommissioning of infrastructure, depending on the infrastructure category – storages or interconnections – and scenario). However, there is in any scenario a clear need for increased coordination at the regional level and between NECPs, NDPs, TYNDPs and PCI/PMI lists.

At the regional level, our analysis indicates that cross-border methane gas infrastructure will continue to be relevant for the transport and storage of (renewable and low-carbon) methane gases at the regional level, particularly for the Germany-Denmark-Poland triangle, but also for the broader North-to-South region towards 2050. Regional dynamics are also pivotal for driving cross-border hydrogen network investments as well as storage (given the expected concentration of underground hydrogen storage capacity in a subset of BEMIP MSs). Likewise, for hydrogen cross-border hydrogen infrastructure and storage will play a pivotal role in integrating renewable and low-carbon hydrogen across the region. Moreover, important interlinkages between the methane gases, hydrogen and electricity sectors are identified.

Adequate coordination is required for the different energy & climate governance and infrastructure planning instruments at the national, regional and EU level. NECPs, associated progress reports and TYNDP scenarios serve to provide guidance regarding biomethane as well as hydrogen supply and demand projects and targets, while NDPs, TYNDPs (and the associated infrastructure gaps reports) and the PCI/PMI lists constitute the main planning instruments for biomethane and hydrogen infrastructure. For biomethane, TSO and DSO network development and decommissioning plans also constitute a relevant planning instrument.

National authorities and TSOs already cooperate within the framework of these instruments and outside of it, for example as part of the BEMIP High-Level Group. Nonetheless, our study has identified significant differences or the lack of guiding national projections and targets for the supply and demand of biomethane and hydrogen as well as the need for additional coherence in infrastructure planning across the different instruments. And while BEMIP MSs might still have significant untapped potential for biomethane production upscaling, national projections or targets can still be comparatively low (although policymakers need to carefully consider the biomass feedstock sustainability and competition with other uses). Furthermore, infrastructure planning is to some extent bottom-up, with projects proposed at the national level being assessed and included in higher-level instruments such as the TYNDPs and PCI/PMI list (with the infrastructure gaps reports and regional initiatives such as the Baltic Sea Hydrogen Collector and the Nordic-Baltic Hydrogen Corridor forming the exceptions). ACER is already required to check the coherence between NDPs and TYNDPs.

Recommendation

Building on the ACER check on NDP/TYNDP coherence, national authorities within the BEMIP High Level Group and TSOs should further assess the coherence between the various energy infrastructure planning instruments listed, providing recommendations on addressing incoherences as well as improving the top-down planning processes, so that infrastructure needs identified at the regional level further drive the identification and development of infrastructure projects (and in the case of methane infrastructure, decommissioning or repurposing of existing assets). The overall process could further support the simplification of the TEN-E Regulation announced as part of the European Grid Package.

Specific attention should be paid to the coherence of infrastructure planning across the different carriers, coordination on decommissioning or repurposing of methane infrastructure, and anticipatory investments for hydrogen infrastructure. Furthermore, for hydrogen infrastructure planning, a coordinated assessment at regional level should be undertaken focusing on underground H₂ storage needs, in order to identify potential candidate projects for the following (third) PCI/PMI cycle (unless the 2nd PCI/PMI list already includes a number of hydrogen storage projects aligned with storage need estimates).

Finally, the initiative could also assess the coherence between supply and demand projections/targets across the various planning instruments, and the potential for increasing national or setting regional targets, considering in the case of biomethane the feedstock sustainability and competition with other uses.

Implementation responsibility

BEMIP High-level group, NRAs, TSOs

Tentative schedule for implementation

2026: Coherence assessment and recommendations, supporting the European Grid Package

Expected impacts

- Increased coherence of supply and demand projects/targets as well as infrastructure projects across different planning instruments
- Improved use of supply and demand projection/targets and identified infrastructure needs for defining and promoting infrastructure projects
- Investment and operational savings through timely identification and development of infrastructure and reduced risks of asset stranding

Barriers for implementation

- Issues faced by the BEMIP region are common to all gas infrastructure corridors, and improvements would need to be coordinated with the upcoming simplification of the TEN-E and associated planning processes
- Established NECP, TYNDP, NDP and PCI/PMI project selection follow set timelines which are not necessarily aligned, hindering use of the same scenario assumptions or consideration of the same infrastructure options

2. Establish a BEMIP working group on best practice sharing and coordination for the integration of biomethane [biomethane]

Context

While significant investments in new methane gas networks should be avoided, limited investments to enable increased injection volumes and transport of biomethane can be justified. While biomethane contributes to decarbonizing gas supply and reducing fossil gas import dependency, it is difficult to demonstrate the benefits of cross-border cooperation on biomethane, as it is primarily locally used. However, as biomethane deployment grows in Denmark and in several other BEMIP MSs (possibly with transmission-connected producers) and starts driving cross-border flows, the relevance of cross-border cooperation (and the related benefits) will further increase.

The 2nd list of candidate PCI/PMIs under the revised TEN-E regulation (published for consultation in Q1 2025) includes the GREENCONNECT project presented by the gas TSOs Energinet (Denmark) and NaTran (France). The project focuses on cooperation between the TSOs for studying aspects related to reverse flow stations, gas quality, odorant management, addressing standardisation, planning, investment and operation activities. The GREENCONNECT project developers recognise that the Danish and French gas systems do not share an interconnection point, but argue that the project is of cross-border relevance. As highlighted in section 4.2, the Danish authorities, TSO and DSO have developed and implemented several measures to facilitate the integration of a high share of biomethane in the gas system. French actors have likewise developed a number of relevant measures.

A similar initiative for sharing of best practices across the BEMIP region could provide high added value, as the BEMIP MSs' gas systems are directly interconnected, and as shown in Chapter 4 important cross-border flows of renewable and low-carbon gases are expected towards 2050 in the region.

Recommendation

National authorities and network operators should establish an initiative for sharing of best practices and coordination across the region, building on already developed measures for the integration of biomethane in the gas grid in for example Denmark, Germany and non-BEMIP MSs such as France and Italy.

The initiative should have a focus on sharing best practices for the integration of high shares of biomethane in the medium to long-term (i.e. not only considering 2030 projections/targets but also the 2040 and 2050 horizon). The exchange of best practices could cover measures such as:

- Development of biomethane and overall methane gases supply and demand scenarios
- Planning, development and construction of reverse methane flow facilities
- Infrastructure decommissioning and repurposing planning, including specific network segments and M/R stations
- Interconnection of distribution networks
- TSO/DSO coordination in system planning and operation
- Oxygen and other contaminants management, including purification (entry/exit/centralized) approaches, sensitive end-user management and operational strategies
- Harmonisation of gas quality standards and grid codes at interconnection points
- Tariff methodologies for connection and injection of biomethane plants
- Integration of large-scale biomethane producers
- Exchange on measures for monitoring and preventing methane emissions from natural gas grid
- Facilitate coordinated decisions at the regional level regarding the provision of specific gas system tariff discounts for renewable and low-carbon gases referred to in Article 18 of EU Regulation 2024/1789

In addition to sharing best practices, the initiative could enhance coordination between NRAs on matters of cross-border relevance. Particularly, national authorities and TSOs should work towards harmonization of gas quality standards and associated measures when these constitute or will constitute a barrier to cross-border flows – for example in the case of the DK-DE border given the more stringent oxygen limits on the German side.

Implementation responsibility

BEMIP high-level group, NRAs, TSOs, DSOs

Tentative schedule for implementation

End 2025: Start of activities

Expected impacts

- Increased awareness regarding biomethane integration measures for BEMIP MSs who could face a significant upscaling in the future, such as Poland
- Increased coordination on aspects of cross-border relevance such as gas quality standardisation and management at interconnection points
- Facilitation of biomethane injection into the grid within all BEMIP MSs by removing existing and upcoming barriers, at lower investment and/or operational cost

Barriers for implementation

- The initiative might overlap with other relevant ones, such as the ENTSOG Prime Movers Group

3. Consider cost recovery models for hydrogen infrastructure with regional coordination, inter-temporal cost allocation and potentially cross-border cost sharing [hydrogen]

Context

The analysis presented in section 5.3 indicates that cross-border hydrogen network and storage infrastructure in the BEMIP region could require investments in the order of 45 billion € until 2050. As presented in section 3.3 other analyses such as from the Investment Needs study for the European Commission also estimate significant investment volumes in hydrogen infrastructure (even more when domestic transmission networks are considered).

The significant investment volumes, challenges in coordinating the development of hydrogen supply, infrastructure and demand as well as the lower infrastructure utilization during the ramp-up phase all entail challenges for the financing of hydrogen infrastructure. The analysis in the present study highlights the cross-border relevance of hydrogen interconnectors and storages, with important regional flows and shared use of hydrogen storage infrastructure. Furthermore, hydrogen interconnectors can benefit also non-hosting Member States and present important synergies (for example the benefits of the entire Nordic-Baltic Hydrogen Interconnector should be larger than the sum of benefits of individual segments), which could be a further argument for cost sharing at the regional level.

As reviewed in section 3.3 Germany is comparatively advanced in establishing mechanisms to allocate risks between hydrogen network operators, network users and the State, such as with the implementation of an intertemporal cost allocation mechanism ("amortization account") and the provision of (partial) guarantees on the depreciation of investments. Related to this, ACER launched a public consultation in Q1 2025 on inter-temporal cost allocation mechanisms for financing hydrogen infrastructure, and will issue a recommendation on the matter by August 2025.

Hence, while financing and tariff-setting for hydrogen infrastructure are important challenges and should to some extent be addressed at regional level, national authorities and infrastructure operators are in many BEMIP MSs at present discussing (or need to start discussing) potential approaches. To facilitate these discussions and ensure a consistent outcome, exchange of best practices and cooperation on cross-border sharing of relevant infrastructure costs would be highly beneficial.

Recommendation

National authorities and infrastructure operators should consider hybrid cost recovery models for hydrogen network infrastructure, with regional coordination and potentially cross-border cost sharing, pursuing cost reflectiveness while facilitating the development and growth of hydrogen supply and demand by containing the grid tariffs during the ramp-up phase at an 'affordable' level.

Specific measures to be considered would include implementing progressive asset depreciation rules, de-risking mechanisms to (partially) guarantee a market-based remuneration level of the assets in the long-term, and cross-border cost sharing of interconnection investment costs (bilaterally for the Member States of the relevant interconnection point, or at the regional level). Cost-sharing in large-scale hydrogen storage projects could also be considered as long as these project contribute to cross-border hydrogen integration, trade and security of supply.

Implementation responsibility

BEMIP HLG, NRAs, TSOs, SSOs

Tentative schedule for implementation

End 2025: launch of initiative

Expected impacts

- Facilitation of cross-border cost sharing agreements for hydrogen interconnectors reflecting expected net benefits of the project for the relevant BEMIP MSs
- Increased awareness of (nascent) best practices for the financing and tariff setting of hydrogen infrastructure

Barriers for implementation

- Cross-border cost sharing agreements are complex and it can be challenging to appropriately take into account uncertainties when defining cost allocation rules. The intertemporal challenges for financing hydrogen infrastructure can further complicate agreements on cross-border cost sharing.

7. Annex A – Country fiches for renewable and low-carbon gases supply, demand and related infrastructure

7.1. Country fiches – hydrogen supply and demand projections

Due to the wide variety of existing projections and targets for the future production and demand of (renewable) hydrogen as well as on the potential production, relevant scenarios in different literature sources were collected and compared in this analysis.

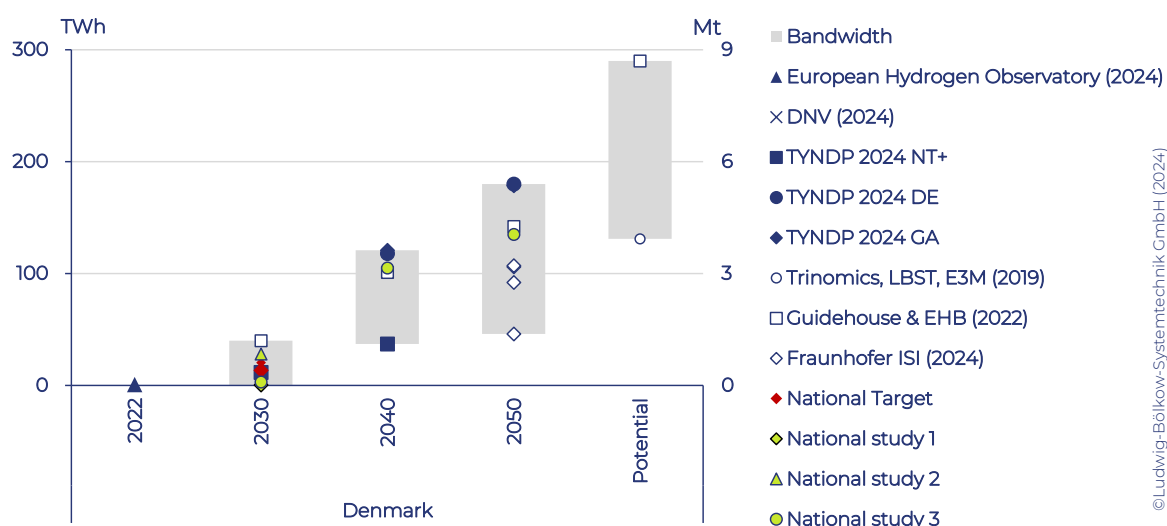
National targets, formulated e.g. within the National Hydrogen Strategies or National Energy and most recent Climate Plans (NECPs), were used for validation and assessment of the data basis and identification of relevant input data to be used for infrastructure modelling in Chapter 5. Furthermore, input received via a stakeholder survey conducted in September and October 2024 were taken into account.

Denmark

Denmark's focus of future hydrogen production is laid on renewable hydrogen.²⁰² The **country's target** for hydrogen production comprises the ramp-up of an electrolyser capacity of 4-6 GW by 2030, as stated in the NECP (2024)²⁰³. Applying conversion factors of 5,000 full load hours and an electrolyser efficiency of 68 %²⁰⁴, this translates into a hydrogen production of around 13.6-20.4 TWh in 2030 (= 'National targets' in Figure 7-1).

Renewable hydrogen market outlook: Figure 7-1 provides an overview on Denmark's projected (renewable) hydrogen production ramp-up according to several literature-based scenarios and sets it into perspective to analyses of the overall production potential (by Trinomics, LBST & E3M (2019) and Guidehouse & EHB (2022)).

Figure 7-1: Renewable hydrogen production projections - Denmark

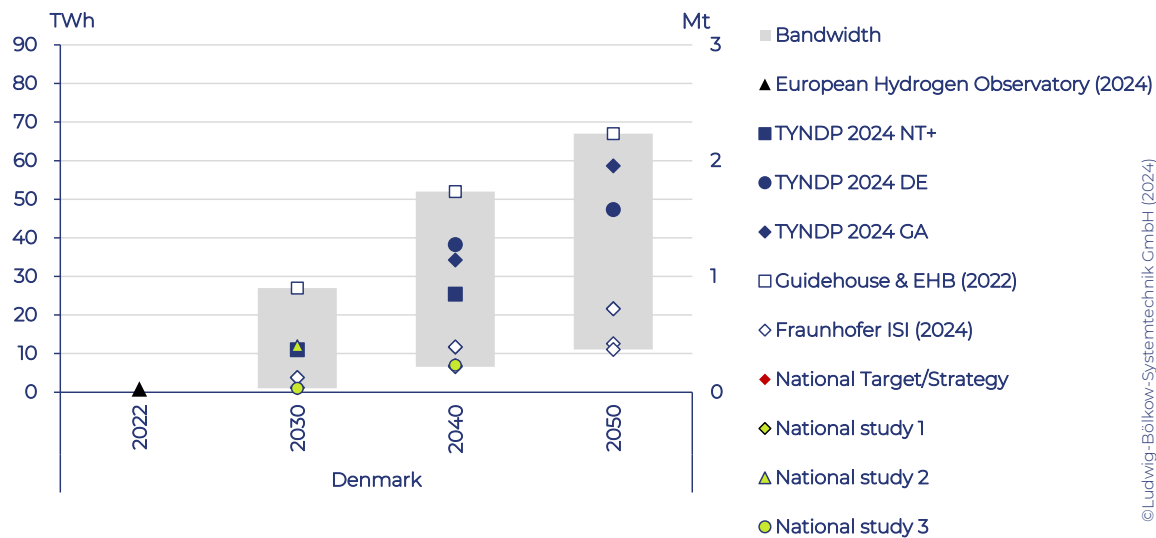


²⁰² Also referred to as green hydrogen by stakeholders in the stakeholder survey.

²⁰³ EC (2024): [Denmark - Final updated NECP 2021-2030 \(2024\)](#)

²⁰⁴ Bases on assumptions in [Energinet, Gasunie \(2023\): Hydrogen Market Assessment Report for Denmark and Germany](#).

Figure 7-2: Hydrogen demand projections - Denmark



The bandwidth of hydrogen supply projections for Denmark ranges from 3 TWh to 40 TWh in 2030 and increases over time to 37 TWh – 121 TWh in 2040 and 46 – 180 TWh in 2050.

Demand projections in general are lower compared to supply, indicating an export potential for Denmark. Values range from 1 – 27 TWh in 2030, over 6.6 – 52 TWh in 2040 to 11 – 67 TWh in 2050. This is in line with the perception of stakeholders that Denmark will position itself as an export country, if the renewable hydrogen production potential is realized to create a surplus to domestic demand.

In comparison with the targets, projections by Guidehouse & EHB (2022)²⁰⁵ for 2030 seem optimistic, while for 2040 and 2050, TYNDP scenarios DE and GA scenarios can be considered as upper bound values. In contrast to that, the NT+ scenario in the TYNDP 2024²⁰⁶ is rather in line with national targets in 2030 and lower for 2040 than other scenarios.

Other national sources include Denmark's Climate Status and Outlook 2023 by the Danish Energy Agency²⁰⁷ ('National study 1'). According to the report, hydrogen production by electrolysis will increase to 3 TWh (10.8 PJ) by 2030 and 5.6 TWh (20.3 PJ) by 2035 (frozen-policy scenario 'with existing measures').

In a study 'Market Assessment – Denmark's potential in a future hydrogen economy' by the CIP foundation published in 2023 (= 'National study 2'),²⁰⁸ the export potential for hydrogen was estimated for 2030. Based on data by the Danish Energy Agency and the Danish Government's Climate Partnership for Energy and Utilities, the authors describe an overall production capacity of 7 GW (around 28 TWh) in 2030, which will cover the domestic demand of about 3 GW (around 12 TWh) as well as an export potential to countries like the Netherlands, Belgium and Germany of 4 GW (around 16 TWh). The study also assesses the overall export scenario of Denmark: 'in case, all screened areas in the country were used for renewable energy expansion and hydrogen production, the surplus hydrogen (after covering domestic demand) would sum up to about 200 TWh.'

The report 'Hydrogen Market Assessment Report' by gas TSOs Energinet (DK) & Gasunie (NL), which was published in 2023 (= 'National study 3')²⁰⁹, provides information on the expectations for the hydrogen market development in both countries as a basis for the realization of cross-border hydrogen infrastructure. Based on the report, hydrogen production projection data of around 3 TWh

²⁰⁵ Guidehouse & EHB (2022): [Five hydrogen supply corridors for Europe in 2030](#)

²⁰⁶ ENTSG / ENTSOE (2024): [Ten-Year Network Development Plan \(TYNDP\)](#)

²⁰⁷ The Danish Energy Agency (2023): [Denmark Climate Status and Outlook 2023](#)

²⁰⁸ CIP foundation (2023): [Market Assessment – Denmark's potential in a future hydrogen economy](#)

²⁰⁹ [Energinet, Gasunie \(2023\): Hydrogen Market Assessment Report for Denmark and Germany](#)

(2030), 105 TWh (2040) and 135 TWh (2050) were derived. In contrast to that, hydrogen demand in Denmark is expected to be significantly lower with 1 TWh (2030), 7 TWh (2040) and 16 TWh (2050).

Stakeholders' feedback from the survey indicated further national sources such as the most updated national climate projections.²¹⁰ These are especially relevant, as projections by Guidehouse & EHB (2022)²¹¹ are based on outdated projections by the Danish Energy Agency's projection back in 2020 and most current data by the Danish Energy Agency in the Climate Status and Projection 2024 (KF24) are recommended.²¹²

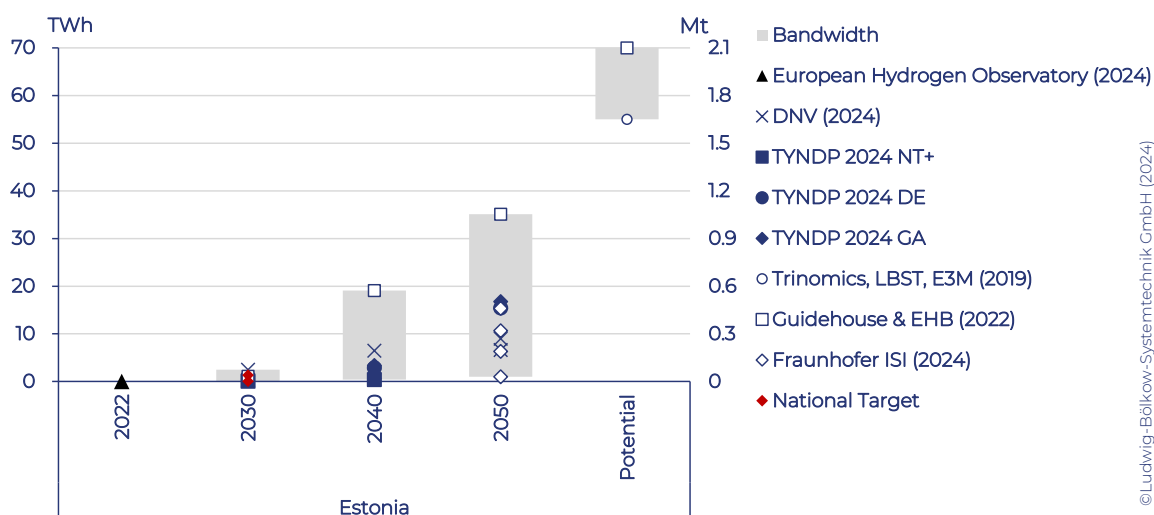
The **theoretical (or technical) renewable hydrogen production potential** for Denmark is between 130 TWh 290 TWh respectively, according to Trinomics, LBST & E3M (2019) and Guidehouse & EHB (2022).

Estonia

Estonia's **national hydrogen strategy** from 2023²¹³ does not see a significant role for hydrogen for balancing the electricity system before 2030. The expected production volumes range (based on third-party estimates) from 2 to 40 kt (around 0.067 – 1.333 TWh) of green hydrogen per year by 2030 ('National target' in Figure 7-3). The strategy does not include further estimates for low-carbon hydrogen.

The projections for the domestic **supply** of hydrogen in Estonia span from 0.06 TWh to 1.33 TWh by 2030, increasing over time to between 0.44 TWh and 19.1 TWh in 2040, and further rising to around 1 TWh to 35 TWh (with several studies around 15 TWh) by 2050. The TYNDP 2024 NT+ scenario has very low projections of Estonian hydrogen supply at only 0.4 TWh in 2040.²¹⁴ Data from different studies are shown in Figure 7-3. According to the analysis and based on stakeholder's feedback, the values provided by Guidehouse & EHB (2022) (white squares) seem to be highly ambitious – requiring a large share of the overall renewable electricity generation in Estonia to be used for hydrogen production.

Figure 7-3: Renewable hydrogen production projections – Estonia



²¹⁰ See Klima-, Energi-, og Forsyningsministeriet (2024): [Klimastatus og -fremskrivning 2024](#) and Klima-, Energi-, og Forsyningsministeriet (2024): [Analyseforudsætninger til Energinet](#).

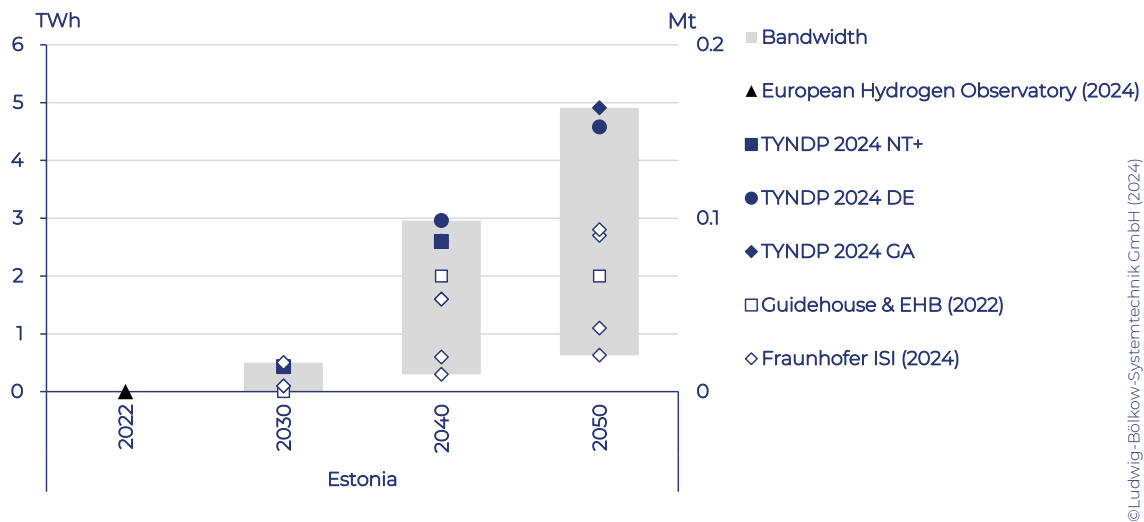
²¹¹ Guidehouse & EHB (2022): <https://www.ehb.eu/files/downloads/EHB-Supply-corridor-presentation-Full-version.pdf>

²¹² The Climate Status and Projection (KF) is the annual assessment conducted by the Ministry of Climate, Energy, and Utilities, including the Danish Energy Agency, with input from researchers at different national institutions of whether Denmark meets its climate targets for 2025 and 2030, as well as its EU climate obligations. See <https://www.kefm.dk/klima/klimastatus-og-fremskrivning/klimastatus-og-fremskrivning-2024>.

²¹³ Eesti vesiniku teekaart (2023): [Eesti vesiniku teekaart](#)

²¹⁴ ENTSG / ENTSOE (2024): [Ten-Year Network Development Plan](#)

Figure 7-4: Hydrogen demand projections – Estonia



Demand estimates range from 0.07 TWh to 0.5 TWh in 2030, rising to 0.3 TWh to 3 TWh in 2040, and reaching 0.06 TWh to 5 TWh by 2050. The expected demands of the TYNDP 2024 NT+ scenario lie within the range of values provided in other studies. According to feedback from the stakeholder survey, the hydrogen demand for 2050 could be in the range of 4-6 TWh – ‘in case, new PtX industries emerge’ (see Figure 7-4).

When it comes to the overall **import needs/export potential**, there is no uniform picture in literature for Estonia. The TYNDP 2024 NT+ scenario is the only scenario expecting higher demand with almost non-existent hydrogen production in 2030 and 2040. Other TYNDP scenarios (DE & GA) expect a relatively balanced supply and demand in 2040 and Guidehouse & EHB (2022)²¹⁵ expect a much higher supply already in that year. The TYNDP 2024 NT+ scenario does not cover the timeframe until 2050, but all other values for 2050 point to a much higher supply than demand, showing the possibility of Estonia to become a hydrogen exporter in the long run.

DNV (2024) estimates the overall domestic hydrogen production could reach around 0.4-2.5 TWh by 2030, 1.9-6.5 TWh by 2040 and 6.6-9.0 TWh by 2050 based on the projected RES production and electricity demand (values represent the conservative and the optimistic scenario). In both cases, around 3.7 TWh of hydrogen can be produced and exported from excess renewable electricity, but in the conservative scenario, the exports only start around 2050. The study concludes for the **optimistic** scenario that in Estonia the development of the renewable sector is driven by a huge availability of offshore wind from 2030 onwards, with complementary generation from onshore wind and solar PV, and that – with the massive deployment of offshore wind energy in 2050 – the energy system becomes self-sufficient. This means that it can cover national demand for electricity and hydrogen, with the potential availability of a surplus leading to energy exports. For the **conservative** scenario, DNV predicts the electricity generation to grow in 2030 and 2040 at a more modest pace, while electricity demand remains stable, but with rising hydrogen demand in the industrial and transportation sectors. As a result, the energy system would possibly depend on imports to meet domestic needs. By 2050, however, with the large-scale deployment of offshore wind energy, the system would become self-sufficient, meeting domestic demand for both electricity and hydrogen, and potentially generating a surplus. Therefore, Estonia is expected to have a high hydrogen production potential, the main question is, how quickly Estonia builds out its renewable energy sources.

²¹⁵ Guidehouse & EHB (2022): [Five hydrogen supply corridors for Europe in 2030](#)

Studies predict different **ratios of supply to demand**. The TYNDP 2024 NT+ scenario does not predict high domestic supply (0.06 TWh in 2030 and 0.435 TWh in 2040) with the demand 6-7 times as high as the supply in the same years. Guidehouse & EHB (2022) have calculated similar demand values for 2040, but have instead calculated a much more rapid increase of domestic hydrogen supply that would increase to 10 to 17 times the amount of today's hydrogen demand. The other TYNDP 2024 scenarios and the Fraunhofer ISI (2024)²¹⁶ scenarios are consistent in that in the long-term, supply will be much higher than demand in Estonia, making the NT+ scenario an outlier.

In contrast to these projections, the literature values for the **theoretical (or technical) renewable hydrogen production potential** are significantly higher. Guidehouse & EHB (2022) provides an estimate for the technical potential by 2050 for renewable hydrogen in Estonia to be around 70 TWh. According to Trinomics, LBST & E3M (2019), the (theoretic) potential for renewable hydrogen production in Estonia is around 55 TWh.

Finland

Finland does not have binding **targets** for hydrogen production, but the latest Government Programme states that Finland aims to account for 10% of the EU's clean hydrogen production and for at least the same percentage of hydrogen use.²¹⁷ In addition, Finland has a non-binding target of electrolysis capacity of 200 MW in 2025 and 1,000 MW in 2030.

From the side of the Finnish government, the Prime Minister's Office has released scenarios from 'No regret' to 'Maximum' on the country's hydrogen scenarios.²¹⁸ These scenarios include volumes of hydrogen demand and supply between 3.7 and 7.8 TWh in **2030**. The scenarios 'No regret A', 'Moderate' and 'Maximum B' are listed as 'National study 1 to 3' in Figure 7-5; supply and demand are very balanced in these scenarios. The values in the TYNDP 2024 NT+ scenario²¹⁹ are much higher for supply (25 TWh) and demand (29 TWh). Guidehouse- & EHB (2022) list even more ambitious supply volumes of around 61 TWh, but a similarly high demand (25 TWh).

By **2040**, hydrogen **supply** is expected by the government to increase to between 5 and 58 TWh. Guidehouse & EHB (2022) expect 93 TWh, while the TYNDP 2024 NT+ scenario predicts 102 TWh supply. The DE and GA scenarios consider even higher supplies of 113 TWh and 132 TWh, respectively.

The hydrogen **demand** values in 2040 span from 2.8 TWh to 71 TWh. The demand values correspond strongly to the supply values of each scenario: in scenarios with high supply, the demand is also expected to be high. By 2040, however, most studies expect supply to be between 1.5 to 4 times as high as demand. Only governmental 'No regret' scenarios predict similar supply and demand. The NT+ scenario provides the most ambitious demand figures for 2040.

By **2050**, the Prime Minister's Office estimates an overall demand for hydrogen of up to 21 TWh and Fraunhofer ISI (2024) up to 45 TWh. Guidehouse & EHB (2022) and the TYNDP 2024 scenarios expect 58 – 71 TWh, showing the wide range of possible results. While some scenarios expect hydrogen **supply** in the range of 3 – 29 TWh, with a slight hydrogen deficit, the more ambitious studies and scenarios expect a supply of 130 – 263 TWh with a hydrogen surplus of almost 200 TWh. Additional data sources provided by stakeholders via the survey are largely in line with the presented

²¹⁶ Fraunhofer ISI (2024): [Hydrogen Infrastructure in the Future CO2-Neutral European Energy System—How Does the Demand for Hydrogen Affect the Need for Infrastructure?](#)

²¹⁷ Ministry of Economic Affairs and Employment (2023): [Government adopts resolution on hydrogen – Finland could produce 10% of EU's green hydrogen in 2030](#)

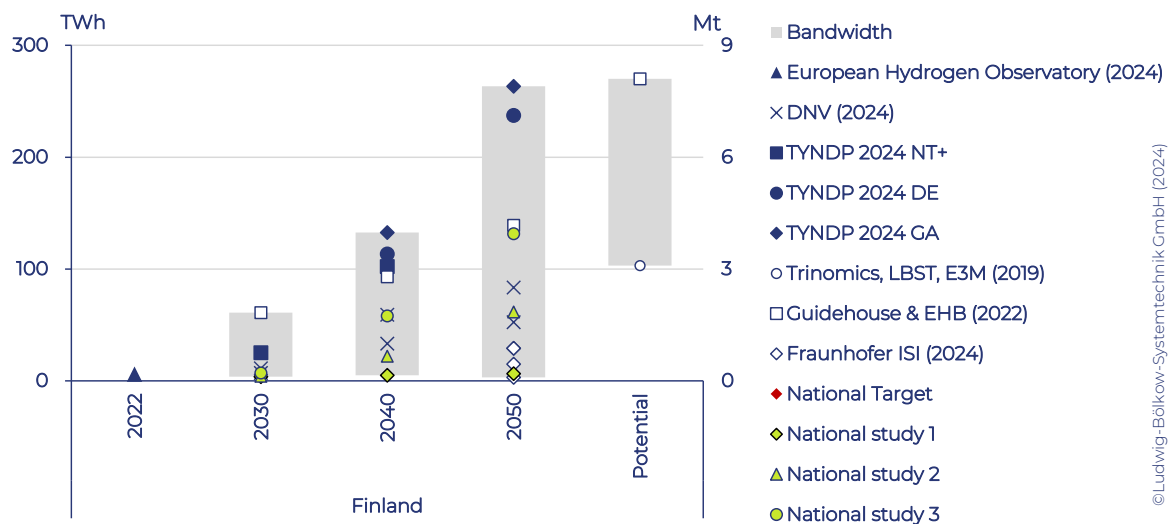
²¹⁸ Prime Ministers's Office Helsinki (2022): [Hydrogen Economy - Opportunities & Limitations, PUBLICATIONS OF THE GOVERNMENT'S ANALYSIS, ASSESSMENT AND RESEARCH ACTIVITIES 2022:41](#)

²¹⁹ ENTSG / ENTSG (2024): [Ten-Year Network Development Plan \(TYNDP\)](#)

Guidehouse & EHB (2022) data.²²⁰ These include a projected hydrogen production between 37-48 TWh in 2030 and 80-135 TWh in 2040 – with significant shares being available for exports.²²¹

DNV (2024)²²² estimates the overall domestic hydrogen production could reach around 7.0-11.1 TWh by 2030, 33.1-59.1 TWh by 2040 and 52.4-83.4 TWh by 2050 based on the projected RES production and electricity demand (values represent the conservative and the optimistic scenario). In both DNV scenarios, Finnish renewable electricity generation will steeply increase. In the conservative scenario, Finland will continue to exceed its RES targets for 2030 (84% actual compared to 57% target) and is expected to maintain this trend until 2050. Hence, by 2040 and 2050, Finland would have an excess of electricity available for hydrogen production. This would amount to between 30 TWh and 80 TWh of electricity, respectively, which could be used for electrolysis and subsequent export (next to production of around 20 TWh for domestic demand). The optimistic scenario is built on projections which indicate that onshore wind capacity will more than double, reaching about 200 TWh in 2050 from 80 TWh in 2030. Additionally, offshore wind generation is expected to increase seven-fold from about 4 TWh in 2030 to 30 TWh by 2050. Nearly all of Finland's electricity demand would thus be met by renewable sources, by 2030. From then on, Finland's electricity generation would surpass its domestic renewable energy targets, a trend projected to continue through 2050. From 2030 onwards, Finland is anticipated to have surplus electricity available for hydrogen production, starting at around 9 TWh in 2030 and expected to increase tenfold by 2050.

Figure 7-5: Renewable hydrogen production projections – Finland

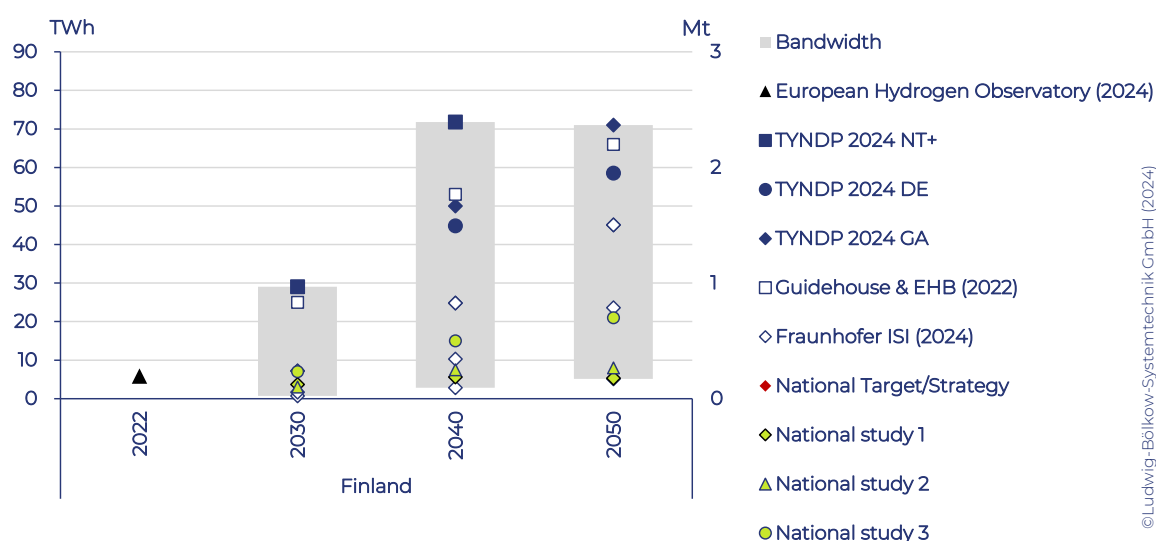


²²⁰ Gasgrid & Fingrid hydrogen economy report: <https://gasgrid.fi/wp-content/uploads/Energy-transmission-infrastructures-as-enablers-of-the-hydrogen-economy-and-clean-energy-system-Final-report.pdf> and Hydrogen economy: Opportunities and limitations (This publication is part of the implementation of the Government Plan for Analysis, Assessment and Research): <http://urn.fi/URN:ISBN:978-952-383-068-4>.

²²¹ Final seminar of Gasgrid's and Fingrid's hydrogen economy project, 2023, <https://gasgrid.fi/wp-content/uploads/Final-seminar-presentation-Gasgrids-and-Fingrids-hydrogen-economy-project.pdf>.

²²² DNV (2024): Potential for a Baltic Hydrogen Offshore Backbone, March 2024, https://www.gascade.de/fileadmin/Dokumente/Wasserstoff/DNV_Baltic_Hydrogen_study_2024.pdf.

Figure 7-6: Hydrogen demand projections – Finland



With regard to the **export potential** of Finland, the country's NECP²²³ states the goal of accounting for 10% of the EU's clean hydrogen production and for at least the same percentage of hydrogen use, therefore seeking to be an important player for hydrogen in Europe. Comparing the domestic surplus electricity generation in the DNV (2024) study with the Finnish Government's analysis of hydrogen demand for e-fuel and hydrogen exports,²²⁴ the 2040 surplus exceeds the stated amount of e-fuel exports (26 TWh) and hydrogen exports (36 TWh). However, by 2050, the surplus falls short of the government's scenario projections, which estimate an export of 51 TWh of hydrogen and 107 TWh of e-fuels. In conclusion, however, the rapid build-out of renewable electricity capacity will likely allow for large amounts of excess electricity that could be exported in the form of hydrogen (and/ or e-fuels). The high potential to become a relevant export country for renewable hydrogen is also shared by stakeholders (stakeholder survey). However, no estimation on the expected export amounts could be provided by stakeholders in the survey at current (early) stage of market development and policy implementation.

Guidehouse & EHB (2022) projects the 2050 **technical potential** for hydrogen in Finland to be around 270 TWh for the year 2050. According to Trinomics, LBST & E3M (2019), the (theoretic) potential for renewable hydrogen production in Estonia is only around 103 TWh. These values are lower than some of the hydrogen supply scenarios, e.g. TYNDP 2024 DE and GA scenarios with up to 263 TWh by 2050, indicating the highly ambitious character of these two long-term projections.

Germany

Germany has doubled its earlier **target** for electrolyser capacity by 2030 from 5 to 10 GW. If 5.000 full-load hours (FLH) and 68 % electrolyser efficiency were assumed, then 34 TWh of hydrogen could be produced in 2030. The German Hydrogen Import Strategy²²⁵ even expects 40 – 50 TWh of (renewable) hydrogen to be produced domestically. Germany's expected national hydrogen demand is between 95 – 130 TWh by 2030, of which 45 – 90 TWh will be imported in the form of hydrogen or hydrogen derivatives (depending on domestic hydrogen production). Of the 95 – 130 TWh demand, around 55 TWh are the existing hydrogen demand (covered by fossil-based hydrogen production today) and around 40 – 75 TWh of additional demand. For 2045, the Hydrogen Import Strategy foresees a

²²³ Finland - Final updated NECP 2021-2030: https://commission.europa.eu/publications/finland-final-updated-necp-2021-2030-submitted-2024_en.

²²⁴ Prime Ministers's Office Helsinki (2022), Hydrogen Economy - Opportunities & Limitations, PUBLICATIONS OF THE GOVERNMENT'S ANALYSIS, ASSESSMENT AND RESEARCH ACTIVITIES 2022:41, https://julkaisut.valtioneuvosto.fi/bitstream/handle/10024/164081/VNTEAS_2022_41.pdf?sequence=1%26isAllowed=y.

²²⁵ German hydrogen import strategy, BMWK July 2024, https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/importstrategie-wasserstoff.pdf?__blob=publicationFile&v=18

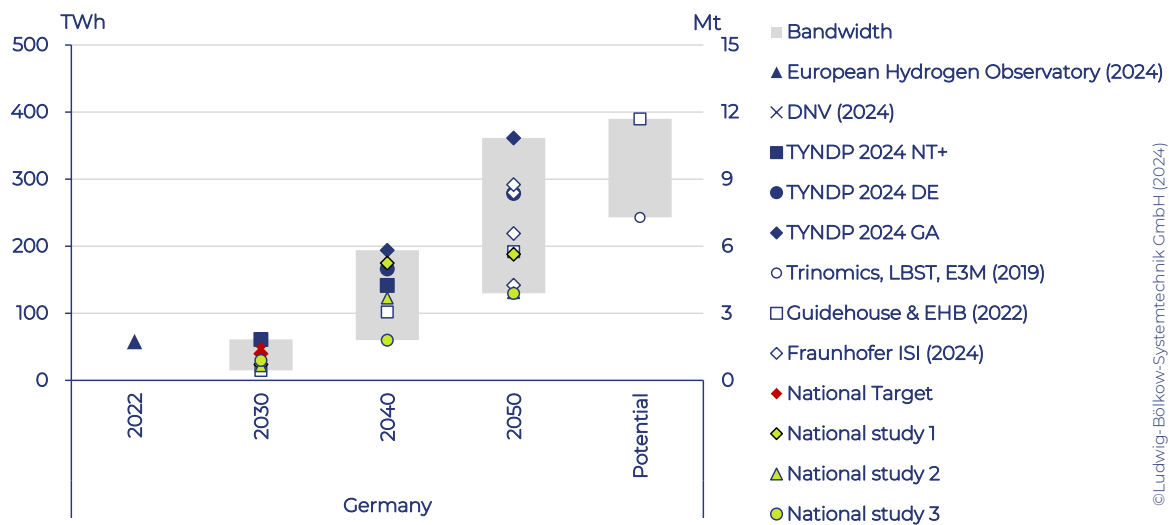
national hydrogen demand between 360 TWh and 500 TWh ('National target/strategy in Figure 7-7), with an additional demand of around 200 TWh of hydrogen derivatives.

In contrast to that, the TYNDP 2024 NT+ scenario assumes a **domestic hydrogen production** of around 61 TWh in 2030 as basis for infrastructure planning. The demand will increase accordingly to about 127 TWh, being at the upper end of the government's expectations. Other studies predict or model domestic production between 15 and 30 TWh (these studies, however, focus on the demand for import infrastructure (Guidehouse & EHB (2022)²²⁶ or focus on minimizing overall energy system costs while not including existing grey hydrogen demand in their assessments).²²⁷

In 2040, predictions for Germany's domestic hydrogen supply range (with one exception) from 102 to 194 TWh. The TYNDP 2024 NT+ scenario lies in the middle with 141 TWh. By 2050, even the most conservative studies expect 130 TWh of domestic production. Supply projections go up to a maximum of 362 TWh (close to the identified production potential in Guidehouse & EHB (2022)).

The range for 2040 **hydrogen demand** is between around 200 TWh for the lowest assumptions and 690 for the highest. The 532 TWh of the TYNDP 2024 NT+ scenario are in the middle of this range. The German import strategy²²⁸ expects a national hydrogen demand of 360 to 500 TWh in 2045, as well as additional demand for 200 TWh of hydrogen derivatives. Most other analysed studies predict the demand in 2050 to be between 500 TWh and 680 TWh. The Global Ambition (GA) scenario of the TYNDP 2024 scenario, however, expects 912 TWh of demand. These values are in line with expectations by the Germany hydrogen council, an expert committee consulting the government during the implementation phase of the national hydrogen strategy. According to a publication in 2024, overall hydrogen demand in Germany could rise from 94-125 TWh (in 2030), 302-387 TWh (in 2040) and 620-1288 TWh (in 2045²²⁹) ('National study 4').

Figure 7-7: Renewable hydrogen production projections – Germany



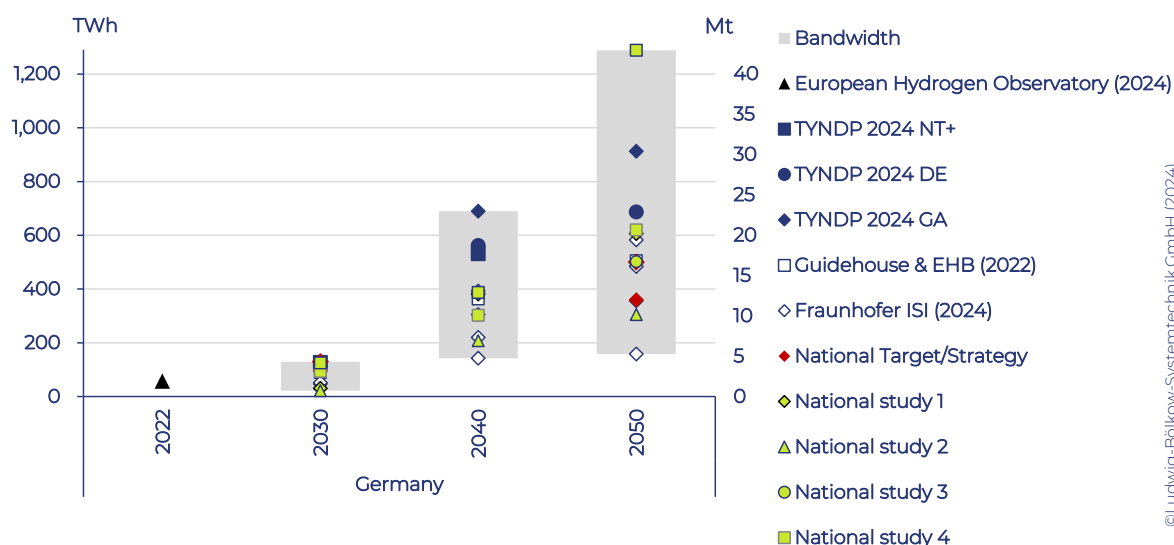
²²⁶ Guidehouse & EHB (2022): Five hydrogen supply corridors for Europe in 2030 - <https://www.ehb.eu/files/downloads/EHB-Supply-corridor-presentation-Full-version.pdf>

²²⁷ BMWK (2024): Long-term Scenarios 3 - Scientific analyses on the decarbonization of Germany <https://langfristszenarien.de/enertile-explorer-en/>

²²⁸ German hydrogen import strategy, BMWK July 2024, https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/importstrategie-wasserstoff.pdf?__blob=publicationFile&v=18

²²⁹ German climate targets aim for reaching climate neutrality already in 2045.

Figure 7-8: Hydrogen demand projections – Germany



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Germany is – according to its strategy and according to the reviewed studies – clearly an **importing country** and is also the country with clearly the highest hydrogen demand and demand deficit (around 45 to 90 TWh to be imported by 2030, see above).²³⁰ According to Fraunhofer ISI et al. (2023)²³¹, long-term import needs would even be significantly higher with between 550 TWh and 883 TWh of hydrogen per year.

The national studies considered in Figure 7-7 are from the long-term scenarios of the Federal Ministry for Economic Affairs and Climate Action (scenario O45-H₂ = 'National study 1' and scenario O45-electricity = 'National study 2'). In addition, a market assessment by Energinet & Gasunie (2023) was included („National study 3').

Latvia

Latvia's NECP²³² contains an indicative target of 61% final energy consumption from renewable sources by 2030, with a >80% share specifically for the electricity sector. While no secondary studies predict power sector development aligned with these targets, the NECP includes the potential to develop 15.5 GW of offshore wind equivalent to an annual energy production of 49.2 TWh.

The projected (renewable) hydrogen production ramp-up in literature as well as the theoretical production potential is shown in Figure 7-9.

The available studies give no indication of significant installed electrolyser capacity by **2030**. However, a limited hydrogen demand is expected to develop, in some volume between 0.1 TWh and 1.4 TWh. The TYNDP 2024 NT+ scenario predicts a demand of around 0.82 TWh.

For **2040**, the TYNDP scenarios differ strongly. The NT+ scenario expects no domestic production and 3.4 TWh of hydrogen imports to cover demand. The DE and GA scenarios, however, assume a domestic production (6.8 – 7.8 TWh) that lies 62 % or 37 % above domestic demand (4.2 – 5.7 TWh) and can thus be exported. Most scenarios from Fraunhofer ISI (2024) expect a demand around

²³⁰ Updated German hydrogen strategy (German: Fortschreibung der Nationalen Wasserstoffstrategie, BMWK 2023, https://www.bmbf.de/SharedDocs/Downloads/de/2023/230726-fortschreibung-nws.pdf?__blob=publicationFile&v=1

²³¹ Fraunhofer ISI, RIFS Potsdam, dena (2023): Mobilizing Europe's Full Hydrogen Potential: Entry-Points for Action by the EU and its Member States. HYPAT Discussion Paper No 5/2023, https://www.isi.fraunhofer.de/content/dam/isi/dokumente/cce/2023/Hypat%20Discussion%20Paper%2005_2023%20Mobilizing%20Europe%E2%80%99s%20Full%20Hydrogen%20Potential%20v01.pdf

²³² Latvia - Final updated NECP 2021-2030 (submitted in 2024), https://commission.europa.eu/publications/latvia-final-updated-necp-2021-2030-submitted-2024_en.

3.3 TWh, as in the NT+ scenario. Guidehouse & EHB (2022) expect a higher supply (9 TWh) and lower demand (1 TWh) than the other sources.

For **2050**, Guidehouse & EHB (2022) and the DE & GA scenarios expect a doubling or more of hydrogen supply to 14 – 20 TWh. Fraunhofer ISI (2024)'s more ambitious scenarios also expect a hydrogen supply of 11 to 15 TWh. For 2050, all reasonably ambitious scenarios expect between 3.1 and 7.7 TWh of demand. By 2050, Guidehouse & EHB (2022), the remaining TYNDP scenarios and the Fraunhofer scenarios all expect Latvia to have created significant exporting capacities of often several times more than the national demand.

The expected hydrogen production potential ramp-up according to DNV (2024) accounts to around 0.5 TWh for the conservative and the optimistic scenario in 2030, and between 2.8 and 2.5 TWh by 2040 and 3.7 and 2.8 TWh by 2050. In DNV's conservative scenario, Latvia will need to import energy and will not have excess electricity that could be used for additional hydrogen production. This expectation is in line with the feedback of the national grid operator Conexus. According to the feedback, especially imports from Finland are considered very important. In an optimistic scenario in DNV (2024) with a faster-developing energy supply, not only the national demand of around 3 TWh will be covered domestically, but also an additional up to 1 TWh of surplus electricity will be available for possibly electrolysis and export of hydrogen.

For 2040 and 2050, feedback from the stakeholder survey indicate that domestic production of renewable hydrogen will be rather limited. A conservative scenario describes around 2.5 TWh in 2040 and 2050. Also, Latvia's hydrogen demand is expected to be limited, due to the lack of industries. Consequently, especially the TYNDP projections for DE and GA seem to be overestimating production development in 2040 and 2050.

Among other renewable energy sources, the potential for offshore wind has led to calculations of significant Latvian **theoretical hydrogen production potential**: 41 TWh (by Guidehouse & EHB 2022) and even around 145 TWh by Trinomics, LBST, E3M (2019).

Figure 7-9: Renewable hydrogen production projections – Latvia

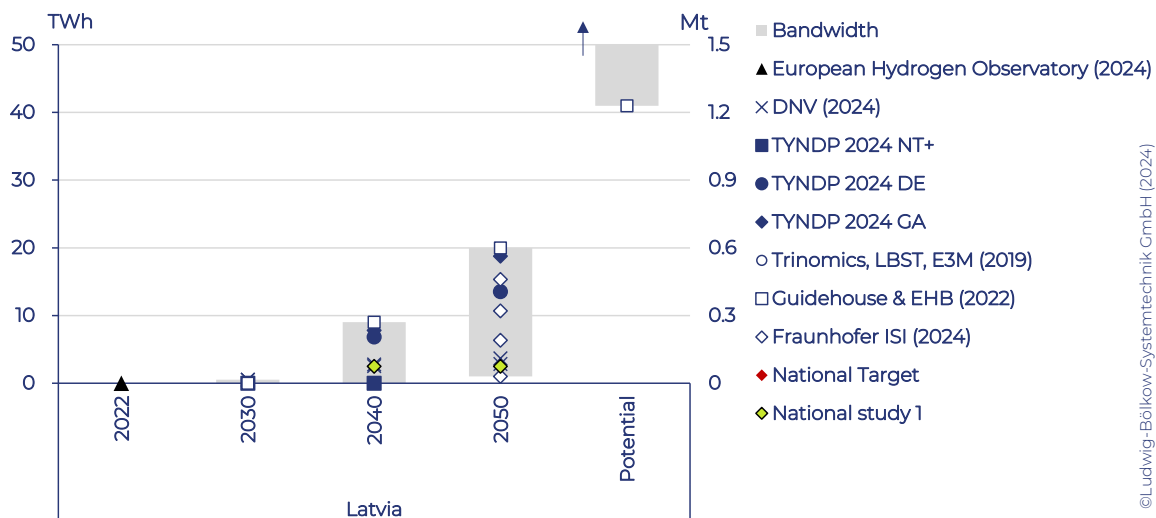
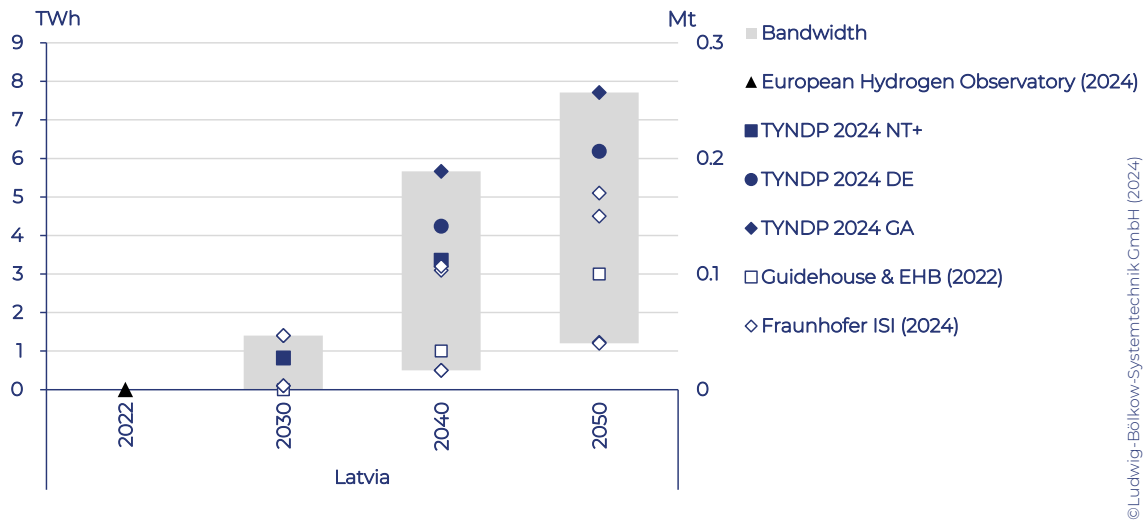


Figure 7-10: Hydrogen demand projections – Latvia



Lithuania

Lithuania's National Energy and Climate Plan (NECP)²³³ sets ambitious goals, aiming for 100% renewable energy in electricity generation starting from 2030. However, the potential surplus electricity available for green hydrogen production for export is expected to decline over time, mainly due to rising domestic hydrogen demand and the country's ambitious targets aimed at electrifying and decarbonizing its demand sectors. Lithuania also adopted a National Energy Independence Strategy 2050²³⁴ and a Hydrogen Roadmap 2050 in 2024. Furthermore, the Hydrogen Roadmap Implementation Plan was approved in December 2024..

However, there are only a few sources for hydrogen **supply** values in Lithuania in **2030**: Guidehouse & EHB (2022) with 1 TWh, the TYNDP 2024 NT+ scenario with 1.5 TWh and the significantly higher value of the National Hydrogen Strategy²³⁵ of 4.3 TWh. DNV (2024) even considers a potential based on renewable electricity ramp-up of up to 5.8-6.4 TWh.

Supply values for **2040** are provided by DNV (2024) with around 7.2-7.3 TWh, Guidehouse & EHB (2022) with 9 TWh, the TYNDP 2024 NT+ at 15 TWh, and two further TYNDP scenarios with 20 and 23 TWh. The TYNDP 2024 NT+ scenario is therefore considered a good average value for 2040.

Fraunhofer ISI (2024) provides additional, more conservative numbers for supply in **2050**, between 1 and 15 TWh. DNV (2024) expects hydrogen production of around 9 TWh in 2050 with little surplus electricity available for additional hydrogen production. Guidehouse & EHB (2022) has predicted a hydrogen supply of 15 TWh, which is at the higher end of these scenarios. The TYNDP scenarios DE and GA provide much higher numbers at 32 and 36 TWh, respectively.

²³³ Lithuania - Final updated NECP 2021-2030, https://commission.europa.eu/publications/lithuania-final-updated-necp-2021-2030-submitted-2024_en.

²³⁴ Ministry of Energy of Lithuania, https://enmin.lrv.lt/public/canonical/1719985901/4829/Seimo_nutarimas_Nr._XIV-2856.pdf.

²³⁵ Lithuanian National Hydrogen Strategy (2024)

Figure 7-11: Renewable hydrogen production projections – Lithuania

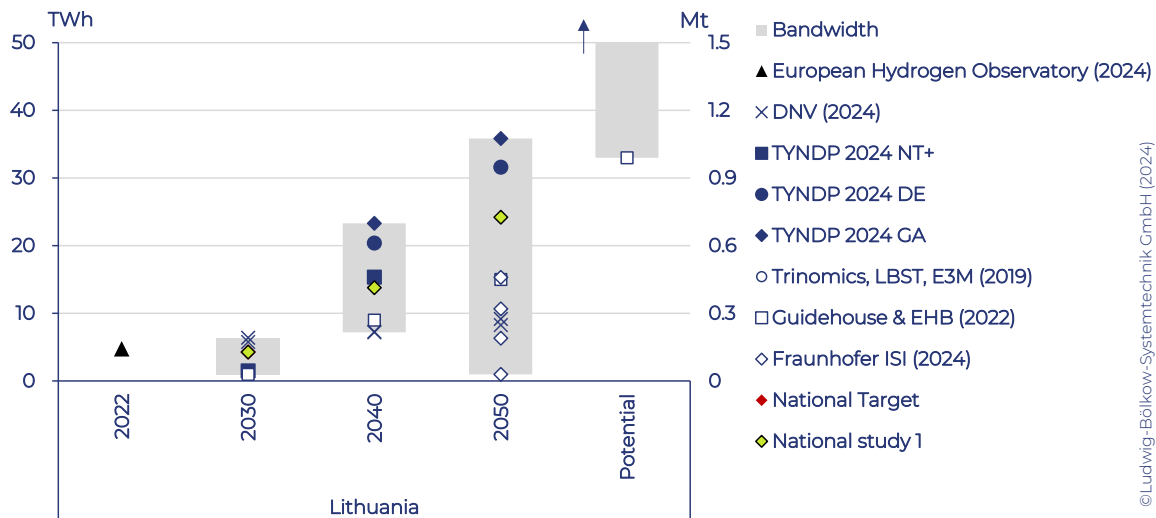
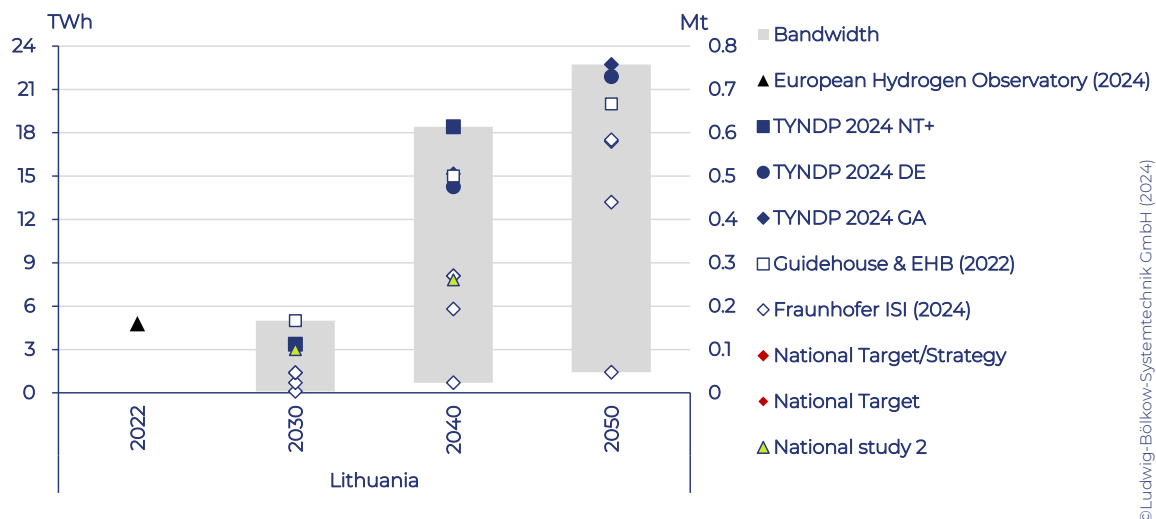


Figure 7-12: Hydrogen demand projections – Lithuania



Based on the National Energy Independence Strategy 2050 (=‘National study 1’ in Figure 7-11), production ramp-up of around 4.3 TWh (2030), 13.8 TWh (2040) and 24.2 TWh (2050) is targeted.

The Lithuanian hydrogen **demand** in **2030** is between 0.1 and 3 TWh in the scenarios of the studies from Trinomics and Fraunhofer ISI. Orlen (‘National study 2’)²³⁶, and the TYNDP NT+ scenario also expect values of around 3 TWh, and Guidehouse & EHB (2022) expects a higher value of 5 TWh, placing the TYNDP NT+ scenario around the average. Most Fraunhofer ISI (2024) projections for demand in **2040** are around 8 TWh, while Guidehouse & EHB (2022) and the two TYNDP scenarios DE and GA expect 15 TWh. The TYNDP NT+ scenario predicts a slightly higher demand at 18 TWh. In **2050**, demands between 0.24 and 23 TWh are covered by the scenarios.

²³⁶ Orlen (2024): Hydrogen Market in Poland and the Baltics until 2040, published June 2024, <https://www.orlen.pl/content/dam/internet/orlen/pl/en/sustainable-development/transition-projects/hydrogen/Hydrogen-market-in-Poland-and-the-Baltics-until-2040.pdf>

This report named ‘Hydrogen Market in Poland and the Baltics until 2040’ by Polish oil and gas company Orlen together with S&P Global, an American Analytics company, was published in June 2024. Its aim is to identify hydrogen demands in the region and analyze challenges to meeting supply and demand requirements. Within the report, hydrogen demand forecasts for the years 2030, 2035 and 2040 are provided, differentiated by country and sector. Since numbers are very small for Latvia and Estonia, they cannot be read from the tables provided and only the numbers for Poland and Lithuania are included.

Guidehouse & EHB (2022) have calculated 33 TWh of technical potential, and LBST estimates based on Guidehouse (2021) a realistic hydrogen potential of 125 TWh.

Poland

Poland is the only country in the BEMIP region that, as of 2024, also considers low-carbon hydrogen from fossil sources with carbon capture and storage technology (CCS) beside renewable hydrogen as feasible domestic hydrogen production technology. Still, the Polish hydrogen strategy only sets a target of 2 GW of domestic electrolysis in 2030, which in the case of 5,000 full load hours and an electrolyser efficiency of 68 % would mean around 6.8 TWh.

This is significantly higher than other values in literature, e.g. by Guidehouse & EHB (2022) and in the TYNDP 2024 NT+ scenario, which both expect a hydrogen **supply** in **2030** of around 3 TWh. The hydrogen **demand** is higher than the supply in 2030 in all studies. The range is between 4.6 TWh, in the lowest Fraunhofer ISI (2024) scenario, and 46 TWh expected in DISE Energy & PWEA (2021) ('National study 3')²³⁷ and the TYNDP 2024 NT+ scenario.

Until **2040**, both supply and demand of hydrogen will increase significantly. The **supply** will increase to between 20 TWh (TYNDP 2024 NT+ scenario) and 70 TWh (TYNDP 2024 GA scenario). There are only few supply predictions for 2040 and the expected values vary strongly. A higher number of sources is available for the **demand** projections. While the TYNDP 2024 NT+ scenario contains the lowest value for 2040 supply, it has the highest value for demand (122 TWh). Most studies predict a hydrogen demand in 2040 of between 90 and 123 TWh. Only Orlen (2024) ('National study 2') and all Fraunhofer scenarios are clearly lower with a range of 19 to 76 TWh.

Neither the TYNDP 2024 NT+ scenario nor the Polish Hydrogen Strategy²³⁸ provide values for **2050**. The values for supply in 2050 that are provided in other studies (shown in Figure 7-13) are between 58 and 189 TWh. Values for hydrogen demand are between 49 and 183 TWh. It seems as if the domestic hydrogen supply is able to close significant parts of the gap to hydrogen demand between 2040 and 2050, even surpassing demand in some scenarios.

Figure 7-13 summarizes analysis results for the projected hydrogen production in Poland. While the existing hydrogen production is fossil based (steam reforming and coal gasification), it is completely covered by dedicated on-site production for e.g. fertilizer production, chemical or petrochemical industry with no need for transport infrastructure. These existing capacities, hence, are not to be considered when analysing needs for a future hydrogen transport infrastructure.

Own estimation of gas transmission operator GAZ-System based on a market screening support the production projections by Guidehouse and EHB (2022) for 2040 and 2050. In 2030, however, a significant higher domestic production of around 15 TWh is expected – facing a domestic demand of around 35 TWh (= 'National study 1').

²³⁷ DISE Energy, PWEA (2021), Green Hydrogen from RES in Poland, <https://www.gov.pl/web/climate/the-clean-hydrogen-from-res-in-poland-report>

This report named 'Green Hydrogen from RES in Poland' was published in 2021 by DISE Energy - the Lower Silesian Institute for Energy Studies – and PWEA (The Polish Wind Energy Association). It provides a holistic overview over the subject of green hydrogen in Poland, addressing issues of supply and demand of the fuel in short and long term. Whilst projections on the supply remain rather vague, the report provides concrete numbers on the forecasted hydrogen demand for Poland. The projections have been developed 'including the author's assessment of the dynamics of development of individual areas of the hydrogen economy.' The forecasts are provided differentiated by sector (industry, transport, heating and electricity) as well as overall.

²³⁸ Polish hydrogen strategy (2021)- Polska Strategia Wodorowa do Roku 2030 z Perspektywą do Roku 2040, <https://www.gov.pl/web/klimat/polska-strategia-wodorowa-do-roku-2030> - Ministry of Climate and Environment (2021), Polish Hydrogen Strategy until 2030 with an Outlook until 2040 <https://www.gov.pl/web/klimat/polska-strategia-wodorowa-do-roku-2030>

Figure 7-13: Renewable hydrogen production projections – Poland

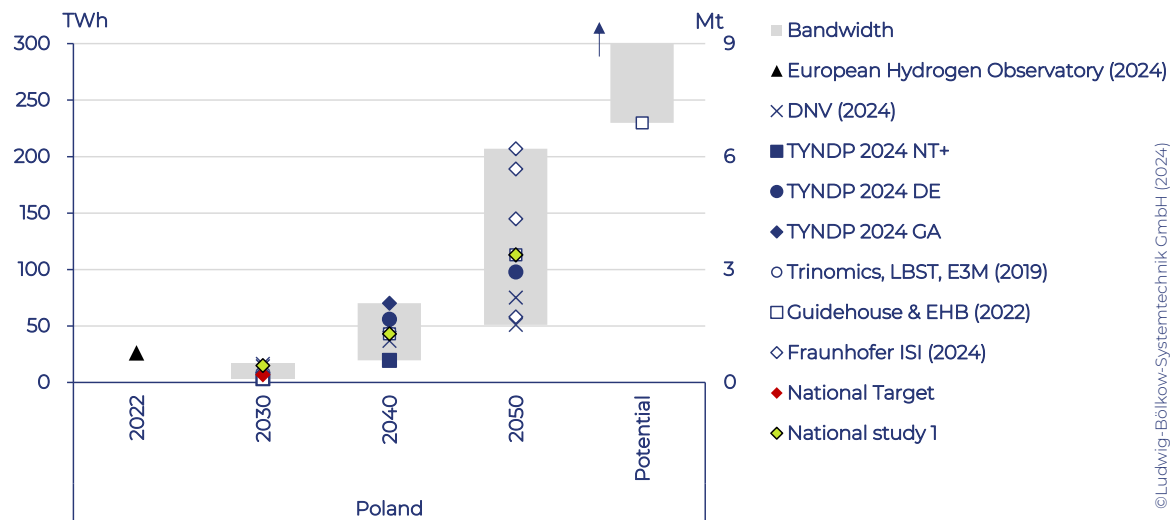
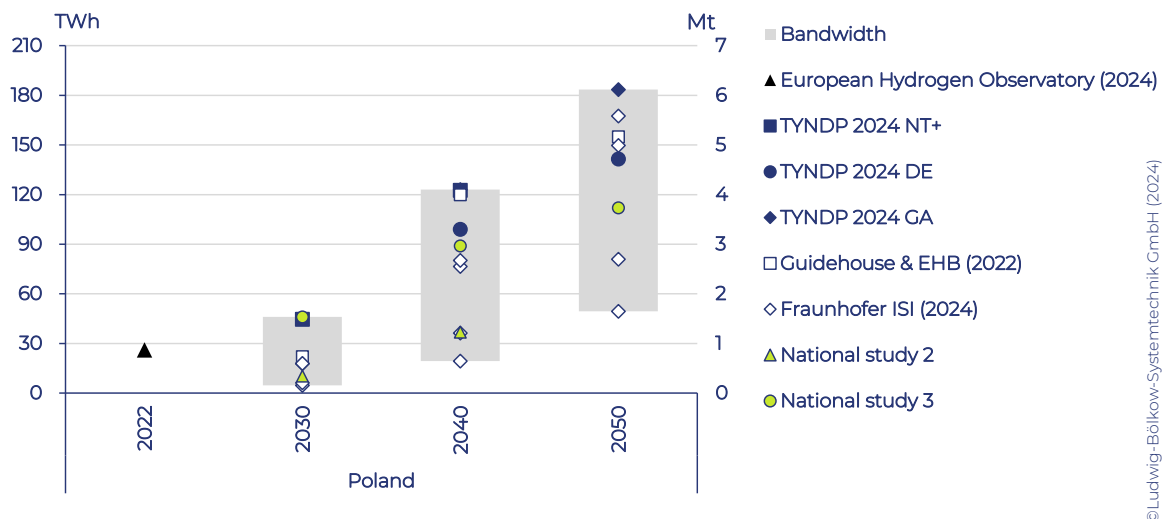


Figure 7-14: Hydrogen demand projections – Poland



Poland's energy landscape is set for significant changes: A shift towards renewables and nuclear power generation and the phasing out of coal by 2040. Therefore, DNV's study (2024) predicts uncertainties on whether Poland can produce sufficient electricity to cover its demand. In the conservative scenario, Poland produces 75 TWh of hydrogen, but needs to import large amounts of electricity which diminishes the opportunity of producing additional quantities of hydrogen. In the optimistic scenario, Poland is transitioning toward a largely renewables-based electricity supply, which is projected to reach a share of 84 % by 2050. Despite increasing electricity demand, this could lead to an overall electricity surplus by 2050. However, much of this surplus would be comprised of non-renewable electricity, making it unusable for green hydrogen production and keeping the renewable hydrogen production potential at the domestic demand of 51 TWh, not allowing for significant green hydrogen exports to add to the domestic hydrogen production.

Poland as a large country has a significantly higher realistic potential and technical potential for hydrogen production from renewable sources than smaller neighbouring countries. The role and contribution of low-carbon hydrogen, however, needs to be discussed in more detail. Stakeholder feedback in the survey focused on renewable hydrogen production.

The technical potential for renewable hydrogen production was calculated by Guidehouse & EHB (2022) to be 230 TWh. Estimations by Trinomics, LBST, E3M (2019), even identified a production potential of 520 TWh.

Sweden

Sweden's existing (fossil-based) hydrogen supply and demand is around 5.8 TWh. In 2021, the Swedish Energy Agency (SEA)²³⁹ has proposed a two-phase strategy to build around 5 GW of electrolyser capacity by 2030 and 15 GW_{el} by 2045 in order to supply the expected demand of 22-42 TWh (2030) and 44-84 TWh (by 2045).

In the near term, until **2030**, this self-sufficient approach is predicted to continue in the TYNDP 2024 NT+ scenario with both (supply and demand) values just over 19 TWh. The NT+ scenario is therefore in line with the national hydrogen strategy of the SEA, although the demand could also be twice as high.

The announced hydrogen demand projects in the 2020 Fossil Free Sweden report²⁴⁰ sum up to 12 TWh in 2030 ('National study 1 and 2'), which is lower than the NT+ scenario (19 TWh). Significantly higher values of demand (50 TWh) and supply (64 TWh) are predicted by Guidehouse & EHB (2022). This source expects a 28% higher supply than demand already in 2030.

Most literature sources predict a substantial increase in supply and demand in Sweden in **2040**. Values for **supply** lie between 55 TWh (TYNDP 2024 NT+) and 125 TWh (Guidehouse & EHB 2022) with further TYNDP scenarios in between. The national hydrogen target proposal to install 15 GW of electrolyzers by 2045, which could lead to 51 TWh. This value is similar to the NT+ scenario's demand and much lower than in the other studies, even though it is for 2045.

Demand predictions in 2040 lie between 53 TWh and 100 TWh. The NT+ scenario is near the lower end at 60 TWh. The SEA expects between 44 and 84 TWh, which is in line with the NT+ scenario, however 5 years later in 2045.

By **2050**, hydrogen **supply** is expected to further increase to between 92 and 166 TWh. The hydrogen demand could increase to between 77 and 123 TWh – according to studies. As of October 2024, Nordion Energi is conducting confidential market surveys with potential producers and offtakers of hydrogen. Currently no detailed information, however, is available.

In terms of becoming an exporter or importer of hydrogen, the sources are divided. The Swedish Energy Agency and the TYNDP 2024 NT+ Scenario expect the buildout of electrolysis capacity to not be able to cover the demand, while Guidehouse & EHB (2022) and the other two TYNDP scenarios expect supply to significantly surpass demand in Sweden. According to stakeholders, Sweden has excellent condition for producing renewable hydrogen from renewable electricity sources in large quantities. However, the long distances to potential off takers and the lack of a dense gas grid require substantial upfront investment to unlock the overall potential. Hence, the future actual production will depend on several factors like transport costs, state subsidies and regulatory environment.

²³⁹ Swedish Energy Agency (2021), Proposal for a Swedish national strategy for hydrogen, electrofuels and ammonia <https://www.enlit.world/hydrogen/sweden-a-national-strategy-for-green-hydrogen/>

²⁴⁰ Fossil Free Sweden (2020), Strategy for fossil free competitiveness, https://fossilfrittssverige.se/wp-content/uploads/2020/12/Strategy_for_sustainable_batter_value_chain.pdf

Fossil Free Sweden, an initiative started by the Swedish government in 2015, published this report named 'Strategy for fossil free competitiveness – Hydrogen' in 2020. The report includes projections for the Swedish hydrogen demand in 2030 and 2045, differentiating between projects via electrolysis and those with 'several production technologies'.

Figure 7-15: Renewable hydrogen production projections – Sweden

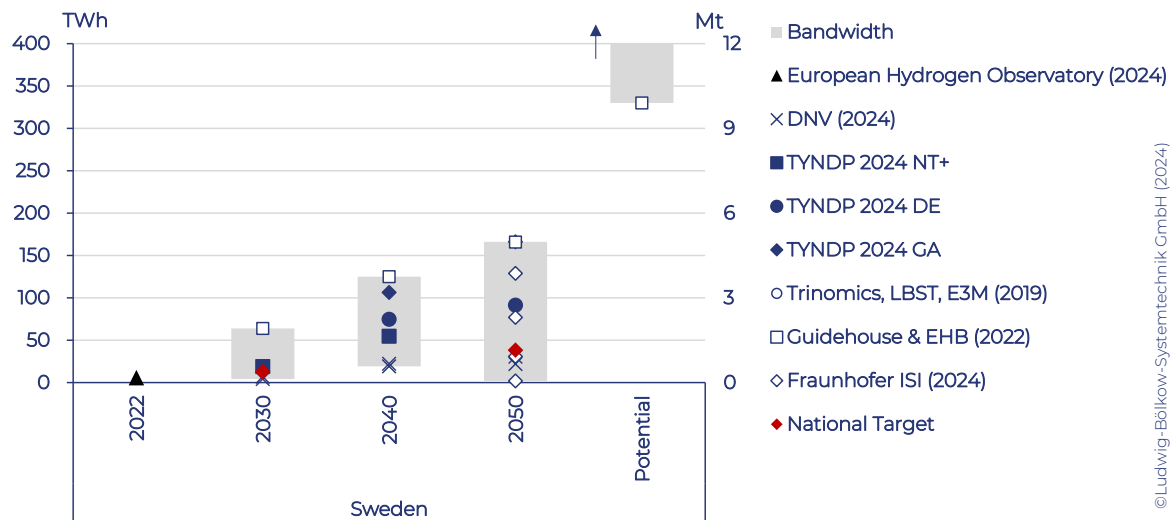
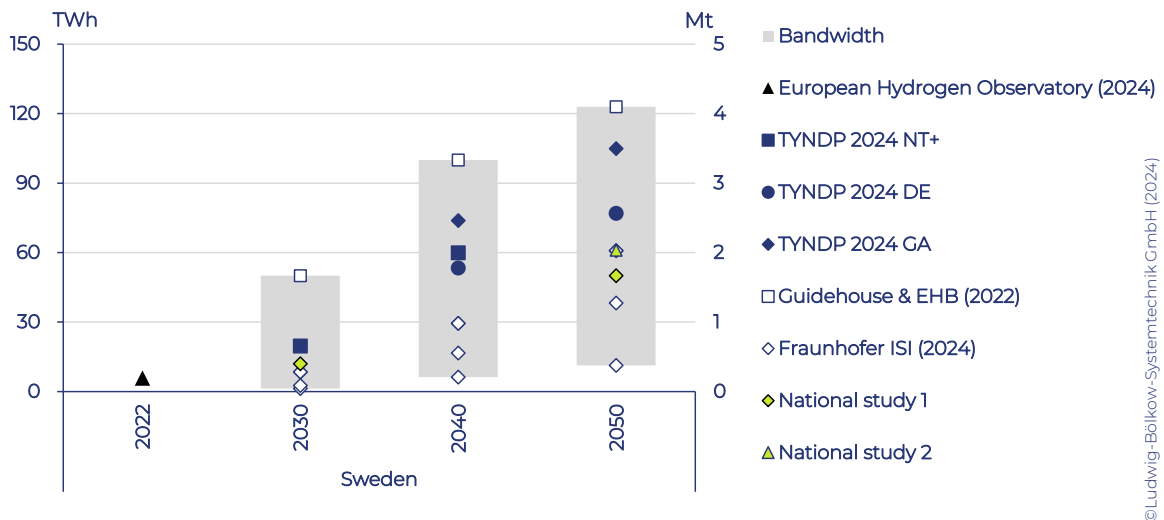


Figure 7-16: Hydrogen demand projections – Sweden



According to the hydrogen production analysis in DNV (2024), Sweden is – in the conservative scenario - unlikely to become a significant green hydrogen exporter in the long term (after initial exports until 2040). This would be primarily due to the anticipated extensive electrification within the country, which is expected to diminish any current or future electricity surplus. Conversely, in the optimistic scenario, Sweden is projected to have a green electricity surplus by 2040, enabling hydrogen exports. This surplus would stabilize after 2040 allowing for the production of up to around 8 TWh of exportable hydrogen, indicating a modest but not substantial export potential.

According to DNV (2024) total Swedish hydrogen production including production serving domestic demand could increase to between 22 and 31 TWh in 2050, depending on the scenario. These numbers come from scenarios built on development plans in the TYNDP 2022 and the updated NECP.

When looking at the technical potential, Guidehouse & EHB (2022) calculated around 330 TWh of **technical renewable hydrogen production potential** in 2050. Estimations by Trinomics, LBST, E3M (2019), even identified a production potential of around 400 TWh.

7.2. Key data sources for hydrogen production and demand

Table 7-1 provides an overview of key data sources identified and used in this study on existing and future production, demand and theoretical/ technical potential for hydrogen. Beside a brief description of relevant content, the table also indicates whether the study coverage contains several EU MS as total or only selected BEMIP MS.

Table 7-1: Overview of key sources for hydrogen

Source	Description	Geographic coverage	Link
European Hydrogen Observatory - Hydrogen Production and Demand (2024)	Status quo on hydrogen production and demand, differentiated by production technology and sector (as of 2022)	EU27 + MS level	Link (production) Link (demand)
IEA Hydrogen Project Database (2024)	Database of existing and planned projects for hydrogen production (Status 10/2024)	global	Link
ENTSOG / ENTSO-E: Ten-Year Network Development Plan (TYNDP) (2024)	Energy system modelling for Europe as basis for infrastructure development, includes data for hydrogen and biomethane, 3 scenarios included: National Trends (NT+), Distributed Energy (DE) and Global Ambition (GA)	EU27 + MS level	Link Link
Guidehouse: Analysing future demand, supply, and transport of hydrogen (2021)	Data on realistic RES electricity potential for wind onshore, wind offshore and PV	EU27 + MS level	Link
Guidehouse / European Hydrogen Backbone: Five hydrogen supply corridors for Europe in 2030 (2022)	Hydrogen demand and supply data based EHB analysis report (June 2021) and further analysis as basis for infrastructure planning. The study includes data on the 'realizable hydrogen potential' for 2030, 2040, and 2050 as well as the 'technical potential' for hydrogen production in 2050. Furthermore, it is differentiated between dedicated green, blue (not present in BEMIP MSs) and grid-based hydrogen production via electrolyzers.	EU27 + MS level	Link
Trinomics, LBST, E3M: Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure (2019)	Estimated (theoretic) potential for hydrogen production	EU28 + MS level	Link
Trinomics, SEI, E3Modelling: Gas Decarbonisation- Pathways for Estonia (3 Baltic states + Finland), Deliverable 8 (2023)	Estimation of (renewable) gas quantities for the years 2030 and 2050 in the four countries investigated.	EE, FI, LV, LT	Link
Fraunhofer ISI: Hydrogen Infrastructure in the Future CO2-Neutral European Energy System—How Does the Demand for Hydrogen Affect the Need for Infrastructure? (2024)	Modelling of future energy system in EU27+UK, Analysis of five scenarios: 1) S1_newIndVC = New global industrial value chains, 2) S2_ChemSteel = Focus H ₂ in chemicals and steel, 3) S3_Ind = Focus H ₂ in industry, 4) S4_IndMob = Focus H ₂ in industry and transport, 5) S5_allSec= H ₂ in all sectors=	EU27+UK + MS level	Link
DNV: Potential for a Baltic Hydrogen Offshore Backbone (2024)	Data on RES and hydrogen production potentials based on renewable electricity ramp-up, as well as LCOH (Levelized Cost of Hydrogen) of BEMIP MS. Optimistic scenario: The renewable targets applied are based on the fossil-free targets which have been stated as new targets in the updated NECP. Conservative scenario: The renewable electricity demand and the supply are based on the 'Lower Electrification Scenario' published by the Swedish Energy Agency (SEA).	BEMIP MS w/o DE + DK	Link

7.3. Country fiches – biomethane production projections

The following country fiches summarize key data on biomethane (=upgraded biogas) production and demand in BEMIP MSs. The data comprise both, current supply situation as well as projections on future biomethane production projection and country's production potential. For each country, key sources by national authorities or stakeholders were identified and analysed. Additionally, input received via a stakeholder survey was included in the different sections.

Where available and considered relevant, also data on key feedstocks, characteristics of biomethane production plants and available gas grid as well as further country-specific aspects were considered.

Denmark

Status Quo: Biogas production in Denmark significantly increased from 2012 onwards following political support and a subsidy scheme. While biogas use for electricity production in CHP plants dominated in the beginning, from 2014 onwards upgrading to biomethane and its injection into the gas grid gained significant importance (around 80% of biogas production in 2023). With that, biomethane accounted for almost 40% of gas transported via the gas system in 2023. A complete coverage of the gas demand is expected by 2029/2030.²⁴¹ These ambitions are already higher than originally formulated in the Green Gas Strategy Denmark (2021)²⁴², which considered a share of up to 70% by 2030.

The overall production of biomethane and biogas in 2022 reached around 29 PJ²⁴³ (around 8.0 TWh), which increased to around 33 PJ (9.2 TWh) in 2023. With that, Denmark is the 6th largest biogas producer in EU27+UK. At the same time, it has the highest biogas production rate per capita in EU27+UK.²⁴⁴ Based on data by the European Biogas Association, Denmark's biomethane production accounted for 6.5 TWh in 2022.²⁴⁵ Biogas Denmark describes that of the 33 PJ in 2023, around 6.5 PJ were not injected into the grid, resulting in around 26.5 PJ (around 7.4 TWh) of biomethane injection in 2023. Based on data in the Biogas Outlook 2024, biogas injection into the grid has increased to around 2.4 PJ/months beginning of 2024, which would translate to an overall biomethane injection of up to 8.0 TWh per year.

In total, there are (as of 2024) around 180 biogas plants in Denmark: 100 agriculture-based biogas production (of which 55 upgrade to biomethane), 49 wastewater treatment plants (of which 2 upgrade to biomethane), 7 industrial biogas plants (of which 1 upgrades to biomethane) and 27 landfills, where biogas is collected.^{246 247} Plants without biogas upgrading normally produce electricity and heat via CHP plants or deliver biogas direct to industry. Location, size and characteristics of Danish biogas (incl. biomethane) production plants in 2023 are collected by the Danish Energy Agency on a map, shown in Figure 7-17.

Further information on challenges of biomethane integration into the natural gas grid in Denmark are described in Chapter 9.5 in Annex C.

Feedstocks: Agricultural plants account for the highest share of biogas production (around 85% in 2022) and will, according to the Danish Energy Agency, further strengthen their role in future biogas production.²⁴⁸ About 75% of biomass input at agricultural biogas plants is based on livestock waste. Further major sources are organic waste fractions from households and industry, as well as straw and energy crops. While slurry (e.g. manure, sewage sludge) accounts for 66% of biomass feedstock (based on input) in all biogas plants in Denmark, it accounts for only 22% of overall biogas production.

The role of straw in total biomass input is very limited today (around 9%). A governmental initiative of 2022 aims to increase its use in the future, especially for reaching the target to cover Danish gas consumption with green gases by 2030.²⁴⁹ In addition, the limit to use energy crops in biogas production was reduced from around 12% in 2022 to 9% in July 2024,²⁵⁰ and is further reduced to 4% for from the 24/25 season, with use of maize as an energy crop not allowed from 25/26.

²⁴¹ Danish Energy Agency (2024): Biogas in Denmark, <https://ens.dk/en/our-responsibilities/bioenergy/biogas-denmark>.

²⁴² Green Gas Strategy Denmark (2021), https://ens.dk/sites/ens.dk/files/OlieGas/green_gas_strategy.pdf.

²⁴³ Original value from source in PJ.

²⁴⁴ Biogas Denmark (2024) Biogas Outlook 2024 - Production and use of biogas in Denmark 2023-2045, 28. May 2024, <https://www.biogas.dk/wp-content/uploads/2024/05/Biogas-Outlook-2024-05-30-WEB-engelsk.pdf>

²⁴⁵ European Biogas Association, EBA Statistical Report 2023.

²⁴⁶ Biogas Denmark (2024) Biogas Outlook 2024 - Production and use of biogas in Denmark 2023-2045, 28. May 2024, <https://www.biogas.dk/wp-content/uploads/2024/05/Biogas-Outlook-2024-05-30-WEB-engelsk.pdf>

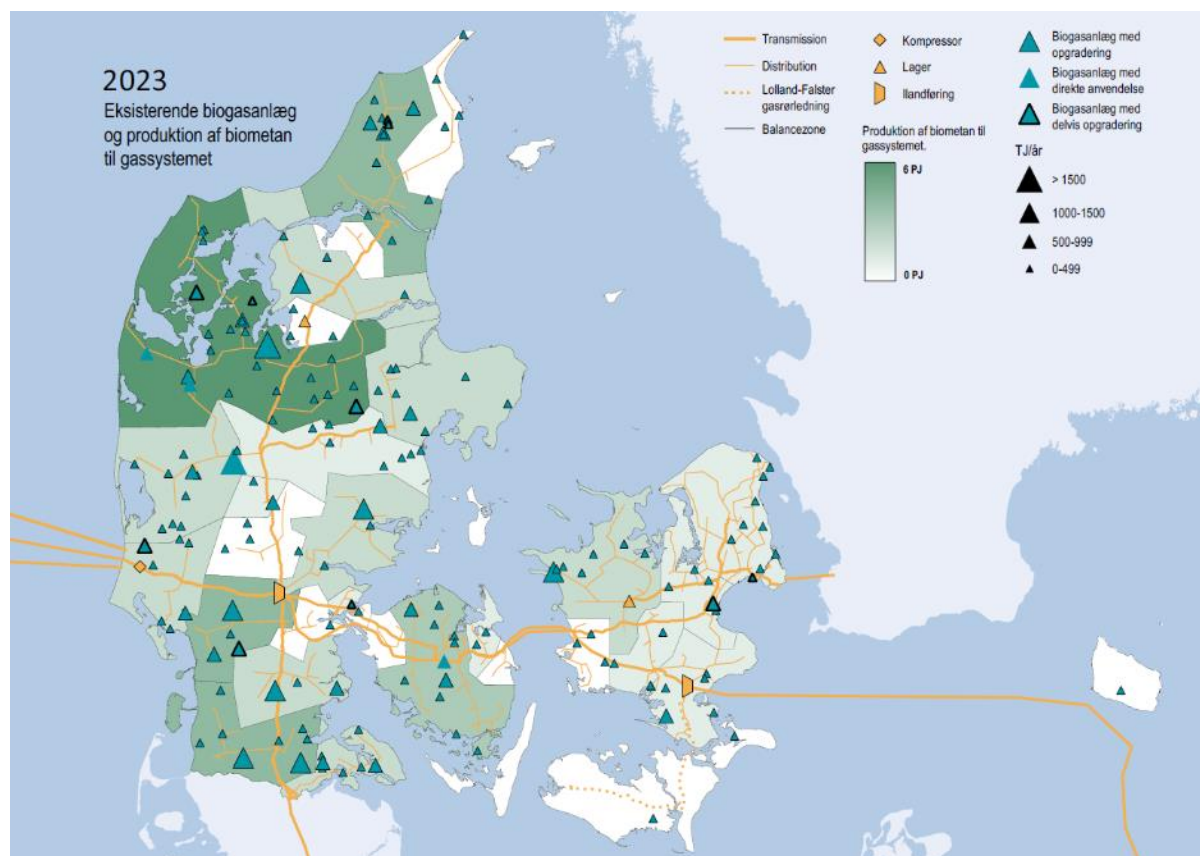
²⁴⁷ GIE, European Biogas Association (2024): European Biomethane Map 2024, <https://www.europeanbiogas.eu/european-biomethane-map-2024/>.

²⁴⁸ Danish Energy Agency (2024): Biogas in Denmark, <https://ens.dk/en/our-responsibilities/bioenergy/biogas-denmark>.

²⁴⁹ Danish Energy Agency (2023): Ny rapport undersøger udfordringerne ved øget brug af halm i biogasproduktion, 11. January 2023, <https://ens.dk/presse/ny-rapport-undersoeget-udfordringerne-ved-oegtet-brug-af-halm-i-biogasproduktion>.

²⁵⁰ Danish Energy Agency (2023): Ny aftale understøtter produktion af dansk biogas, 04. April 2023, <https://www.kefm.dk/aktuelt/nyheder/2023/apr/ny-aftale-understoetter-produktion-af-dansk-biogas>.

Figure 7-17: Map of Danish biogas plants in 2023 (Source: Danish Energy Agency²⁵¹)



Projections and Potential: According to stakeholders, the future role of natural gas in Denmark is as follows: gas consumption from the heating sector will decrease drastically due to the increasing market share of district heating and heat pumps. At the same time (natural) gas will still be used for industry processes and peak load power plants. In addition, Denmark will remain an important country for natural gas transit to demand centres in central Europe. Despite that, the role of biomethane in the domestic gas system will continuously grow.

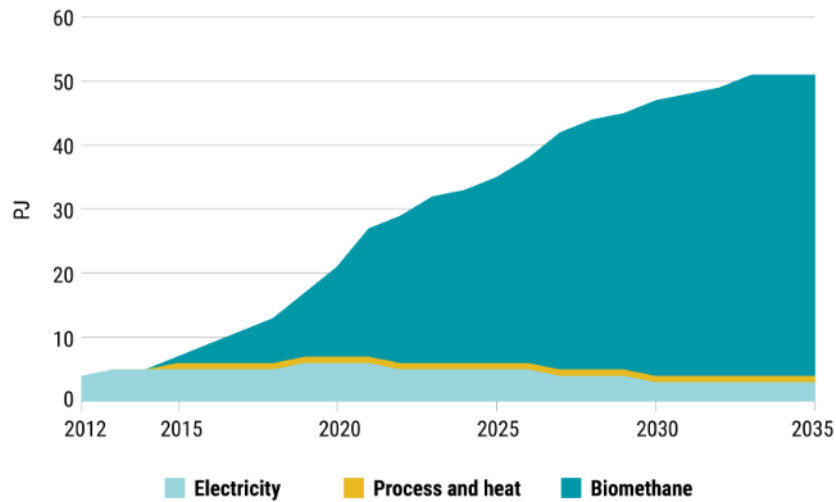
The NECP submitted by Denmark in 2024 includes a target to cover 100% of gas in the Danish gas system with green gases in 2030 ('National target'). In addition, support schemes for production and use of biogas shall ensure an overall volume of around 1.4 bcm (around 14,7 TWh) by 2030. Based on the Climate Status and Projection 2024 (KF24)²⁵², it is expected that the share of upgraded biogas/biomethane in the pipeline gas will be around 124% in 2030 and around 156% in 2035, with Danish gas consumption being green.²⁵³ According to this, an enormous increase in biomethane production to over 45 PJ or 12.5 TWh is expected until 2035 and around 14 TWh in the long run. With that, Denmark positions itself as future exporter of biomethane after 2030. The forecast of historical and expected future biogas production in Denmark according to KF24 is also published by the Danish Energy Agency (see Figure 7-18).

²⁵¹ Danish Energy Agency (2023): [Map of Danish biogas plants](#)

²⁵² The Climate Status and Projection (KF) is the annual assessment conducted by the Ministry of Climate, Energy, and Utilities, including the Danish Energy Agency, with input from researchers at different national institutions of whether Denmark meets its climate targets for 2025 and 2030, as well as its EU climate obligations. See <https://ens.dk/analyser-og-statistik/analyseforudsagtelser-til-energinet>.

²⁵³ Final update of Denmark's [National Energy and Climate Plan for the period 2021-2030](#), June 2024, https://commission.europa.eu/document/download/13353c72-43bc-486e-bc82-9e8ea7588734_en?filename=DK_FINAL%20UPDATED%20NECP%202021-2030%20%28English%29.pdf

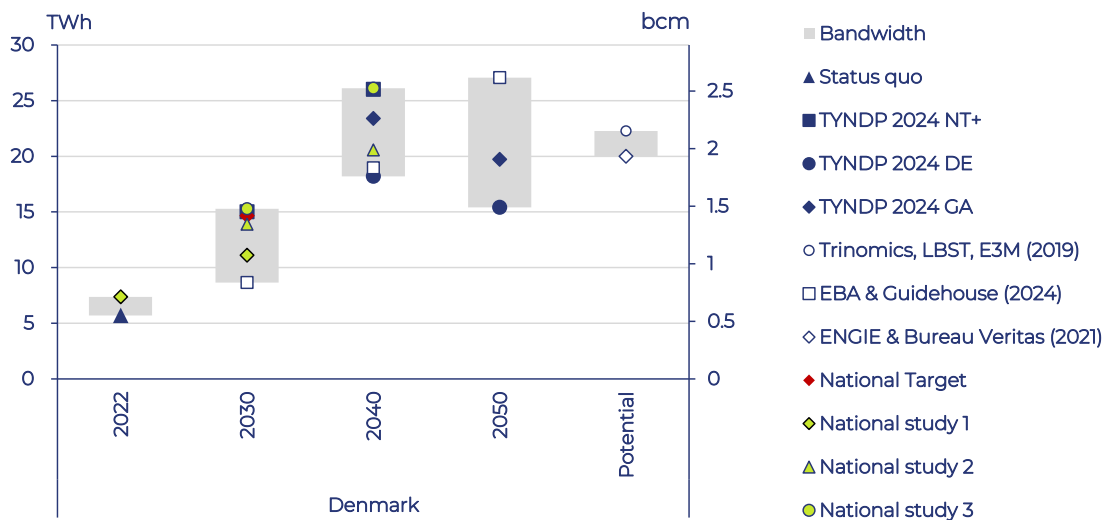
Figure 7-18: Historical and expected future biogas production in Denmark (Source: Danish Energy Agency)



In 2024, Biogas Denmark published a report called 'Biogas Outlook 2024 - Production and use of biogas in Denmark 2023-2045' ('National study 1' in Figure 7-19).²⁵⁴ The report analyses two scenarios (Frozen Policy and Green Policy) based on Danish Energy Agency's former (overly ambitious) AF22 scenario set. Starting from a raw biogas production of 33 PJ (9.17 TWh) in 2024, the overall biogas production will increase to 40 PJ (11.1 TWh) (Frozen Policy) and 50 PJ (13.9 TWh) (Green Policy Proposal) by 2030 and 60 PJ or 16.7 TWh (Green Policy) by 2035.

These values are in line with the supply data provided in TYNDP 2024 NT+ with around 15 TWh in 2030. For 2040 and 2050, overall production and demand volumes derived from national studies may rather be in line with the TYNDP 2024 Distributed Energy scenario.

Figure 7-19: Biomethane production outlook Denmark



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According to numbers of the European Biogas Association, Denmark's current biogas production accounts for around 32% of its production potential of upgraded biogas in 2050 (second highest share

²⁵⁴ Biogas Denmark (2024): [Biogas Outlook 2024 - Production and use of biogas in Denmark 2023-2045](#), 28. May 2024,

after Germany with 45%). These numbers show that already today, Denmark has utilized a considerable portion of its biomethane potential.²⁵⁵

This is in line with an analysis by the University of Southern Denmark in 2020²⁵⁶ which projected the (presently) available domestic biomass resources for biogas production to be around 50 PJ or 13.9 TWh by 2030 (of which, 80% will be upgraded and fed into the gas system). In the long term the biogas potential is stated with 74 to 94 PJ / year (around 20.6 to 26.1 TWh) for the year 2040 (depending on technological development and the possibility to use straw as input) ('National study 2 and 3'). The production of synthetic methane using hydrogen and biogas's CO₂ would even increase the potential for green gases in the Danish gas grid to up to 160 PJ/year.

Another potential analysis on the realistic potential²⁵⁷ estimated an overall biomethane potential for Denmark of around 22,3 TWh.

Estonia

Status Quo: The Interreg project Best-Ace provides a comprehensive overview of the current status of biogas and biomethane production in Estonia.²⁵⁸ According to that, in 2021 about 200 GWh of biogas were produced, of which 152 GWh were upgraded to biomethane. The entire biomethane production was used in the transport sector.²⁵⁹ During the past years, several existing biogas plants (used for electricity production from biogas) were converted to biomethane production units, resulting in an overall decrease in electricity production from biogas from 17 GWh to 7 GWh between 2021 and 2022.²⁶⁰

In total, the European Biomethane Map²⁶¹ currently (as of June 2024) lists 8 biomethane installations for Estland (all of which came into operation after 2018). The overall biomethane production in Estonia increased to around 211 GWh in 2023 according to Elering, the national gas and electricity TSO and issuing body for renewable gas Guarantees of Origin.²⁶²

For Estonia, it must be stated that not all biomethane production plants are connected to the gas grid.²⁶³ In total, the grid operator Elering states, that in 2023, around 52.3% of produced biomethane were directly injection into the grid (DSO level), while 47.7% were transported to gas stations or transported to another injection point.²⁶⁴

Feedstocks: The main contributions of feedstocks are animal manure (61.1 GWh), sewage sludge (55.6 GWh) and residues from the food industry (25.0 GWh).²⁶⁵

²⁵⁵ Biogas Denmark (2024) Biogas Outlook 2024 - Production and use of biogas in Denmark 2023-2045, 28. May 2024, <https://www.biogas.dk/wp-content/uploads/2024/05/Biogas-Outlook-2024-05-30-WEB-engelsk.pdf>

²⁵⁶ Wenzel H, JM Triolo, LV Toft, N Østergaard (2020): Energiafgrøedeanalysen. SDU og SE-GES, ISBN: 978-87-93413-18-4, https://ens.dk/sites/ens.dk/files/Bioenergi/energiafgrøedeanalysen_med_bilag.pdf

²⁵⁷ Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure, <https://op.europa.eu/en/publication-detail/-/publication/10e93b15-8b56-11ea-812f-01aa75ed71a1/language-en>

²⁵⁸ Interreg Best Ace (2023) State of Play Report, April 2023, <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>

²⁵⁹ European Biogas Association (2024): Decoding Biogases – Made in Europe, Sustainable, Affordable, July 2024, https://www.europeanbiogas.eu/wp-content/uploads/2024/07/Decoding-Biogases_EBA-Statistical-Report-Brief.pdf

²⁶⁰ Trinomics, SEI, E3Modelling (2023), Gas Decarbonisation- Pathways for Estonia (3 Baltic states + Finland), Deliverable 8, 27 November 2023, <https://energiatalgud.ee/sites/default/files/2024-02/Gas%20decarbonisation%20pathways%20-%20D8%20final%20report%20-%20kokkuv%3%B5te.pdf>

²⁶¹ GIE, European Biogas Association (2024): European Biomethane Map 2024, <https://www.europeanbiogas.eu/european-biomethane-map-2024/>

²⁶² elering (2024): Biomethane origin certificates, <https://elering.ee/biometaani-paritolutunnistused>

²⁶³ Interreg Best Ace (2023) State of Play Report, April 2023, <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>

²⁶⁴ See DEVELOPMENT PLAN FOR THE ESTONIAN GAS TRANSMISSION NETWORK / EESTI GAASIÜLEKANDEVÕRGU ARENGUKAVA 2024-2033, <https://elering.ee/sites/default/files/public/Gaas/Gaasis%3BCsteem/Eesti%20gaasi%3BClekandev%3CB5rqu%20arengukava%202024-2033.pdf>

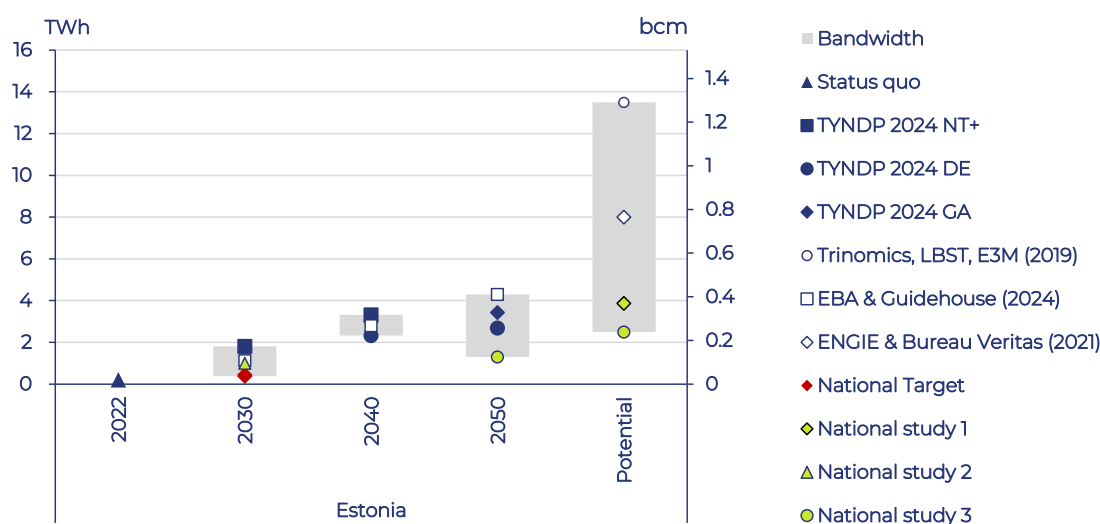
²⁶⁵ Interreg Best Ace (2023) State of Play Report, April 2023, <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>

Projections and Potential: According to the draft update of Estonia's National Energy and Climate Plan for 2030²⁶⁶, the role of biomethane in Estonia will be very strong in the transport sector (via CNG stations) in the period 2023-2035. The document mentions a national production target for biomethane of 383 GWh that will be needed to meet the targets derived from RED III in the transport sector (= 'National target 1' in Figure 7-20). According to stakeholders' feedback, even up to 450 GWh biomethane would be required ('National target 2') and up to 1 TWh is considered economically feasible in the market ('National study 2'). Key updated data on future energy system projections will be published in the reviewed Estonian Energy Sector Development Plan (ENMAK) by the Estonian government.

The use cases for gas in general and to an increasing extent also biomethane in the future Estonian energy system will, according to Stakeholders' feedback, be focused on the following applications: sectors that require high temperatures and applications, where green alternatives like electricity, are not feasible or there is no hydrogen infrastructure in place. In addition, also the use as fuel for gas power plants in order to provide electricity in periods of low RES generation is mentioned. According to that, an upcoming study on the long term gas consumption by Civitta Eesti AS also forecasts a biomethane share of 3% for 2030, 22% for 2040 and 88% for 2050 in the overall gas demand, which is expected to drop significantly (from around 3.4 TWh in 2022 to below 1 TWh in the long term). It should be noted that there was a significant decrease in country's gas consumption after the Russian invasion in the Ukraine from originally around 5.0 TWh in 2021. Depending on the further development, it can be expected that overall gas consumption may be recover by the end of 2030s before a transition to renewable energies and gases will significantly decrease overall demand.

In the study "Estonian Gas Market Study – Consumption Forecast until 2050" by Civitta Eesti AS and the Estonian TSO elering, even slightly more ambitious biomethane shares in the Estonian gas network are projected with 6% for 2030, 56% by 2040 and 92% by 2050.²⁶⁷ As the study is not published yet, no results are included in Figure 7-20.

Figure 7-20: Biomethane production outlook Estonia



Estimates by the European Biogas Association²⁶⁸ describe a 'realistic estimate for biomethane potential' in Estonia from around 1.1 TWh (2030) to 2.8 TWh (2040) and 4.3 TWh (2050). Despite its

²⁶⁶ Government of the Republic of Estonia (2023): Draft update of Estonia's National Energy and Climate Plan for 2030, https://commission.europa.eu/document/download/81c1c07b-0763-499e-ab8f-068b8e70e018_en?filename=Estonia_Draft_Updated_NECP_2021-2030_en_1.pdf

²⁶⁷ Estonian Gas Market Study – Consumption Forecast until 2050, Summary of the results. November 2024. Study not published yet.

²⁶⁸ European Biogas Associations / Guidehouse (2024) Biogas towards 2040 and beyond - a realistic and resilient path to climate neutrality, https://www.europeanbiogas.eu/wp-content/uploads/2024/04/Biogases-towards-2040-and-beyond_FINAL.pdf

rather low production of around 0.2 TWh of biomethane in 2023, the European Biogas association estimates that Estonia is only using about 5% of its production potential of around 4.2 TWh.²⁶⁹ The IEA bioenergy Country Report on Estonia of 2021 reports a biomethane potential of around 370 million m³ (around 3.9 TWh) ('National study 1') which is equivalent to about 82% of national natural gas consumption (in 2015).²⁷⁰ In contrast to that, the Interreg project Best-Ace estimates that the potential raw materials are sufficient to produce about 1.0–1.3 TWh of biomethane per year (in around 20–30 biomethane production plants). If even herbaceous biomass from arable land is included, the value may increase to about 2.0–2.5 TWh per year ('National study 3').²⁷¹ In that case, the competition to food and feed crop plantation needs, however, to be considered.

The estimate on the overall potential by Trinomics, LBST & E3M (2019) of nearly 14 TWh can only be considered as a theoretical maximum. Another study on the biogas production potential is currently under preparation by the University of Tartu and Tallinn University of Technology.

Comparing these figures to the TYNDP 2024 scenarios it is obvious that assumed biomethane production for the 2030 to 2050 period is rather high compared to other estimates on local projection levels. The values for the NT+ (2030) and the DE scenario for 2040 and 2050 with 1.8, 2.3 and 2.7 TWh, respectively, seem to provide a good overall estimate.

Finland

Status Quo: Biogas production in Finland reached about 1 TWh per year in 2023. Additional 52 biogas projects with an additional capacity of 1.2 TWh/yr are currently planned or under construction (as of April 2024). Out of these new plants, a considerable share of over 90% will be biomethane plants with liquefaction units to produce liquefied biomethane for the transport sector.²⁷²

Already today, 24 biomethane plants are listed in the European Biomethane Map for Finland (status: June 2024). Total production is estimated to be around 0.356 TWh.²⁷³ According to the Interreg Best Ace project, a major share of biomethane currently used is consumed in the transport sector (over 90% in 2022).²⁷⁴ In 2022, Finland had around 77 CNG filling stations and 14 LNG filling stations. In addition, there were 15 610 CNG-powered passenger cars, 469 CNG trucks and 55 LNG trucks.

In contrast to that, only 5 biogas plants (with upgrading unit to biomethane) are connected to the natural gas grid in the southern part of Finland – increasing the need for off-grid transportation of biomethane.²⁷⁵

Projections and potential: In general, according to survey feedback of infrastructure providers, natural gas is expected to play a significant role in the energy transition between 2030 and 2050. In addition, the existing methane network would need to transport the increasing production volumes of biomethane and synthetic gas. A significant share of biomethane production will thus be injected into the gas grid, especially as the infrastructure for (off-grid) biomethane injection points and the regulatory framework continue to develop. Already by 2030, it is expected that biomethane will cover a large share of the gas demand in Finland. This share is expected to further increase towards 2040 and 2050 as new biogas plants are commissioned and the infrastructure for biomethane production and distribution improves.

While data on future projections on biomethane injection into the Finnish grid are rare, the National biogas Roadmap by the Finnish Biocycle and Biogas Association of 2021 sets a target of 4 TWh of

²⁶⁹ European Biogas Association, EBA Statistical Report 2023.

²⁷⁰ IEA Bioenergy Country Report (2021): Implementation of bioenergy in Estonia – 2021 update, November 2021, https://www.ieabioenergy.com/wp-content/uploads/2021/11/CountryReport2021_Estonia_final.pdf

²⁷¹ Interreg Best Ace (2023) State of Play Report, April 2023, <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>.

²⁷² Virolainen-Hynnä, A. (Finnish Biogas and Biocycle Association) (2024): Biogas has potential, 06. May 2024, <https://www.bioeconomy.fi/biogas-has-potential/>

²⁷³ DG Ener (2023): Biomethane Country fiche

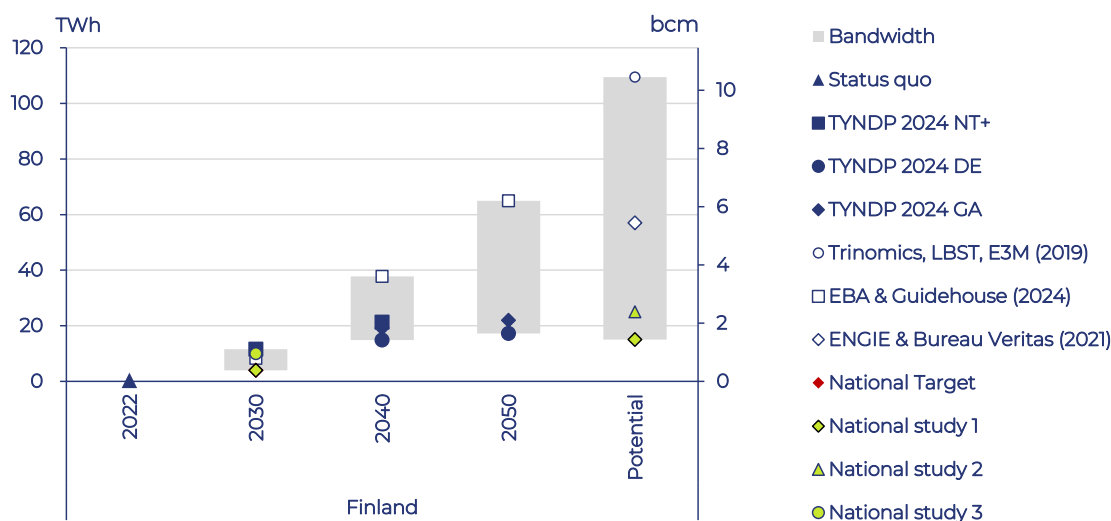
²⁷⁴ Interreg Best Ace (2023) State of Play Report, April 2023, <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>.

²⁷⁵ Interreg Best Ace (2023) State of Play Report, April 2023, <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>.

biogas production in 2030 ('National target' in Figure 7-21) and a potential between 15 TWh (techno-economic) and 25 TWh (theoretical) ('National study 1 and 2').²⁷⁶ Stakeholder feedback on the survey rather indicated a potential growth of biogas, biomethane and synthetic methane / e-methane production to about 10 TWh by 2030 ('National study 3').

These values are significantly lower than the 'realistic biomethane production' estimates provided by the European Biogas Association with around 8 TWh (2030), 38 TWh (2040) and 63 TWh (2050). The estimate on the overall potential by Trinomics, LBST & E3M (2019) of nearly 110 TWh can only be considered as a theoretical maximum.

Figure 7-21: Biomethane production outlook Finland



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Comparing these estimations with the scenario data of the TYNDP 2024, 2030 estimations seem to overestimate biomethane supply which can be injected in Finland by 2030 significantly (at least factor 3). In the long term, however, especially the more conservative data in the distributed energy scenario compared to the global ambition scenario seem to provide a good basis for further analysis.

Germany

Status Quo: Germany is the leading country for biogas and biomethane in Europe in absolute terms. In 2022, Germany was responsible for more than 50% of overall biogas production in the European Union, with over 10,000 biogas production plants in operation.²⁷⁷ While these existing biogas plants have an annual production of around 100 TWh (mostly used for electricity and heat production), the biogas upgrading to biomethane with injection into the gas grid is less developed. According to Eurostat data for 2022, overall consumption of biogases in Germany was around 94.5 TWh (see Table 16). Based on data of the German Biomass Research Centre (DBFZ)²⁷⁸, in 2022 there were 248 plants for upgrading biogas to biomethane with an overall production capacity of around 152.000 m³/h (annual production of around 10.6 TWh). According to current data of EBA, the actual production of biomethane in 2022 was around 12.8 TWh,²⁷⁹ of which around 1.1 TWh were used in the transport sector.²⁸⁰ In contrast to that, data by the German TSOs indicate a biogas production in Germany of around 91 TWh, of which around 10.4 TWh biomethane.

²⁷⁶ Finnish Biocycle and Biogas Association (2022): National biogas roadmap: Finland, <https://biokierto.fi/wp-content/uploads/2022/08/Biogas-Roadmap-Finland.pdf>.

²⁷⁷ Eurobserv'ER (2023): Biogas barometer 2023, <https://www.eurobserv-er.org/pdf/biogas-barometer-2023/?tmstv=1698391863>.

²⁷⁸ DBFZ (2023): Biogaserzeugung und -nutzung in Deutschland - Report zum Anlagenbestand Biogas und Biomethan, https://www.dbfz.de/fileadmin/user_upload/Referenzen/DBFZ_Reports/DBFZ_Report_50.pdf.

²⁷⁹ Guidehouse & Gas for Climate (2023): Market state and trends in renewable and low-carbon gases in Europe.

²⁸⁰ Deutsche Energie-Agentur, dena (2023): Marktmonitoring Bioenergie 2023 – Datenerhebungen, Einschätzungen und Prognosen zu Entwicklungen, Chancen und Herausforderungen des Bioenergiemarktes, https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2023/ANALYSE_Marktmonitoring_Bioenergie_2023.pdf.

Current data by GIE and EBA even list 254 biomethane production plants in Germany in 2024.²⁸¹ Most of these biomethane plants inject the produced biomethane directly into the gas grid.

With an annual production of around 10.6-12.8 TWh²⁸², biomethane accounts for around 1.5% of the overall natural gas demand ('National study 1' in Figure 7-23)²⁸³, while the largest part of the German gas consumption of around 810 TWh in 2023²⁸⁴ is imported (mainly from Norway, the Netherlands and Belgium)²⁸⁵. In addition, there is a small domestic natural gas production of around 4,8 bcm (48.8 TWh).

Since 2014, the majority of biomethane plants built was in the middle capacity range between 350 and 700 m³/h, while the total capacity increase has significantly slowed down after the subsidies for biogas upgrading was terminated by the renewable energy act in 2013. According to the NECP²⁸⁶, current support for biomethane plants is done via an annual tender of around 600 MW installed biomethane capacity. However, there is no target for biomethane production.²⁸⁷

The regional distribution of biomethane production sites is shown in Figure 7-22.

Feedstocks: In contrast to other regions assessed in this study, the majority of the biomethane input material (in 2022) are energy crops in Germany (~80% based on energy content). Here, maize silage represents around 60% of biomass input (energy-based). Other energy crops account for around 22%, manure for 10% and waste-based feedstocks for around 9% of the input materials.²⁸⁸ In the past years, the share of manure has increased.

²⁸¹ GIE, European Biogas Association (2024): European Biomethane Map 2024, <https://www.europeanbiogas.eu/european-biomethane-map-2024/>.

²⁸² The former value was derived by DBFZ (2023) from installed capacity and assuming an operation during 7,000 FLH per year.

²⁸³ DBFZ (2023): Biogaserzeugung und -nutzung in Deutschland - Report zum Anlagenbestand Biogas und Biomethan, https://www.dbfz.de/fileadmin/user_upload/Referenzen/DBFZ_Reports/DBFZ_Report_50.pdf.

²⁸⁴ BnetzA (2024): Gas supply in 2024, 04. January 2024, <https://www.smard.de/page/home/topic-article/444/211846>.

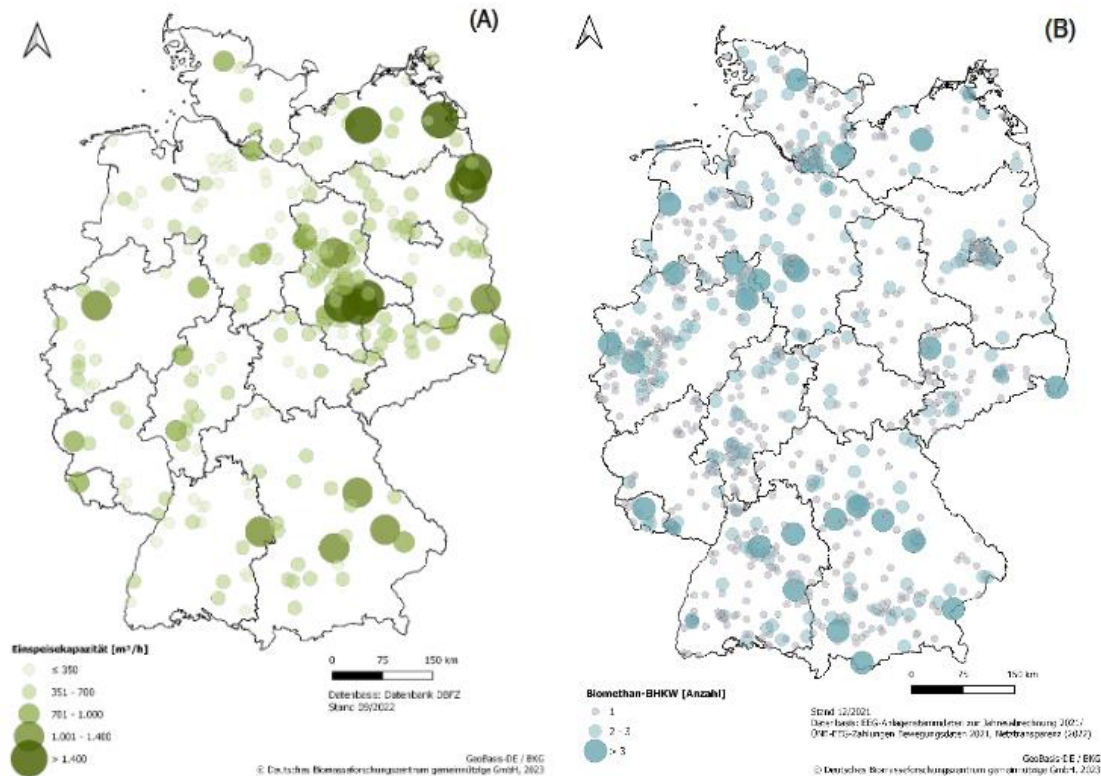
²⁸⁵ Import patterns are changing dynamically caused by the the invasion of Russia in Ukraine

²⁸⁶ German Government (2024): Final updated NECP 2021-2030, August 2024, https://commission.europa.eu/publications/germany-final-updated-necp-2021-2030-submitted-2024_en.

²⁸⁷ An comprehensive analysis of the German biomethane policy and its impact on biomethane production can also be found in Strategy& (2024): Biomethane in Poland.

²⁸⁸ German Energy Agency (dena): Branchenbarometer Biomethan 2023, 01. August 2023, <https://www.dena.de/infocenter/branchenbarometer-biomethan-2023/>

Figure 7-22: Production sites of biogas upgrading plants, differentiated by injection capacity (in m^3 (n) biomethane per hour). Source: DBFZ, status: 09/2023)



Projections and potential

Key national modelling framework for the future energy system in Germany are the long-term scenarios by the Federal Ministry for Economic Affairs and Climate Action (BMWK).²⁸⁹ While these include comprehensive analyses for hydrogen and natural gas, the role of biomethane in the future energy system is considered limited (both for electricity and heating demand in key scenarios O45 Electricity (high electrification) and O45 Hydrogen (high deployment of hydrogen). These scenarios do not predict an expansion of biomass use. In addition, no use of energy crops for biomass production is foreseen from 2035 onwards.²⁹⁰

Electricity generation from biomass (biogas and solid biomass) is expected to decrease from 42 TWh/yr in 2025 to 11 TWh/yr in 2045, probably mainly to the decrease of the use of energy crops and because of a decrease of biogas availability. The cultivation of energy crops such as maize monoculture is a subject of controversial discussions due to negative impacts on soil, water and biodiversity. Germany is the most populated country in the region considered here.²⁹¹ There is a strong competition for the use of land in Germany. Therefore, the German 'National Biomass Strategy' (2022) focuses on security of food supply first and cascaded use of biomass (prioritization of biomass use for material within the framework of a circular economy, bioenergy mainly from residues).²⁹² For this

²⁸⁹ Bundesministerium für Wirtschaft und Klima (BMWK) 2024; Langfristszenarien – Scenario explorer; 2024;

<https://langfristszenarien.de/enertile-explorer-de/szenario-explorer/angebot.php>.

²⁹⁰ ifeu – Institut für Energie- und Umweltforschung Heidelberg et al. (2023): Langfristszenarien für die Transformation des Energiesystems in Deutschland 3 - T45 Welten - Rahmendaten zu Biomassepotenzialen und den Emissionen aus dem Landwirtschafts- und dem LULUCF-Sektor; 24. July 2023

²⁹¹ 237 inhabitants per km^2 in Germany versus e. g. 130 per km^2 in Denmark, 122 per km^2 in Poland, or 44 per km^2 in Lithuania.

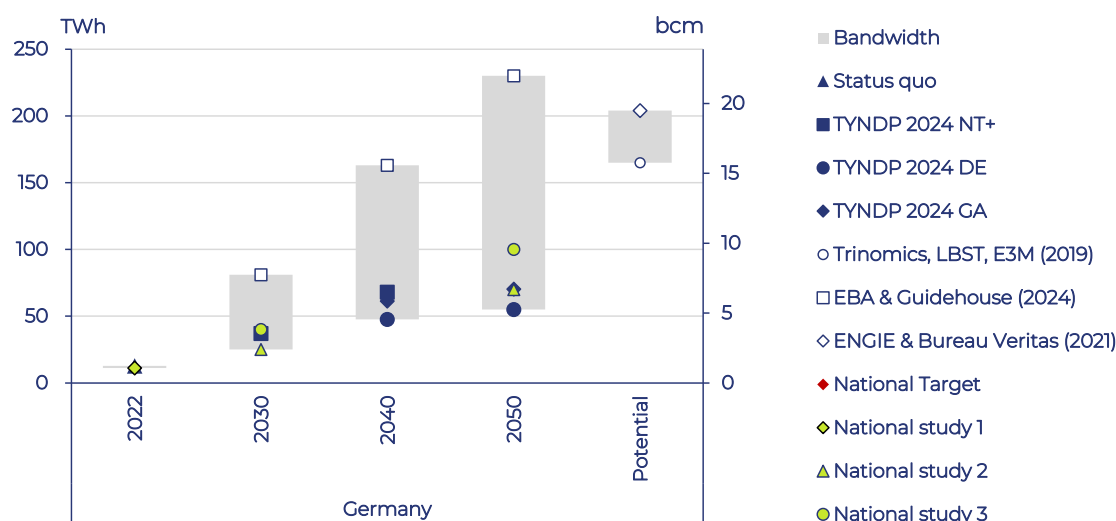
²⁹² Bundesministerium für Wirtschaft und Klima (BMWK); Bundesministerium für Ernährung und Landwirtschaft (BMEL); Bundesministerium für Umwelt, Naturschutz, nukleare Sicherheit und Verbraucherschutz (BMU): Eckpunkte für eine Nationale Biomassestrategie (NABIS); 28. September 2022; <https://www.bmu.de/download/eckpunkte-fuer-eine-nationale-biomassestrategie-nabis>.

reason, biomethane for injection into a pipeline grid does not play a significant role in the German energy strategy.

It can be expected that existing biogas production already covers a large range of realistically available biomass feedstocks and that future increases in biomethane production will rather be driven by implementing large-scale central biogas upgrading and injection plants, which collect biogas from several existing small-scale biogas facilities. Existing biogas production of around 90-100 TWh may therefore serve as a proxy for the future biomethane potential. This is also supported by feedback of Germany biogas stakeholders ('National study 2 and 3').

The figures provided by the European Biogas Association indicate an enormous potential of around 80 TWh (2030), 160 TWh (2040) and 230 TWh (2050) may therefore overestimate the actual possible development in Germany. Most notably, the political strategy to minimize the use of energy crops like maize for biogas production significantly reduces the overall realizable share of the theoretical biomethane potential. The injection into a natural gas grid may, in the long-term, be limited to medium and large injection plants in certain regions where then a dedicated biomethane grid could remain in operation, while other grid areas may be decommissioned with decreasing natural gas demand. Main applications for biomethane will focus on flexible electricity generation for grid balancing as well as (in the mid-term) a decarbonisation of existing natural gas plants for peak power generation.²⁹³

Figure 7-23: Biomethane production outlook – Germany



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Latvia

In the past, the focus of biogas production in Latvia was on energy production in CHP plants (687 GWh in 2021) as well as the use of upgraded biogas in transport.²⁹⁴ Today, there are four biomethane production facilities in Latvia, which do not inject into the gas grid.²⁹⁵ Main application is the supply of the existing around 48 biogas stations (CNG and LNG) for the transport sector. In addition, a planned renewable admixture obligation of 3% for gas traders will also enhance the use in the energy sector.

²⁹³ Arnold et al. (2023): The role of biogas in an climate-neutral 100% renewable electricity system 2035, 2023, https://epub.wupperinst.org/frontdoor/deliver/index/docId/8141/file/8141_Arnold.pdf.

²⁹⁴ Trinomics, SEI, E3Modelling (2023), Gas Decarbonisation- Pathways for Estonia (3 Baltic states + Finland), Deliverable 8, 27 November 2023, <https://energiatalgud.ee/sites/default/files/2024-02/Gas%20decarbonisation%20pathways%20-%20D8%20final%20report%20-%20kokkuv%C3%B5te.pdf>.

²⁹⁵ GIE, European Biogas Association (2024): European Biomethane Map 2024, <https://www.europeanbiogas.eu/european-biomethane-map-2024/>.

However, due to a phasing out of subsidies, several biogas plants had to close or look for other markets. A first injection point is planned to be built in Džūkste with an overall capacity of around 11.5 bcm or 112 GWh per year.²⁹⁶ The national grid operator Conexus has evaluated additional potential locations for injection points in a public consultation.²⁹⁷

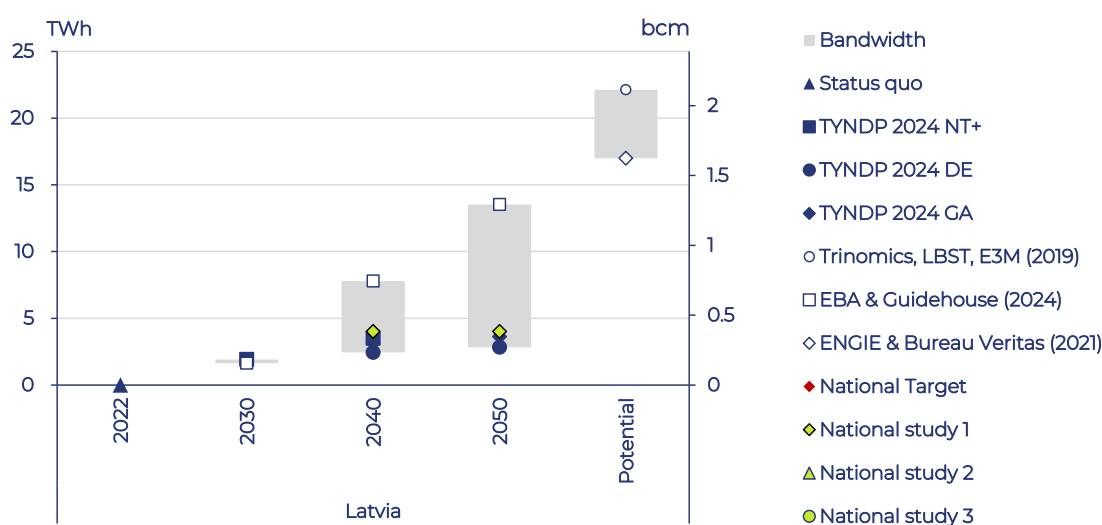
Stakeholders estimate that around 20% of national natural gas consumption of around 8 TWh in 2024 could be replaced by biomethane.²⁹⁸

In the 2030 to 2050 timeframe, natural gas is, according to stakeholders, expected to play a transitional (yet essential) role in Latvia's energy system as the country gradually shifts towards renewable energy sources. Main use cases are balancing renewables, electricity and heat generation during winter as well as energy security.

According to the Interreg Best Ace project, the Latvian Biogas Association recommends a target for a biomethane production capacity of 680 GWh by 2030.²⁹⁹ In the long term, studies indicate that biomethane production could increase to around 2 TWh by 2030 and up to 3 TWh by 2050.³⁰⁰

In contrast to that, potential estimations by the European Biogas Associations increase from around 2 TWh by 2030 to 13 TWh by 2040 and around 17 TWh by 2050. Trinomics, LBST & E3M (2019) even estimated a theoretical potential of 22 TWh. These numbers, however, are – according to Stakeholder feedback – significantly above national realistic estimations by the Latvian Biogas Association and the gas transmission system operator. Main reason, according to stakeholders, is that wood gasification is considered as relevant biomethane production technology in the future in these studies, although the application in Latvia is expected to be low. Instead, a 'more realistic' estimation of about 4 TWh (based on anaerobic digestion of manure from existing farms) is recommended ('National study 1' in Figure 7-24).

Figure 7-24: Biomethane production outlook – Latvia



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²⁹⁶ Cabinet of Ministers Republic of Latvia (2024): Latvia to invest EUR 134.4 million in energy security and biomethane production, 02. July 2024, https://www.mk.gov.lv/en/article/latvia-invest-eur-1344-million-energy-security-and-biomethane-production?utm_source=https%3A%2F%2Fwww.bing.com%2F.

²⁹⁷ conexus baltic grid (2024): Results of the Public Consultation on New Biomethane Injection Points, 30. August 2024, <https://www.conexus.lv/aktualitates-sistemas-lietotajiem-eng-575/publikas-apsriesanas-rezultati-par-jaunu-biometana-ievades-punktu-potencialajam-attistibas-vietam>.

²⁹⁸ <https://eng.ism.lv/article/economy/economy/24.03.2023-conexus-plans-biomethane-infrastructure-in-latvia.a502184/>
²⁹⁹ Interreg Best Ace (2023) State of Play Report Focus liquified biomethane gas (LBG) for transport sector <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>.

³⁰⁰ Trinomics, SEI, E3Modelling (2023), Gas Decarbonisation- Pathways for Estonia (3 Baltic states + Finland), Deliverable 8, 27 November 2023, <https://energiatalgud.ee/sites/default/files/2024-02/Gas%20decarbonisation%20pathways%20-%20D8%20final%20report%20-%20kokkuv%C3%B5te.pdf>.

Under these considerations, selecting the TYNDP NT+ scenario for 2030 and the DE scenario for 2040 and 2050 seems reasonable.

Lithuania

Lithuania currently has two biomethane production sites with injection units into the national gas grid. The capacities of both sites, which came into operation in 2023 and 2024, respectively, are around 100 GWh and 21 GWh per year. By September 2024, the feed-in quantity of biomethane in Lithuania reached 87 GWh.³⁰¹

A goal, outlined by Lithuania's Ministry of Energy, is to produce at least 950 GWh of biomethane by 2030.³⁰² A general focus of future use of biomethane will be within the transport sector as well as for substituting natural gas in industrial applications.

Based on data announcements of the national grid operator Amber Grid, further 13 biomethane producers have been granted connection to the transmission network, with six agreements already signed. Hence, biomethane injected into the national grid will increasingly gain importance with an additional 500 GWh/yr.³⁰³

According to feedback from national stakeholders and based on the 'National Strategy for Energy Independence' ('National study 1 and 2')³⁰⁴ approved in 2024, injection into the Lithuanian grid is expected to reach 1.4 TWh by 2030 and 3.4 TWh by 2040. In case of significant market development, the 2030 potential could even reach around 2.5 TWh according to that source.

With that, biomethane production could – according to stakeholder feedback in the survey - already achieve a market share of 10% of gas transported via the transmission system in comparison to Lithuania's overall gas demand (2024-2033 forecast: around 16.7 TWh/yr). Due to booked capacities, the use of natural gas pipelines may be required until the mid 2040s, according to national grid operator Amber Grid.

Estimations of the long-term (theoretical) potential range from around 18 TWh in ENGIE & Bureau Veritas (2021) to 21 TWh in Trinomics, LBST & E3M (2019).

³⁰¹ Amber Grid (2024): Second biomethane injection point in Lithuania already operational, 07. Oktober 2024,

<https://ambergrid.lt/en/for-media/news/second-biomethane-injection-point-in-lithuania-already-operational/1085>.

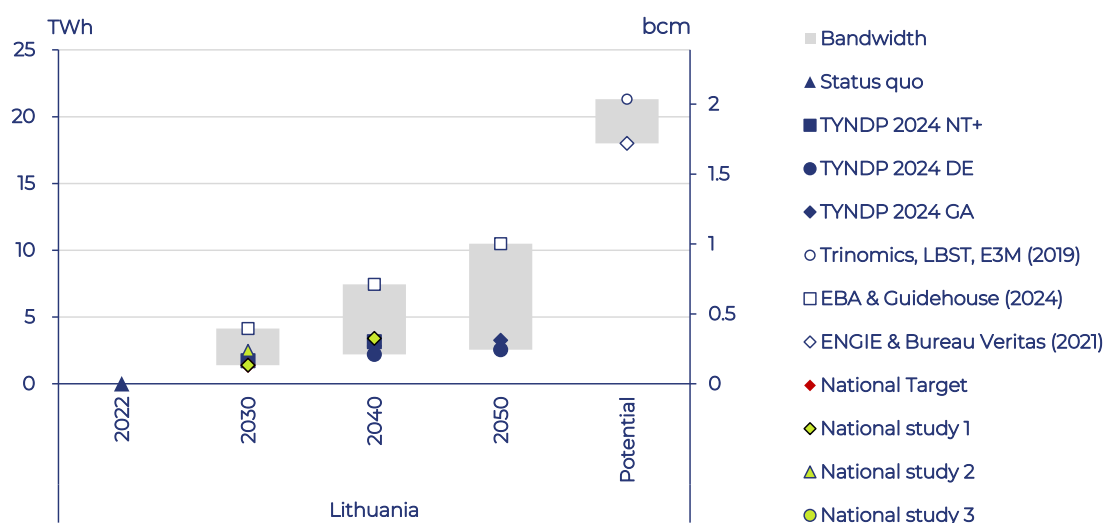
³⁰² Trinomics, SEI, E3Modelling (2023), Gas Decarbonisation- Pathways for Estonia (3 Baltic states + Finland), Deliverable 8, 27 November 2023, <https://energiatalgud.ee/sites/default/files/2024-02/Gas%20decarbonisation%20pathways%20-%20D8%20final%20report%20-%20kokkuv%C3%B5te.pdf>

³⁰³ Amber Grid (2024): Second biomethane injection point in Lithuania already operational, 07. Oktober 2024,

<https://ambergrid.lt/en/for-media/news/second-biomethane-injection-point-in-lithuania-already-operational/1085>.

³⁰⁴ Lithuania's National Energy Independence Strategy' (2024), <https://e-seimas.lrs.lt/portal/legalAct/lt/TAD/TAIS.429490/asr>

Figure 7-25: Biomethane production outlook - Lithuania



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The proposed selection of the TYNDP 2024 NT+ scenario value for 2030 and DE scenario for 2040 and 2050 seems reasonable – maybe even conservative based on the overall comparison.

Poland

Status Quo

According to a report by Strategy&, there are currently (as of August 2023) around 380 biogas plants, where biogas is converted into electricity (total capacity around 280 MW_{el}).³⁰⁵ Both, municipal biogas plants (including waste water) as well as agricultural biogas plants are in operation. According to stakeholders' feedback, Poland has more than twice as many biogas plants that use sewage sludge or a segregated biodegradable fraction from waste as a feedstock compared to agricultural biogas plants.

Despite these high numbers of biogas production facilities, Poland does not have any biomethane production units with injection into the gas grid. With an existing natural gas network in Poland of approximately 12,000 km (transmission network) and 200,000 km (distribution network), upgraded biogas with injection into the grid could be an interesting option to contribute to the decarbonization of the gas sector.

According to feedback by GAZ-Systems, the Polish gas grid operator, as of August 2024 there were two applications for connections of biomethane plants to the grid as well as eight issued connection conditions. However, up to that point, no signed connection agreements existed.

Projections & Potential

Several studies attest Poland a high biomethane production potential, even one of the highest in EU27. In total, Strategy& estimates that more than 300 large and 800 medium-sized biogas installations could potentially be deployed, with large facilities being interesting for biomethane injection into the grid. In total, the authors estimate that currently only about 3% of the total biogas production potential is being used in Poland. While a dedicated biomethane strategy in the country is missing, Strategy& has simulated two cases for the potential development of biomethane in Poland. Possible pathways include a ramp-up in biomass production to around 0.3-0.8 bcm (3.3-

³⁰⁵ Strategy& (2024): Biomethane in Poland. <https://www.strategyand.pwc.com/pl/en/publications/2023/biomethane-in-poland-strategic-and-investment-perspective.html>.

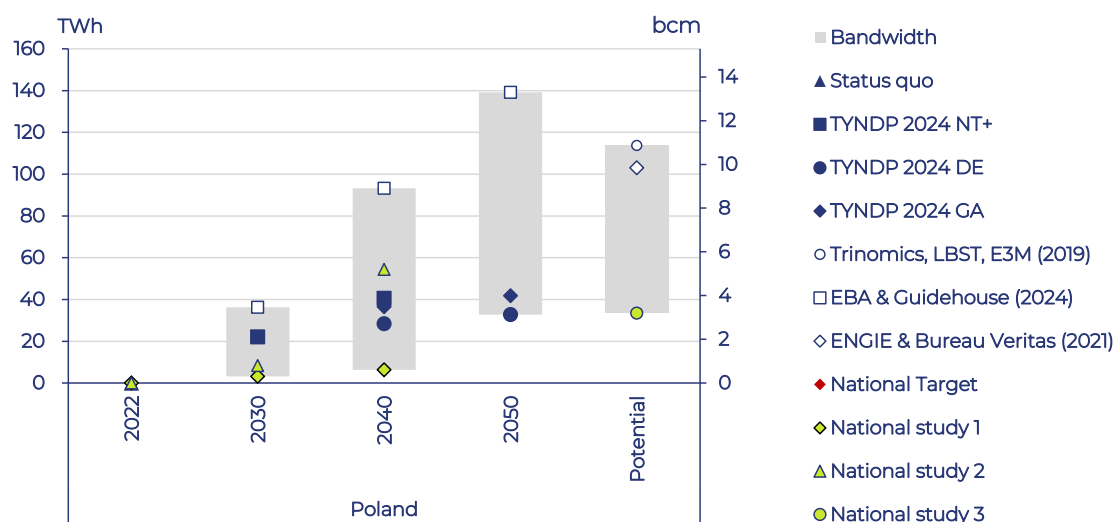
8.4 TWh) in 2030 and 0.6-5.2 bcm (around 6.3-54.3 TWh) in 2035 (shown for 2040), for a realistic and an optimistic variant, respectively ('National study 1 and 2' in Figure 7-26).

According to the latest available data from the National Centre for Research and Development (NCBR), the estimated potential for biomethane is substantially lower. Based on the analysis, the bandwidth is between 3.2 bcm/year (33 TWh) ('investment potential') (= 'National study 3'), 4.7 bcm/year (49 TWh) ('implementation potential') and 8 bcm/year (84 TWh) ('technical potential')³⁰⁶.

These projections are significantly lower than the estimations by the European Biogas Association on a biomethane potential of up to 3,4 bcm (36.0 TWh) by 2030. According to the study, the potentials ('realistic estimate') may even increase to 9.2 bcm/year (96 TWh) from anaerobic digestion and additional 3.8 bcm (40.0 TWh) from thermal gasification by 2050.³⁰⁷ With that, Poland has the 5th highest biomethane potential in EU-27 (after Germany, France, Spain and Italy). Trinomics, LBST, E3M (2019) even estimated the production potential based on available feedstocks and land restrictions for Poland in the long-term to be around 113 TWh.³⁰⁸

In contrast to that, stakeholders estimate that the long-term biomethane demand will be up to 3.5 to 4 bcm/year (around 37-42 TWh), of which around 2 bcm will be needed as industry feedstock and 1.5 to 2 bcm to balance the energy system.

Figure 7-26: Biomethane production outlook - Poland



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Based on these data, and also due to the fact that there is no coherent biomethane strategy (or targets) in place for biomethane injection in Poland, the assumptions in the TYNDP on biomethane supply with about 22TWh in 2030 may be too optimistic. In the 2040 and 2050 timeframe, an increase to about 28.4 TWh and 32.7 TWh, respectively, may – with respective support policies implemented – be possible.

Sweden

Status Quo: Gas plays a very limited role in the energy system of Sweden. Only 3% of total energy supply of 525 TWh in 2022 was provided as gas. This includes biogas, LPG and natural gas. Also, the biomethane market in Sweden is rather small and consist of off-grid uses or injection in regional grids.

³⁰⁶ National Centre for Research and Development (NCRD) (2024): Realistic potential for biomethane production in Poland, May 2024, <https://www.gov.pl/attachment/1d27ccd0-14be-46ee-9535-68cef31dd0b>. DISE ENERGY - Lower Silesian Institute for Energy Studies (2024): From natural gas to biomethane - Decarbonising the Polish gas industry. Report 2024.

³⁰⁷ European Biogas Association & Guidehouse (2024): Biogases towards 2040 and beyond, April 2024, <https://www.europeanbiogas.eu/biogases-towards-2040-and-beyond/>

³⁰⁸ Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure, <https://op.europa.eu/en/publication-detail/-/publication/10e93b15-8b56-11ea-812f-01aa75ed71a1/language-en>

Biogas was produced in around 284 biogas plants (total production 2.3 TWh) in 2022. Co-digestion plants make up for most of the biogas production (50%), followed by waste water treatment plants (33%)³⁰⁹. A clear differentiation between biogas production and biomethane production (both, for injection as well as liquified biogas (LBG)) is not always possible based on literature sources.

In 2021, 71 biomethane upgrading units with an annual production of about 1.5 TWh biomethane existed.^{310,311} As of June 2024, the European Biomethane map lists 74 biomethane plants for Sweden. However, the amount injected into the existing gas grids was only 550 GWh, while the remaining biogas is either locally used or compressed or liquified for use in the transport sector. Especially the amount of LBG has increased in recent years.³¹² In 2023, the total volume that was produced in five LBG plants from upgraded biogas reached 180 GWh.³¹³

According to ENERGIGAS SVERIGE, between 2015 and 2022, the biomethane use in the gas grid increased from around 0.2 TWh to 2.5 TWh. Of that, the major part is imported from Denmark – in total around 2 TWh.³¹⁴ In addition, around 226 GWh LBG was imported to Sweden via trailers. While biomethane in the form of CNG and LNG is mainly used in the transport sector (makes up for around 95% of sold volumes in transport for both CNG/CBG and LNG/LBG), grid-based biomethane is used to substitute natural gas in industry and heating.

Projections and Potential: According to national assessments, the industry demand for biogas may increase to around 10 TWh by 2030.³¹⁵ This value was already proposed as a national goal in a market study in 2020 ('National study 1' in Figure 7-27), however, up to today, there is no binding national target adopted.³¹⁶ The reason for this value is that beside the heating market also the existing use of natural gas as commodity for industrial processes may need to be replaced with biomethane in the future. Due to this substitution, however, the actual future further role of natural gas will be limited. Stakeholders, however, stress in the survey that due to reasons of security of supply (natural gas considered as back-up option), also beyond 2030 natural gas will be needed.

According to industry estimations, of the national biogas demand of around 10 TWh, around 8 TWh might be directly injected into the grid ('National study 2'), while 2 TWh will be based on imports from Denmark.³¹⁷ Off-grid uses of biomethane (mainly as a vehicle fuel) are estimated to be around 12 TWh in 2030 and additionally 4 TWh of LBG in 2040.³¹⁸

Sweden's further biomethane potential is mainly driven by two factors: on the one hand, due to the lack of large amounts of agricultural residues and animal manure, the use of industrial wastewater seems to be very interesting, making up for over 50% of Sweden's biomethane production potential via anaerobic digestion in 2040.³¹⁹ The higher potential, on the other hand, is furthermore attributed to thermal gasification, with forestry residues and wood waste being the major feedstocks. According to EBA (2024)³²⁰, within Europe Sweden possesses the highest potential of all EU Member States for thermal gasification (>4.6 bcm/year or around 48 TWh) in 2040.

³⁰⁹ Energigas Sverige (2024): Biomethane in Sweden – market overview and policie, <https://www.energigas.se/Media/ternoznh/biomethane-in-sweden-240327.pdf>.

³¹⁰ Guidehouse & Gas for Climate (2023): Market state and trends in renewable and low-carbon gases in Europe

³¹¹ Energigas Sverige (2024): Biomethane in Sweden – market overview and policie, <https://www.energigas.se/Media/ternoznh/biomethane-in-sweden-240327.pdf>.

³¹² Energigas Sverige (2024): Biomethane in Sweden – market overview and policie, <https://www.energigas.se/Media/ternoznh/biomethane-in-sweden-240327.pdf>.

³¹³ Energigas Sverige (2024): Statistics on biogas, <https://energigas.se/fakta-om-gas/biogas/statistik-om-biogas-2023/>.

³¹⁴ Energigas Sverige (2024): Statistics on biogas, <https://energigas.se/fakta-om-gas/biogas/statistik-om-biogas-2023/>.

³¹⁵ Nordion Energi (2024): Industry players: 'Biogas production must increase fivefold by 2030', 28. February 2024, <https://nordionenergi.se/nyheter/2024-02-28-industriaktorer-biogasproduktionen-maste-femdubblas-till-2030>

³¹⁶ SOU 2019: Mer Biogas för ett hållbart Sverige, Betänkande av Biogasmarknadsutredningen, 2019,, https://www.regeringen.se/contentassets/19fc575360724f2492bea2cb9e25b7e8/sou_2019_63_webb_rev.pdf.

³¹⁷ Feedback on survey.

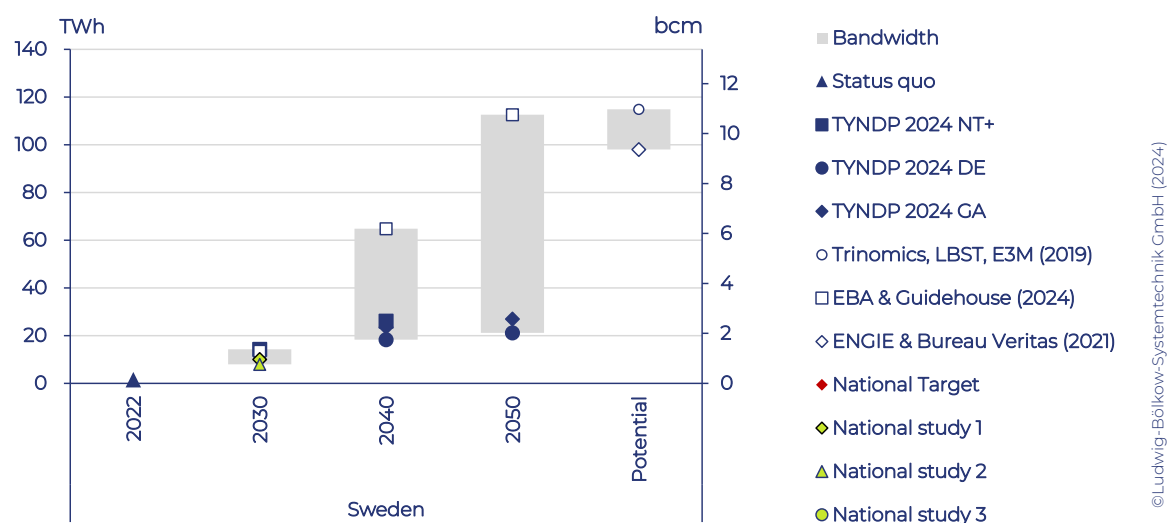
³¹⁸ Interreg Best Ace (2023) State of Play Report Focus liquified biomethane gas (LBG) for transport sector <https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf>.

³¹⁹ European Biogas Associations / Guidehouse (2024) Biogas towards 2040 and beyond - a realistic and resilient path to climate neutrality, https://www.europeanbiogas.eu/wp-content/uploads/2024/04/Biogases-towards-2040-and-beyond_FINAL.pdf

³²⁰ European Biogas Associations / Guidehouse (2024) Biogas towards 2040 and beyond - a realistic and resilient path to climate neutrality, https://www.europeanbiogas.eu/wp-content/uploads/2024/04/Biogases-towards-2040-and-beyond_FINAL.pdf

Assessments of the long-term potential range between around 98 TWh (ENGIE & Bureau Veritas (2021)), 113 TWh (EBA & Guidehouse (2024)) and 115 TWh (Trinomics, LBST, E3M (2019)).

Figure 7-27: Biomethane production outlook – Sweden



Looking at projections in grid planning studies, the proposed supply development in the TYNDP NT+ scenario for 2030 seems overly ambitious, surpassing injection volumes expected by industrial stakeholders in the stakeholder survey significantly (14.2 TWh vs. 8 TWh). Based on current developments and limited grid availability, it can however, be derived that biomethane usage after 2030 will rather be at the lower end of the corridor implemented in the TYNDP scenarios – due to the limited gas infrastructure in Sweden.

7.4. Key data sources for biomethane production and demand

7-1 provides an overview of key data sources used in this study on existing and future use and potential for biomethane. Beside a brief description of relevant content, the table also indicates whether the study coverages the EU as a whole or selected BEMIP MSs. Further sources on national level were the National Energy and Climate Plans (NECPs)³²¹, National Biomethane Strategies and further studies by national stakeholders.

Table 7-2: Overview of main literature sources on biomethane production (status quo, projections and potential)

Source	Description	Geographic coverage	Link
Guidehouse & Gas for Climate (2023): Market state and trends in renewable and low-carbon gases in Europe	Number of total biomethane plants and production volumes	EU27 + DK, DE, SE	Link
Gas Infrastructure Europe / European Biogas Association (2024): European Biomethane Map 2024	Number of total biomethane plants in Europe (based on EBA Statistical Report 2023)	EU27 + MS level	Link
DG Ener (2023): Biomethane country fiches	Overview: Biogas & biomethane data per country (based e.g. on Eurostat, EBA and Guidehouse)	EU27 + MS level	Link
European Biogas Association (2024): Decoding Biogases	Summary of key facts on biogas and biomethane production and use in Europe	EU27 + MS level	Link
Eurostat (2024)	Data on biomethane and biogas production / consumption	EU27 + MS level	Link
Eurobserv'ER (2023): Biogas barometer 2023	Data on biogas and biomethane in EU27	EU27 + MS level	Link
IEA 2021 Country Reports (2022)	Country Reports on energy supply	Selected countries	Link

³²¹ EC (n.d.): [National energy and climate plans](#)

Source	Description	Geographic coverage	Link
ENTSOG / ENTSOE (2024): Ten-Year Network Development Plan (TYNDP)	Energy system modelling for Europe as basis for infrastructure development, includes data for hydrogen and biomethane 3 scenarios included: National Trends (NT+), Distributed Energy (DE) and Global Ambition (GA)	EU27 + MS level	Link
European Biogas Association & Guidehouse (2024): Biogases towards 2040 and beyond	'Realistic estimate for biomethane potential' for 2030, 2040 and 2050	EU27 + MS level	Link
Interreg Best Ace (2023) State of Play Report	state of play in a market perspective for biogas for the countries Estonia, Finland, Latvia and Sweden as of 2022/2023.	EE, FI, LT, SE,	Link
Trinomics, SEI, E3Modelling (2023): Gas Decarbonisation- Pathways for Estonia (3 Baltic states + Finland), Deliverable 8, 27 November 2023,	Estimation of (renewable) gas quantities for the years 2030 and 2050 in the four countries investigated.	EE, FI LV, LT,	Link
Guidehouse & Gas for Climate (2022): Biomethane production potentials in the EU	Biomethane potential and cost components involved in the production of biomethane (update in 'Gas for Climate 2024: Biogases towards 2040 and beyond')	EU27 + MS level	Link
Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure	Estimated potential for biomethane	EU27 + MS level	Link
ENGIE & Bureau Veritas (2021): Biomethane: potential and cost in 2050	Biomethane: potential and cost in 2050	EU27 + MS level	Link

8. Annex B - Benefits of and policies for the integration of biomethane and hydrogen in the BEMIP region

8.1. Benefits from use of renewable and low carbon gases

8.1.1. Key benefits of a fuel switch from fossil gas

The key benefits and potential negative impacts are structured according to the following categories:

- Market coupling;
- Competitiveness and affordability;
- Energy system integration;
- Sustainability;
- Security of energy supply.

The assessment of the key benefits and the potential negative impacts was developed based on the available literature for the EU and BEMIP region, as well as based on feedback received from stakeholders to the survey. Table 8-1 summarises the main findings and provides further details on the analysis below.

Table 8-1 Key benefits and potential negative impacts of biomethane and renewable/ low-carbon hydrogen deployment in the BEMIP region

Key benefits and potential negative impacts of a fuel switch from fossil gas to renewable and low-carbon gases	Biomethane	Hydrogen
Market coupling		
+ Regional production can shift an import-oriented methane market to a regionally-integrated methane (and in the medium term also hydrogen) market, driven by differences in production capacities, profiles and costs, demand volumes and profiles, and by security of supply/ curtailment considerations	✓	✓
! Local production could hinder market coupling if gas/ hydrogen quality is not harmonised at regional level regarding relevant parameters such as e.g. O ₂ content for methane, and purity and permissible contaminants for hydrogen	✓	✓
! Regional trade could be hindered in case guarantees of origin (GOs) are not mutually recognised within BEMIP region	✓	✓
! Access to wholesale markets for distribution-connected biomethane producers may require reverse-flow (distribution to transmission system) facilities as a pre-condition, when distributed biomethane injection volumes exceed local consumption	✓	
Competitiveness and affordability		
+ Domestic production stabilises wholesale gas market prices, reduces external dependence and thus strengthens market fundamentals	✓	
+ Participation of biomethane suppliers in gas market increases liquidity and reduces market concentration	✓	
+ A regionally-integrated hydrogen market could have higher liquidity compared to current gas markets, benefitting industrial users, fuel suppliers and other selected hydrogen users		✓
! As renewable and low-carbon gases are still more expensive than fossil gas, its deployment can negatively affect the competitiveness of industrial gas users and affordability for households in the absence of mitigating measures.	✓	✓
+ Use of renewable and low-carbon gases could entail the development of new process technologies, and provide a comparative advantage in certain downstream markets valuing products with a low-carbon footprint	✓	✓
Energy system integration		
+ Methane and hydrogen storage can provide flexibility to the power system, especially in seasonal (winter peak electricity demand and 'dunkelflaute') timeframe	✓	✓
+ Electrolysers can additionally provide short-term demand-side flexibility		✓
+ Biogenic CO ₂ can be captured in biogas/-methane production processes, for use in industry, greenhouses and energy applications (e.g. e-methane or e-fuels production), substituting fossil CO ₂ sources	✓	
+ Biomethane can in transitional period be employed in hybrid heat pumps to foster sector coupling and alleviate congested electricity networks, when electricity-only heat pumps are not yet a viable solution	✓	
+ Allows for further utilisation (and possibly repurposing) of existing gas network and storage infrastructure while phasing out fossil gas	✓	✓
+ Potential for increasing the circularity of the economy with for example the production of natural fertilisers, reduction of emissions to land, water and air, and management of wastewaters	✓	
+ Enables continued use or cost-efficient repurposing of existing infrastructure	✓	✓

Key benefits and potential negative impacts of a fuel switch from fossil gas to renewable and low-carbon gases	Biomethane	Hydrogen
! Renewable electrolytic H ₂ production can pressure electricity prices and crowd-out the direct electrification of certain applications if regulation and price signals are not well-designed and coherent		✓
! Hydrogen supply, infrastructure and demand development risks can lead to stranded assets as well as compromise the decarbonisation of sectors which would otherwise employ other approaches such as energy efficiency and direct electrification measures		✓
Sustainability		
+ Substitution of fossil fuels by biomethane or hydrogen is one of the key options to reduce GHG emissions in hard-to-electrify end-uses as well as for feedstock in industrial processes	✓	✓
+ Biomethane use can reduce emissions of air pollutants (e.g. NO _x , SO ₂), depending on feedstock used for biogas production and on substituted fuel	✓	
! Actual sustainability benefits depend on the biogas feedstock type, gasification process and management practices for mitigating methane emissions in production, transport and storage (e. g. using manure leads to higher environmental benefits than using crops - CO ₂ capture can increase sustainability of process)	✓	
! Actual sustainability benefits also depend on the management practices for mitigating methane/hydrogen emissions in production, transport and storage	✓	✓
Security of energy supply		
+ Domestic renewable and low-carbon gas production reduces fossil fuel imports and thus energy dependence	✓	✓
+ Storage of renewable and low-carbon gases improves security of gas and electricity supply	✓	✓
! Imports can, to some extent, be an adequate option to maintain security of supply at least cost, albeit with a shift in main energy partners		✓
! There is a large uncertainty regarding the future availability (and sustainability) of import sources particularly from non EU hydrogen or its derivatives		✓

Market coupling benefits

The **integration of biomethane** into the gas system and market faces significant challenges, including harmonisation of gas quality across the BEMIP region, mutual recognition of certificates of origin, and access of distribution-connected producers to wholesale markets.

However, the integration of biomethane and hydrogen in the region can also provide an important impulse to market integration. A significant deployment of biomethane in the BEMIP region (combined with a reduction in overall methane gases demand) will lead to an important shift in the region's energy dependence and flow of methane gases along the value chain.

Currently, BEMIP MSs import the large majority of their natural gas demand. The TYNDP 2024 draft scenarios expect that the EU27 methane import dependency would shift from 86% currently to 78-89% in 2030 depending on the scenario, further decreasing in 2050 to 0% under the DE scenario and 16% in the GA scenario. This would represent an absolute decrease of 31% and 21% in the DE and GA scenarios in 2030 compared to current imports and even 100% and 92% by 2050, respectively.³²²

The supply and demand data assessed in Chapter 1 indicates this shift towards lower import dependency will also be observed in the BEMIP region. Increasing domestic supply should also lead to changes in regional cross-border flows, contributing to the further regional gas market integration.

At the domestic level, biomethane integration could also contribute to market coupling. In 2021, most grid-connected biomethane plants did so at the distribution level. Only about 20% of biomethane plants were connected to the transmission level in Finland, 40% in Germany, and a small percentage (less than 5%) in Denmark and Sweden.³²³ Moreover, particularly in some BEMIP MSs such as Sweden and Finland, a significant number of biomethane plants are not connected to the gas grid given it only covers a part of the territory. Further biomethane development in the region could be facilitated by the development of some additional sections of methane networks and further grid reinforcement measures (as long as the risk of lock-in in fossil gases is addressed) and improve market access to biomethane producers and consumers (see also section 9.5).

Enabling **cross-border infrastructure and trade for hydrogen** will require significant investments in production and import infrastructure, interconnected pipelines and agreements on harmonised technical specifications, including gas quality, as well as (bankable) off-take agreements.

A future regional hydrogen market could be more integrated than current import-dependent natural gas markets, given that regional hydrogen production will constitute an important share of supply, and that regional differences in renewable hydrogen potential constitute a main driver of regional integration. National differences in the renewable electricity supply mix for hydrogen production across BEMIP MSs, in the deployment of low-carbon hydrogen and in the role of hydrogen (and derivatives) imports can be important aspects driving cross-border infrastructure and trade. The potential and location of underground hydrogen storages could also provide an important stimulus for the interconnection of national hydrogen systems. However, there is still significant uncertainty on the level of and timing for the interconnection of future hydrogen markets in the BEMIP system.

Competitiveness and affordability

Locally produced biomethane can enhance competition in the gas market, diversifying supply sources and increasing the number of producers/suppliers with the result of a more liquid market compared to current conditions (as long as production reaches sufficient volumes at the national or regional level). The same could be the case for renewable and low-carbon hydrogen, although it can be expected that it will have a lower number of producers and consumers compared to methane gas, at least in the early stage of roll-out.

³²² *ENTSOE and ENTSO-E (2024): TYNDP 2024 – Scenario Report Data Figures*

³²³ *EBA (2022): Statistical Report 2022.*

As renewable and low-carbon gas is still more expensive than fossil gas, its deployment can negatively affect the competitiveness of industrial gas users and, if used domestically, its affordability for households. The implementation of ETS II for buildings, road transport and additional sectors, as well as expected higher prices of the Emissions Trading System (ETS) prices along with the implementation of the Carbon Border Adjustment Mechanism (CBAM) and the revision of the Energy Taxation Directive to better account for the energy and carbon footprint of energy products could help level the playing field with fossil energy carriers. Renewable and low-carbon gases could even become more competitive than fossil fuels when the negative externalities associated with GHG and other air emissions were fully internalized in market prices, however, at a price level considerably higher than today. While such measures improve the comparative competitiveness of such renewable and low-carbon gases, it does not improve the competitiveness of industry compared to non-EU countries (except for access to the internal market in the case of products in the scope of the CBAM). Further information on production costs developments for biomethane and hydrogen are presented in section 8.1. The affordability of renewable and low-carbon gases for end-users is in some BEMIP MSs improved by national subsidies to producers or other incentives such as a reduction of connection or access network tariffs, as well as the Social Climate Fund currently under implementation. A further discussion on identified policies and measures in the BEMIP MSs is presented in section 3.2.

Energy system integration

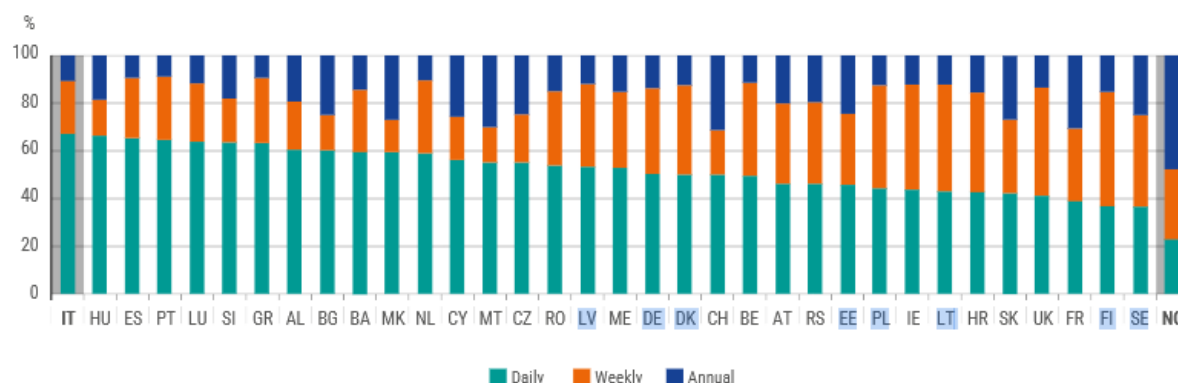
This section discusses the contributions and challenges of biomethane and (renewable and low-carbon) hydrogen related to the relevant pillars of the EU energy system integration strategy: energy efficiency and circularity, sector coupling and direct electrification of end-uses, higher consumer participation, and energy infrastructure integration.

The ENTSO-E's TYNDP 2022 Regional Investment Plan for the Baltic Sea³²⁴ notes that flexibility needs will drive a stronger integration of the region's power systems, with greater integration of the region's synchronous areas and north-south electricity flows. Furthermore, the nuclear power plants' decommissioning in Germany, Denmark and Finland as well as the decommissioning of coal fired power plants, particularly in Poland and Germany, will lead to security of supply challenges which in turn will require new (flexible) power plant capacities, grid infrastructure development, and further procurement of system services by network operators.

ENTSO-E has recently assessed the flexibility needs of the European electricity system. The share of daily, weekly and annual flexibility needs per BEMIP Member State in 2030 varies – with daily flexibility driving needs for Latvia (LV), Germany (DE), Denmark (DK) and Estonia (EE) (although weekly flexibility needs remain important). On the contrary, weekly and daily flexibility needs are more balanced in Poland (PL), Lithuania (LT), Finland (FI) and Sweden (SE). Annual flexibility needs are generally lower for all BEMIP Member State, although they can represent over 20% of total needs for Estonia (EE) and Sweden (SE).

³²⁴ ENTSO-E (2023): [TYNDP 2022 Regional Investment Plan - Baltic Sea](#)

Figure 8-1 Share of flexibility needs by timeframe across several countries in 2030 according to
ENTSO-E³²⁵



Both biomethane and hydrogen can contribute to the long-term adequacy and short-term flexibility needs of the power system. Specifically, methane and hydrogen storage can provide flexibility to the power system in the seasonal (winter peak electricity demand and during ‘dunkelflauten’) timeframe. Moreover, electrolyzers can provide demand-side flexibility by immediately reacting to market prices signals, and biomethane can, in a transitional period, also provide flexibility through the use in gas power plants or hybrid heat pumps, when direct electrification is not an adequate option. Studies for Gas Infrastructure Europe highlight other benefits on gas/hydrogen storage and the value of underground storage to the overall system, including reduced investment needs in supply and other infrastructure elements and reduced greenhouse gas emissions through the flexibility provision which reduces the curtailment of renewable energy sources and the need for unabated fossil fuel use.^{326,327}

The integration of biomethane and hydrogen will also impact investment needs in other sectors. It can reduce investment needs in peak electricity generation and networks, especially depending on the localisation of electrolysis facilities. The Danish power-to-X strategy highlights that in order to efficiently utilise the electricity network, electrolyzers need to be located in areas close to production, where new major consumption can be more easily integrated, namely in North-Western Jutland and Southern Zealand.³²⁸ With this, also needs for electricity grid reinforcement can be reduced. Furthermore, the deployment of biomethane and hydrogen opens the possibility to continue the utilisation (in the case of hydrogen through repurposing) of existing gas infrastructures without hindering the phase out of fossil gas. In any case, appropriate policies to avoid any lock-in risks³²⁹ for the gas infrastructure should be avoided.

Biogenic CO₂ can furthermore be captured in biogas/-methane production processes, for use in industry, greenhouses and energy applications (e.g. e-methane or e-fuels production), substituting fossil CO₂ sources. More broadly, there is a potential for increasing the circularity of the economy with for example the production of natural fertilisers, reduction of emissions to land, water and air, and management of wastewaters.

Renewable electrolytic hydrogen production is specifically dependent on and can entail unwanted effects for the power system. In cases where electrolyzers are not co-located with renewable electricity production facilities, this could entail higher utilisation of, or require new power transmission infrastructure, onshore and/or offshore. In a context of rising direct electrification, it could exacerbate grid congestion. Moreover, depending on the regulatory framework and price

³²⁵ ENTSO-E (2024): [System Flexibility Needs for the Energy Transition](#)

³²⁶ Artelys (2022): [Showcasing the pathways and values of underground hydrogen storages](#)

³²⁷ Guidehouse (2021): [Picturing the value of underground gas storage to the European hydrogen system](#)

³²⁸ Danish Ministry of Climate, Energy and Utilities (2021): [The government's strategy for power-to-X](#)

³²⁹ The risk that despite policy objectives the continued use and investment in gas and hydrogen infrastructure enables the continued dependency on natural gas and/or increased use of unabated fossil fuel-derived hydrogen or limits the transition towards direct electrification options.

signals, electrolytic hydrogen production could lead to an increase of electricity prices in non-peak demand periods, and negatively affect the business case of certain direct electrification options, if not countered through regulation.

Sustainability

Biomethane and renewable or low-carbon hydrogen can provide important sustainability contributions, by substituting unabated fossil fuels as energy inputs or feedstock in existing or new (hard-to-electrify) applications and thus mitigating greenhouse gas emissions. Moreover, biomethane use can reduce emissions of air pollutants emissions (e.g. NO_x, SO₂), depending on the feedstock used for biogas production and on the substituted fuel.

Trinomics and Artelys (2020)³³⁰ noted that the GHG mitigation impacts of gas infrastructure projects depend on a number of factors, particularly on the production method and inputs employed, as well as on the fossil fuel type being substituted. For example, employing grid electricity for hydrogen production can at present still increase GHG emissions compared to hydrogen production from natural gas without CCS, as can some methods of e-methane production due to conversion losses and depending on the CO₂ source. In contrast, renewable electrolytic hydrogen or biomethane production from wet manure with adequate digestate treatment can have significant positive impacts on GHG emissions (and other pollutants).

Therefore, a number of aspects need to be considered when assessing the impact of infrastructure projects enabling the integration of biomethane and renewable and low-carbon hydrogen:

- Overall, actual sustainability benefits depend on the lifecycle emissions, influenced in turn by the **inputs (energy or feedstock), production processes and management practices** for the integrated biomethane/hydrogen as well as the **lifecycle emissions of the substituted fossil fuel**. For fuels of biological origin such as biomethane or biohydrogen³³¹, the possibility of employing by-products such as biogenic CO₂ is also relevant;
- Substitution of fossil fuels by biomethane and renewable and low-carbon hydrogen enhances the sustainability of the overall energy system, but **energy efficiency measures and direct electrification in suitable processes and applications is a preferred option** in terms of sustainability;
- From a sustainability standpoint, the **avoidance of lock-in into unabated fossil pathways** potentially enabled by the continued use of or investment in methane or hydrogen infrastructure is an important point of attention;
- **Methane or hydrogen emissions during production, transport and storage** significantly affect lifecycle emission impacts and can lead from a positive to negative GHG emission impact in case of significant methane or hydrogen leakages. A framework for mitigating methane emissions from the natural gas value chain is being implemented by the EU with the EU Regulation on Methane Emissions Reduction in the Energy Sector³³². This Regulation is expected to have a positive impact also on methane infrastructures transporting and storing biomethane. However, the Regulation does not apply to biomethane production facilities. Furthermore, there is no comparable framework in place for hydrogen emissions, on which further research is necessary despite increasing attention for example with a recent report of the Joint Research Centre of the European Commission (JRC).³³³

³³⁰ Trinomics and Artelys (2020): *Measuring the contribution of gas infrastructure projects to sustainability as defined in the TEN-E Regulation*

³³¹ Hydrogen produced from biogenic sources such as biogas or biomass. See European Biogas Association (2023): *Decarbonising Europe's Hydrogen Production with biohydrogen*

³³² Regulation (EU) 2024/1787 on the reduction of methane emissions in the energy sector and amending Regulation (EU) 2019/942

³³³ JRC (2022): *Hydrogen emissions from a hydrogen economy and their potential global warming impact*

JRC (2024): *Environmental life cycle assessment (LCA) comparison of hydrogen delivery options within Europe*

Security of energy supply

Locally produced biomethane and hydrogen enhance security of energy supply by reducing import dependency and contributing to supply diversification. As indicated above, in the TYNDP 2024 draft scenarios EU27 methane import dependency would decrease to 0% in 2050 under the DE scenario and to 16% in the GA scenario.³³⁴ While in October 2024 country-level data was not yet available for the draft scenarios, several EU Member States (including BEMIP MSs) are expected to become significant producers of biomethane and renewable or low-carbon hydrogen (even if there is still high uncertainty on the exact levels).

Notwithstanding the economic benefits of domestic clean energy production, energy imports can to some extent be an adequate option to maintain energy supply at least cost. Although there is still high uncertainty regarding the future availability (and sustainability) of (particularly non-EU) hydrogen (and derivatives) import sources, hydrogen imports could contribute to mitigating risks related to insufficient domestic supply capacities during a transition period. The development of partnerships with multiple hydrogen producing countries and eventually a global hydrogen market could further contribute to supply diversification.

Moreover, both biomethane and hydrogen are suitable for seasonal storage and can therefore enhance security of supply for the respective carrier, as well as for the electricity system as mentioned above. Large-scale hydrogen storage can take place in underground salt or porous reservoirs, if existent (see technology fiches in Annex C). While the locations of suitable formations are unevenly spread across the BEMIP region and further experience needs to be developed on hydrogen storage (particularly in porous reservoirs), it can be expected that it will contribute to the future security of supply in the BEMIP region (albeit, significant uncertainty still exists on the exact level of contribution).

8.1.2. Consideration of key benefits of a fuel switch in existing Cost-Benefit-Analysis methodologies for hydrogen and smart gas grid projects

For comparison, the table below presents the indicators employed in the following Cost-Benefit-Analysis (CBA) methodologies:

- JRC (2023) Harmonised System-wide Cost-Benefit Analysis for Candidate Smart Gas Grid Projects³³⁵
- JRC (2023) Harmonised System-wide Cost-Benefit Analysis for Candidate Hydrogen Projects³³⁶
- ENTSOG (2023) Draft Single-Sector Cost-Benefit Analysis (CBA) Methodology³³⁷
- ENTSOG (2024) Annex D1 Implementation Guidelines for Project-specific Cost-Benefit Analyses of Hydrogen Projects³³⁸

Most key benefits as well as the potential negative impacts identified in the previous section are indeed represented in some form in the indicators used (see Table 8-2), albeit indirectly – for example, the benefits of market coupling/competitiveness/affordability are represented mostly through the resulting socio-economic welfare changes, and the benefits of security of supply are represented through lower curtailment of gas or hydrogen demand. While methane emissions are properly considered in the current methodologies, the risks (and potential benefits of better management) of hydrogen emissions could be implemented in future revisions of the methodologies.

³³⁴ ENTSOG and ENTSO-E (2024) TYNDP 2024 – Scenario Report Data Figures

³³⁵ JRC (2023): [Harmonised System-wide Cost-Benefit Analysis for Candidate Smart Gas Grid Projects](#)

³³⁶ JRC (2023): [Harmonised System-wide Cost-Benefit Analysis for Candidate Hydrogen Projects](#)

³³⁷ ENTSOG (2023): [Draft Single-Sector Cost-Benefit Analysis \(CBA\) Methodology](#)

³³⁸ ENTSOG (2024): [Annex D1 Implementation Guidelines for Project-specific Cost-Benefit Analyses of Hydrogen Projects](#)

Table 8-2 Indicators used in the CBA methodologies for hydrogen and smart gas grid projects

CBA methodology	Smart gas grids (JRC)	Hydrogen projects (JRC)	Hydrogen projects (draft single-sector ENTSOG)	Hydrogen projects (PS-CBA ENTSOG)
Market coupling/ Competitiveness/ Affordability	B6 Increase of socio-economic welfare in the gas system	B6 Improvement of market integration	B2 Socio-economic welfare for hydrogen sector D6 Cross-border impact of hydrogen transmission projects	B4: Increase of market rents
Energy system integration	B3 Variation of the share of renewable and low-carbon gases integrated into the gas network B7 Cross-sectoral cost savings	B3 Integration of renewable and low-carbon hydrogen potential into the system B7 Increase of cross-sector flexibility	B3 Renewable energy integration	B3.1: Integration of renewable electricity generation B3.2: Integration of renewable and low-carbon hydrogen
Sustainability / Environment	B1 Variation of GHG emissions B2 Variation of non-GHG emissions B4 Detection of methane leakage	B1 Variation of GHG emissions B2 Variation of non-GHG emissions	B1 Societal benefit due to GHG emissions variation B4 Societal benefit due to non-GHG emissions variation	B1: Societal benefit due to GHG emissions variations B2: Societal benefit due to non-GHG emissions variations
Security of supply	B5 Reduction of curtailed gas demand	B4 Substitution effect – fuel switching D5 Reduction of curtailed hydrogen demand	B5 Reduction in exposure to curtailed demand	B5: Reduction in exposure to curtailed hydrogen demand

8.1.3. Assessment of sectors which could benefit from increased production of biomethane and/or renewable and low-carbon hydrogen

As indicated above, the exact benefits of a fuel switch to biomethane and/or renewable and low-carbon hydrogen depend on the specific sector where the substitution is taking place and the substituted fossil fuels.

On the **supply side**, several sectors can benefit from an increased domestic production of renewable and low-carbon gas, in particular:

- **Agriculture and waste collecting and processing industry:** biogas production can be an economically and environmentally attractive solution for farmers and waste collecting companies that have high volumes of manure and waste/residues, which cannot be used in other processes (as feed, food or feedstock). Gasification can be considered for direct local use (combined heat and power, CHP) if the local heating needs are sufficiently stable and high. Otherwise upgrading to biomethane quality for injection into the methane grid (to substitute natural gas) or use of liquefied/compressed biomethane (LBC/CBG) in the transport sector to substitute LNG/CNG is a more appropriate option. The residue from the gasification process or the fermentation (substrate) can be treated and substitute chemical fertilisers.
- **Equipment suppliers and installers:** replacing imports of fossil fuels by domestically produced renewable and low-carbon gas provides opportunities for companies that produce, install and maintain equipment, e.g. digesters, electrolyzers, etc.
- **Tertiary sector,** for supply of services to the concerned enterprises, incl. management of guarantees of origin.
- **Methane (hydrogen) DSOs/TSOs and storage operators:** deployment of biomethane (and hydrogen) offers opportunities for methane (hydrogen) network/storage operators to continue to value their assets and eventually repurpose some of them for dedicated hydrogen use.

- **Electricity producers:** flexible use of electricity in electrolyzers for hydrogen production will reduce the number of hours with negative prices and hence improve the business case of (renewable) electricity production.

On the **demand side**, the following sectors can benefit from an increased domestic production or imports of renewable and low-carbon gas:

- **Industry:** using renewable and low-carbon gas allows the industry to decarbonise hard-to-electrify processes, in particular applications where gas molecules are required as feedstock.
- **Transport sector:** biomethane (compressed or liquified) and hydrogen can be used in combustion engines or fuel cells to replace fossil fuels. However, for several transport uses, in passenger road and rail transport, direct electrification by using domestic electricity is from an energy efficiency perspective more appropriate than switching to biomethane or hydrogen. For certain transport modes, in particular long-haul road, maritime and aviation transport, renewable and low-carbon gas and its derivatives might become an adequate decarbonisation option, especially due to advantages of infrastructure needs (capacity and spaces requirements along key transport corridors). The optimal solution will depend on the outcome of ongoing technological developments and on the respective cost levels of the different options (including charging/ refuelling infrastructure and all other components in the supply chain).
- **Tertiary and residential energy users:** substitution of fossil fuels by biomethane for heating in buildings can allow decarbonising the concerned energy use. While biomethane can indeed be considered an adequate transitional solution for the residential sector in cases where direct electrification is not (easily) possible, hydrogen should however not be promoted as a suitable alternative, as direct electrification of heating needs is from a technical economic, and energy perspective a better option where this is possible. For district heating grids connected to gas-fired power plants, however, substitution of natural gas by biomethane or hydrogen may be considered as a viable option in certain cases. While some transmission gas networks may in the future be repurposed for dedicated hydrogen use, it is not expected that repurposing distribution networks that serve tertiary and residential buildings only, would become an appropriate option.

8.2. Energy system integration in the BEMIP region

Stakeholders³³⁹ were asked about **what solutions are needed in their country, or in the BEMIP region more widely, to enhance energy system integration** (i.e. considering the role of electrolysis, methanation or hydrogen/(bio)methane-fired power plants). Below we summarize their feedback as well as discussed possible approaches for streamlined infrastructure planning.

Hydrogen

The integration of hydrogen with the broader energy system in the BEMIP region depends on several key elements, including the development of **transmission and storage infrastructure, cross-border cooperation**, and the alignment of **regulations and market principles**. Stakeholders emphasized that the hydrogen and electricity systems must be **interlinked**, particularly as the growing share of intermittent renewables in the electricity grid drives demand for **flexibility services**. “fully unlock the potential of energy system integration, the links between the **hydrogen and electricity systems and markets** must be strengthened. This requires not only technical infrastructure but also market mechanisms that incentivize hydrogen producers to operate in a flexible manner in response to short-term fluctuations in the electricity system.

³³⁹ See list of stakeholders in D – Stakeholder engagement

Stakeholders said that hydrogen infrastructure must bridge the gap between **supply and demand centres**, creating a well-connected, cross-border hydrogen market. For example, in Finland, hydrogen production is expected to rely heavily on **electrolysis**, which requires robust infrastructure to connect hydrogen producers with end-users and integrate storage facilities for seasonal energy balancing. For the region, access to **central European hydrogen storage facilities** could be essential for ensuring energy security and balancing supply during periods of low renewable generation.

Another barrier to hydrogen integration is the lack of **end-use readiness**. Stakeholders noted that many **end appliances** (such as ovens, kilns, and engines), are not yet hydrogen-compatible, posing challenges to the adoption of hydrogen across different sectors. Moreover, the physical and chemical properties of hydrogen, such as diffusion and safety considerations, require ongoing innovation and adaptation of infrastructure to ensure secure and efficient transport and use. End-user readiness is further assessed in section 9.6.

To support the transition, stakeholders emphasized the need for **close cooperation among BEMIP MSs, energy regulators, and hydrogen operators** on a coordinated approach to harmonize domestic hydrogen market regulations and fast-track permitting procedures. This would facilitate the timely implementation of hydrogen projects and ensure the financial viability of hydrogen operators. **Customer engagement** was also highlighted as critical for matching producers with off-takers on both national and regional levels and creating a functioning market.

When suggesting solutions, a recurring theme in the feedback is the importance of **cross-border financing** to support large-scale hydrogen infrastructure projects. Ensuring access to funding is particularly important for projects involving electrolysis and renewable energy integration, given the high upfront costs. **Risk mitigation is equally important**, especially during the early stages of hydrogen market development. Stakeholders stressed the need for public guarantees and subsidies to de-risk investments and encourage early adopters. This is crucial to address the uncertainty in market demand and the financial sustainability of operators in the absence of a mature, steady market for hydrogen.

The need for cross-border **hydrogen infrastructure and corresponding markets** was clear from the survey replies- not only to unlock different use cases of the carrier, but to improve energy security, and facilitate the balancing of renewable energy across the region. Cooperation is seen as necessary not only for physical infrastructure but also for regulatory alignment, as stakeholders call for national laws underpinned by mutually aligned principles to ensure consistent standards across BEMIP countries, and reduce delays in project implementation.

Cooperation in **research and development**, particularly in large-scale seasonal energy storage and the adaptation of end-use appliances, is also seen as critical for driving accelerating market readiness.

Biomethane

Stakeholders identified several critical solutions for better energy system integration of biomethane and e-methane with the broader energy system. First, the potential for large-scale gasification of forestry residues and digestion of non-conventional digestates, such as straw, offers significant opportunities for expanding biomethane production. Secondly, the **availability of biogenic CO₂** combined with the high availability of wind power presents a unique opportunity for the **future production of e-methane in the region**. Denmark, for example, is investigating the future possibilities of biogenic CO₂ from biomethane with green hydrogen for synthetic methane production to achieve decarbonization goals.

Stakeholders furthermore emphasized the need for **renewable energy tracking systems** that are harmonized across energy carriers, including gaseous and liquefied biomethane, power-to-gas, and gas-to-power systems. Ensuring consistency in **guarantees of origin, sustainability standards, and commercial tools** is essential to creating an integrated and transparent market.

Infrastructure development is viewed as prerequisite to realizing the integration of biomethane into the energy system, and stakeholders called for immediate attention to the **practical aspects of**

production, transportation, storage, and use of renewable gases. Ensuring economic competitiveness is critical for these solutions to scale. In Estonia, for instance, the anticipated phase-out of oil shale power plants by 2033 creates a pressing need for **dispatchable generation capacity** in the form of methane or hydrogen-fired power plants, reinforcing the link between biomethane and the broader energy system.

Despite its potential, **financing remains the greatest challenge** for deploying biomethane and e-methane technologies, and their integration into the wider system. Stakeholders think that most BEMIP MSs require substantial public and private investments, as well as EU grants, to advance research (incl. feasibility studies), development, and deployment. Stakeholders highlighted the high upfront costs of infrastructure, renewable energy generation, and grid balancing, which must be addressed through targeted funding mechanisms and risk-sharing strategies.

Possible approaches for streamlined infrastructure planning for hydrogen and biomethane integration

In this section we outline the main barriers for integrated system planning, and suggest improved regulatory approaches to streamline these processes, where possible, introducing concrete tools/methods to be employed by network operators.

Consistency in network planning at both European and national levels is key to streamline investments and ensure efficient network development. In November 2024, ACER released an evaluation on how well national gas and hydrogen Network Development Plans (NDPs) align with the Ten-Year Network Development Plan (TYNDP) of ENTSO-E and ENTSG³⁴⁰ – and has recommended to **improve the consistency in gas network planning by:**

- Consulting stakeholders and coordinate with neighbouring operators to exchange information on scenarios, infrastructure gaps, and cross-border projects.
- Coordinating the timing of national planning with the TYNDP development process as much as possible.
- Reinforce the oversight of national regulatory authorities.
- Emphasise the integration of low-carbon and renewable gases, along with decommissioning and repurposing projects.

At a European level, ENTSG handles network development planning through three main steps: creating scenarios, identifying infrastructure needs, and evaluating projects to determine their cost-benefit potential. At the national level, each Member State (MS) defines its own process for scenario development, needs assessment, and evaluation of potential solutions before including projects in its NDP. Given the mentioned inconsistencies, in its assessment report, ACER further highlights the following **methodological approaches for streamlined gas network planning:**

1. NDPs should be based on compatible scenarios, that are in line with the decarbonisation targets of national and European Energy Climate plans
2. Joint gas and electricity scenario definitions, and increased engagement with the distribution level
3. Increased public consultation and coordination between operators during the preparation of NDP
4. Sector-integrated modelling, at least covering the electricity and the gas sectors
5. During the CBA process, evaluate value of the cost of disruptions of gas supply routes, to account for existing and future risks
6. Include biomethane developments/projects in the gas NDPs
7. Further cooperation between transmission system operators (TSOs), distribution system operators (DSOs), and hydrogen/biomethane producers

³⁴⁰ ACER (2024): [*Opinion on the review of gas and hydrogen national Network Development Plans to assess their consistency with the EU Ten-Year Network Development Plan*](#)

8. Priority access and connection for biomethane injections to the gas transmission network, along with incentives for biomethane production, are instrumental to facilitate the achievement of REPowerEU and national biomethane targets.

Hydrogen Europe also brings additional aspects in their report on infrastructure financing, specific to hydrogen:

1. **Hydrogen storage considerations** should be reflected in long term planning. NDPs should provide opportunities for hydrogen stakeholders to actively engage with electricity and gas operators, to ensure energy storage considerations are integrated into the design and operation of electricity and gas networks, with special attention paid to areas with high renewable energy variability.
2. The European Commission should initiate **a strategy for a European Hydrogen Infrastructure Strategy** (similar to the EU Action Plan for Grids³⁴¹) to address infrastructure gaps, storage needs, and integration of carriers like ammonia and methanol. This strategy should also focus on fast-tracking key hydrogen projects, long-term network planning, and retrofitting methane grids for hydrogen compatibility, while proposing mechanisms to finance this hydrogen infrastructure.
3. **Offshore hydrogen infrastructure should be included in planning** to support renewable energy development. The TEN-E Regulation should be updated to strengthen provisions for offshore hydrogen in the Offshore Network Development Plan (ONDP). ENNOH should be involved in ONDP iterations to integrate electricity, gas, and hydrogen infrastructure. The next ONDP should adopt a two-system approach (pipelines + electric cables) and reconsider congestion payment mechanisms to incentivize investments in grid management and energy storage.³⁴²

Specifically related to hydrogen on the European level, according to the report of Hydrogen Europe planning challenges can be tackled by, first, **improving how energy system needs are identified** and **revising the cost-benefit analysis of projects accordingly**. Second, thorough planning is essential, both from the bottom-up and top-down levels, to ensure that hydrogen infrastructure aligns with regional specificities. Additionally, when retrofitting networks, it is crucial to coordinate the build-out to secure supply for existing natural gas users, whose gas flows through these specific pipelines might decrease or be replaced by hydrogen³⁴³.

³⁴¹ European Commission (2023): Factsheet_EU Action Plan for Grids

³⁴² Hydrogen Europe (2024): [Hydrogen Infrastructure: The Recipe for a Hydrogen Grid Plan](#)

³⁴³ Hydrogen Europe (2024): [Hydrogen Infrastructure: The Recipe for a Hydrogen Grid Plan](#)

9. Annex C - Challenges of transitioning the current BEMIP natural gas infrastructures

This annex presents an overview of the current natural gas system in BEMIP as well as reviews the challenges related to the transition of the gas infrastructure in the BEMIP MS to accommodate for renewable and low-carbon gases. The information is structured as follows:

- Overview of the current natural gas system in the BEMIP region in section 9.1.
- Perspectives of future cross-border flows in the region in section 9.2.
- Country fiches on gas infrastructure in 9.2.
- Technology fiches describing technology and challenges are presented for hydrogen technologies in section 9.4.
- The bottlenecks for the integration of biomethane into the existing natural gas system are analysed in section 9.5, including general aspects on biomethane for the BEMIP region as well as a detailed Case Study for Denmark.
- Finally, section 9.6 provides an outlook on the readiness of end-users in case of substituting existing natural gas supply with either hydrogen or biomethane. Relevant challenges and adaptation needs are presented.

9.1. Overview of the current natural gas system in the BEMIP region

As underlined in section 2.1, natural gas still plays a key role in the BEMIP region's energy supply. In that context, recent infrastructure projects aimed at enhancing the integration of the gas and electricity systems and markets in the region, to support regional cooperation for energy infrastructure development.

Recent projects have decreased the energy isolation of the Baltic Sea region. In terms of gas interconnections, the Baltic States had indeed been isolated for a long time, being only connected to the Russian gas supply system. Since 2017, Finland and the Baltic states have been working collectively to achieve gas market integration of the four countries, establishing for this purpose the Regional Gas Market Coordination Group

(RGMCG). The *Baltic connector* pipeline was commissioned in 2020, interconnecting the gas markets of Finland and the Baltic states and providing Finland a connection to the *Klaipeda LNG* terminal in Lithuania (in operation since December 2014)³⁴⁴ and the *Inčukalns* underground gas storage facility in Latvia.

Further actions have been undertaken to complete the connection of the three Baltic States with central European networks, and to develop a regional integrated gas market. For instance, the commissioning of the *Gas Interconnection Poland-Lithuania* (GIPL) in 2022 now enables the Baltics and Finland to trade natural gas with central Europe.



Figure 9-1 Regional gas market integration of the Baltic States, Finland and Poland (Source: ENTSOG)

³⁴⁴ KN Energies, 2024. [Klaipėda LNG terminal](#)

Figure 9-2 Current and planned gas infrastructures in Poland
(Source: ENTSOG)



The integration of **Poland** into the regional and European gas system was also supported by the GIPL connection, as well as its connection to Denmark, and indirectly Norway, via the *Baltic Pipe* project commissioned in 2022, and Slovakia, to ensure the national energy security of supply. Natural gas and its infrastructure play a pivotal role in the Polish energy transformation by supporting its switch from coal to gas. Hence, an increase in gas demand is expected until the 2030s and planned diversification projects will lead to a more than doubled import capacity in the country. Recent developments include the expansion of the *Świnoujście* LNG terminal (with a regasification capacity increasing from 5 bcm/year to 8 bcm/year as of January 2025), the *Baltic Pipe*, the

GIPL and the Poland–Slovakia interconnector. To accommodate these enhanced gas imports, the Polish TSO, GAZ-SYSTEM, also plans investments for 2,000 km of new transmission pipelines and further development of the distribution grid.³⁴⁵

³⁴⁵ IEA (2022). *Poland Natural Gas Security Policy*

Another tangible action was the **merger of the Danish and the Swedish gas markets** in 2019 as a single balancing zone, JBJ (joint balancing zone). In fact, the Swedish natural gas system is dependent on the Danish system with an interconnection between the two serving as the sole import route for natural gas into Sweden. Besides, it is to be noted that the Swedish gas system only supplies the south-west of the country, while the vast majority of the territory is not covered by any gas system. Thus, the interconnection with Denmark is critical for Sweden's gas supply, and the Danish gas system not only provides direct supply to Sweden but also acts as a transit network, connecting the Swedish market to the rest of the European gas market. As a result, the integration of Sweden and Denmark as a joint balancing zone has had a positive impact on security of supply by improving both the robustness of the system and competition in the joint market. Hence, the integration of the Swedish and Danish gas markets is an example of a broader effort to enhance regional energy cooperation in Northern Europe. In 2023/2024, the gas supply from the Danish Tyra fields was interrupted due to infrastructure redevelopment in the hub. The supply resumed in 2024, yet, both Denmark and Sweden have become more dependent on natural gas imports from Germany during that period.

Figure 9-3 Danish and Swedish gas infrastructure map (Source: ENTSOG)



Figure 9-4 Tyra gas fields (Source: TotalEnergies)



Germany's gas system is well interconnected with the rest of the continent and it plays a crucial role in the European energy supply, serving as a key central hub for gas trade. Indeed, considerable amounts of gas are transported across Germany to other EU Member States. In terms of infrastructure, Germany has one of the most developed pipeline networks in Europe, facilitating both domestic supply and international trade with a 40,000 km long transmission system, and 500,000 km distribution systems.

Figure 9-5 Gas infrastructure network in Germany (Source: ENTSG)



Table 9-1 Existing cross-border gas capacities in BEMIP regions as of 1st January 2025. Source: ENTSOE System Capacity Map

From country	To country	Technical physical capacity (MW)
Germany	Denmark	3,958
Denmark	Germany	1,853
Germany	Poland	12,829
Denmark	Poland	13,400
Poland	Denmark	3,800
Estonia	Finland	2,938
Finland	Estonia	3,250
Lithuania	Latvia	3,750
Latvia	Lithuania	3,417
Lithuania	Poland	2,420
Poland	Lithuania	3,055
Estonia	Latvia	3,500
Latvia	Estonia	3,500

9.2. Perspective of future cross-border flows in the BEMIP region

This section provides an assessment of the potential and future perspectives of cross-border flows of renewable and low-carbon gases in the BEMIP region and other, neighbouring EU-27 Member States and third countries.

This assessment is built on the data gathered as part of the literature review, presented in Chapter 2 of this report, as well as the data gathered through surveying key stakeholders in each BEMIP MS. The analysis is based on differentials in production costs (section 9.2.1), the existing and future (2030, 2040 and 2050) regional/country-level supply and demand potentials (section 9.2.2), gas storage capacities and security of supply considerations (section 9.2.3), which can justify/necessitate cross-border infrastructure and gas flows.

9.2.1. Cost indications for renewable gas production

Production costs of hydrogen in the BEMIP MS

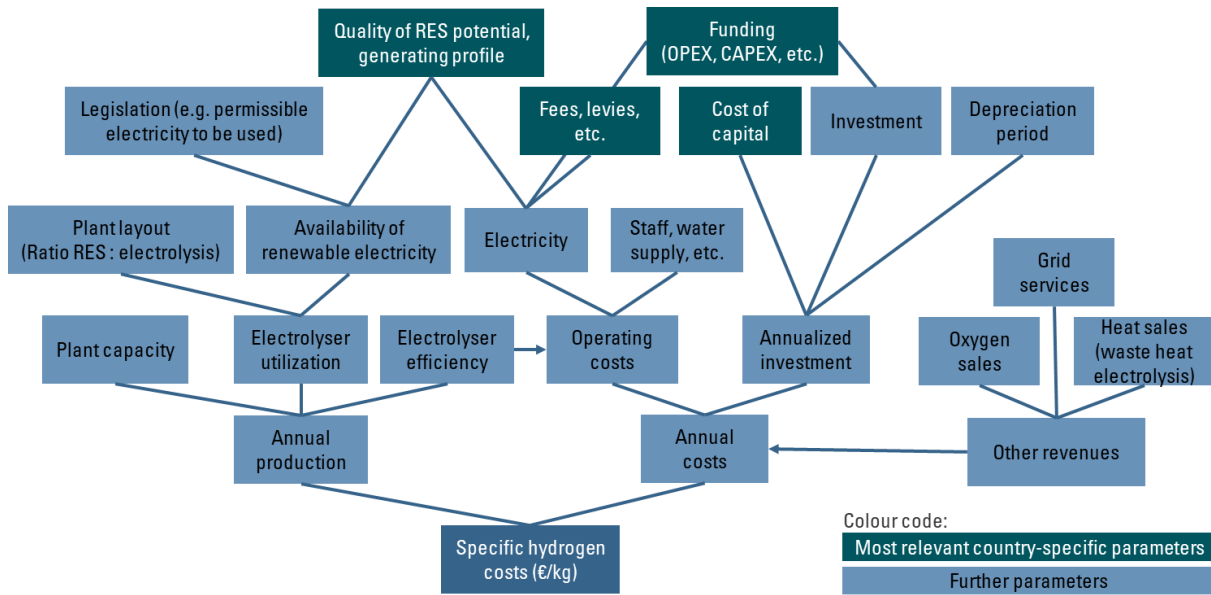
In general, hydrogen production costs are influenced by various parameters and boundary conditions, which can be technology-specific, site-specific, or country-specific. Within the context of decarbonization of the gas infrastructure in the BEMIP MSs, hydrogen produced via electrolysis using renewable electricity is considered to be the most relevant production method, as domestic low-carbon hydrogen production is rarely a focus of policy measures so far in the region (see section 3.2).³⁴⁶ Therefore, the following analysis focuses exclusively on renewable electrolytic hydrogen.

Hydrogen production costs are typically expressed as **specific costs in € per kilogram of hydrogen**. These can be calculated (in simplified terms) as the annual production costs minus revenues from other streams (e.g., sale of waste heat from the electrolyser or grid services) divided by the annual hydrogen production volume.

Several parameters affect the annual hydrogen production volume and, hence, the production costs of an electrolysis plant. Key parameters and their main interactions are shown in the map depicted in Figure 9-6.

³⁴⁶ It should, however, be noted that countries like Germany are working on a national Carbon Management Strategy that may also include the aspect of hydrogen production using CCS technology. However, also due to the planned election in Germany in February 2025, existing drafts are expected to be subject to fundamental revisions.

Figure 9-6: Mind-map of selected parameters impacting specific hydrogen production costs



Annual production volume is primarily determined by the electrolyser utilization rate, which depends on the **availability of renewable electricity**. This availability, in turn, is influenced by the quality, quantity, and mix of renewable energy resources, which vary by site and country. Legislation also plays a role, such as the Renewable Energy Directive in the European Union, which defines the types and conditions of renewable electricity permissible for hydrogen production. The renewable potentials for solar power are similar but rather weak in most regions of the BEMIP MSs (compared to e.g. Southern Europe). The annual output from solar plants e.g. in Southern Germany or Poland is only 10 to 20% higher compared to regions in Southern Sweden or Finland³⁴⁷. However, there are regions with high wind speeds suitable for efficient power generation (onshore and/or offshore) in all BEMIP MSs³⁴⁸. Particularly outstanding are the wind speeds (onshore and offshore) in Denmark and Northern Germany. In general, however, the wind power capacity factor and production costs favour hydrogen production from offshore wind in the North Sea compared to the Baltic Sea³⁴⁹. Overall, in the regions around the Baltic Sea, hydrogen production based on electrolysis powered by renewable energy sources will likely be supplied from wind power (onshore and/or offshore), with potentially some solar power added to improve electrolyser utilization.

Renewable energy availability not only impacts the utilization rate but also the **specific cost of renewable electricity** used in electrolysis. Electricity costs are a critical factor in hydrogen production costs, as approximately 50 kWh of electricity is required to produce one kilogram of hydrogen. High-quality renewable energy sources can help reduce specific electricity costs by maximizing annual electricity production from renewable plants. Additional costs, such as grid fees and levies, can further influence electricity prices. Other operating costs, such as water supply and staffing, generally have a minor impact on overall hydrogen costs.

Regarding **annualized investment costs for electrolyser plants**, capital expenditure is a significant factor. While equipment costs are typically technology-specific rather than country-specific within the BEMIP region, the cost of capital is a relevant country-specific parameter, as national risk premiums applied to interest rates in financial markets influence capital costs. This is especially important as this factor is often overlooked in analyses describing hydrogen production costs. Also,

³⁴⁷ Global Solar Atlas 2.0, by the company Solargis s.r.o. on behalf of the World Bank Group, accessed January 2025

³⁴⁸ DNV (2024): Potential for a Baltic Hydrogen Offshore Backbone; 7 March 2024

³⁴⁹ Global Wind Atlas version 3.3, by the Technical University of Denmark (DTU) in partnership with the World Bank Group, accessed January 2025

other aspects (e.g. government guarantees, business risk, technology maturity) can have a relevant impact on the cost of capital. For the BEMIP MSs, the country-specific risk premium varies between 0% (DK, DE, SE) and 1.5 % (LV)³⁵⁰.

General Note: The wide range of parameters, their varying impacts, and the uncertainty of future developments result in the use of diverse assumptions in different studies. Consequently, the results of individual studies—potentially employing different calculation methodologies as well—are generally not directly comparable. Instead, cost-indications for the BEMIP MS in the following are derived based on selected regional studies to provide a general trend.

For regions surrounding the Baltic Sea (without DE, DK), a forecast of **hydrogen production costs** based on onshore and offshore wind power are shown in Figure 9-7³⁵¹ for the year 2040. Based on onshore wind, production costs for renewable hydrogen vary between below 6 €/kg and above 15 €/kg, with the best regions in each country enabling costs of roughly between 6 and 8 €/kg of hydrogen. Offshore wind offers superior capacity factors, enabling lower hydrogen costs. Cost of around 5 €/kg are according to the study forecast expected to be achievable in all of the six analysed BEMIP MS (i.e. Estonia, Finland, Latvia, Lithuania, Poland and Sweden; with the cost data in the regions refer to their wind power offshore location).

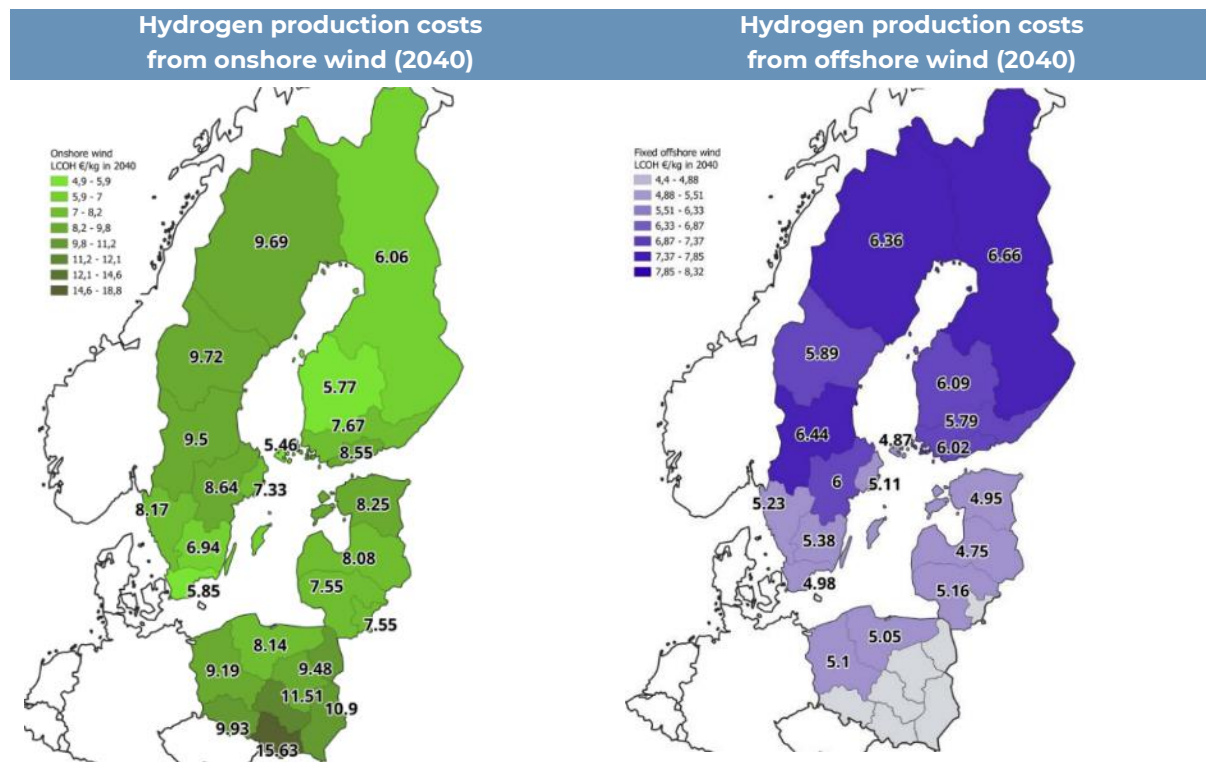
For Denmark and Germany, hydrogen production costs based on offshore wind from the Baltic Sea can be estimated at just under 5 €/kg, for the year 2040. This estimate is based on the aforementioned production costs and the fact that both countries have the lowest electricity costs from offshore wind in the Baltic Sea region³⁵².

³⁵⁰ Damodaran, A.: *Country Risk: Determinants, Measures, and Implications – The 2024 Edition*; 14 July 2024

³⁵¹ DNV (2024): *Potential for a Baltic Hydrogen Offshore Backbone*; 7 March 2024

³⁵² COWI: *Study on the Baltic offshore wind energy cooperation under BEMIP*, June 2019

Figure 9-7: Hydrogen production costs from onshore and offshore wind power around the Baltic Sea, in 2040 (Source: DNV (2024))



Instead of using renewable electricity specifically from onshore or offshore wind turbines, grid electricity can also provide a basis for electrolyser operation. However, in this case, depending on the GHG footprint of grid electricity, the criteria of the revised RED II³⁵³ may no longer be met. RED II criteria allow the use of grid electricity in bidding zones with a renewable electricity mix of over 90%. This could in the future become a significant driver for BEMIP MSs, allowing grid electricity to then be used for electrolysis of renewable hydrogen, greatly lowering LCOH and increasing financial attractiveness of domestic renewable hydrogen production³⁵⁴.

If in 2023 the 4,000 hours with the lowest wholesale electricity prices per country and year had been used for hydrogen production via electrolysis, the hydrogen costs would be 4.1, 4.4, and 5.1 €/kg for Finland, Sweden, and Norway, respectively. For Denmark, Latvia and Lithuania costs would be at 6.2 €/kg and at 7.2 €/kg for Estonia. The highest costs are identified for Germany (9.2 €/kg) and Poland (12.4 €/kg), according to Hydrogen Europe³⁵⁵. These figures assume neither the provision of subsidies nor exemptions from fees and levies for the operation of electrolysers.

Production costs of biomethane in the BEMIP Member States

To assess and compare the production costs of biomethane in BEMIP MSs, a simplified cost modelling (production costs) for biomethane production for different processes and framework conditions in the BEMIP region is carried out. With this approach, key cost drivers of today's biomethane production can be identified.

For comparison, biomethane production via anaerobic digestion with downstream upgrading to grid quality methane as well as via gasification of wood chips with downstream methanation are considered for the cost calculation.

³⁵³ Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast)

³⁵⁴ DNV (2024): Potential for a Baltic Hydrogen Offshore Backbone; 7 March 2024

³⁵⁵ Hydrogen Europe: Clean Hydrogen Monitor 2024

The basic assumptions comprise:

- Discount rate: 4%
- Depreciation period: Lifetime of production facilities (typically 15 to 25 years)

The costs of capital per year are calculated using the PMT function in excel (amount paid each period) and divided by the annual biomethane production to get the cost per unit of biomethane. The CAPEX indicated in literature sources before 2023 is converted to 2023 values via the Chemical Engineering Plant Cost Index (CEPCI). Table 9-2 shows the CAPEX per kW of installed capacity for different plant capacities.

Table 9-2: Capital expenditure (CAPEX) per kW of installed capacity for different plant capacities

Capacity (MW _{CH₄} , LHV)	Biogas generation (€/kW _{CH₄})	Biogas upgrading (€/kW _{CH₄})	Total (€/kW _{CH₄})	Feedstock/ reference
1.2	2,020	1,860	3,880	Manure, maize silage ³⁵⁷
4.8	1,330	970	2,300	Manure, maize silage ³⁵⁷
10.0	1,470	550	2,020	Manure, slaughter waste, food waste (Horsens Bioenergi) ^{360,360}
16.6 (liquefied CH ₄)	2,330	950 (incl. liquefaction)	3,280	Manure, food waste (Götene plant) ³⁵⁶

The data for CAPEX, feedstock and electricity consumption and other operating costs such as labor and process chemicals are derived from developers of biogas plant projects, e.g. Gasum³⁵⁶, biogas plant manufacturers, academia^{357 358 359}, and governmental organizations³⁶⁰.

The cost data for biomethane from gasification of wood chips are derived from a study carried out by the Gas Technology Institute (GTI)³⁶¹ and are based on a facility with a capacity of 9,850 Nm³ of biomethane per hour with a CH₄ content of 96.5% and a H₂ content of 1.34%.

The costs for labour, diesel, and feedstock other than residues are different for different regions. Furthermore, typical biomethane production capacities per biogas/biomethane plant are different depending on the countries.

There is a significant cost reduction from upscaling resulting in lower biomethane costs for large biogas plants. In Germany, Poland, Estonia, Latvia, and Lithuania the **biogas plants are located rather decentralised nearby farms**. A mix of biomass from energy crops, such as maize whole-plant silage, and manure is used as feedstock. In Denmark, Sweden, and Finland large **centrally located biogas** plants use feedstock transported from farms (e. g. manure) or cities (organic waste)^{362 363}. Mainly residues such as manure, agricultural waste, sewage sludge, food waste, and waste from food industry are used as feedstock^{362 356}. In Denmark there are very large central biogas plants which produce up to 400 GWh (lower heating value, LHV) of biomethane per year, e. g. Tønder Biogas³⁶⁴. In Finland the share of biogas produced in on-farm agricultural waste facilities amounted to about 5%

³⁵⁶ Suomilammi (Gasum), A.: Increasing biomethane availability in the market; 1 November 2023

³⁵⁷ Dunkelberg, E., Salecki, S., Weiß, J., Rothe, S., & Böning, G.: Biomethan im Energiesystem - Ökologische und ökonomische Bewertung von Aufbereitungsverfahren; March 2015

³⁵⁸ Kuratorium für Technik und Bauwesen in der Landwirtschaft (KTBL): Energiepflanzen; 2006

³⁵⁹ Quakrim, A.: An Environmental (LCA) and economic assessment (LCC) of on-farm and centralized alternatives for biogas production for two Swedish farms in Götene; 2023

³⁶⁰ Danish Energy Agency; IBTech: Biogas plants in Denmark and Mexico; 2019

³⁶¹ Gas Technology Institute (GTI): Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes; February 2019

³⁶² Bioenergy Insight, B.: 'Finland's largest biogas plants' are making progress; 8. December 2023

³⁶³ Oaklin: Von Danish large-scale biogas plant sold to supplier association and Skovgaard Energy; 2024;

<https://www.oaklins.com/news/en-DK/230920-large-scale-biogas-plant-sold-to-supplier-association-and-skovgaard-energy>

³⁶⁴ Agromek: Von Tønder Biogas - one of the largest biogas plants in Europe; 4. July 2024; <https://www.agromek.com/articles-and-inspiration/case/toender-biogas-one-of-the-largest-biogas-plants-in-europe>

of all biogas produced in 2023³⁶⁵. Large central plants producing 150 GWh (LHV) of biomethane per year are planned³⁶².

Figure 9-8 and Figure 9-9 show the estimated costs of biomethane via anaerobic digestion and for biomethane via gasification of wood chips per BEMIP MS.

Figure 9-8: Estimated costs in 2023 of biomethane production via anaerobic digestion

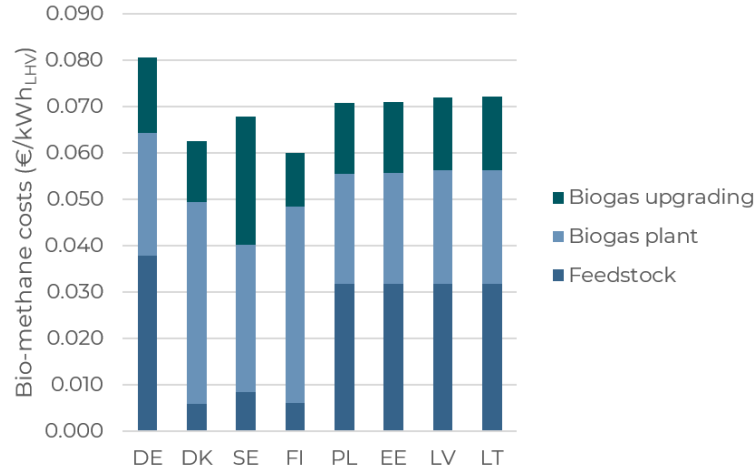
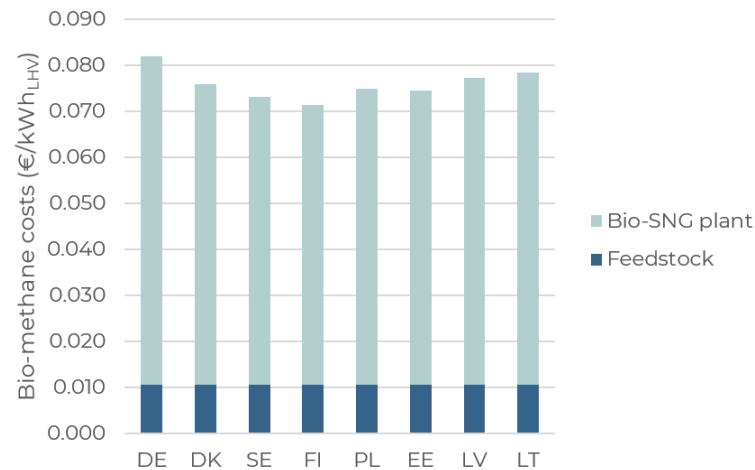


Figure 9-9: Estimated costs in 2023 of biomethane production via gasification of wood chips with downstream methanation



The production costs of biomethane via anaerobic digestion in Denmark, Sweden, and Finland are lower than in the other countries as they mainly use residues as feedstock. If biomethane is produced via gasification of wood chips, the costs for electricity (to process the wood chips) mainly lead to the differences between the countries.

Future cost levels will depend on several factors, including, e.g.

- availability and cost of suitable feedstock, taking into account developments in the agriculture sector, and competition between different uses of biomass (as food, feed and feedstock in industrial processes or for energy purposes)
- environmental constraints, including the treatment of substrate
- potential to scale up installations taking into account regional availability of biomass and transport costs
- potential to directly use biogas without upgrading it to biomethane

³⁶⁵ Bioenergy Insight (2024): [Finland records lower biogas production for 2023](#);

- role of gasification technology.

In addition, costs for grid connection and compression may need to be considered, depending on the regulatory environment (see also discussion in section 9.5).

A detailed analysis of future biomethane production costs is not part of this study.

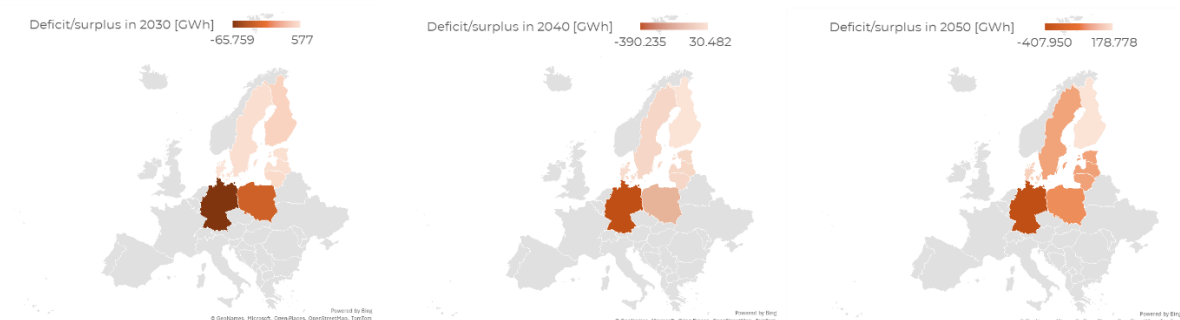
9.2.2. Cross-border trade potential

Evolution of potential supply and demand of renewable and low-carbon hydrogen in the BEMIP Member States

This section explores the potential evolution of the renewable and low-carbon hydrogen supply/demand levels in each BEMIP MS to indicate where cross-border flows would occur in the future, based on the TYNDP 2024 NT+ (for the 2030- and 2040-time horizons) and DE (for the 2050 time horizon) scenarios. The analysis is based on the scenario selection and analysis already performed in section 2.2.2 for hydrogen and section 2.3.2 for biomethane, respectively.

Figure 9-10 presents the relative surplus or deficit of (renewable and low-carbon) hydrogen in the BEMIP region in the years 2030, 2040 and 2050. The figure helps to visualise the expected cross-border flows and the overall regional dynamics.

Figure 9-10 Differences in potential hydrogen supply and demand between BEMIP MSs, based on TYNDP 2024 scenarios



The exact numbers per MS are shown in detail in Table 9-3, in each of the three investigated time frames.

Table 9-3 The hydrogen surplus or deficit in each BEMIP MS in the investigated time horizons

	Deficit/surplus in 2030 [GWh]	Deficit/surplus in 2040 [GWh]	Deficit/surplus in 2050 [GWh]
Denmark	577	11 695	132 518
Estonia	-376	-2 156	10 883
Finland	-3 997	30 482	178 778
Germany	-65 759	-390 235	-407 950
Latvia	-820	-3 357	7 357
Lithuania	-1 852	-3 052	9 718
Poland	-41 371	-103 137	-43 782
Sweden	-474	-5121	14 531

By 2030, while the German hydrogen demand according to the TYNDP 2024 NT+ scenario is projected to double, its hydrogen supply would not significantly change volume-wise, meaning that Germany turns into (by some margin) the largest net importer of hydrogen in the region. Poland is projected to follow a similar trend, the two countries together accounting for the bulk (107 TWh) of the region's (114 TWh) hydrogen supply deficit. The other BEMIP MS seem to be scaling up their hydrogen supply and demand much more in parallel with each other – but apart from a slight surplus

in Denmark, all would remain dependent on imports from external (and consequently non-BEMIP) sources (see also Figure 2-11).

The 2040 projections in the TYNDP 2024 NT+ scenario show a significant upscaling of production capacities in especially Finland, and to a lesser extent in Denmark – marking the emergence of a significant export potential within the region. Finland is expected to produce 30 TWh surplus of hydrogen by 2030 – only half of which could potentially be absorbed by the neighbouring Sweden and the Baltic countries. The Danish (about 12 TWh) surplus could serve to supply both the Swedish and German demand. Still, by 2040 the cumulative hydrogen deficit of the BEMIP region is expected to reach 460 TWh, pointing to the need for imported supply from e.g. Southern Europe and non-EU countries (see also Figure 2-12).

By 2050, the rest of the BEMIP region (apart from Germany and Poland) emerges as a potential net exporter of hydrogen according to the TYNDP 2024 DE scenario. Especially Denmark and Finland have ambitious plans/projections, resulting in a production surplus of about 310 TWh in the region. This indicates the need for significant import capacities from outside the region (see also Figure 2-13).

Based on these projections, there is a remarkable imbalance between the hydrogen production and demand, peaking in the 2040-time horizon, with the upscaling of Danish and Finnish production lagging significantly behind the growth in German and Polish demand. This poses a noteworthy risk and uncertainty for the development of cross-border hydrogen pipeline infrastructure within the region and connected to other sourcing countries.

Evolution of potential supply and demand of biomethane in the BEMIP Member States

Figure 9-11 below shows the evolution of the biomethane supply/demand balance of the BEMIP MS based on the most recent available data (2022) and the TYNDP 2024 NT+ and DE projections. The figure shows a relatively stable geographical balance over the 2030-2040-2050 timeframe, with no significant shifts in the overall dynamics of the biomethane market in the region. According to the projections, the BEMIP region as a whole remains a net importer of (bio)methane all throughout the investigated timeframe, with the emerging exporters (Denmark, Finland and Sweden) never matching a significant amount of the demand. This demand is heavily concentrated in Germany and Poland, and while the production of biomethane is significantly upscaled until 2050 in all BEMIP MSs (2-50 times compared to the 2022 production) the most relevant shift on this market is the diminishing deficit in Germany (and Poland to a lesser extent).

Figure 9-11 Differences in potential biomethane supply and demand levels between BEMIP MSs

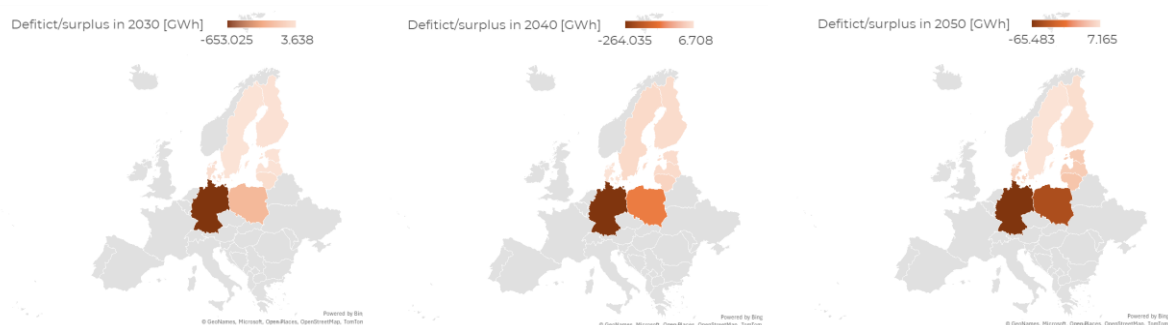


Table 9-4 Biomethane surplus/deficit in different BEMIP MSs

	Deficit/surplus in 2030 [GWh]	Deficit/surplus in 2040 [GWh]	Deficit/surplus in 2050 [GWh]
Denmark	-16 724	-4 371	2 507
Estonia	-1 350	-1 246	-169
Finland	-6 172	-7 602	5 431

	Deficit/surplus in 2030 [GWh]	Deficit/surplus in 2040 [GWh]	Deficit/surplus in 2050 [GWh]
Germany	-653 025	-308 437	-65 483
Latvia	-1 883	-1 962	-66
Lithuania	-26 974	-20 923	-2 462
Poland	-237 231	-240 801	-50 184
Sweden	3 638	9 137	7 165

The most recent (2022) data shows that the entire BEMIP region, with every Member State individually, has a higher biomethane and natural gas demand than production – with Germany and Poland together accounting for 95% of this demand.

This situation is not expected to change significantly by 2030 according to the TYNDP 2024 NT+ scenario, when Sweden alone turns into a potential net exporter (with a 4 TWh surplus) thanks to a faster upscale in production than in demand (see also Figure 2-22).

By 2040, according to the projections, of TYNDP 2024 NT+ scenario, Sweden stays the only country within the region with a notable ~9 TWh surplus in (bio)methane production (see also Figure 2-23).

By 2050 the (bio)methane balance of the region is expected to remain negative according to TYNDP 2024 DE scenario, but substantially closer to parity mainly due to the decreasing overall gas demand (in every Member State but especially in Germany) (see also Figure 2-24).

9.2.3. Underground gas storage capacities

This section explores the differences between the existing natural gas storage capacities (i.e. salt caverns and porous media storages) within BEMIP MS, with particular attention to the repurposing potential (for dedicated hydrogen storage).

Existing underground gas storages capacities for natural gas

The figure below shows the BEMIP MS with existing (natural gas) storage capacity (with a darker shade), possibly available to be repurposed for hydrogen storage in the future. Currently, only five BEMIP MS have underground gas storage facilities – including Sweden with its very limited storage capacity (in lined rock cavern, only 0.1 TWh) and no capacity extension in the planning either.

Figure 9-12 BEMIP MSs with existing gas storage capacities

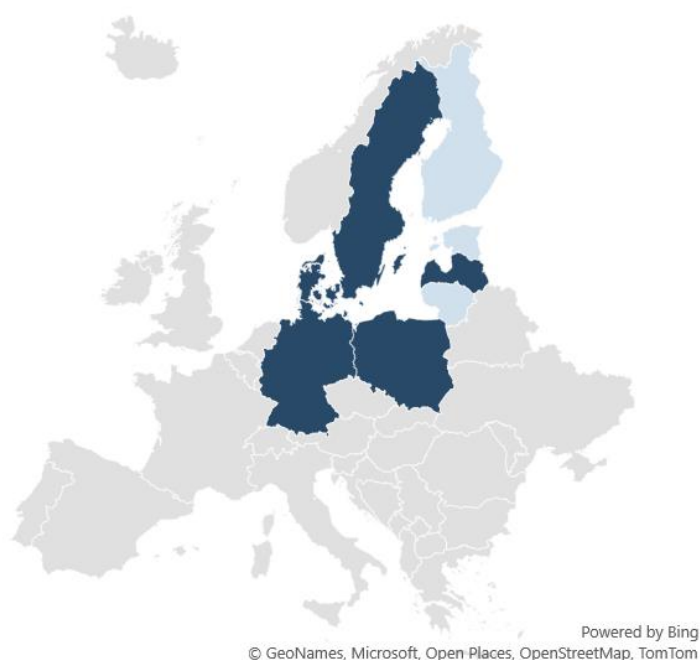


Table 9-5 below shows the underground gas storage capacities available, planned or under construction in the BEMIP MS. The BEMIP MSs without current storage capacities (Estonia, Finland, and Lithuania) have no announced plans for establishing storage capacities in the future either. The only BEMIP MS with plans to expand their storage capacities are Germany and Poland, which are also the largest consumers of natural gas within the BEMIP region.

Table 9-5 Existing and planned natural gas storage capacities in BEMIP MS

	Capacity in 2022 [TWh]	Under construction [TWh]	Planned [TWh]	Type
Denmark	10.5	-	-	Salt caverns
Estonia	-	-	-	-
Finland	-	-	-	-
Germany	260.5	-	5.9	Aquifers and salt caverns
Latvia	24.2	-	-	Aquifers
Lithuania	-	-	-	-
Poland	38.4	0.7	9.0	Salt caverns and depleted gas fields
Sweden	0.1	-	-	Lined rock cavern

In general, underground gas storage sites are technically feasible to store large amounts of biomethane. One key challenge, however, is the share of oxygen in the gas as it may need to be removed before injection into a storage site due to potential risk of microbiological activity or oxidation. Further details can be found in section 9.5 on the technical bottlenecks on biomethane integration into the natural gas system.

Hydrogen storage potential in BEMIP Member States

The lack in existing projects for new or repurposed storage facilities in Europe is considered a key bottleneck of the hydrogen infrastructure development. While repurposing can be considered a

time- and cost-efficient approach to provide certain storage capacities (as long as the storage sites are not needed for natural gas anymore), countries without any existing gas storage facilities, like Finland and Sweden, are facing increasingly pressing challenges. Even more so, as both are projected to become large producers of hydrogen (and biomethane) by 2040 and 2050 (see section 'Potential supply and demand'). Based on the TYNDP 2024 NT+ and DE scenarios, Finland especially is about to become the largest potential exporter of hydrogen within the region. Combined with the long lead times for new infrastructure/storage projects, and the lack of announced plans (apart from a few, non-specific initiatives to research possible sites coming from the TSO and research institutions^{366,367}), this would result in significant amounts of cross-border flows from Finland to BEMIP MS with a supply deficit and/or with existing storage capacities. Potential target countries include Germany and Poland by 2040 already. Similar conclusions can be drawn for biomethane where both Finland and Sweden would become net exporter in the 2050-time horizon according to the DE scenario of the TYNDP 2024.

Similarly, the German Association of Energy and Water Industries (BDEW) estimates that the long-term hydrogen storage need in the **Germany** will reach 14-17 TWh by 2035 and 76-80 TWh by 2045³⁶⁸. However, the project that already reached FID (as of August 2024) only constitutes a negligible amount (0.002 TWh) of storage capacity for the German hydrogen economy. Even combined with the projects in an advanced stage (but without formal FID, overall about 0.7 TWh), there remains a significant gap on the 2030-2035 horizon. Uncertainty regarding the profitability of such projects, regulatory uncertainty, and lengthy approval procedures are among the reasons for the delay or the missing construction/repurposing plans³⁶⁹. With typical project lead-times varying between 1-12 years³⁷⁰ depending on the type of large-scale storage (cavern, depleted gas field, aquifer), meeting the estimated 14-17 TWh need is becoming an increasingly significant challenge by 2035.

The Green Hydrogen Hub project in **Denmark** envisions a 200 GWh hydrogen storage facility (in salt caverns) in the country (repurposing less than 2% of the current natural gas storage capacity, in Lille Torup), but without specifying a timeline³⁷¹. In April 2024, Energinet started a stakeholder consultation on the preparation of the country's hydrogen pipeline and storage infrastructure. This has been done in close cross-border cooperation with Germany, with the expectation that (a part of) the Danish hydrogen production will serve export purposes to the German consumer base³⁷².

The **Polish Ministry of Climate** also recently finished its public consultation on a new regulatory framework aimed at accelerating the hydrogen infrastructure development, and announced plans to convert (some of) the capacity of the existing Kosakowo natural gas storage site into the country's first hydrogen storage facility³⁷³.

From a **theoretical potential perspective**, there is significant hydrogen storage potential in the BEMIP region, albeit distributed unevenly across the different reservoir categories. The figure below presents the assessment of the HyStories project, indicating Germany has the largest potential for hydrogen storage considering the study assumptions. For Germany and Poland this is mainly driven by the potential of depleted gas fields, while other BEMIP MSs could draw on other reservoir types. It must be noted that, as discussed in section 4.2.1 below, each storage type will likely serve different purposes in the future (regarding provision of short- vs long-term storage services). Hence the more

³⁶⁶ VTT (2024): [VTT, GTK and industrial partners initiate groundbreaking research project on hydrogen storage](#)

³⁶⁷ Gasgrid (2024): [Finland – a great hydrogen power. Could hydrogen be the next Finnish success story?](#)

³⁶⁸ BDEW (2024): [FINANZIERUNGSMCHANISMUS FÜR DEN AUFBAU VON WASSERSTOFFSPEICHERN](#)

³⁶⁹ BDEW (2024): [FINANZIERUNGSMCHANISMUS FÜR DEN AUFBAU VON WASSERSTOFFSPEICHERN](#)

³⁷⁰ TNO (n.d.): [Improving regulation of natural gas storage](#)

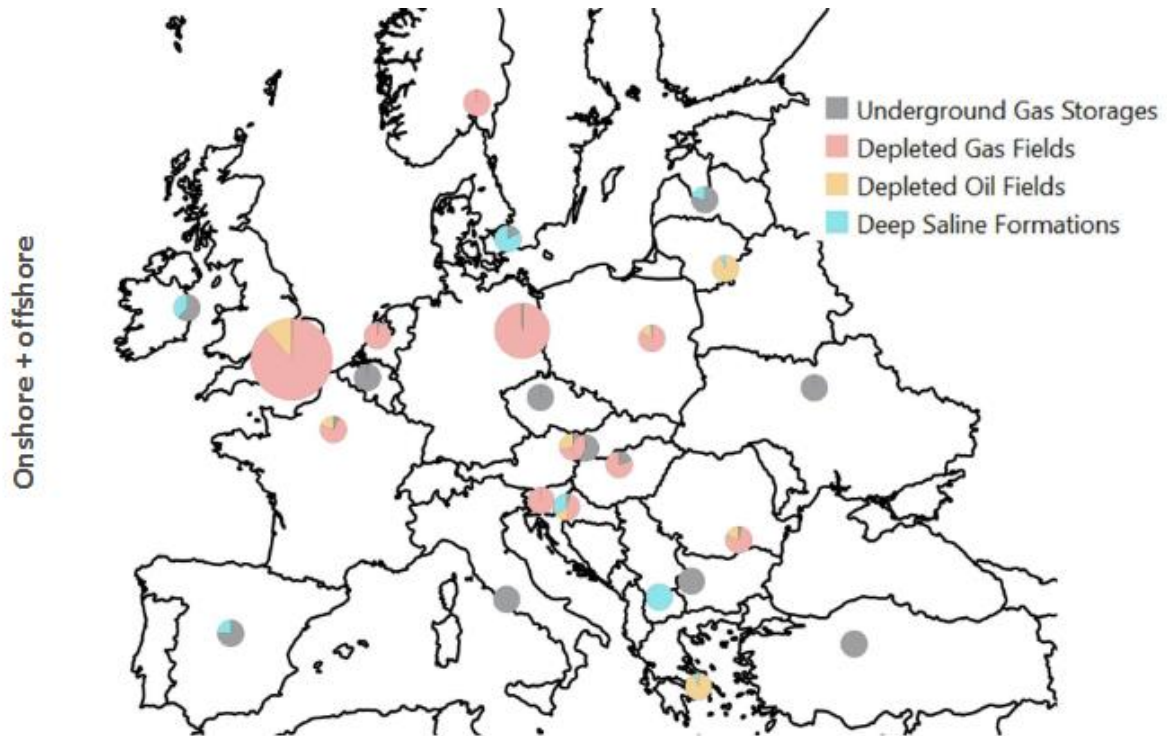
³⁷¹ Green Hydrogen Hub Denmark (n.d.): [New, large-scale hydrogen hub to support Denmark's green transition](#)

³⁷² Energinet (2023): [Hydrogen market assessment report](#)

³⁷³ Ministry of Climate and Environment (2024): [Paulina Hennig-Kłoska na Pomorzu o polityce wodorowej Polski](#)

limited potential of salt caverns does not mean they will not play a relevant role in the future regional hydrogen system.

Figure 9-13 Storage potential per country and storage category (Source: HyStories, the size of the pie chart is proportional to the country capacity)³⁷⁴



³⁷⁴ Geostock (2022): [HyStories - 3D multi-realization simulations for fluid flow and mixing issues at European scale](#)

9.3. Country fiches – gas infrastructure

Denmark

ENERGINET

evida

	Transport	Distribution
System operator	Energinet	Evida A/S
System's length	~7 000km	18 000 km 310 000 Consumers (02/2025)

Interconnectors	The Danish gas system is directly interconnected with Germany, Sweden and recently Poland through the <i>Baltic Pipe</i> , which establishes a new gas corridor from Norway to Poland. Hence, with the completion of the <i>Baltic Pipe</i> project, Denmark is now connected to Norway's extensive offshore gas fields.
LNG terminals	No LNG terminal in operation in Denmark.
Storage facilities	Denmark includes two onshore storage facilities, operated by Gas Storage Denmark: Lille Torup – Salt Cavern and Stenlille – Aquifer.

Estonia

elering

gaasivõrk

Energate
Gate to Energy

	Transport	Distribution
System operator	Elering	AS Gaasivõrk
System's length	977 km	1 620 km

Interconnectors	The Estonian gas system is interconnected with Latvia, and with Finland through the subsea <i>Balticconnector</i> (around 77 km of offshore pipeline). Historically, Estonia had gas connections with Russia.
LNG terminals	No LNG terminal currently in operation in Estonia. However, two are planned for 2025 ³⁷⁵ : one in Paldiski, another in Tallinn.
Storage facilities	No existing UGS facilities are present in Estonia.

³⁷⁵ GIE LNG Database

Finland



	Transport	Distribution
System operator	Gasgrid Finland	Auris Energy
System's length	1150 km Concentrated in the southern regions of the country. No existing gas pipeline going up the North of Finland, none in the Bothnian Bay.	The network covers 17 cities, town and municipalities in Southern Finland.

Interconnectors	The Finnish gas system is solely interconnected with Estonia through the subsea <i>Balticconnector</i> . Historically, Finland had a gas connection with Russia through the Imatra border point. However, the import of Russian natural gas to Finland through this point was ended in 2022.
LNG terminals	Two LNG entry points are currently in operation in Finland: a large-scale floating storage and regasification unit (FSRU) in Inkoo and a smaller terminal in Hamina and Inkoo. The commissioning of the FSRU in Inkoo in 2023 enabled Finland to break out of its dependence on Russian pipeline gas.
Storage facilities	No existing UGS facilities are present in Finland.

Germany

	Transport	Distribution
System operator	Germany has a unique structure compared to other European countries with 16 gas TSOs ³⁷⁶ . OGE operates the largest German gas transmission system and ONTRAS the second largest.	Around 700 distribution system operators.
System's length	40 000 km	More than 470 000 km

Interconnectors	As described above, Germany's gas system is well interconnected with the rest of Europe: the Netherlands, Denmark, Belgium, France, Switzerland, Austria, the Czech Republic and Poland. It is also directly connected to non-EU natural gas suppliers, such as Norway and, historically, Russia (Nord Stream pipeline system).
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³⁷⁶ [Gasunie \(n.d.\). Infrastructure in Germany](#)

LNG terminals	Three LNG terminals are currently in operation in Germany, all FSRUs installed between 2022 and 2023 to face the disruptions in Russian gas supply: • Wilhelmshaven, • Brunsbüttel, • The Baltic Energy Gate (originally in Lubmin, moved to Mukran on the island of Rügen), Several developments are also planned before 2030: • An additional floating storage regasification unit (FSRU) in Wilhelmshaven, planned for 2025. • A first fixed onshore terminal in Stade, near Hamburg, planned for 2026/2027.
Storage facilities	More than 60 operational onshore UGS exploiting several types of technologies: salt caverns, aquifers and depleted gas fields.

Latvia



	Transport	Distribution
System operator	Connexus Baltic Grid	GASO
System's length	1,190 km	5,200 km ³⁷⁷

Interconnectors	The Latvian gas system is interconnected with Estonia and Lithuania.
LNG terminals	No LNG terminals are currently in operation in Latvia, but one is planned in Skulte.
Storage facilities	<i>Inčukalna</i> is an onshore aquifer storage facility that plays an important role in regional gas supply security. It provides seasonal flexibility to all three Baltic states.

Lithuania



	Transport	Distribution
System operator	Amber Grid	ESO, UAB Intergas
System's length	2 228 km	Around 20 000 km

³⁷⁷ *Gaso (n.d.). Apstiprina jaunus dabasgāzes sadales tarifus*

Interconnectors	The Lithuanian gas system is interconnected with Latvia and Poland recently with the commissioning of <i>GIPL</i> . Lithuania is also connected to Belarus and Russia (Kaliningrad).
LNG terminals	The <i>Klaipėda</i> LNG Terminal is a floating storage and regasification unit (FSRU) that has been in operation since 2014. This has enhanced Lithuania's energy security.
Storage facilities	No UGS facility is in operation in Lithuania.

Poland



	Transport	Distribution
System operator	GAZ-SYSTEM	49 DSOs
System's length	12 121 km	No data found.

Interconnectors	The Polish gas system is the second most interconnected in the region after Germany. It is interconnected with the Baltic States thanks to the Poland-Lithuania Gas Interconnector (<i>GIPL</i>), Germany through several interconnections, the Czech Republic, Ukraine and Belarus. And more recently to Slovakia since 2022 and to Denmark and Norway with the <i>Baltic Pipe</i> .
LNG terminals	The <i>Świnoujście</i> LNG Terminal went into operation in 2016 with an expansion planned. The development of an FSRU is also planned in the Gdańsk area.
Storage facilities	There are nine operational UGS facilities in Poland: 7 depleted gas fields and 2 salt caverns. Another salt cavern project is planned in Damasławek, to be operational in 2026, as well as an extension of the current existing one in Kosakowo.

Sweden



	Transport	Distribution
System operator	Nordion Energi/Swedegas	Several DSOs, Nordion Energi/Weum being the country's biggest gas distributor.
System's length	620 km concentrated in the country's south-western region	3 456 km ³⁷⁸

³⁷⁸ Ei (n.d.). [The Swedish natural gas system structure](#)

Interconnectors	The Swedish gas system is exclusively interconnected to Denmark.
LNG terminals	No LNG terminal is operating in Sweden which solely depends on imports from Denmark.
Storage facilities	There is one small onshore hard rock cavern facility in operation in Skallen. Its limited capacity is to equalize short term consumption peaks. However, it does not provide seasonal flexibility for which Sweden relies on infrastructures in other countries such as Denmark.

9.4. Hydrogen infrastructure

The following technology fiches introduce the main technologies relative to hydrogen transport, storage and maritime imports, focusing on technology maturity, key benefits and challenges, as well as main technical and economic parameters. When relevant, considerations regarding repurposing of existing infrastructure are added.

The Technology Readiness Level (TRL) scale is a method developed to consistently identify the maturity of different technologies, it ranges from level 1 (Basic technology research) to level 9 (system proven in operational environment).

A) Hydrogen transport network (pipeline) – Onshore

TECHNOLOGY DESCRIPTION

Hydrogen onshore pipelines can either be repurposed—converting existing natural gas pipelines into dedicated hydrogen pipelines – or newly constructed. Due to the differing properties of hydrogen compared to natural gas, the operating conditions and requirements for these pipelines will vary accordingly.

TECHNOLOGICAL READINESS

	The technology readiness level (TRL) for repurposed onshore pipelines is 8 (first of a kind commercial). Currently, there is only a 12 km repurposed pipeline in the Netherlands, transporting over 133 GWh of hydrogen annually. For newly constructed onshore hydrogen pipelines, the TRL is 9 (commercial operation in relevant environment). The first hydrogen pipeline was commissioned in 1938, and today, approximately 2,000 km of hydrogen pipelines are operational across Europe, generally located close to large hydrogen users such as petroleum refineries and chemical plants³⁷⁹.
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BENEFITS

- Cost-efficient transport mode for larger gas volumes
- Repurposing of natural gas pipelines may reduce investment needs compared to new infrastructure

BOTTLENECKS AND CHALLENGES

- Hydrogen is generally more corrosive than the natural gas composition the pipeline networks were designed for, increasing the embrittlement hazard³⁸⁰
- Hydrogen poses an increased risk of leakage due to smaller molecule size³⁸¹
- Other technical/safety challenges such as material fatigue due to vibrations, material degradation, cooling and thermal management,
- Compression needs may exceed capability of original compressors in case of repurposed pipelines, reducing cost savings compared to a new hydrogen pipeline³⁸²

³⁷⁹ IEA (2024): [ETP Clean Energy Technology Guide](#)

³⁸⁰ Li et al. (2024): [A review on hazards and risks to pipeline operation under transporting hydrogen energy and hydrogen-mixed natural gas](#)

³⁸¹ Raj et al. (2024): [Evaluating hydrogen gas transport in pipelines: Current state of numerical and experimental methodologies](#)

³⁸² Lipiainen et al. (2023): [Use of existing gas infrastructure in European hydrogen economy](#)

- Expertise in repurposing gas pipelines still under development, including regarding models for flow simulation
- Supply and demand uncertainty increase business case risks
- Coordination for development of infrastructure, supply and end-use is challenging
- Transport tariffs can be above willingness-to-pay of customers in ramp-up phase, hindering overall market development

SPECIFIC ASPECTS REGARDING REPURPOSING

In general, experience with converting gas pipelines exist, e.g. based in Germany, there were several changes in the transported gas in the past decades³⁸³:

- Mains gas / coke oven gas to natural gas
- Low-calorific gas (L gas) to high-calorific gas (H gas)
- Substitution of odorants

As described above, conversion of natural gas pipelines to hydrogen is a rather new topic. **Key challenges** in this regard are:

- Safety (= material compatibility, tightness of material, corrosion):
 - Selection of suitable pipe materials (e.g. different steel qualities, coatings, PE pipes for low-pressure transport, etc.)
 - Replacement of sensitive grid components, e.g. valves, compressor stations, etc.
- Gas quality and contaminants:
 - Cleaning measures to remove residues like methane and sulphur compounds that may have accumulated due to prior use of pipeline for natural gas (see pigging process description below). In addition, adsorption processes at sensible grid components, e.g. storage sites, are required to remove traces of sulphur compounds
 - Continuous measurement and regular removal of contaminants required, even after transition, until all traces of former use are gone (at least expected in years after conversion)
 - The standard CEN/TS 17977:2023³⁸⁴ already provides requirements for the hydrogen quality, introduced a minimum hydrogen content of 98 mol-% and limits for admissible contaminants
- Impact on pipeline capacities:
 - Lower capacity: due to the lower heating value of hydrogen compared to natural gas, in general, a higher gas flow and pressures are needed to transport the same amount of energy per unit of time
 - Operational: reduction in line pack capacity of the pipelines and potential changes in gas flow direction due to new supply structure in European gas market

Key advantages of repurposing compared to newly built pipelines:

- Significant cost savings compared to newly built pipelines (see economic parameters below)
- Faster deployment: less time-consuming approval, planning and construction processes compared to new pipelines

Based on literature, different **potential options for pipeline repurposing** exist³⁸⁵:

- No changes to pipeline, but enhanced monitoring and maintenance and replacement of most critical components (=main approach, see process described below)

³⁸³ DBI GUT & Frontier Economics (2022): [H₂ short study: Hydrogen quality in an all-German hydrogen network](#)

³⁸⁴ CEN/TS 17977:2023: Gas infrastructure – quality of gas – hydrogen used in rededicated gas systems

³⁸⁵ Télessy et al. (2024): [Repurposing natural gas pipelines for hydrogen: Limits and options from a case study in Germany](#)

- Admixing degradation inhibitors (e.g. oxygen (O₂), sulphur dioxide (SO₂) or carbon monoxide (CO), but at cost of lower hydrogen quality
- Pipe-in-pipe (PIP) approach, an inner pipe is inserted into the existing steel pipeline to form a physical barrier between hydrogen and steel
- Inner coating of steel pipeline (difficult for existing pipeline infrastructure)

Process (cleaning protocol proposed by DNV³⁸⁶):

- (1) Pre-cleaning using cleaning pigs: removal of loose dirt and liquids from former use for natural gas
- (2) Introduce and preserve pipeline under low-pressure nitrogen atmosphere
- (3) Maintenance and replacement of valves
- (4) Pig-run under nitrogen atmosphere with monitoring of contaminants in nitrogen. Additional pig-run, if criteria are not met
- (5) Displacement from nitrogen to hydrogen via separation pig-run

TECHNICAL PARAMETERS

Compressor power consumption per km	0.19 – 0.33 MW _e /km ³⁸⁷
Pressure conditions	30 – 80 bar ³⁸⁸

ECONOMIC PARAMETERS

CAPEX (depending on pipeline size)³⁸⁹

Installation costs	350 – 1,520 €/MW/km
Repurposing costs	80 – 470 €/MW/km

OPEX (depending on pipeline size)³⁹⁰

Fixed operating costs	3 – 14 €/MW/km/year
Variable operating costs (including electricity costs for compression)	0.067 – 0.67 €/tH ₂ /km

³⁸⁶ Henk Top – DNV New Energy (2024): *ENTSO-GAS QUALITY & HYDROGEN WORKSHOP 07*, November 2022, Conversion of a natural gas pipeline to hydrogen transport and the effects of impurities on the hydrogen quality

³⁸⁷ Guidehouse & EHB (2021): *Analysing future demand, supply, and transport of hydrogen*

³⁸⁸ Guidehouse & EHB (2021): *Extending the European Hydrogen Backbone*

³⁸⁹ Pipeline CAPEX: Guidehouse & EHB (2023): *Implementation Roadmap – Cross border projects and costs update*. Compressor CAPEX: Guidehouse & EHB (2024): *EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure*

³⁹⁰ Guidehouse & EHB (2024): *EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure*; ENTSO-E & ENTSG (2024): *TYNDP 2024 Scenarios Methodology Report*

B) Hydrogen transport network (pipeline) – Offshore

TECHNOLOGY DESCRIPTION

Hydrogen offshore pipelines could either be repurposed—converting existing natural gas pipelines into dedicated hydrogen pipelines – or newly constructed. Due to the differing properties of hydrogen compared to natural gas, the operating conditions and requirements for these pipelines will vary accordingly.

TECHNOLOGICAL READINESS



The Technology Readiness Level (TRL) for offshore pipelines ranges between 4 and 5. There is currently no standard for hydrogen offshore pipelines³⁹¹. The H2Pipe³⁹² project aims to establish a pipeline code for design, construction and operation of offshore pipelines.

BENEFITS

- Higher energy transmission capacity, lower energy losses – economically more feasible than alternatives, such as ship transfer, especially for higher volumes and longer distances
- Low operational costs, long lifetime of assets
- Decreased space requirements – existing natural gas pipelines may be reused, and the transportation of hydrogen via pipelines offers larger capacity per landing point

BOTTLENECKS AND CHALLENGES

- Geopolitical vulnerability – the seabed infrastructure is hard to shield from acts of sabotage as international law restricts the national autonomy in their respective EEZ³⁹³ and because the offshore territory is too large to be covered effectively by security forces
- Especially in the case of flexible pipes, the effectiveness of the existing subsea inspection techniques and standards is questionable, with hydrogen posing an increased safety risk
- High longitudinal/bending stresses, strain and fatigue loading
- Need for definition of allowable defects and engineering critical assessment criteria³⁹⁴

SPECIFIC ASPECTS REGARDING REPURPOSING

While there is much experience with onshore hydrogen pipelines, so far, no offshore pipeline systems for hydrogen exist and therefore also no experience with repurposing natural gas pipelines to hydrogen.³⁹⁵ In general, however, advantages and challenges described for onshore pipelines also are valid for offshore pipelines.

In addition, further **key challenges are specific for offshore pipelines** as they arise from the offshore environment^{396, 397},

³⁹¹ IEA (2024): [ETP Clean Energy Technology Guide](#)

³⁹² DNV (2021): [Transportation of hydrogen gas in offshore pipelines: H2Pipe](#)

³⁹³ CEPA (2023): [A Baltic No-Go Zone Is Tempting But Wrong](#)

³⁹⁴ Wood (2024): [The Challenges on the Development and Sustainable Construction of Infrastructure - Design Challenges for Offshore Hydrogen Pipelines](#)

³⁹⁵ Bob Inglis, Wood (2024): Presentation at Enagás H2 Technical Day. Design Challenge for Offshore Hydrogen Pipelines.

³⁹⁶ Bob Inglis, Wood (2024): Presentation at Enagás H2 Technical Day. Design Challenge for Offshore Hydrogen Pipelines.

³⁹⁷ Wood (2023): [Repurposing gas transmission pipelines for hydrogen](#)

- High longitudinal/bending stresses within pipeline girth welds
- High strain loading (e.g. global buckling, accidental loading)
- Fatigue loading (e.g. Vortex Induced Vibration (VIV) and storage cycles)
- Definition of allowable defects and engineering critical assessment (ECA) criteria

In summary, a high stress design approach is necessary for repurposed offshore pipelines and therefore a tighter control of spans and damages is required as for the use of natural gas.

According to learnings from the project 'Technical Assistance on Hydrogen Quality Standardisation'³⁹⁸, industry stakeholders still await widely recognised guidance for the design and specification of offshore hydrogen pipelines, with the standards DNV H2Pipe JIP and DNV-ST-F101 supplement to be released in 2025.

TECHNICAL PARAMETERS

Compressor power consumption per km	0.19 – 0.33 MW _e /km ³⁹⁹
Pressure conditions	30 – 80 bar ⁴⁰⁰

ECONOMIC PARAMETERS

CAPEX (depending on pipeline size⁴⁰¹)⁴⁰²

Installation costs	600 – 1,200 €/MW/km
Repurposing costs	140 – 320 €/MW/km

OPEX (depending on pipeline size)⁴⁰³

Fixed operating costs	6 – 14 €/MW/km/year
Variable operating costs (including electricity costs for compression)	0.067 – 0.17 €/tH ₂ /km

³⁹⁸ Contract: ENER/C2/2023-397.

³⁹⁹ Guidehouse & EHB (2021): [Analysing future demand, supply, and transport of hydrogen](#)

⁴⁰⁰ Guidehouse & EHB (2021): [Extending the European Hydrogen Backbone](#)

⁴⁰¹ Investment costs in €/MW/km are higher for small pipelines than for large ones.

⁴⁰² Pipeline CAPEX: Guidehouse & EHB (2023): [Implementation Roadmap – Cross border projects and costs update](#). Compressor CAPEX: Guidehouse & EHB (2024): [EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure](#)

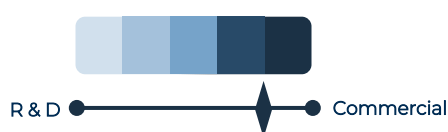
⁴⁰³ Guidehouse & EHB (2024): [EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure](#); ENTSO-E and ENTSG (2024): [TYNDP2024 Scenarios Methodology Report](#)

C) Underground hydrogen storage – Salt caverns

TECHNOLOGY DESCRIPTION

Salt caverns, are artificial cavities in underground salt formations, created by dissolving rock salt through water injection. Salt caverns are currently used for natural gas storage and are suitable for storing pure hydrogen due to their low cushion gas requirements, the high sealing properties of rock salt and the inert nature of the salt formations, which limits hydrogen contamination risks. However, the geographical availability of salt caverns is limited. Salt cavern storage is considered to be flexible and would allow several cycles of gas injection and withdrawal annually. Experience to date has shown that hydrogen can be effectively stored in salt caverns under low-frequency cyclic loading conditions. Current research focuses on exploring the feasibility of repurposing salt caverns previously used for natural gas or oil storage⁴⁰⁴.

TECHNOLOGICAL READINESS



The Technology Readiness Level (TRL) of hydrogen storage in salt cavern is 9 (commercial operation in relevant environment). For salt cavern repurposing, the TRL is approximately 8. Hydrogen storage in salt caverns has been operationally and commercially demonstrated since 1972, in the United Kingdom and in the United States of America. In Teesside, UK, three salt caverns provide a total storage capacity of 28 GWh, while in the Texas Gulf Coast, USA, three caverns offer a combined capacity of 478 GWh. In Europe, several projects are underway to repurpose or create new salt caverns for hydrogen storage. Examples include the Hystock project in the Netherlands, as well as the H2CAST Etzel and Hydrogen Pilot Cavern Krummhörn initiatives in Germany⁴⁰⁵.

BENEFITS

- Lower amount of cushion gas necessary (compared to aquifers and depleted fields)⁴⁰⁶
- Higher potential to fast cycling compared to porous reservoirs, enabling provision of short-term storage services
- The salinity of the cavern reduces the amount of microorganisms in the storage site, leading to lower levels of hydrogen loss over time through microbial consumption

BOTTLENECKS AND CHALLENGES

- Geographical distribution of suitable formations is uneven in BEMIP MSs
- Pressurization of the cavern (i.e. for gas storage purposes) leads to salt creeping and the eventual closure of the cavern⁴⁰⁷ (or partial loss of its technical capacity) over time – the larger the difference between internal and external pressure, the faster the creep deformation
- Subsidence over salt caverns as a result of salt creeping, and the related need for monitoring

⁴⁰⁴ IEA (2024): [ETP Clean Energy Technology Guide](#); Danish Energy Agency (2024): [Technology Data for Energy Storage](#)

⁴⁰⁵ IEA (2024): [ETP Clean Energy Technology Guide](#)

⁴⁰⁶ Prigmore et al. (2024): [Cushion Gas Consideration for Underground Hydrogen Storage](#)

⁴⁰⁷ O. A. M. Zamani, D. Knez (2024): [Well Integrity in Salt Cavern Hydrogen Storage](#)

- Low pressure caverns prone to fatigue due to cyclic pressure and temperature variations – leading to cracks, gas migration, and losses
- Lack of experience with the operation of these type of storage sites (particularly for fast cycling) and regarding precision of the models developed to predict the cavern's behaviour
- Salt deposits lead to hydrogen impurity⁴⁰⁸
- Supply, demand and network infrastructure development uncertainty increase business case risks
- Storage service tariffs can be above willingness-to-pay of customers in ramp-up phase, hindering overall market development

SPECIFIC ASPECTS REGARDING REPURPOSING

In general, hydrogen can be stored in salt caverns (or even lined rock caverns), similar to natural gas. After decommissioning and cleaning with inert gas (nitrogen), especially above ground facilities need to be revised (e.g. compressor stations, purification units, injection and rejection system).

Advantages of repurposing:

- Similar to pipeline systems, e.g. reduced costs and deployment time

Key challenges:

Key challenges arise due to contaminations of the stored natural gas, requiring purification processes before and behind the storage.

- Additional purification need before injection, e.g. to remove water, methane or sulphur traces that could potentially serve as feedstock for microbiological processes contaminating the stored gas (challenge mostly related to porous media but also observed for salt caverns)
- Hydrogen quality of withdrawn gas:
 - Possible sources for contamination: Brine residues, residues of former use for natural gas (or other gases), microbiological activity (despite high salinity)⁴⁰⁹
 - More complex purification needs compared to natural gas will be required:
 - Set up (example from industry for withdrawal rate of 1 million Sm³/h): water separation, multi-step PSA/TSA (processes for natural gas removal, especially for porous media storages) and desulfurization process line
 - Hydrogen quality above ISO 14687 Grade A (≥98 mol%) considered to be economically challenging⁴¹⁰, as beside drying, desulphurisation and dehydrogenation, also PSA would be required.
- Economic challenges:
 - Reduced storage capacity (due to lower energy content of hydrogen) and reduced injection and retrieval speed compared to former natural gas use at same site
 - Competition with use for natural gas

TECHNICAL PARAMETERS⁴¹¹

⁴⁰⁸ Minougou et al. (2023): *Underground hydrogen storage in salt caverns: Challenges of impure salt structures*

⁴⁰⁹ Dopffel, N., An-Stepec, B. A., Bombach, P., Wagner, M., & Passaris, E. (2024): *Microbial life in salt caverns and their influence on H2 storage—Current knowledge and open questions*. *International Journal of Hydrogen Energy*, 58, 1478-1485.
<https://doi.org/10.1016/j.ijhydene.2024.01.334>

⁴¹⁰ Frontier Economics & DBI (2024): *Interview-basierte Analyse aktueller Entwicklungen zur Wasserstoffqualität. Study for GETH2 and DVGW*. Available online: <https://www.frontier-economics.com/media/n12a0myg/frontier-dbi-best-practice-studie-zu-wasserstoffqualitaet-fuer-geth2-dvgw-januar-2024-stc.pdf>

⁴¹¹ Danish Energy Agency (2024): *Technology Data for Energy Storage*

Storage capacity	200 – 2,500 tH ₂ per cavern
Electricity need for compression	~ 4 kWh/kgH ₂
Roundtrip efficiency	~ 89% (including electricity for compression)
Discharge time	Typically a few weeks
Storage geometrical volume	70,000 – 600,000 m ³
Nominal pressure	40-300 bar (80% of the initial salt formation pressure at the desired depth)
Cushion gas requirement (% of overall capacity)	30%

ECONOMIC PARAMETERS	
CAPEX	
Installation costs	~15 – 50 €/kgH ₂ stored ⁴¹²
Repurposing costs	~ 10 – 20 €/kgH ₂ stored ⁴¹³
OPEX	
Fixed operating costs	~ 4% CAPEX ⁴¹⁴

⁴¹² RTE (2023): [Enjeux du développement des infrastructures de stockage et de transport d'hydrogène associés au développement de l'électrolyse et leviers d'optimisation avec le système électrique](#); Guidehouse (2024): [The role of underground hydrogen storage in Europe](#); Artelys & Frontier Economics (2024): [Why European underground hydrogen storage needs should be fulfilled](#); Hystories (2022): [Assumptions and input parameters for modelling of the European energy system](#)

⁴¹³ RTE (2023): [Enjeux du développement des infrastructures de stockage et de transport d'hydrogène associés au développement de l'électrolyse et leviers d'optimisation avec le système électrique](#); Guidehouse & Gas for Climate (2023): [Assessing the benefits of a pan-European hydrogen transmission network](#)

⁴¹⁴ Guidehouse & Gas for Climate (2023): [Assessing the benefits of a pan-European hydrogen transmission network](#)

D) Underground hydrogen storage – Porous media storages

TECHNOLOGY DESCRIPTION	
Depleted reservoirs and aquifers are both composed of porous sedimentary rocks sealed by impermeable layers. They can be used for gas storage after hydrocarbons (for depleted fields), or water (for aquifers) have been extracted. These reservoirs can store billions of cubic meters of gas, depending on size and pressure limits, typically up to a few hundred bars. While their injection and withdrawal rates are limited by rock permeability, they are best suited for balancing seasonal gas fluctuations due to their large capacity⁴¹⁵.	
TECHNOLOGICAL READINESS	
	The technology readiness level is 3 for aquifers and 4 for depleted reservoirs. Some gas storage operators have proven the ability to store methane-hydrogen blends in depleted reservoirs, but the storage of pure hydrogen is still at the early prototype phase. Aquifers represent about 13% of existing capacity in Europe. Town gas (50-60% hydrogen content) was stored in some saline aquifers in Czech Republic, Germany and France in the 1970s. However, pure hydrogen storage in aquifers has not yet been tested⁴¹⁶.

BENEFITS

A) Depleted reservoirs

- More abundant availability of suitable formations in BEMIP region (compared to salt caverns)
- Geologically more suitable for hydrogen storage (less reactive minerals)

B) Aquifers: Relatively ubiquitous geographical formation distribution in BEMIP region, making it a good system-level storage option in regions where salt caverns are not present

BOTTLENECKS AND CHALLENGES

A) Depleted reservoirs

- Wettability – hydrogen has a preferential adhesion to the porous media making up the storage site, increasing the unrecoverable share of injected gas⁴¹⁷
- Viscous fingering – hydrogen has more mobility than the residual natural gas still in the reservoir (as there always is an unrecoverable share), displacing it unevenly, leading to additional losses⁴¹⁸
- Hydrogen can chemically interact with the residual hydrocarbons in these fields, leading to purity issues
- Limited operational experience with the technology

⁴¹⁵ IEA (2024): [ETP Clean Energy Technology Guide](#); Artelys & Frontier Economics (2024): [Why European underground hydrogen storage needs should be fulfilled](#)

⁴¹⁶ IEA (2024): [ETP Clean Energy Technology Guide](#)

⁴¹⁷ Homoud et al. (2024): [Enhancing Hydrogen Recovery from Saline Aquifers: Quantifying Wettability and Hysteresis Influence and Minimizing Losses with a Cushion Gas](#)

⁴¹⁸ Dehury et al. (2024): [Dynamics of hydrogen storage in subsurface saline aquifers: A computational and experimental pore-scale displacement study](#)

- Supply, demand and network infrastructure development uncertainty increase business case risks
- Storage service tariffs can be above willingness-to-pay of customers in ramp-up phase, hindering overall market development

B) Aquifers

- Undesirable biochemical reactions (related to hydrogen's diffusivity with residual fluids present in aquifers) can lead to loss of purity of stored hydrogen
- Porous reservoirs lead to a volume loss due to capillary trapping⁴¹⁹ (greater than in the case of natural gas, as hydrogen molecules are smaller, and thus harder to contain)
- Hydrogen's low density can lead to gravity segregation, rendering fractions of the injected gas unrecoverable during the withdrawal phase⁴²⁰
- Limited practical experience with the technology
- Supply, demand and network infrastructure development uncertainty increase business case risks
- Storage service tariffs can be above willingness-to-pay of customers in ramp-up phase, hindering overall market development

SPECIFIC ASPECTS REGARDING REPURPOSING

In depleted gas fields, still high amount of natural gas is present. Therefore, hydrogen stored in these porous media storages will contain high shares of natural gas that needs to be removed. The share of natural gas is only considered to slowly decrease over time (some years) after repurposing.

The major challenges driving down the quality of hydrogen which can be guaranteed from porous media-type storages are microbiological activity, residues from natural gas in storage, and space for purification infrastructure:

Key challenges:

- Additional purification needs compared to salt caverns due to significant amounts of methane in gas streams
 - After repurposing, most likely not be possible to completely remove natural gas present from former use (esp. for depleted gas fields)
 - Natural gas and its components (e.g. sulphur, sulphur compounds and short chain hydrocarbons) need to be removed before injection into the gas system
- Additional challenges due to new purification needs (esp. for porous media storage):
 - Challenge identified for separating methane residues (and short-chained hydrocarbons) in the gas stream with major hydrogen losses, one option investigated is blending different gas streams adding significant complexity to above ground facilities at storage sites
 - When present in high shares, separation of natural gas from hydrogen results in high hydrogen content in tail-gas stream → economic challenges due to high gas flows
 - (re-)use of tail gas requires additional space for direct local use; disposal of tail gas subject to permitting and regulatory restrictions
 - even a rather low grid quality level of 98% hydrogen is already considered as challenge for porous media storage operators

TECHNICAL PARAMETERS

Electricity need for compression	~4 kWh/kgH ₂
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⁴¹⁹ Cunqi et al. (2023): [Mechanism Comparisons of Underground Hydrogen Storage in Heterogeneous Aquifers](#)

⁴²⁰ Buscheck et al. (2024): [Underground storage of hydrogen and hydrogen/methane mixtures in porous reservoirs: Influence of reservoir factors and engineering choices on deliverability and storage operations](#)

Roundtrip efficiency	~87% (including electricity for compression) ⁴²¹
Discharge time	Typically, one to a few months ⁴²²
Storage geometrical volume	0.3-2 billion m ³ for aquifers; several billions of m ³ for depleted fields ⁴²³
Nominal pressure	15 – 300 bar for depleted reservoirs ⁴²⁴
Cushion gas requirement (% of overall capacity)	Typically, ~50-60% ⁴²⁵

ECONOMIC PARAMETERS	
CAPEX ⁴²⁶	
Installation costs	~ 20 – 60 €/kgH ₂ stored
Repurposing costs	~ 15 – 35 €/kgH ₂ stored
OPEX ⁴²⁷	
Fixed operating costs	~4% CAPEX

⁴²¹ Hystories (2022): [Assumptions and input parameters for modelling of the European energy system](#); Danish Energy Agency (2024): [Technology Data for Energy Storage](#)

⁴²² Guidehouse (2024): [The role of underground hydrogen storage in Europe](#); Artelys & Frontier Economics (2024): [Why European underground hydrogen storage needs should be fulfilled](#); Hystories (2022): [Assumptions and input parameters for modelling of the European energy system](#)

⁴²³ Danish Energy Agency (2024): [Technology Data for Energy Storage](#)

⁴²⁴ Artelys & Frontier Economics (2024): [Why European underground hydrogen storage needs should be fulfilled](#);

⁴²⁵ IEA (2024): [ETP Clean Energy Technology Guide](#); Artelys & Frontier Economics (2024): [Why European underground hydrogen storage needs should be fulfilled](#); Danish Energy Agency (2024): [Technology Data for Energy Storage](#)

⁴²⁶ Guidehouse & Gas for Climate (2023): [Assessing the benefits of a pan-European hydrogen transmission network](#); Hystories (2022): [Assumptions and input parameters for modelling of the European energy system](#)

⁴²⁷ Guidehouse & Gas for Climate (2023): [Assessing the benefits of a pan-European hydrogen transmission network](#)

E) Above ground hydrogen storage – Pressurised tanks

TECHNOLOGY DESCRIPTION

Pressurized storage tanks are the most established technology for hydrogen storage, typically used for small to medium-scale industrial applications and refuelling stations. Tanks are categorized into five types, from all-metal designs (Type I) to advanced polymer-lined (Type III), fully composite tanks (Type IV and V), with Types III and IV preferred for high-pressure applications due to their lightweight and high gravimetric capacity. Tanks store compressed hydrogen gas at pressures between 50 and 1000 bar. While steel tanks dominate industrial and refuelling station use and showcase significantly lower costs than other types, advanced composite tanks have significantly improved storage efficiency in automotive and mobile hydrogen transport⁴²⁸.

TECHNOLOGICAL READINESS



Pressurized storage tanks are already a well-established technology. As regard expectations for costs decrease, type I tanks, limited by their reliance on steel, show minimal potential for future performance gains. Type II and III tanks have moderate improvement potential with advancements in composite materials. Type IV tanks, however, have the greatest opportunity for improvement, driven by goals set by the U.S. Department of Energy (DoE) to enhance storage capacity and support the commercialization of fuel cell vehicles⁴²⁹.

BENEFITS

- Independent of geological conditions/location, providing a solution to regions/stakeholders where underground hydrogen storage (UHS) is not a possibility
- Allows (limited) storage capabilities co-located with consumption, enabling on-site balancing and production
- Guarantees the stability and purity of stored hydrogen

BOTTLENECKS AND CHALLENGES

- High material/investment costs due to the special technical needs⁴³⁰, pressurisation costs and limited storage capacity⁴³¹ resulting in higher cost of storage, therefore, lack of competitiveness compared to underground storage solutions, except in cases where strictly needed such as for transshipment and storage in refuelling stations
- Space requirements (in adherence especially with safety regulations) – firewalls, separation distances, etc.⁴³²
- Advanced safety measures required due to an elevated risk of leakage and explosion
- Storage losses due to leakages
- Limited scalability (compared to UHS)
- Lack of (uniform) standards, unclear permitting procedures and requirements

⁴²⁸ Danish Energy Agency (2024): [Technology Data for Energy Storage](#)

⁴²⁹ Danish Energy Agency (2024): [Technology Data for Energy Storage](#)

⁴³⁰ Meda et al. (2023): [Challenges associated with hydrogen storage systems due to the hydrogen embrittlement of high strength steels](#)

⁴³¹ Cheng et al. (2024): [Review of common hydrogen storage tanks and current manufacturing methods for aluminium alloy tank liners](#)

⁴³² OSHA (n.d.): [Occupational Safety and Health Standards - Hazardous Materials - Hydrogen](#)

TECHNICAL PARAMETERS ⁴³³	
Nominal pressure	50-1,000 bar
Storage capacity	Typically, a hundred kilograms to a few tons H ₂
Electricity need for compression	~4 kWh/kg H ₂
Roundtrip efficiency	~88% (including electricity for compression)
Discharge time	Typically, a few hours to a few days
Footprint	10-100 m ²

ECONOMIC PARAMETERS ⁴³⁴	
Investment costs	~500-1,000 €/kg H ₂
Fixed Operating Cost	~2% CAPEX

⁴³³ Danish Energy Agency (2024): [Technology data for energy storage](#)

⁴³⁴ Artelys & Frontier Economics (2024): [Why European underground hydrogen storage needs should be fulfilled](#)

F) Hydrogen maritime imports in the form of ammonia

TECHNOLOGY DESCRIPTION

To meet expected hydrogen demand, the EU MS plan to import hydrogen from regions with high renewable energy potentials, like the MENA region or South America for instance.

Due to the low volumetric energy density of hydrogen and the high costs associated with pure gaseous hydrogen tankers, the most cost-effective methods for future hydrogen transport involve using liquid hydrogen carriers. These notably include liquid hydrogen (LH2) and ammonia. Current projects under development in Europe mostly plan to import hydrogen in the form of ammonia and convert it back to hydrogen.

Although ammonia import infrastructure is already well developed in Europe (around 2.4 Mt ammonia imported in 2023⁴³⁵), large-scale ammonia cracking is not yet commercially mature. The existing import capacity can accommodate around 4 Mt ammonia per year, which would amount to some 0.7 Mt H2 per year if cracked back to hydrogen (if process energy is supplied externally), as hydrogen constitutes approximately 18% the weight of ammonia.

TECHNOLOGICAL READINESS



~TRL 4

Large-scale ammonia cracking is not yet technically mature, research is ongoing to reduce the energy consumption and cost of ammonia cracking.⁴³⁶

Ammonia can be decomposed into nitrogen and hydrogen, with small-scale, high-temperature (600-900 °C) cracking using inexpensive materials like iron already commercially available. However, this process consumes about 30% of ammonia's energy content and rarely includes hydrogen purification. Lower temperature (~450 °C) cracking reduces energy consumption but relies on costly precious-metal catalysts like ruthenium. Low-temperature cracking without or with limited precious metals is still underdeveloped. Additionally, cost-effective and efficient technologies for hydrogen purification post-cracking are needed to meet strict purity standards for applications like fuel cells. Innovations are required to improve efficiency, reduce costs, enhance purity, and enable scaling of ammonia cracking technologies.

According to JRC (2022)⁴³⁷ and based on TYNDP 2024 projects with publicly available cost figures, the cost of ammonia cracking infrastructure can be estimated to roughly 15-30 mn. €/GWh H2/day.

Regarding the total cost of transport, a benchmark by Gas for Climate (2022) reports cost estimates of approximately 2 €/kg H2/10,000 km in the short to medium-term⁴³⁸

BENEFITS

- High experience in ocean ammonia transportation and terminal storage

⁴³⁵ World Bank (2023): [European Union ammonia imports in 2023](#)

⁴³⁶ IEA, ETP clean energy technology guide

⁴³⁷ JRC (2022): [Assessment of Hydrogen Delivery Options](#)

⁴³⁸ Gas for climate (2022): [Facilitating hydrogen imports from non-EU countries](#)

BOTTLENECKS AND CHALLENGES

- Due to the lower energy density of hydrogen compared to natural gas, the existing terminals need modifications/expansion to be able to handle larger volumes of gas to produce the same level of energy output
- Hydrogen has a lower liquefaction temperature, meaning the existing terminals require additional cooling capabilities and boil-off gas management systems
- Pipelines, valves and storage tanks of existing terminals need to be retrofitted to withstand hydrogen and ammonia's corrosiveness⁴³⁹
- Ammonia toxicity requires additional safety measures⁴⁴⁰
- The confined spaces of regasification terminals pose increased safety risks in light of hydrogen's flammability, requiring stringent regulations
- Need for further technical development of ammonia cracking, for example to address hydrogen poisoning, water resistance, and activity issues of catalysts used in electrically heated crackers⁴⁴¹
- Negative perception of ammonia storage⁴⁴²
- The regulatory environment needs to be adapted to provide adequate guidance on the requirements for the design and operation of regasification terminals for hydrogen

⁴³⁹ Negro et al. (2023): [The Potential Role of Ammonia for Hydrogen Storage and Transport: A Critical Review of Challenges and Opportunities](#)

⁴⁴⁰ Negro et al. (2023): [The Potential Role of Ammonia for Hydrogen Storage and Transport: A Critical Review of Challenges and Opportunities](#)

⁴⁴¹ Trangwachirachai et al. (2024): [Recent progress on ammonia cracking technologies for scalable hydrogen production](#)

⁴⁴² Park et al. (2023): [Consumers' acceptance of the explosion, toxicity, and odour potential of ammonia: A survey on consumers' choice of an ammonia-based hydrogen refuelling station](#)

9.5. Bottlenecks for the integration of biomethane into the current natural gas infrastructures

The injection of increasing volumes of biomethane into the existing natural gas grid results in challenges and bottlenecks that need to be tackled by the different stakeholder groups, e.g. biomethane producers, grid operators, end-users and politics.

The following Chapter summarises and describes key challenges and bottlenecks that arise from a technical, safety or economic perspective. Required countermeasures are discussed in case of increased biomethane injection volumes in the European gas grid. In addition, a case study using the example of Denmark is included into the analysis, as Denmark covers a significant share of domestic natural gas use with biomethane (see also section 2.3) and hence already today faces challenges that may not be present in other countries of the BEMIP region.

9.5.1. General challenges for the integration of biomethane into the natural gas grid

Key challenges for the integration of biomethane into the natural gas grid were collected based on the input of key stakeholders from the eight BEMIP MSs on the survey conducted in the context of this study. There are mainly related to (1) grid injection and connection, (2) gas quality (incl. e.g. oxygen limits) and (3) grid operation (e.g. reverse flow) and are described in the present section. The aim is to understand which general measures are required to facilitate the integration of biomethane into the gas system and – where possible – identify additional costs that may be incurred by network users.

(1) Injection plant locations and grid connection

To increase the volumes of biomethane injection into the grid, the location of new production facilities and biomethane injection points are essential. The issue of cost allocation among parties was also raised as important challenges by stakeholders.

In some countries, the **distance of production sites (incl. feedstock sources) to the natural gas grid injection points** are very high, resulting in high costs for the grid connection or logistic costs for collecting feedstocks or biogas from decentral production sites to central upgrading and injection facilities. This is especially the case for countries with no extensive gas network in place.

In general, biomethane is injected into the low-pressure distribution grid. However, for large plants, a direct connection to the high-pressure grid may be required (incl. the compression of the injected gas to up to 80 bar). Based on a survey of ACER in 2022 among European NRAs⁴⁴³, direct injection of biomethane into the transmission system already occurs in Denmark Germany and Sweden, while it is not yet the case for Estonia, Latvia, Lithuania, and Poland (with no information received from Finland). For these large-scale injection facilities, **optimal plant locations** are required in close vicinity to the transmission system, as the injection of high gas volumes should ideally take place into a pipeline with a high and consistent gas flow around the year, to minimize the impact of biomethane injection on gas quality due to e.g. seasonal patterns. Finding suitable locations and getting required permissions and land use rights was mentioned as a key challenge in this regard to achieve a working business case.

The easy transportability of biomass feedstocks like straw (even by ship) compared to manure or litter also led to the development of large-scale biomethane plants located in harbour areas with a direct connection into the transmission system. Examples for Denmark are described in the case study below.

While a so-called **right to inject**, i.e. the obligation for network operators to provide a connection point for biomethane producers upon request exist in most European Member States (incl. Denmark,

⁴⁴³ ACER (2022): [*OPINION No 08/2022 ON THE REVIEW OF GAS AND HYDROGEN NATIONAL NETWORK DEVELOPMENT PLANS TO ASSESS THEIR CONSISTENCY WITH THE EU TEN-YEAR NETWORK DEVELOPMENT PLAN – ANNEX III*](#)

Estonia, Germany, Latvia and Lithuania), no such obligation was reported for e.g. Poland and Sweden (as of 2022).⁴⁴⁴ Further alignment was introduced by the Hydrogen and Decarbonised Gas Package which foresees a right to injection in all Member states after national transposition.⁴⁴⁵

From an economic perspective, the issue of **cost sharing between biogas/biomethane producers and grid operators** is considered as important issue. Until 2024, costs for grid connection, injection and gas quality assurance and metering are regulated on a national level among European Member States, as no specific European requirements exist. The variations between European Member States were summarized in 2024 in the context of the GreenMeUp project.⁴⁴⁶

According to this, **grid connection costs** (i.e., costs for injection station and connection gas pipelines) varies among EU countries. Based on survey feedback, the grid connection costs are shared between biomethane producer and grid operator in ten EU countries (incl. Estonia, Germany and Latvia). In Germany, e.g., the plant operator must bear 25% of the construction cost and the gas grid operator 75%. The share of the biomethane plant operator, however, must not exceed 250,000 € for connecting pipes less than 1,000 m, while they bear the additional costs above that distance alone. In contrast to that, ten countries (incl. Lithuania, Poland and Sweden) do allocate all costs for grid connection on the biomethane producers. Hence, these costs were identified as important barrier preventing the integration of biomethane into the system and investment support for grid connection was mentioned as a key gap in some of those Member States. No information was provided for eight countries (incl. Denmark and Finland).

In the context of the present study, the issue of clarity on the **right to connect to gas network** was also mentioned by the Danish Energy Agency as a gap in existing policies. Current measures in Denmark implemented to maximise biomethane injection include that costs related to upgrading biogas to biomethane as well as the cost related to connecting the upgrading facility to the gas network are to be financed by the plant operator. At the same time, grid operators (DSOs) are responsible for grid reinforcement measures (e.g. grid expansion, compression and reverse flow capacities) – which is ultimately financed via the feed-in tariff. For TSO level, compression needs to be ensured by injecting party, being a considerable challenge for plant operators. Hence, harmonised rules on the required inlet pressure may be considered as an important step to prevent distribution grid operators from bearing additional costs for compression needs. Today, most biomethane injection plants operators inject in a low-pressure regime.⁴⁴⁷ With harmonized rules and cost sharing between plant and grid operators, operators of upgrading and injection plants may already have an incentive to use upgrading technologies that provide an output pressure level between 4 and 15 bar, reducing the need for additional compression before injection.

In addition to that, there are also different approaches regarding **injection fees for biomethane**, e.g. charges related to installation and maintenance of metering and measurement systems, grid access charges or cost of measures for ensuring gas quality. Such charges exist in eleven out of the EU-27 countries (incl. Latvia, Lithuania and Sweden), while nine countries (incl. Germany, Estonia and Poland) do not have injection charges. No data was available for eight countries. One example described is Sweden, where 'the TSOs and DSOs charge injection fees. However, the height of the fee can be reduced if the biogas producer chooses to pay a larger connection fee. If the biomethane producer covers all the connection cost, the injection fee is zero. The TSO will also charge a pressure increase fee if the connection of biomethane production will increase the grid pressure.'⁴⁴⁸ In contrast to that, biomethane operators must pay a so-called transmission system entry-exit fee of 2.97 €/MWh charged by the TSO.

⁴⁴⁴ ACER (2022): *OPINION No 08/2022 ON THE REVIEW OF GAS AND HYDROGEN NATIONAL NETWORK DEVELOPMENT PLANS TO ASSESS THEIR CONSISTENCY WITH THE EU TEN-YEAR NETWORK DEVELOPMENT PLAN – ANNEX III*

⁴⁴⁵ GreenMeUp project (2024): *VARIATIONS IN NATIONAL REGULATIONS WITH RESPECT TO BIOMETHANE GRID CONNECTION*.

⁴⁴⁶ GreenMeUp project (2024): *VARIATIONS IN NATIONAL REGULATIONS WITH RESPECT TO BIOMETHANE GRID CONNECTION*.

⁴⁴⁷ FNB Gas (2024): *Current challenges and solutions from the perspective of the FNB*

⁴⁴⁸ GreenMeUp project (2024): *VARIATIONS IN NATIONAL REGULATIONS WITH RESPECT TO BIOMETHANE GRID CONNECTION*, p.6

(2a) Gas quality in general/standardisation of gas quality

The process of biogas upgrading to biomethane is essential as biogas contains significant shares of carbon dioxide and other components that need to be removed before injection into the gas grid. The upgraded biogas (=Biomethane), however, in general still has a different gas composition compared to average natural gas (which itself differs strongly depending on the source), as it, for example, has a considerable high share of methane, but also with e.g. oxygen, hydrogen or ammonia considered as potential critical contaminants with respective limits.

Differences in **gas quality standards** across BEMIP MSs present major barriers to cross-border biomethane transport. As these standards were formulated on a country level mainly according to the respective natural gas supply situation, the quality requirements for e.g. the methane content, Wobbe index and contaminants like sulphur or oxygen differ among European Member States. The importance of international harmonisation of gas quality was also stressed by the European Biogas Association, as *'differentiating between natural gas and biomethane and meticulously defining parameters such as oxygen, sulphur, and carbon dioxide will facilitate biomethane uptake and cross-border trade in the coming years, enabling the sector to deploy 35 bcm by 2030.'*⁴⁴⁹ But also on a national level, the integration of growing volumes of renewable gases like biomethane (but also hydrogen in terms of hydrogen blending) poses additional challenges on the system as these gases significantly impact the composition of the gas, resulting in new efforts related to billing based on the energy content of the gas. Gas flow simulations are used by different gas operators to project gas distribution in the grid and with that the energy amount delivered to customers for an adequate billing.

MARCOGAZ has published an overview of current gas quality standards for European countries that are required for biomethane to be injected into the natural gas networks.⁴⁵⁰ The document contains information of 14 European countries, including Denmark, Germany, Poland and Sweden. Beside calorific gas properties like gross calorific value, Wobbe index and relative density, also a wide set of possible trace components like water, sulphur, oxygen or carbon dioxide are listed (see Table 9-6).

Table 9-6: Quality required for biomethane to be injected into natural gas networks in different European countries (Source: MARCOGAZ)

Country	Denmark	Germany	Poland	Sweden
Gross Calorific Value (GCV) (kWh/m ³)	-	8.4-13.1	> 10.55	-
Wobbe Index (WI) (kWh/m ³)	14.1 - 15.5	11.0 – 13.0 (L-gas) 13.6 – 15.7 (H-gas)	12.5 – 15.8	-
Relative density	0.555 - 0.7	0.55 - 0.75	0.555 - 0.7	0.555 - 0.70
Reference conditions	25°C / 0°C, 101.325 kPa	25°C / 0°C, 101.325 kPa	25°C / 0°C, 101.325 kPa	15°C / 15°C, 103.25 kPa
Gross calorific value (GCV) (MJ/m ³ , 15/15)	-	28.7 – 44.7	-	-
Wobbe index (WI) (MJ/m ³ , 15/15)	48.2 – 52.9	37.6 – 44.4 (L-gas) 46.4 – 53.6 (H-gas)	-	-
Exemplary key contaminants:				
Water (mg/m ³)	-	<50 (MOP >10 bar) <200 (MOP <10 bar)	-	<32
Total Sulphur (mg S/m ³)	<30	<6 <8 (after odorization)	<40	≤20 (without odorant) ≤30 (with odorant)
CO ₂ (% Mol)	<2.5 (TSO level) <3 (DSO level)	< 10 L-gas* < 5 H-gas*	<3	≤4
O ₂ (% Mol)	<0.5	<0.001 (MOP >16 bar) <3 (MOP <16 bar)	<0.5	≤1
H ₂ (% Mol)	-	<2**	<2	≤2

⁴⁴⁹ European Biogas Association (2024): *Biomethane standards: facilitating renewable gas uptake*

⁴⁵⁰ MARCOGAZ (2024): *Quality of biomethane required in European countries for injecting into natural gas grid - Update.*

Country	Denmark	Germany	Poland	Sweden
Reference	-	DVGW G260 *DVGW G262 ** DIN 51624	Regulation of the Minister (national law) ²	EN 16726 EN 16723-1 EN 16723-2
Update at	March 2018	March 2018	January 2024	January 2019

1: properties calculated at reference condition 15°C/ 15 °C, 103.25 kPa, using ISO 13443:2006 Annex A conversion factors. Rounded to 1 decimal.

2: Polish Regulation of the Minister:

1. Regulation of the Minister of Economy of July 2, 2010 on detailed conditions for the operation of the gas system – consolidated text issue (published: Journal of Laws of 2018, item 1158); Quality requirements are set-up in Paragraph 38, page 10.
2. Regulation of the Minister of Energy of September 21, 2018 amending the regulation on detailed conditions for the operation of the gas system (published: Journal of Laws of 2018 item 1814); This document does not change requirements regarding gas quality.
3. Regulation of the Minister of Climate and Environment of August 6, 2022 amending the regulation on detailed conditions for the operation of the gas system (published: Journal of Laws of 2022 item 1899); Updated quality requirements are given in Paragraph 2, Subsection 18), page 4.

International activities on standardisation gas quality with importance to the biogases sectors is done by CEN. Key working groups dealing are SECT/SF GAS I/JWG GQS and CEN/TC 408 (see Table 9-7 for details).

Table 9-7: Relevant standardisation committees and standards regarding gas quality (Source: GreenMeUp (2024) ⁴⁵¹)

CEN Working Group/Technical Committee	Name of Relevant Standard	Description
SECT/SF GAS I/JWG GQS	Gas quality standard – EN 16726	This standard specifies gas quality characteristics, parameters, and their limits, for gases classified as group H that are to be transmitted, injected into and from storages, distributed, and utilized.
CEN/TC 408	Natural gas and biomethane for use in transport and biomethane for injection in the natural gas grid EN 16723-1 and EN 16723-2	Standardization of specifications for biomethane as fuel for engines and of biomethane for injection in the natural gas grid, including any necessary related methods of analysis and testing.

EN 16726 by CEN represents the key standard for harmonizing gas grid operation and interoperability of (natural) gas systems across different member states. Within an ongoing revision (to be published in 2025), key gas quality aspects like oxygen limits or Wobbe Index are to be included (in addition to updates in other contaminant levels) – also driven by current developments of an increasing role of biomethane in the natural gas supply. Still, due to the specific characteristics of biomethane, additional standards exist, namely EN 16723-1⁴⁵² and EN 16723-2⁴⁵³. The documents describe further parameters for biomethane injection and integration into the grid as well as its safe application in transport. As indicated by stakeholders, up to today, existing gas quality standards according to the use and transport of gas do not yet match well on the technical level required. In the light of the key challenge of higher oxygen levels and their impact of gas properties like Wobbe index, the calorific values and relative density of the gas, currently further work is hence ongoing in CEN/TC 408 with regard further revision of both standards to enhance integration of high volumes of biomethane into the grid.⁴⁵⁴

⁴⁵¹ GreenMeUp (2024): [Development of Standardisation Processes for Biomethane - Deliverable n.1.4](#)

⁴⁵² CEN - EN 16723-1 (2016): *Natural gas and biomethane for use in transport and biomethane for injection in the natural gas network - Part 1: Specifications for biomethane for injection in the natural gas network*

⁴⁵³ CEN - EN 16723-2 (2017): *Natural gas and biomethane for use in transport and biomethane for injection in the natural gas network - Part 2: Automotive fuels specification*

⁴⁵⁴ European Biogas Association (2024): [Biomethane standards: facilitating renewable gas uptake - News](#)

The **responsibility of gas quality measurement and gas metering** (for volume and energy content) is another aspect, differing among Member States, hampering smooth internal market integration.⁴⁵⁵ Both aspects provide key information to ensure that the biomethane injected meets the required quality standards and legal specifications for billing purposes. While gas quality measurement is the responsibility of biomethane producer in most countries (exemption e.g. in Poland, with no biomethane injection so far), the grid operator is mainly responsible for gas metering (exemptions, e.g. Latvia and Lithuania). Ensuring the respective gas quality needed for injection was also mentioned by stakeholders being an obstacle for a more ambitious ramp-up of biomethane, as the responsibility for biomethane upgrading mostly lies with the biomethane producers.⁴⁵⁶ In Denmark, before injection, official metering & regulation stations continuously measure the quality of biomethane, and the injection is interrupted, in case the gas is not meeting specification requirements. As a countermeasure, most biomethane plants also have an internal measurement devices to be able to act in case of quality deviations and to prevent potential cut-offs due to official measurements at metering & regulation stations.

(2b) Not-harmonised oxygen limits across BEMIP MSs

For biomethane to reach a sufficient gas quality, sulphur needs to be removed to prevent e.g. catalyst poisoning in several applications. The sulphur removal is done using oxygen which leads to an average oxygen content of about 0.5% for European biomethane plants⁴⁵⁷ compared to natural gas, which is considered oxygen-free. The content of oxygen, however, impacts gas properties during use or combustion. Also, oxidation reaction can occur and even microbiological growth resulting in formation of unwanted contaminants can be enhanced in underground gas storages.⁴⁵⁸ Further possible effects of high oxygen levels are corrosion in underground or above-ground facilities or formation of 'black powder' in high-pressure pipelines. Hence, specific strategies for oxygen removal are required.

The maximum oxygen content allowed is dictated by the most sensitive grid elements. According to a study by MARCOGAZ, *'permissible oxygen content is dependent on the specific facility and must therefore be assessed case by case. An oxygen limit of 100 ppm or more is acceptable for some UGS facilities. More sensitive storage facilities or oxygen sensitive industries require a permissible oxygen concentration of 10 ppm at most.'*⁴⁵⁹

Figure 9-14 shows that **oxygen limits** in the gas grid widely differ among European countries. While Denmark, for example, limits the oxygen content to 1,000 ppm (=0.1%) at entry, storage and transit points, a higher limit of 5,000 ppm (=0.5%) at metering points for biomethane to facilitate biomethane injection.⁴⁶⁰ However, due to increasing share of biomethane in the grid, the dilution effect of biomethane in natural gas diminishes and, as a consequence, Denmark already faces the challenge in complying with CEN gas quality standards due to the high volumes of biomethane injection, particularly the low oxygen content required at interconnection points to underground storage sites (0.001%)⁴⁶¹. Consequently, the cross-border trade (e.g. the flow of biomethane from Denmark towards Central Europe) is limited and additional operational costs need to be recovered from the network users.

⁴⁵⁵ GreenMeUp project (2024): [VARIATIONS IN NATIONAL REGULATIONS WITH RESPECT TO BIOMETHANE GRID CONNECTION](#).

⁴⁵⁶ ACER (2022): [OPINION No 08/2022 ON THE REVIEW OF GAS AND HYDROGEN NATIONAL NETWORK DEVELOPMENT PLANS TO ASSESS THEIR CONSISTENCY WITH THE EU TEN-YEAR NETWORK DEVELOPMENT PLAN – ANNEX III](#)

⁴⁵⁷ Danish Gas Technology Centre (2022): [Cost-efficient handling of oxygen from bio-methane in the European gas grid](#)

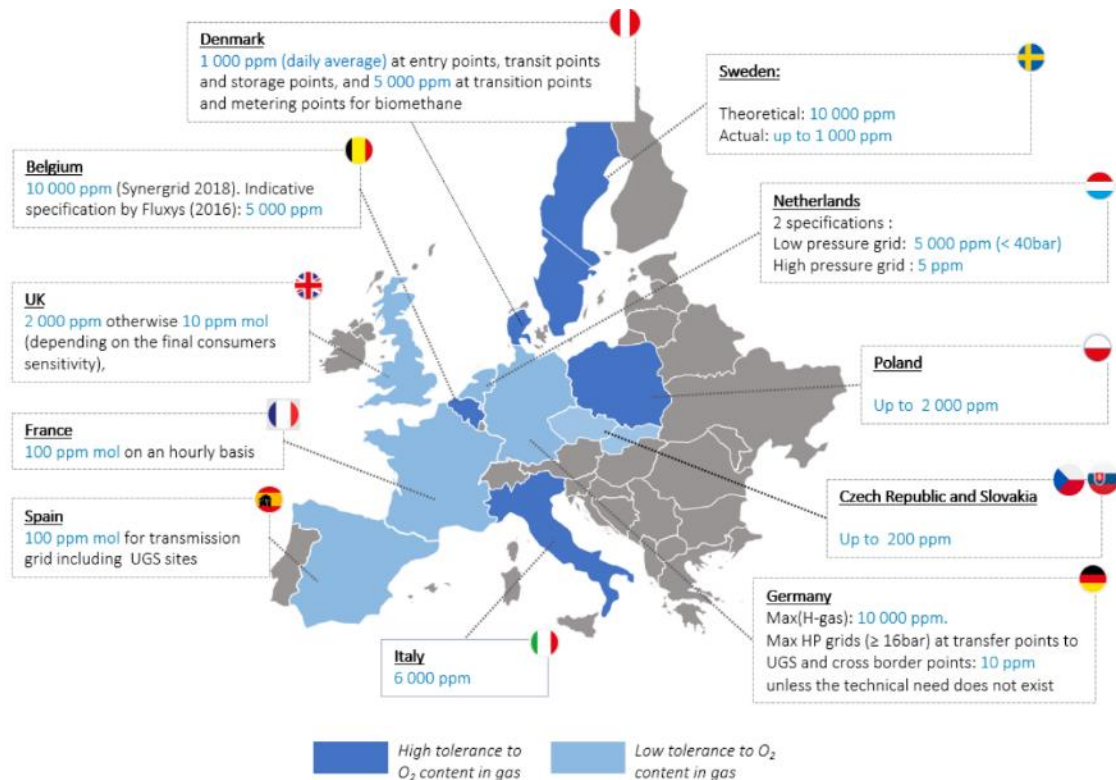
⁴⁵⁸ For Latvia, challenges regarding the oxygen level were mentioned in the survey in the context of the connection to Inčukalna Underground Gas Storage (UGS), as elevated oxygen levels can compromise the storage and safety standards.

⁴⁵⁹ MARCOGAZ (2022): [Biomethane Acceptance in Underground Gas Storage Facilities](#)

⁴⁶⁰ Denmark has increased the oxygen limit to 5,000 ppm (0.5%) in 2012/13. This level serves as a compromise between the costs of upgrading and purifying biogas to biomethane without imposing additional risks to the different infrastructure elements.

⁴⁶¹ According to EN 16726, the mole fraction of oxygen shall not exceed 10 ppm (0.001 mol %), expressed as a moving 24-hour average, at network entry points and interconnection points. In case, there are no sensible installations in the grid (e.g. underground storage systems), also higher limits of up to 10,000 ppm (1 mol%) may be applied.

Figure 9-14: Maximum admissible oxygen content in European gas networks (Source: MARCOGAZ⁴⁶²)



Reducing the oxygen content can either be done directly at the biomethane production or injection facility or at another location in the gas system (e.g. at UGS or at border crossing). The Danish Gas Technology Centre has analysed the cost-efficient management of oxygen from bio-methane in the European grid in a study in 2022, focussing on Denmark and Germany (beside France and Italy) as case studies.⁴⁶³ In the analysis, the authors identified the most cost-efficient solution for oxygen removal: either at each biomethane plant (by avoiding oxygen addition at all or by catalytic removal of oxygen) or by catalytic removal of oxygen close to sensitive grid elements (i.e. UGS facilities).⁴⁶⁴ One key result of the report is that the sweet spot from where central purification is more cost-efficient than decentral purification (at the plant) is reached at a biomethane share of >65 % in the gas grid for Denmark and >35 % for Germany. The difference is explained by the nature of the biomethane plants (size, upgrading technology) and gas storages in the respective country. The cheapest option, however, is avoiding oxygen in the biomethane production process (e.g. for sulphur removal). A biological sulphur cleaning technology based on scrubbing with aqueous sodium hydroxide solution and regeneration of the scrubbing agent by bacteria in a separate bioreactor could be an interesting option for biomethane plants (compared to the injection of oxygen direct into the fermenter)⁴⁶⁵. However, financial support is considered important, especially for small facilities. In general, the H₂S content of the biogas before cleaning also is a key factor determining most cost-efficient solution. Finally, the authors also propose to reduce overall costs are either to concentrate on large upgrading and injection plants using economy of size for gas purification. Where possible, less-sensible UGS facilities should be identified, reducing the need for deoxidation at each facility.

⁴⁶² MARCOGAZ (2022): [BIOMETHANE ACCEPTANCE IN UNDERGROUND GAS STORAGE FACILITIES](#)

⁴⁶³ Danish Gas Technology Centre (2022): [Cost-efficient handling of oxygen from bio-methane in the European gas grid](#)

⁴⁶⁴ Other options like removal at injection points to the transmission grid (i.e. reverse flow stations) or directly at cross-border points were not considered in the analysis.

⁴⁶⁵ Deutsches Biomasseforschungszentrum (2014): [Leipzig: Leitfaden Biogasaufbereitung und -einspeisung; 5. Auflage](#)

(3) Reverse flow measures (compression and deodorization)

There are different options, on how the injection of biomethane into the natural gas grid can occur. Today, several small and medium-sized biomethane plants are connected to low-pressure distribution pipelines (e.g. via 4 bar connection pipelines for Denmark). Within these regional grids, biomethane is supplied to residential and industrial end-users. Depending on the structure of the grid, even higher shares of biomethane compared to the overall national system may be possible and the consequences on the gas quality managed.

In contrast to that, biomethane production technologies with higher output pressure or large-scale plants requiring a higher pipeline gas throughput for dilution effects will rather be connected to high-pressure DSO level (e.g. 20-40 bar for Denmark) or TSO level (up to 80 bar for Denmark).⁴⁶⁶

With growing injection volumes, **reverse flow** from low-pressure distribution to high pressure distribution and even transmission level gains importance as soon as regional biomethane supply exceeds regional demand. In this case, **additional compressor stations** and other measures need to be implemented. In general, grid operators bear the costs for these grid measures. Uncertainties in the ramp-up of biomethane injection makes it difficult to have optimal timing and locations for reversed flow facilities. Hence a strong cooperation between grid operators (TSOs and DSOs) as well as biomethane producers is required – also with regard to cost division.

While Denmark, Germany and Sweden are already exploring or deploying reverse flow options from distribution to transmission systems, many countries in the BEMIP region do not yet have the necessary compressor stations and other equipment to facilitate reverse flows. This restricts biomethane transport to a regional level only (via the distribution grid) and, hence, also restricts (physical) cross-border trading. In general, however, also several stakeholders do not consider the implementation of reverse flow measures as a general technical but a cost challenge.

Reverse flow from distribution to transmission level may not only require additional compressor stations but also the **operation of deodorization plants**, in case gas odorization is only present at distribution level, as e.g. in Denmark, Germany or Poland.⁴⁶⁷ Odorisation agents are added to the gas to introduce a characteristic smell for safety reasons in case of leakages. Tetrahydro thiophene is the most common odorant used in European countries. In case of different odorization practices at the transmission level between countries, this could also lead to barriers to cross-border flows or the need for deodorisation at interconnection points in the future. For example, while in Sweden odorization is required at the transmission level, this is not the case of Denmark or Germany.⁴⁶⁸

Stakeholders mention that additional research on management of odorization and de-odorization may potentially lead to more efficient solutions enhancing reverse and cross-border biomethane flows. This may, e.g. be the case for the use of sulphur-free odorants.

Further topics that were mentioned by stakeholders:

Further aspects mentioned by stakeholders as important barriers and challenges include the following aspects. As these are mostly related to regulatory aspects, they will not be discussed in more detail:

- Different national systems of guarantees of origin (GO) for biomethane producers as well as different national registers and authorities in each country. Limited acceptance of certificates between countries.

⁴⁶⁶ Example Denmark: The biomethane must have the same pressure as the target network at the connection point. The gas pressure is specified in the connection agreement which the network owner and the upgrade facility must conclude prior to any injection of the biomethane into the Danish gas transmission system.

⁴⁶⁷ Germany: DVGW G 280, EN ISO 13734; Denmark: DVGW G 280, GR-A (Danish Gas Code; Poland: National Regulation Dz.U. 2018, No 1158, PN-C-04751:2011, PN-C-04753:2011. MARCOGAZ (2021): [NATURAL GAS ODORISATION PRACTICES IN EUROPE](#)

⁴⁶⁸ Germany: DVGW G 280, EN ISO 13734; Denmark: DVGW G 280, GR-A (Danish Gas Code; Poland: National Regulation Dz.U. 2018, No 1158, PN-C-04751:2011, PN-C-04753:2011. MARCOGAZ (2021): [NATURAL GAS ODORISATION PRACTICES IN EUROPE](#)

- Interfaces of voluntary schemes for Proof of Sustainability (PoS) and integration in the Union database.
- No digitalisation of biomethane GO and PoS, which is required to facilitate issuance and trading on an EU-wide basis.
- Difficulties to meet the criteria in Article 4(1c) of the TEN-E regulation for a **PCI under the 'smart gas grid' infrastructure category** due to the mainly national character of biomethane projects. Reverse flow measures, for example, are being developed in cooperation between DSOs and TSOs from the same country. Under Article 4 of the TEN-E Regulation, however, for a project to become a PCI it has to, among others, involve at least two Member States either by crossing the borders or by having a significant cross-border impact even if located on the territory of one Member State.^{469 470}
- The regulatory environment in Member States as well as the lack of ?? political support often is mentioned as a key challenge preventing a steeper ramp-up of biomethane production and injection into the grid in Europe. This refers to support measures and policies as well as the harmonisation between countries.

9.5.2. Case study – Denmark

The Danish gas market is highly interesting and contains many relevant measures for the integration of biomethane which could be adapted for other BEMIP MSs, as it already today comprises a high share of biomethane (reaching around 40% at the end of 2023), with the intention to further increase production. Hence, actors in Denmark already face some issues and challenges arising from the integration of biomethane in the existing natural gas system that other countries may only face at a later stage of the decarbonisation efforts. This analysis describes the Danish gas system and infrastructure-related measures adopted or under implementation for the integration of biomethane. A further summary of the current situation of the Danish biomethane market can also be found in Annex A.

The Danish TSO Energinet summarises key challenges in the long-term development plan for 2024 (LUP24) reports which serves as a key basis for the present analysis.⁴⁷¹ The reports name several drivers that creates a need for additional investments into the gas system to allow for a full utilization and integration biogas and biomethane. These include:

- **Gas supply and demand projects in Denmark:** Increasing production of (domestic) biomethane combined with a declining demand for gas, leading to a comparatively fast substitution of natural gas in the gas system;
- **Biogas pockets at DSO level:** Local surplus biomethane production⁴⁷² (so-called 'biogas pockets' in several locations), requiring the (temporal) change in gas flow direction at interconnection points between TSO and DSO grid (i.e. reverse flows). This demands the installation of **reverse flow facilities** (incl. compressor and deodorization) at existing metering and regulation stations (M/R stations);
- **Large production sites connected to transmission system:** relevant especially for large straw-based biogas plants.
- **Additional grid measures:** Grid expansion at DSO level needs to minimize the number of reverse flow stations or to make up for new (geographical) production and demand patterns;
- **M/R stations and decommissioning needs:** Continuous analysis of demand for M/R stations and overall gas grid connections to limit continuous maintenance and reinvestment costs;

⁴⁶⁹ EC (2020): [COM\(2020\) 824 final](#) and EC (n.d.): [QANDA_23_6048_EN.pdf](#)

⁴⁷⁰ In the last PCI selection process of 2022, two candidates for the BEMIP region were submitted under the 'smart gas grid' category:

-Implementation of smart solutions for injection of renewable gases in Latvia, promoted by Conexus Baltic Grid;

-Reverse flow biomethane Denmark vol.2, promoted by Energinet.

However, none of these projects was selected for Commission Delegated Regulation (EU) 2024/1041 of 28 November 2023.

⁴⁷¹ Energinet (2024): [Energinet's long-term development plan 2024](#)

⁴⁷² Includes biomethane from biogas upgrading as well as biomethane produced by methanation of CO₂ from biogas upgrading with (renewable) hydrogen.

- **Oxygen limit:** Challenge of increasing O₂ concentrations due to increased biomethane injection and impact on cross-border gas trade due to stricter national oxygen concentration limits in bordering countries;

The following Chapter provides a description of these drivers and their impact on infrastructure needs that are related to the continuous ramp-up in biomethane production and injection in gas grids in Denmark. Where possible, costs associated with the implementation of grid-related enabling measures are presented. The aim of this work is to provide some complementary insights to the methane-related modelling of the grid in Chapter 5.

i) Gas supply and demand projections in Denmark

Based on analysis by Energinet and the Danish Energy Agency from 2022, gas consumption is expected to decline rapidly in the next years from a peak of around 25 TWh in the 2020s to around 10-12.5 TWh in the long-term. This development is mainly driven by political ambitions of phasing out gas for heating, e.g. in household gas boilers. The energy crisis following the Russian invasion of Ukraine, led to a significantly reduction in national gas demand projections compared to earlier forecasts, with the actual demand reaching around 20.9 TWh in 2023 and with the revised projected long-term demand totalling around 10 TWh.⁴⁷³ As can be seen in Figure 9-15, there has been a significant decrease in the number of customers connected to Evida's distribution network in the last years.

Figure 9-15 Number of private gas customers connected to the Evida network⁴⁷⁴



Domestic gas production in terms of biomethane will, on the other hand, continuously grow, and is expected to match gas demand by 2029, already, according to the recent Danish Climate Status and Projection (KF) for 2024.⁴⁷⁵ These data are also basis for own analysis by Danish transmission system operator Energinet (see Figure 9-16), however – large uncertainties regarding the actual development needs to be mentioned as additional biomethane production will to a large extent depend on support policy. Beside biomethane, also on-site biomethanol production could be a viable path for several producers in the future. In addition, the role of e-methane produced from biogenic CO₂ and renewable hydrogen is not clear, yet.

⁴⁷³ Energinet (2023): [Report on security of gas supply 2023](#)

⁴⁷⁴ Evida (2024): [Conversion mapping II](#)

⁴⁷⁵ Danish Ministry of Climate, Energy and Utilities (2024): [Climate Status and Projections 2024](#)

Figure 9-16: Project biomethane production and gas demand in Denmark (Source: Energinet⁴⁷⁶)

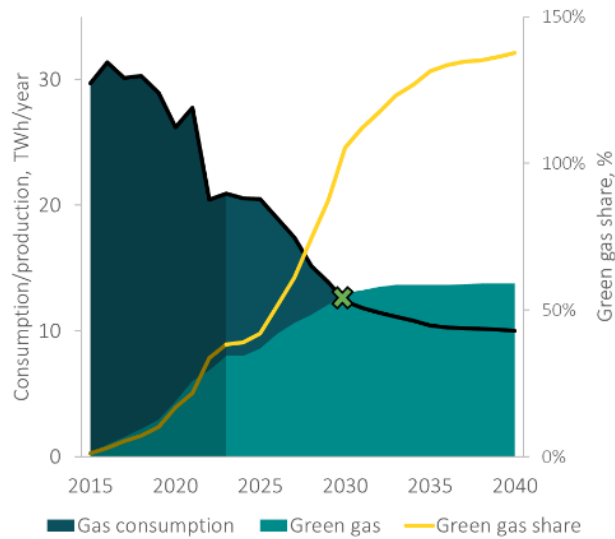
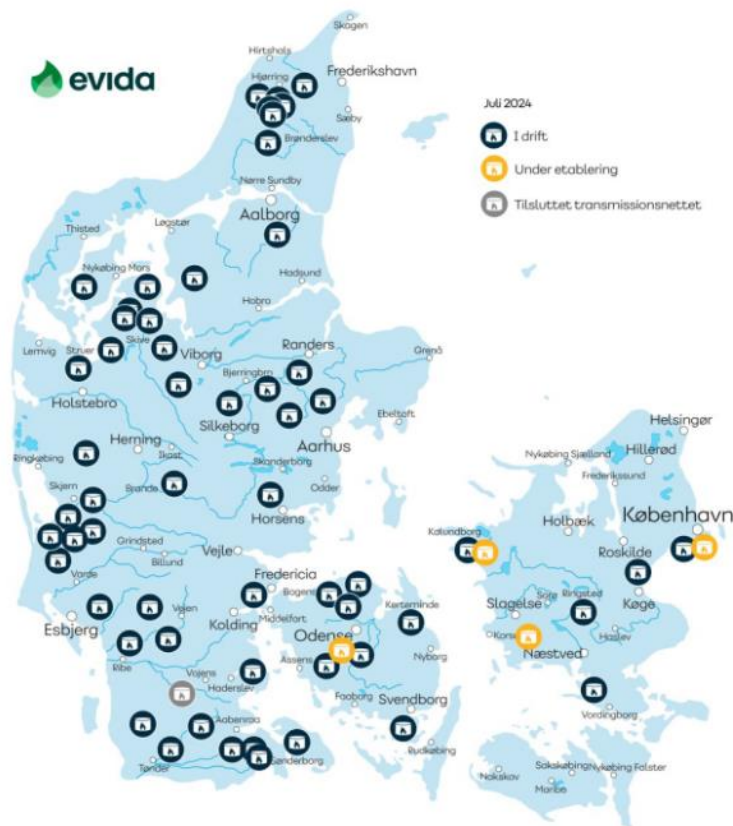


Figure 9-17 presents the biomethane plants in Denmark as of July 2024, with all of 58 plants connected to the distribution grid, except for one which is connected to Energinet's grid. A gap in a coherent support scheme in recent years has, however, resulted in a period with very low new connections of biomethane plants to the national distribution grid.

Figure 9-17 Biomethane plants in Denmark as of July 2024 (Source: evida⁴⁷⁷)



⁴⁷⁶ Henrik Gunnertoft Bojsen, Senior Manager (Energinet): BEMIP Decarbonization of Gases Meeting, 06 November 2024. Decarbonization of gases in Denmark.

⁴⁷⁷ Evida (2024): [Conversion mapping II](#)

These changes in consumption and supply require infrastructure measures in the gas system. The combination of reduced gas demand and increased biomethane production results in a (temporal) reversal of gas flows, requiring the transportation of gas away from the distribution grids using reverse flow facilities.

In addition, the geographical distribution of biomethane is different for the different grid regions. The biomethane share can exemplarily range from only 3% in the capital region around Copenhagen to around 58% in Northern and Central Denmark, and around 70% in Southern Denmark. Consequently, effects on gas grid operation like reverse gas flows need to be considered regionally. In addition, due to the strong seasonal variations in the gas demand pattern and geographical variations of biomethane production, gas quality is dominated by biomethane differently throughout the year or among the different grid areas.

ii) Biogas pockets at DSO level, local oversupply and construction of reverse flow facilities

Biogas pockets describe grid areas on DSO level where local surpluses in biomethane production cannot fully be consumed to local gas users only. These surpluses may only occur during summers, where gas demand is lower. They, however, have a serious impact on the gas system as sufficient capacity for injection into the high-pressure transmission grid is needed.

Examples for the occurrence of challenges with local oversupply and insufficient reverse flow capacities can be found in central and Southern Jutland.⁴⁷⁸ A new plant Karup (central Jutland) was therefore put into operation in 2022, however, problems with an existing plant in Viborg required the temporarily reduction of biomethane production in the region of around 10-15 GWh, as these could not be forwarded into the transmission system. A reduction of local biomethane production of around 15-40 GWh was also needed in the Southern Jutland region, where delays in the grid connection at DSO level for the new reverse-plant at the Terkelsbøls distribution grid limited reverse flow capacity.

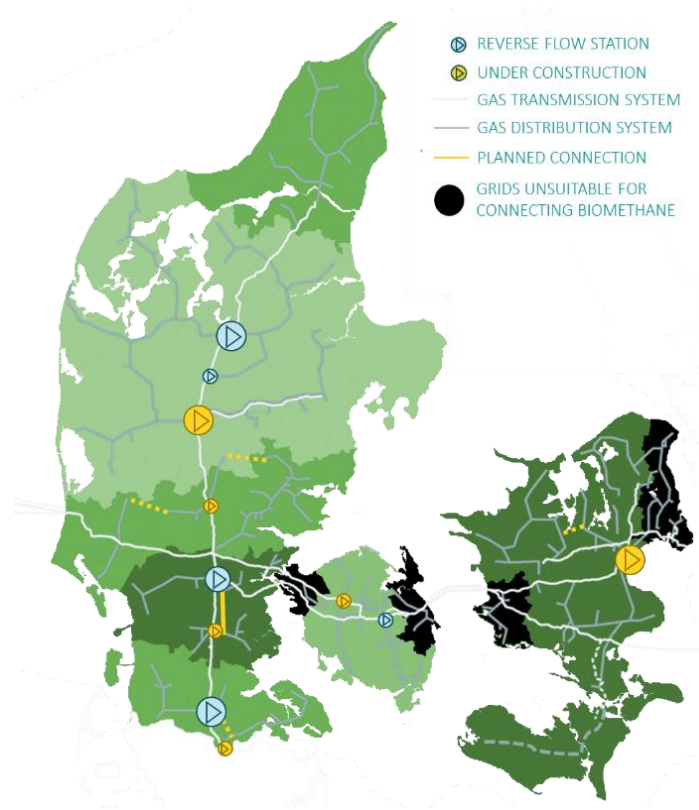
According to Evida⁴⁷⁹, it should however, be noted that these events are rare. Line pack capacity of the distribution grid can be used in several cases, to bridge times with lower consumption but continuous production, e.g. during weekends. In addition, there is close cooperation between DSO and TSO to add additional capacities for reverse flow stations where needed. Due to planning and construction time of in general around 2.5 years, Evida even built a containerized interim reverse flow solution in one case that was then handed over to Energinet.

In 2024, already five reverse flow stations to allow gas flow from distribution to transmission system were in operation in Denmark. According to Energinet, additional six reverse flow stations are planned or under construction. The locations are shown in the map in Figure 9-18. These stations mainly sit at existing M/R-stations at the connection between TSO and DSO grid and include additional compressor and deodorization units to allow for the reversion of the gas flow. Energinet's network development plan 2024 indicates that there is no need for further investments beyond these to enable the integration of biomethane. All reverse flow stations are operated by Energinet, although exceptionally Evida built one station and transferred ownership to Energinet.

⁴⁷⁸ Energinet (2023): [REPORT ON SECURITY OF GAS SUPPLY 2023](#)

⁴⁷⁹ Interview with Jensen, N. and Andersen, T. (Evida) on 16th January 2025.

Figure 9-18: Existing and planned reverse gas stations in Denmark (Source: Energinet⁴⁸⁰)

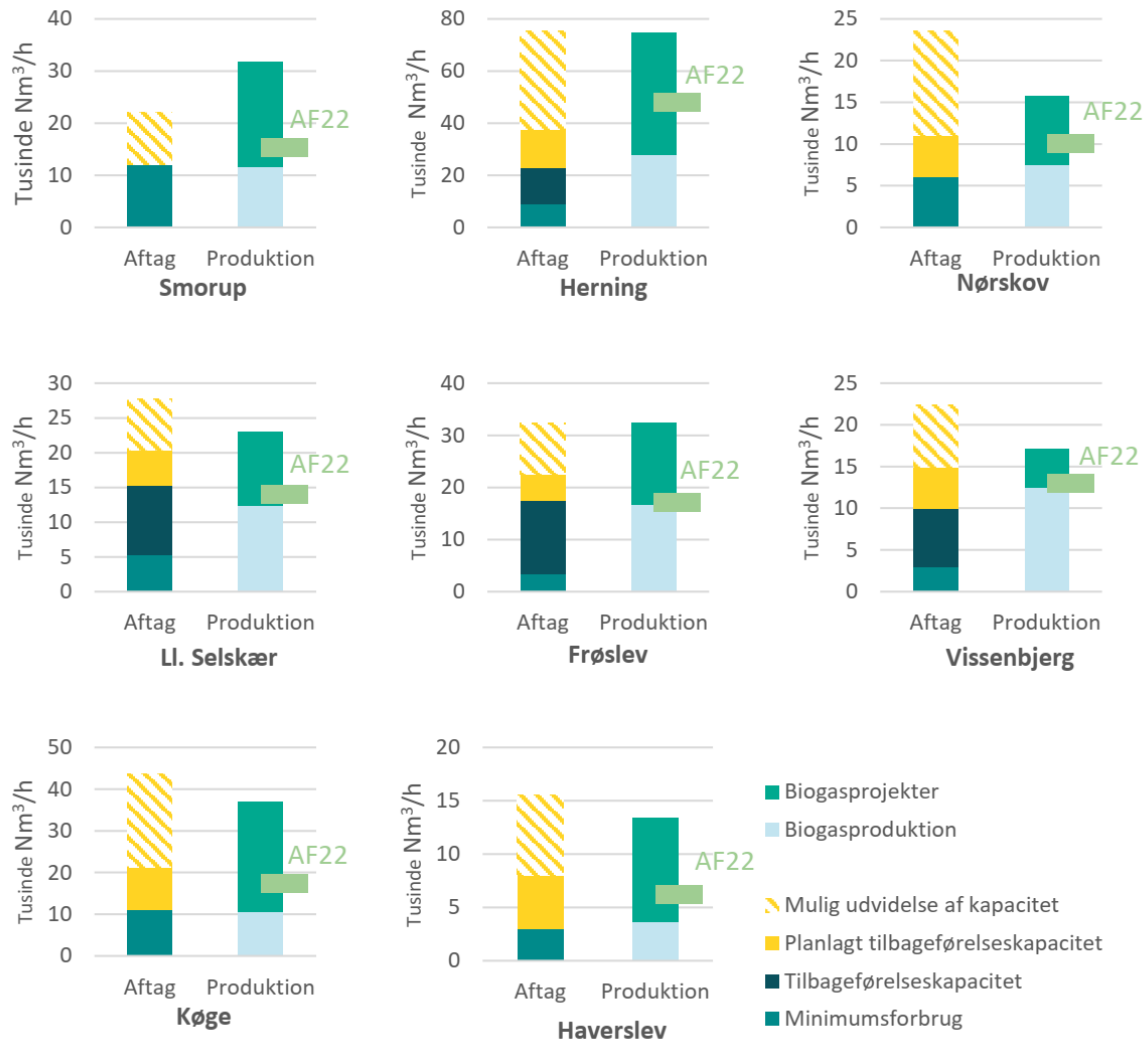


Although reverse flow stations are important for the distribution system to work, they are in the responsible of the TSO who builds and operates them.

One of the challenges in developing reverse flow facilities is appropriately dimensioning their capacities considering the possible development of biomethane production and consumer demand connected to each facility. Figure 9-19 illustrates the interaction between current/potential production, demand and current/planned/possible reverse flow capacities in different network areas.

⁴⁸⁰ Henrik Gunnertoft Bojsen, Senior Manager (Energinet): BEMIP Decarbonization of Gases Meeting, 06 November 2024. Decarbonization of gases in Denmark.

Figure 9-19: Expected gas offtake and biomethane production in areas where new reverse flow plants are planned⁴⁸¹



Translation

Aftag = offtake	Produktion = production	
Biogas production	Biogas projects	Minimum consumption
Current reverse-flow capacity	Planned reverse-flow capacity	Possible reverse-flow capacity

The role of reverse flow is, hence, also important in terms of CO₂ emissions, as biomethane production that cannot be injected into the transmission system needs to be shut down. Consequently, natural gas is used to make up for these volumes of biomethane. Energinet's existing reverse flow facilities mostly consist of two parallel compressors, which periodically are simultaneously operating⁴⁸². Based

⁴⁸¹ Energinet (2024): [Long-term development plan 2024 – Needs analysis for gas transmission 2023](#)

⁴⁸² Although redundancy in compressor power was part of original planning, high needs for reverse-flow-capacity periodically requires a simultaneous operation of both compressors for most stations – primarily during the summer holidays with minimal consumption.

on company's estimations, a compressor outage could thus, theoretically, lead to increased CO₂ emission of around 1,500 tonnes CO₂ per year.⁴⁸³

iii) Large production sites connected to transmission system

Another aspect with continuously growing importance is the construction of large-scale biogas plants that cannot easily be integrated into the gas distribution system, as gas flows as well as capacities of e.g. reverse flow stations would be not sufficiently high. In Denmark, these projects mainly focus on biogas production from straw feedstock, as straw can, in contrast to other biomass sources like slurry, be transported easily over long distances and, hence, be collected in large, central biogas facilities, especially at harbour locations. Examples are projects in Stigsnæs and Vordingborg.

While average biogas plant sizes connected to the grid after 2019 were around 2,000 Nm³/h (which already is high compared to other European countries, see Table 2-5), these new plants have sizes of up to 17,000 Nm³/h. Therefore, these single plants even sometimes have higher capacities than reverse flow stations allowing flow from DSO to TSO level (normally around 8,000-16,000 Nm³/h). A connection consequently may be only feasible directly to the transmission system, although until now only one plant is connected to it (note: mainly due to geographical reasons in this case).

A key challenge for biomethane operators in cases of direct connection at TSO level, however, is that they need to bear the costs for gas compression before injection. Stakeholders indicated that a revision of the current regulations may be required in this case to allow for a feasible business case – also for large-scale biomethane plants.

iv) Additional grid measures

In order to minimize investment needs in infrastructure measures like e.g. reverse flow stations, also connecting of existing grid parts on distribution level can be a more economical option. As indicated in graph Figure 9-18 with the yellow lines, some additional connection pipelines are planned to further develop the natural gas grid.

With these projects, seven large distribution grids (different green shadowed areas in Figure 9-18) are bidirectionally connected to the transmission system. Integrated network planning and a close collaboration between the Danish TSO (Energinet) and DSO (Evida) allowed a cost optimal grid planning including ties for interconnecting separate grids on DSO level resulting in a lower number of reverse flow stations needed. As can be seen in Figure 9-18, five of such ties were under construction. The estimated CAPEX investment for these measures is around € 64 million, according to information provided by Evida⁴⁸⁴. With these measures, only a few distribution grid areas which are not considered suitable for the (further) injection of biomethane into the Danish grid remain.

v) M/R-stations and decommissioning needs

The M/R-stations are unstaffed facilities located at the interconnection points between the high-pressure transmission grid and the lower-pressure distribution grid. They serve different functions, including measuring the gas flow, decreasing the pressure as well as heating the gas (to counteract cooling during expansion). In addition, odorants are added to the gas as these are required in the DSO system.

Changes in demand and supply patterns in the gas systems also have impact on the capacity requirements of M/R-stations. In the past year, several new large gas consumers increased the capacity needs of M/R-stations at different locations in Denmark. While e.g. in the Aalborg, the increase could be covered with the existing M/R-station design, the capacity of the two M/R-stations new Odense in Koelbjerg and Højby reached their limit, and modifications will be required to increase the TSO to DSO gas flow capacity.

⁴⁸³ Energinet (2022): [LONG-TERM DEVELOPMENT NEEDS IN THE DANISH GAS SYSTEM - Energinet's long-term development plan 2022 – Needs analysis](#)

⁴⁸⁴ Interview with Jensen, N. and Andersen, T. (Evida) on 16th January 2025.

However, additional biomethane injection as well as a decreasing gas consumption also reduced TSO to DSO gas flow capacities needs of M/R-stations in other regions. Examples (based on projections by Energinet⁴⁸⁵) comprise Southern Jutland (decrease by around 75-94 percent in M/R-station capacity needs by 2030) and Middelfart (by up to 70 percent), as well as the greater Copenhagen area (up to 70 percent). These reduction in capacity needs opens the opportunity for optimization by downscaling or closing down specific M/R or distribution and regulation (D/R) stations (even in connection with parts of the distribution grid) if economically and technically feasible. Especially ring-connected stations where gas can be introduced from several points of the network, such closure is possible. For example, in 2024 Evida announced the closure of 3 M/R and D/R stations in the Horsens area. However, such measures generally only are considered, if reinvestments in existing stations are needed.

In 2024 Evida published its second conversion mapping analysis,⁴⁸⁶ where it indicates that according to the analysis' assumptions, 88% of the sub-networks in the gas distribution system are considered economically viable to the 2050 horizon.⁴⁸⁷ Moreover, of the remaining 12% of sub-networks which are deemed unprofitable, 1/3 have biomethane plants, utilities (heat and/or electricity producer) and/or industry connected to them – with industry making up the largest share of the users connected to these unprofitable subnetworks (although the report highlights the uncertainties associated with the analysis). Nonetheless, the conclusion is that only a small share of sub-networks has biomethane networks connected to them.

vi) Oxygen limit

Due to the high share of biomethane in the grid, Denmark is one of the first countries to observe relevant **issues with the existing limits for oxygen** being accepted in the grid. While high levels of up to 0.5% are being allowed internally, international standards like EN 16726 opens the possibility for different countries to rather use very low oxygen acceptance levels of 0.001%. This difference of a factor of 500 forces Danish TSO grid operator to either restrict cross-border flows or add additional centralised deoxidation measures at cross-border interconnection points.

Experiences with oxygen measurement at Danish gas storage sites are, hence, considered very valuable, also for other BEMIP MS. Measurements in Zealand and North Jutland showed significant peaks in oxygen concentration during summer months in last years.⁴⁸⁸ During that time, average concentration was around 25-30 ppm and 50-60 ppm in 2021 and 2022, respectively, with regular peak above 100 and 200 ppm, respectively. With the Danish limit being 5000 pm / 0.5%, these peaks are still acceptable. However, impact on microbiological activity and corrosion is subject to continuous research.

With larger volumes of biomethane soon flowing in the European grid, other Member States will likely encounter the same challenges. Hence, according to national grid operators, a removal of this barrier will reduce the costs associated with integration and exporting biomethane, thereby benefiting the common EU endeavours to drive a fast and cost-effective decarbonization of the gas system, but also to support the objectives of the internal market for energy. Further details on the issue of oxygen limits in the context at interconnection points to neighbouring countries can be found in Figure 9-14.

To account for the differences in gas quality, different measures were applied in the Danish TSO grid.⁴⁸⁹

⁴⁸⁵ Energinet (2022): [LONG-TERM DEVELOPMENT NEEDS IN THE DANISH GAS SYSTEM - Energinet's long-term development plan 2022 – Needs analysis](#)

⁴⁸⁶ Evida (2024): [Conversion mapping II](#)

⁴⁸⁷ It should be noted that decommissioning is used as a tool for ongoing optimization of the infrastructure based on a cost-benefit calculation. In any case, decisions will be taken in dialogue with the authorities and impact on costumers is to be avoided.

⁴⁸⁸ Energinet (2024): [Energinet's long-term development plan 2024](#)

⁴⁸⁹ Energinet (2022): [LONG-TERM DEVELOPMENT NEEDS IN THE DANISH GAS SYSTEM - Energinet's long-term development an 2022 – Needs analysis](#)

- One option is to blend 'domestic' biomethane/natural gas blends with imported natural gas streams allows reducing the overall oxygen share before exporting. Exemplarily, biomethane from South and North Jutland was mixed with natural gas from the North Sea or Germany before the export to Sweden. In this case, also dialogue with grid operators and customers lead to an increase in admissible oxygen limits from 0.1% to 0.2% and later 0.5%.
- For other parts, the practice of sectioning was applied, keeping certain grid areas / pipelines free of biomethane by not allowing any biomethane injection, e.g. done in Egtved. With that measure, the very low oxygen limits of Germany can be ensured.
- Finally, also the option of oxygen removal at central grid locations or interconnection points may be needed, connected with additional costs for domestic gas operators (and hence gas customers).

Besides oxygen, also hydrogen management systems are implemented to account for increased hydrogen concentrations in the natural gas in order to take different national limits for hydrogen contaminations into account. Potential sources for hydrogen are e.g. the hydrogen slip from biomethane or e-methane injection, but also the active blending of hydrogen into the natural gas grid.

Cost implications: DSO tariff structures and additional investment needs

In 2025 a new distribution **tariff structure** entered in force in Denmark, with the following main changes:

- Introduction of system with fixed (per year) and capacity-based components to the consumer tariff, which previously only included volume-based and metering components;
- Introduction of an injection tariff for biomethane producers, while previously only consumers paid for access to Evida's networks;
- Harmonisation of tariffs between the three Evida distribution companies (North, South and Fyn)

The table below presents the estimated contribution of these tariff components to Evida's total revenues for 2025. As can be seen, the new fixed and capacity-based components for consumers should represent around 56% of Evida's tariff revenues in that year, while the new tariffs for biomethane producers should account for around 23% of revenues. Consumer and producer fixed/capacity-based components now represent 72% of Evida's collected tariffs.

Table 9-8 Distribution of Evida revenues per tariff component in 2025⁴⁹⁰

Component	Share (Million DKK)	Share of total revenue (%)
Consumers (volume)	87	9%
Consumers (system – fixed)	210	21%
Consumers (system – Capacity-based)	359	35%
Consumers (metering)	126	12%
Producer (system – capacity-based)	163	16%
Producer (volume-based)	67	7%
Total	1.012	100%

Evida's tariff methodology allocates among others the following costs to biomethane producer tariffs:

- Electricity costs for compressors
- Costs for preventive/remedial maintenance and general compressor operation
- Other operating costs attributable to biomethane production
- Depreciation of assets attributable to biomethane production

⁴⁹⁰ Evida (2024) Metodeanmeldelse – Evidas metode for beregning af tariffer for brug af distributionssystemet

In 2025, depreciation of assets attributable to biomethane production should constitute around 96 million DKK, or 28% of total depreciation costs,⁴⁹¹ which is a significant portion.

In the context of tariffs, the survey conducted in this study indicate network operators perceive another obstacle for further grid development related to the gas tariff discounts for renewable (and low-carbon) gases at gas entry, storage and interconnection points, introduced e.g. as optimal provisions by the Hydrogen and Decarbonised Gas Market Package. The gas tariff discounts for interconnection points are criticised by some network operators, which consider it could compromise revenue recovery and the cost reflectivity of the tariffs, especially in gas grids dominated by renewable gases.

It must be noted that the Danish regulator exempted Evida in 2024 from applying tariff discounts to the feed-in of renewable gases to the gas grid. In its decision, the Danish regulator indicates that it considers that the promotion of biomethane in Denmark can be achieved without the injection tariff discounts, and that in a context of high penetration of biomethane the discounts could compromise the financial framework for Evida's investments.⁴⁹² The regulator furthermore closed in January 2025 a consultation on the provision of a similar exemption to Energinet.⁴⁹³

In summary, **infrastructure investment needs** to enable integration of biomethane into the Danish gas grid comprises the following components:

DSO level:

- 5 additional connection lines planned to connect different grid areas and to minimize need for reverse flow stations (estimated CAPEX around 64 million €)
- Compressors at biomethane plants connected to distribution grid (CAPEX and OPEX considered relevant)
- Connection of new biomethane producers to the grid
- Additional costs for grid simulation tools, required e.g. for billing based on energy content of the gas

TSO level:⁴⁹⁴

- Installation of reverse flow facilities (incl. compression and deodorization) (Cost estimation: around 100 million DKK / 15 million € per plant, high OPEX expected for deodorization and compression.⁴⁹⁵
- Measures to deal with oxygen limits (e.g. gas flow, removal of oxygen): Currently considered as research topic. CAPEX estimate around 9-39 million DKK per installation (3,600-15,000 Nm³/h). OPEX around 0.19 DKK/Nm³.

At the transmission level, distribution of reinvestments needed into the grid were described by Danish TSO Energinet in the long-term development plan 2024 (LUP24).⁴⁹⁶ In this document, the cost allocation for reinvestments over a 10-year period (2024-2034) among the different are shown, with maintenance of subsea lines (38%) and reinvestment in M/R-stations (23%) and compressor stations (19%) accounting for the major shares. It should be noted that these reinvestment needs are strongly dependent on the age of the installations. Reinvestments in rather new M/R-stations may thus further increase in the future. In contrast to that, reinvestments in connections to biogas plants, including reverse flow measures, only corresponds to around 6%.

⁴⁹¹ Evida (2024) Metodeanmeldelse – Evidas metode for beregning af tariffer for brug af distributionssystemet

⁴⁹² Danish Utility Regulator (2024): [Afgørelse om undtagelse fra tariffabat efter gasforordningen artikel 18, stk. 5](#)

⁴⁹³ Danish Utility Regulator (2024): [Høring over at Energinet undtages fra at anvende tariffabatter iht. gasmærksforordningens artikel 18](#)

⁴⁹⁴ Interview with Nielsen, M. G.; Hansen, A. M. (Energinet) on 17th January 2025. Cost data based on 2024 data.

⁴⁹⁵ Based on data by Energinet, current CAPEX estimates for reverse-flow stations are in the range 100-138 million DKK per station (4,000-20,000 Nm³/h); OPEX estimate are around 0.3 DKK/Nm³.

⁴⁹⁶ Energinet (2024): [Energinet's long-term development plan 2024](#)

In addition to that, also some OPEX cost estimates for deodorization needs⁴⁹⁷ were provided to treat biomethane that is injected from DSO to TSO grid. According to estimations by Energinet, these costs are expected to increase from about 10-12 million DKK/year (= around 1.3-1.6 million €⁴⁹⁸) in 2023 to around 60-90 million/year (=8-12 million €) by 2050. The high OPEX for deodorisation is caused by the need to frequently replace the filter materials of the deodorization plant. Costs estimations for oxygen removal were described by the Danish Gas Technology Centre.⁴⁹⁹ According to that, extra costs for oxygen removal can account for up to 10-12% compared to the costs for sulphur cleaning, upgrading and injection of a biogas plant, increasing the overall biomethane costs by around 1.5-1.9 percent (depending on size of the plant).

9.6. Readiness of end-users for low-carbon gases

Different types of gas, such as natural gas with low or high calorific value (L-gas, H-gas), upgraded biogas, or hydrogen, possess varying gas properties, including molecular weight, density, calorific value, flame speed, chemical composition, and Wobbe Index. The substitution of one gas by another necessitates careful analysis and often significant adaptations to end-use applications.

The following sections outline the most relevant modifications to industrial end-use applications when transitioning from natural gas to hydrogen or biomethane.

Hydrogen

Switching end-use applications from natural gas to hydrogen usually requires significant adaptations as chemical and physical properties of methane, which is the main component of natural gas, and hydrogen differ significantly. For example, flame temperatures of hydrogen are about 300°C hotter and flame speed is more than three times faster than for methane⁵⁰⁰.

Over the past years, the **power sector** intensively worked on the topic of switching gas turbine power plants to pure (and mixed) hydrogen operation in the future. When considering converting power plants to pure hydrogen use, two initial situations need to be distinguished. On the one side, there are existing power plants that were solely designed to work on natural gas. Converting those plants to hydrogen is feasible but requires substantial changes to the plant, longer conversion time and higher investment. On the other side, there are newly built so-called 'hydrogen ready' plants⁵⁰¹. Those plants are designed to run on natural gas first but are prepared to be efficiently converted to hydrogen use at a later stage. It is important to mention that those plants still require adaptation before running on hydrogen. However, the conversion is much quicker and less costly. It is expected that by the end of the decade, turbines for 100 % hydrogen are commercially available for all turbine sizes⁵⁰⁰.

To convert a plant to hydrogen operation, adaptations might be required e.g. in the gas supply system, the combustion system of the gas turbine, the flue gas system or safety system (fire and explosion protection). Indicative costs for a full plant conversion from natural gas to hydrogen are in the order of 13 % to 45 % of the initial gas turbine costs for new build plants and in the order of 36 % to 70 % for existing plants (Those percentages refer to the costs of the gas turbine only but include the cost for converting the entire plant).⁵⁰² The costs for constructing a new large-scale power plant using 100 % hydrogen from the beginning are expected to be in the same order (with a potential slight cost premium of about 10%) as new plants using natural gas. However, the cost premium depends e.g. on plant technology and plant capacity and can be higher for smaller plants. In addition to technical conversion, certain adaptations to authorisation and permitting are also required. Not all relevant regulations and laws do yet take hydrogen powered plants into consideration⁵⁰³.

⁴⁹⁷ Energinet (2024): [Energinet's long-term development plan 2024](#)

⁴⁹⁸ Based on an exchange rate of 1 DKK = 0.13 €.

⁴⁹⁹ Danish Gas Technology Centre (2022): [Cost-efficient handling of oxygen from bio-methane in the European gas grid](#)

⁵⁰⁰ De Vos, R.: Ten fundamentals to hydrogen readiness ([Siemens energy homepage](#)), 13 September 2022, accessed Jan.2025

⁵⁰¹ Zindel, E.: Wasserstoffbereitschaft und -verbrennung in Gaskraftwerken, 19 October 2022

⁵⁰² Vgbe: position paper – H2-readiness for gas turbine plants, January 2023

⁵⁰³ Christidis, A. et al.: H2-Ready Gas-fired power plants, November 2023

The technical situation for power plants based on stationary gas engines is similar. To achieve 100 % hydrogen operation, adaptations to the combustion chamber, fuel supply and safety systems are required. Commercial availability of hydrogen powered engines for electricity production is expected for the end of this decade.⁵⁰⁴

Today, the European **glass industry** uses natural gas as its main energy feedstock. The industry's energy consumption is mainly required for the melting process which takes place at about 1,200 °C to 1,600 °C and accounts for 50% to 85% of the total energy consumption of glass manufacturing⁵⁰⁵. In order to reduce greenhouse gas emissions, the industry has been working on alternatives to fossil fuel use during the past years. Potential options for decarbonized energy supply include the use of electricity, hydrogen (incl. hydrogen-oxyfuel) or a combination of both. Electricity is already used in combination with natural gas, today, in so-call hybrid melters. Further carbon reduction options e.g. by using heat recovery systems exist. It must be noted that the energy supply to the melting furnace must not be interrupted for longer periods. This would lead to a solidification of the molten glass and would thus destroy the melting furnace.

The use of hydrogen as (main) energy is not commercial state-of-the-art, yet. However, laboratory scale glass production with 100 % hydrogen as well as first trials for industrial-scale applications have been achieved in the recent past⁵⁰⁶. In Europe, various projects (e.g. ZeroCO2Glass⁵⁰⁷; H2Glass⁵⁰⁸) are currently ongoing to develop the technologies required to use hydrogen as a fuel in the melting furnace. One of the main challenges when using hydrogen involves the furnace design that needs to address aspects such as changing flame characteristics or higher combustion temperature which can have an impact on the glass quality. Further challenges involve safety considerations and cost competitive and uninterrupted fuel supply. First commercial projects using a mix of electricity and hydrogen are announced go online in 2027⁵⁰⁹.

Greenhouse gas emissions in **cement production** primarily occur during clinker production. Approximately two-thirds of these emissions are process-related, stemming from the decarbonization of limestone, while the remaining third arises from the fuels used. The integration of hydrogen in cement production aims to partially replace conventional fuels. However, hydrogen flames have low radiant heat, leading to poor heat transfer to the material in rotary kilns. Consequently, hydrogen is likely to be used as a supplementary fuel alongside established materials. Current research suggests that up to 10% of the main burner's energy can be supplied by hydrogen without compromising kiln operation. Higher usage rates would require further investigation, particularly regarding clinker phase formation and product quality. This approach aligns with efforts to decarbonize the industry while maintaining production standards.⁵¹⁰

The use of hydrogen in combination with other fuels is currently being further investigated and has already been proven in some projects^{511 512}.

The use of hydrogen as a raw material in the **chemical and petrochemical industries** often necessitates significant modifications to processes and plant configurations. One key challenge lies in the requirement for carbon, which is inherently present in fossil fuels but must be supplied from alternative sources when using renewable hydrogen. Potential sources of carbon include direct air capture technologies or biogenic origins, such as biomass or waste streams.

⁵⁰⁴ BDEW Diskussionspapier: H2-Prozessleitfaden: Strom- und Wärmeerzeugung auf der Basis von erneuerbaren und dekarbonisierten Gasen, 4 August 2023

⁵⁰⁵ Zier, M. et al.: A review of decarbonization options for the glass industry; *Energy Conversion and Management*; 2021

⁵⁰⁶ Schott: Premiere – Schott produces optical glass with 100 percent hydrogen; April 2024; [company webpage](#)

⁵⁰⁷ ZeroCO2Glas: Development of a novel hydrogen-fired glass melting furnace with the aim of a CO2-neutral container glass production (2022-2026); [Link](#);

⁵⁰⁸ Pilkington: Pilkington UK plans to scale low-carbon glass production under pioneering hydrogen plans, 23 July 2024.

⁵¹⁰ Verein Deutscher Zementwerke - VDZ: Dekarbonisierung von Zement und Beton – Minderungspfade und Handlungsstrategien; 2020

⁵¹¹ IPCEI project TITAN: Pioneering Green Hydrogen for Industrial Cement Production in Greece

⁵¹² ZKG cement: HeidelbergCement produces cement with climate-neutral fuel mix using hydrogen technology; 2021

Biomethane

When it comes to the substitution of natural gas by biomethane, the necessary adaptations of end-users are limited. Before injection of biomethane into the grid, the gas must comply with the grid specifications of the respective grid operator. An overview of the gas quality of biomethane required in European countries for injecting into natural gas grid was summarised by MARCOGAZ in 2024.⁵¹³

There may, however, be challenges related to the **variations in gas quality**. In general, biomethane production is rather constant throughout the year, while the natural gas demand has a strong seasonal pattern (driven by its use in the heating sector). Consequently, the share of biomethane in the grid will be higher in times of low demand (e.g. in summer times or – to a lesser extent – during the weekend, when there is less demand from industrial processes). These variations result in variations in the gas quality and calorific properties of the gas received by end-customers with potential impact on efficiency of the process, safety (i.e. emissions or thermal overload) or product quality.

Most customers can deal with variations in gas properties within a certain range of up to +/-5 percent without major issues. Specific applications in metal, ceramics and glass industry may, however, already need countermeasures at lower variation values.⁵¹⁴ Based on feedback by Danish grid operator Evida⁵¹⁵, there are, however, certain applications where natural gas is used as feedstock for certain processes. As an example from the biochemical industry, protein production was mentioned. These customers are very sensitive when it comes to variations gas properties and, hence, additional measures to ensure a steady quality are applied.

In summary, however, no significant issues are identified in completely substituting the gas supply from natural gas to biomethane.

⁵¹³ MARCOGAZ (2024): [Quality of biomethane required in European countries for injecting into natural gas grid - Update](#).

⁵¹⁴ DVGW German Technical and Scientific Association for Gas and Water (2018): *Hauptstudie zur Analyse der volkswirtschaftlichen Auswirkungen von Gasbeschaffenheitsschwankungen auf die Sektoren des Gasverbrauchs und deren Kompensation: Phase 2 - Hauptstudie Gasbeschaffenheit*.

⁵¹⁵ Interview with Jensen, N. and Andersen, T. (Evida) on 16th January 2025.

10. Annex D – Stakeholder engagement

The stakeholder survey supporting Task 1 was sent out to 93 organisations, via 144 email addresses, on September 9th, 2025. Between this date and December 6th, 2024, 13 key organisations provided answers to the survey⁵¹⁶ and the follow-up questions posed by the consultants. These organisations are listed below, by country:

- **DE**
 - German Biogas Association (FvB)
 - Cascade together with other TSOs
 - Federal Ministry for Economic Affairs and Climate Action (BMWK) together with the National Regulator (BNetzA)
- **DK**
 - Danish Energy Agency
 - Energinet
- **EE**
 - Elering
 - Estonian Competition Authority
- **FI** – Gasgrid Oy
- **LT**
 - Amber Grid together with Ministry of Energy
 - Lithuanian Energy Agency
- **LV** - Conexus
- **PL** - Gaz-System
- **SE** - Nordion Energi / Swedegas

In addition, interviews were held with Evida and Energinet on the challenges and bottlenecks for the integration of biomethane into the natural gas system.

We extend our sincere appreciation to all stakeholders who participated in the survey and contributed valuable input and feedback throughout the course of this study, including during the BEMIP High Level Group meetings and public workshops. Their contributions were instrumental to the successful completion of this work.

⁵¹⁶ Master file with survey responses can be shared with DG ENER upon request, subject to agreement.

11. Annex E - Modelling assumptions

This section provides details about the methodology and key assumptions related to the modelling exercise developed in this study (see section 5).

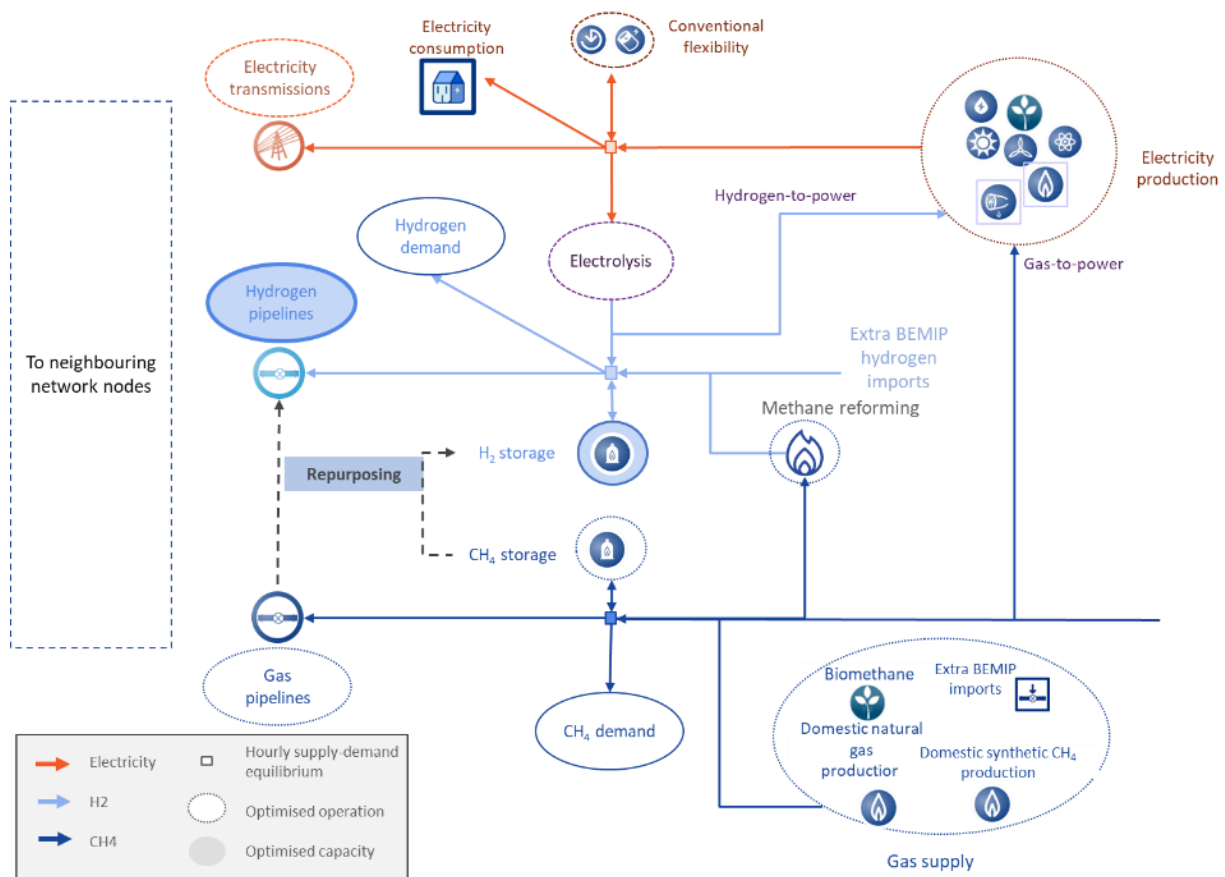
Detailed model structure

The figure below provides an overview of all technologies explicitly represented in the model and the interlinkages between the three energy carriers, electricity, gas and hydrogen. Assets are either subject to dispatch optimisation (the model optimises the hourly consumption/production patterns of the considered technology, subject to the techno-economic constraints, based on exogenous capacities) or both capacity and dispatch optimisation (plain circles). In this case, in addition to the optimised operations, **the model optimises the level of investments** in the technology based on assumptions such as investment costs and potentials. The optimal level of investment thus results of the trade-off between investment costs and system operation cost, in order to minimize total system cost.

Hydrogen can be supplied both via electrolysis, methane reforming (possibly with carbon capture) or via hydrogen imports. Electrolysis are modelled explicitly, dynamically linking the electricity and hydrogen systems.

Hydrogen infrastructure is optimised by the model, including underground hydrogen storage in salt caverns and porous medias (supposed to be available only as of 2040 due to lower TRL) and above-ground hydrogen storage, as well as cross-border pipeline capacities. The model has two options, investing in new hydrogen pipelines or repurposing existing natural gas pipelines. Similarly, natural gas storage infrastructure can be repurposed to hydrogen.

Figure 11-1: Overview of energy vectors and technologies represented in the model



Baseline scenario assumptions

The baseline scenario represented in this study is mostly aligned with assumptions from the TYNDP 2024 scenarios, as indicated in the table below. It is to be noted that since the model explicitly represents sector-coupling, part of the energy consumption is endogenously optimised by the model, this is notably the case for:

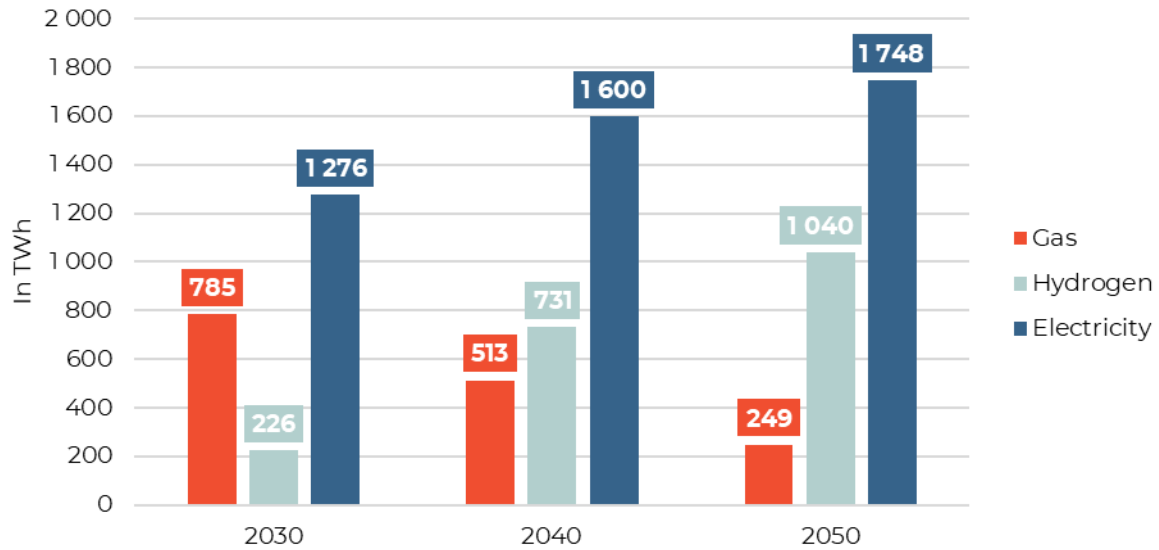
- Hydrogen consumption of hydrogen-to-power assets
- Electricity consumption of electrolyzers
- Methane consumption of power generation and hydrogen production units (methane reforming)

Therefore, part of the energy demand is exogenous (i.e., a model input, for instance the electricity consumption in the residential sector), while the other part is endogenous (i.e. a model output, for instance the electricity consumption of electrolyzers). Exogenous energy demand volumes are displayed in Figure 11-2 below while Table 11-1 presents an overview of the main modelling assumptions.

Table 11-1: Overview of main modelling parameters and sources in the study baseline scenario

	Parameter	2030	2040	2050	Comments
Power	Final demand	NT+		DE	Consumption of electrolyzers is endogenous
	Production capacities	NT+		DE	
	Storage/Transmission Infrastructure	NT+		DE	
	Exchanges with rest of Europe	NT+		DE	
Hydrogen	Final demand	NT+		DE	Consumption of hydrogen-to-power assets is endogenous
	Production capacities	NT+		DE	
	Storage Infrastructure	Capacities optimised with PCI level as minimum infrastructure			
	Hydrogen pipelines				
	Extra-EU import potentials	NT+		DE	
	Exchanges with rest of Europe	NT+		DE	
Methane	Methane final demand	NT+		DE	Consumption of SMR and gas-to-power are endogenous
	Biomethane supply	NT+	DE	DE	
	Residual domestic natural gas production and synthetic methane production	NT+		DE	
	Gas import capacities	Based on existing capacities			
	Storage and pipelines	Starting from existing capacities, model can repurpose or decommission part of the infrastructure			
	Exchanges with rest of Europe	NT+		DE	

Figure 11-2: Exogenous energy demand in the BEMIP region in the study baseline scenario (TWh LHV⁵¹⁷). (Source: ENTSO-E & ENTSG, 2024)



Note: These demand volumes exclude hydrogen and methane demand for electricity generation, as well as electricity consumption for electrolysis and steam methane reforming (SMR) demand which are outputs of the model. It is to be noted that while methane consumption remains in 2050, this is supplied via biomethane and synthetic methane.

The baseline scenario used in this study follows TYNDP 2024 scenarios, which are designed considering the climate and energy policy targets, in particular:

- A 55% reduction in net GHG emissions in 2030 compared to 1990 (Fit-for-55)
- A share of 42.5% in renewable energy in gross final energy consumption by 2030 (Renewable Energy Directive)
- A reduction of energy consumption of 11.7% in 2030 compared to projections of the 2020 EU Reference scenario (Energy Efficiency Directive)
- Carbon neutrality by 2050.

Sensitivity analysis scenario assumptions

The sensitivity analysis scenario investigates the impact of a delayed transition, with a delayed uptake of hydrogen in the first stages of the pathway modelling, while conserving the scenario assumptions in 2050. Indeed, in the hydrogen consumption scenarios benchmark (see section 2.2.2), TYNDP 2024 NT+ 2030 and 2040 scenarios are rather ambitious in terms of development of hydrogen consumption, while DE 2050 scenario is more conservative. Based on national studies and stakeholder's feedback, country specific adaptations to biomethane supply potentials from TYNDP scenarios are also considered in the sensitivity analysis.

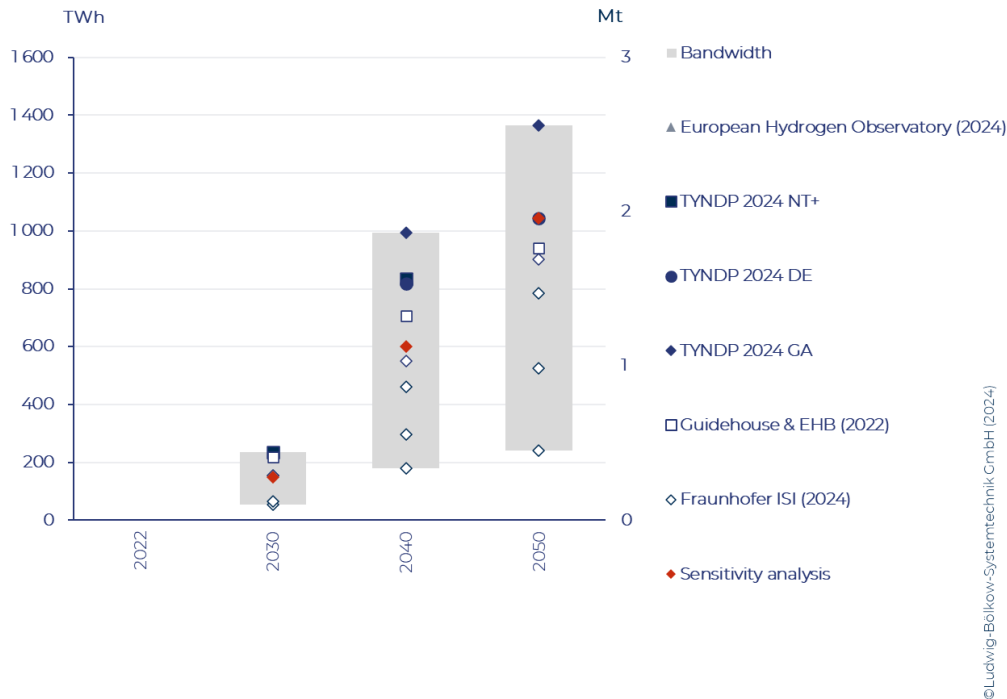
Regarding hydrogen supply and demand, the following adaptations are considered:

- Hydrogen consumption decreases to 150 TWh in 2030 and 600 TWh in 2040 (see figure below)
- Hydrogen-fired power plants from the NT+ scenario are assumed to remain methane-fired power plants in 2030 and 2040 (delayed switch from methane to hydrogen)
- No hydrogen consumption in residential and tertiary sectors is considered in 2030 and 2040
- Hydrogen consumption profiles are adapted accordingly, which impacts the seasonality of hydrogen consumption

⁵¹⁷ LHV: Lower Heating Value

- Electrolysers capacities are reduced in all countries in the same proportions as hydrogen consumption in 2030 and 2040
- A delayed development of offshore wind is also considered compared to the NT+ scenario, power generation from wind offshore decreases by the equivalent of the consumption of removed electrolysis capacity
- Potential imports from Norway considered in the NT+ 2040 scenario are no longer considered as available (imports in the form of ammonia and from the rest of EU are still available)

Figure 11-3 Overview of hydrogen consumption in benchmarked scenarios and sensitivity



Regarding methane supply and demand, the following adaptations are considered:

- The delay on the development of hydrogen consumption is assumed to impact methane demand
 - o An analysis of alternative energy carriers is performed depending on end-uses for which hydrogen consumption is reduced
 - o Reduced hydrogen consumption may typically impact methane or oil products consumption depending on the sectors
 - o Overall, the final methane demand (excluding power generation) rises from 785 TWh to 817 TWh in 2030, and from 513 TWh to 585 TWh in 2040
- MS-specific adaptations to biomethane supply assumptions are considered for 2030 and 2040
 - o Updates are based on the literature (in particular, national studies) and stakeholder's feedback
 - o Most significant changes are seen in 2030 (from 105.5 TWh to 71 TWh at BEMIP level) where NT+ scenario is most optimistic
 - o At the BEMIP level, country-specific adaptations translate into an overall marginal decrease of total biomethane supply in 2040 (from 134 TWh to 129 TWh)

Figure 11-4 Methane demand in the baseline and sensitivity scenarios

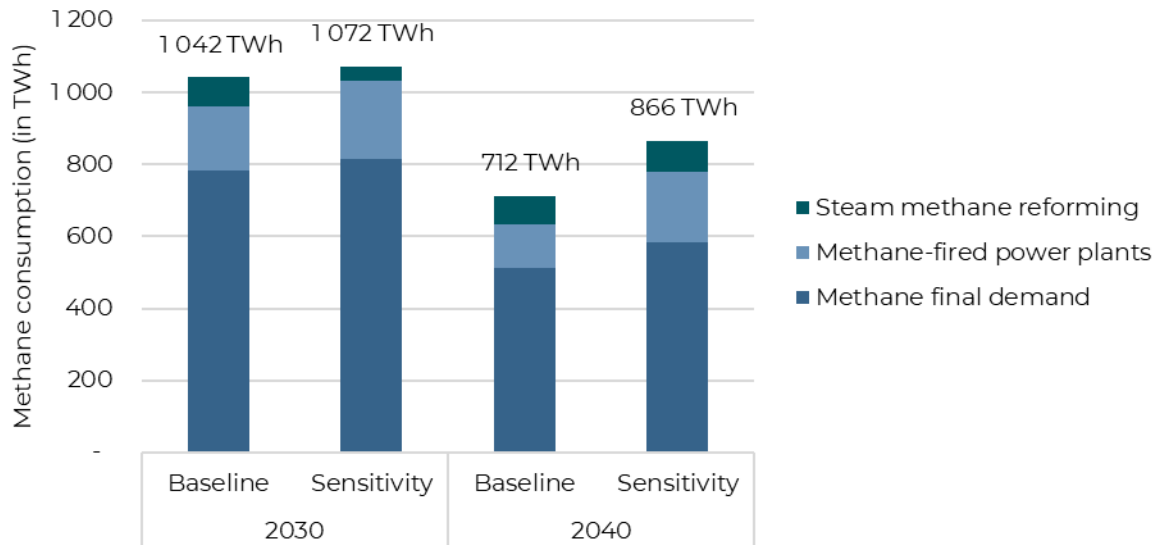
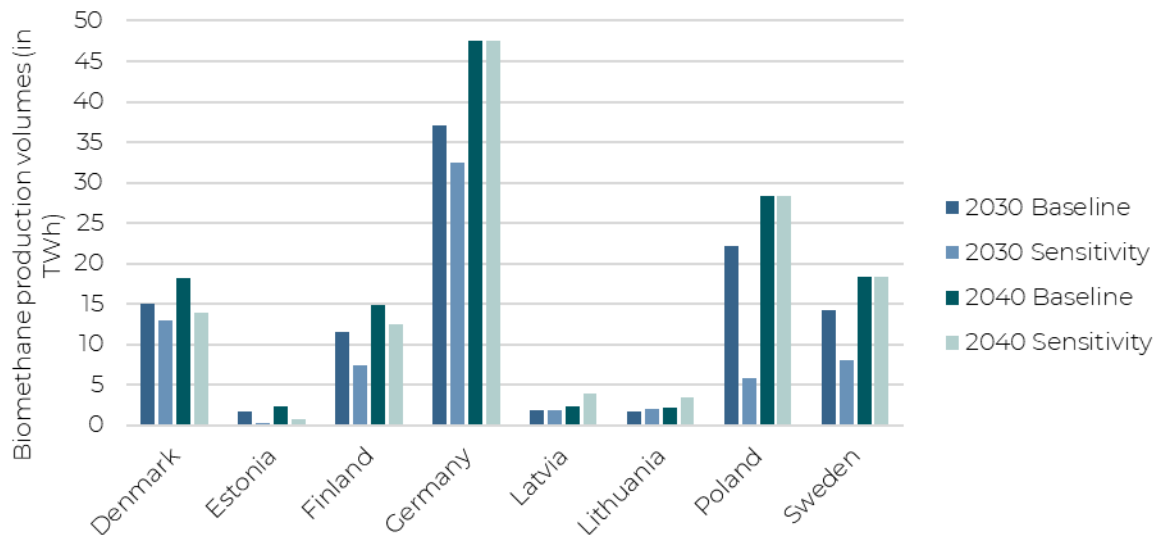


Figure 11-5 Biomethane production volumes in the baseline and sensitivity scenarios



Investment costs assumptions

In addition to the PCIs from the first PCI/PMI list which are enforced as minimum infrastructure levels in the modelling, the development of new and repurposed hydrogen infrastructure is optimised by the model. The model can invest in:

- New or repurposed cross-border hydrogen pipelines
- New or repurposed underground hydrogen storage assets
- Above ground hydrogen storage assets

Additionally, the model considers the possibility of repairing and retrofitting Nord Stream pipelines to transport hydrogen. The cost optimisation approach consists in determining the aggregated capacity (in MW for pipelines and MWh for storage) that minimises the sum of investment costs and system operation costs, up to 2050. The cost assumptions for these potential investments are described below.

Cost assumptions for hydrogen pipelines – both onshore and offshore, whether repurposed or newly constructed – are based on data from the latest EHB reports^{518 519 520} (with recent revisions including the impact of inflation). Consistently with these studies, a 50-year operational lifetime for both new and repurposed pipelines is assumed, alongside a weighted average cost of capital (WACC) of 5%.

Onshore pipelines

Table 11-2 Investment cost assumptions for new onshore hydrogen pipelines

Pipeline size (mm)	Pipeline CAPEX (M€/km)	Capacity (MW LHV)	Compression CAPEX (M€/km)	Compressor annual fixed OPEX as % of CAPEX	Pipeline annual fixed OPEX as % of CAPEX	Total CAPEX (€/MW/km)	Total fixed OPEX (€/MW/km/year)
500 (S)	1.8	1200	0.026	1.7%	0.9%	1521.7	13.9
900 (M)	3.2	4700	0.093	1.7%	0.9%	700.6	6.5
1200 (L)	4.4	13000	0.183	1.7%	0.9%	352.5	3.3

Since the model does not differentiate between individual sections of a cross-border pipeline, which may vary in size, and because the optimized interconnections do not necessarily align with existing projects, we apply the following capacity-weighted average costs, derived from Table 11-2 to design investment candidates: **513.3€/MW/km for CAPEX** and **4.7€/MW/km/year for fixed OPEX**. This approach gives more weight to larger pipelines, which typically form the bulk of cross-border interconnections, ensuring cost assumptions are not underestimated.

Table 11-3 Investment cost assumptions for repurposed onshore hydrogen pipelines

Pipeline size (mm)	Pipeline CAPEX (M€/km)	Capacity (MW LHV)	Compression CAPEX (M€/km)	Compressor annual fixed OPEX as % of CAPEX	Pipeline annual fixed OPEX as % of CAPEX	Total CAPEX (€/MW/km)	Total fixed OPEX (€/MW/km/year)
500 (S)	0.54	1200	0.026	1.7%	0.9%	471.7	13.9
900 (M)	0.64	3600	0.04	1.7%	0.9%	188.9	8.2
1200 (L)	0.88	13000	0.183	1.7%	0.9%	81.8	3.3

To design investment candidates, we apply the following capacity-weighted average costs derived from Table 11-3: **129.7€/MW/km for CAPEX** and **5.0€/MW/km/year for fixed OPEX**.

⁵¹⁸ EHB (2023): [European Hydrogen Backbone](#)

⁵¹⁹ EHB (2021): [Extending the European Hydrogen Backbone](#)

⁵²⁰ EHB (2024): [EHB Implementation Roadmap: Public support as catalyst for hydrogen infrastructure](#)

Offshore pipelines

Table 11-4 Investment cost assumptions of new offshore hydrogen pipelines

Pipeline size (mm)	Pipeline CAPEX (M€/km)	Capacity (MW LHV)	Compression CAPEX (M€/km)	Compressor annual fixed OPEX as % of CAPEX	Pipeline annual fixed OPEX as % of CAPEX	Total CAPEX (€/MW/km)	Total fixed OPEX (€/MW/km/year)
900 (M)	5.44	4700	0.158	1.7%	0.9%	1191.1	11.0
1200 (L)	7.48	13000	0.311	1.7%	0.9%	599.3	5.6

To design investment candidates, we apply the following capacity-weighted average costs derived from Table 11-4: **756.4€/MW/km CAPEX** and **7.0€/MW/km/year for fixed OPEX**.

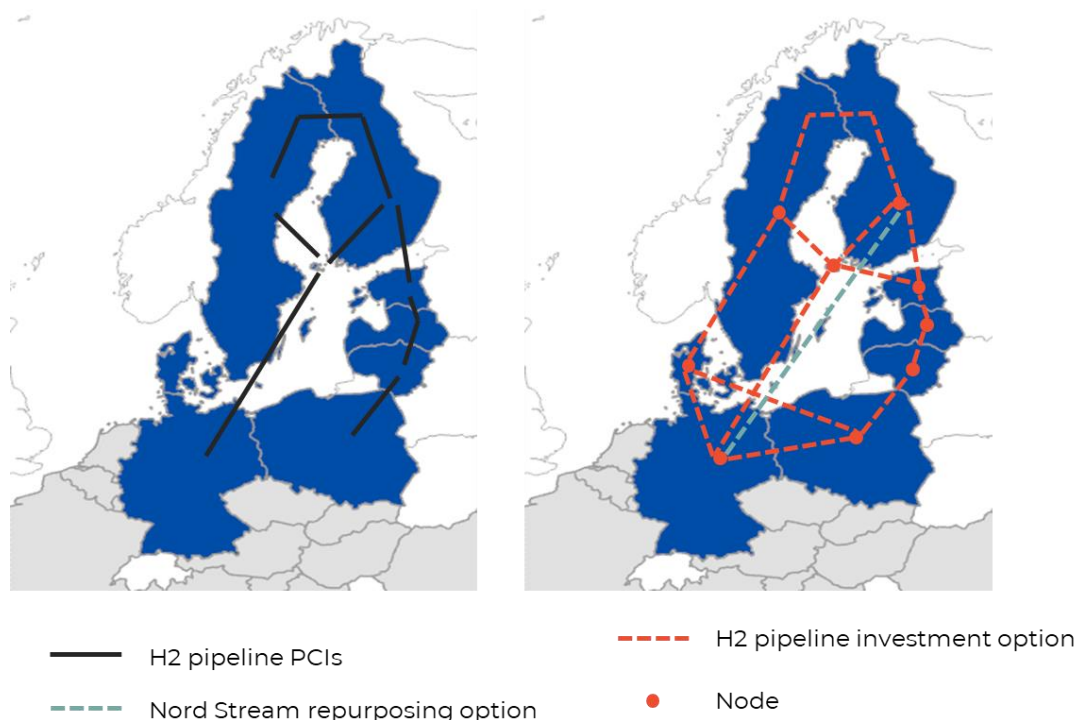
Table 11-5 Investment cost assumptions for repurposed offshore hydrogen pipelines

Pipeline size (mm)	Pipeline CAPEX (M€/km)	Capacity (MW LHV)	Compression CAPEX (M€/km)	Compressor annual fixed OPEX as % of CAPEX	Pipeline annual fixed OPEX as % of CAPEX	Total CAPEX (€/MW/km)	Total fixed OPEX (€/MW/km/year)
900 (M)	1.09	3600	0.068	1.7%	0.9%	321.7	13.9
1200 (L)	1.50	13000	0.311	1.7%	0.9%	139.3	5.6

To design investment candidates, we use the following capacity-weighted average cost derived from Table 11-5: **178.9€/MW/km CAPEX** and **7.4€/MW/km/year for fixed OPEX**. The model also considers the opportunity to repurpose Nord Stream pipelines to transport hydrogen between Finland and Germany, based on the cost assumptions mentioned above.

For each cross-border investment candidate, the cost in €/MW/km is then multiplied by 30% of the distance from capital to capital, following the [methodology in the TYNDP 2024 scenarios](#). However, in the case of the onshore investment candidate between Sweden and Finland, we account for the specific geographic configurations of these countries. Pipeline investment candidates are represented in Figure 11-6 along with the hydrogen pipelines PCIs that are implemented as minimum capacities in the model. Some investment options correspond to borders where there are already existing projects while others correspond to potential projects.

Figure 11-6 Overview of pipeline investment options considered for the modelling



Hydrogen storage

Technical and economic parameters for hydrogen storage facilities are shown in Table 11-6. Variable costs and efficiencies are derived from [Hystories](#) project assumptions, while investment cost estimates are based on both the [GIE Targets UHS Study](#) and the [Gas for climate study on the benefits of a pan-European hydrogen transmission network](#). Consistent with these sources, a weighted average cost of capital (WACC) of 5% is assumed for all storage technologies.

Table 11-6 Technical and economic assumptions for new hydrogen storage facilities

Technology	Type	CAPEX (€/MWh)	Fixed OPEX (€/MWh/yr)	Lifetime (yr)	Round-trip efficiency	Discharge time (hours)
Salt cavern	New	900	36	50	100%	400
Salt cavern	Repurposed	600	36	50	100%	400
Porous media⁵²¹	Repurposed	450	18	50	97%	1000
Tanks	New	33000	660	30	100%	48

The potential for underground hydrogen storage is significantly influenced by geological and technical constraints. In the BEMIP region, only Denmark, Germany and Poland currently have the geological capability to store hydrogen in salt caverns - the most mature technology available for large-scale hydrogen storage. Starting in 2040, hydrogen storage in depleted gas fields or aquifers could also become viable in Denmark, Germany and Poland, as well as Lithuania and Latvia. However, Estonia, Finland and Sweden lack the geological conditions necessary for underground hydrogen storage. Hence, investment candidates for the development of above-ground hydrogen storages (tanks) will only be considered in these countries.

⁵²¹ The porous media category includes both aquifers and depleted gas fields, which share comparable technical and economic characteristics.

Figure 11-7 presents the storage investment candidates considered for the years 2030 and 2040. For the year 2050, the same investment options available in 2040 will still apply, the storage PCIs are also represented (salt caverns projects in Denmark and Germany).

Figure 11-7 Overview of hydrogen storage investment candidates by technology in 2030 and 2040

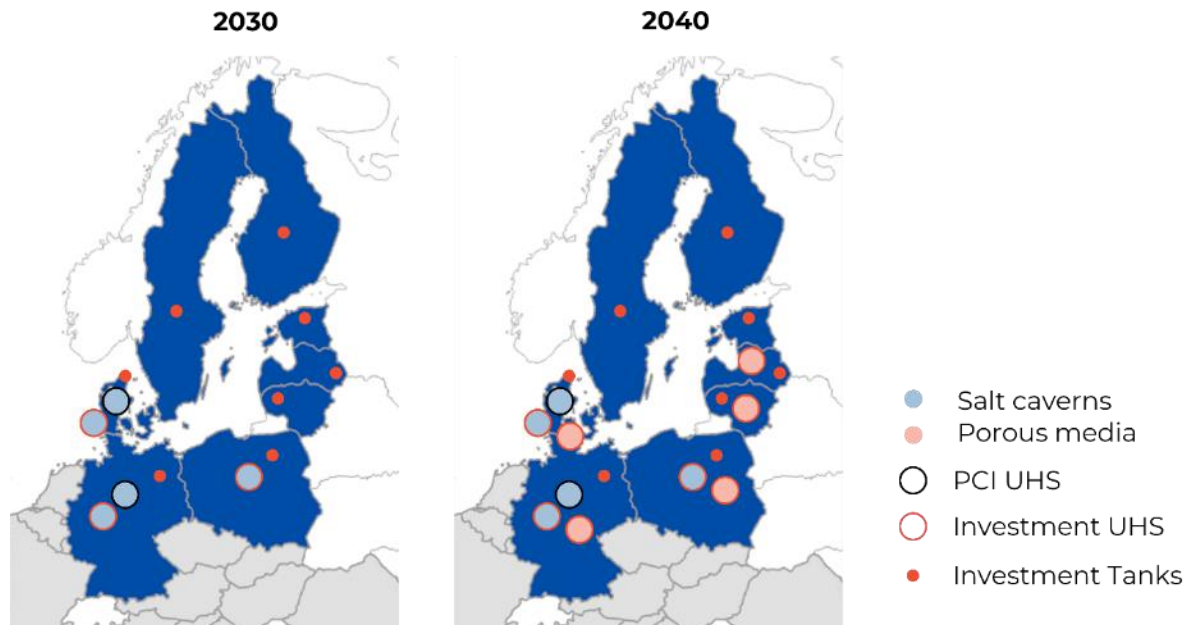
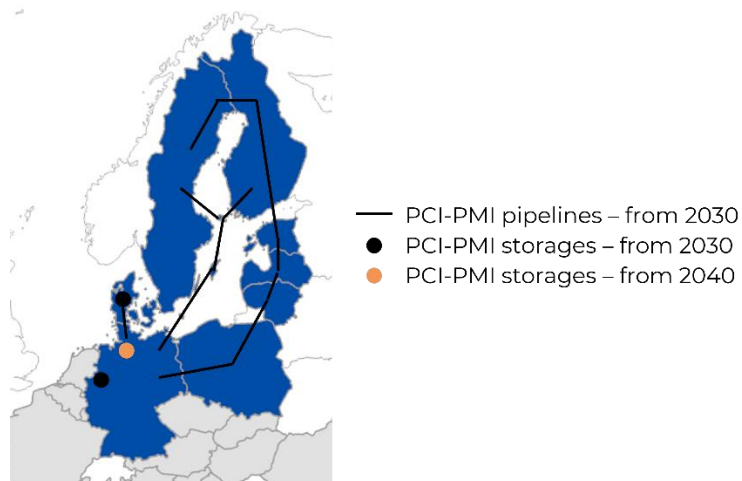


Figure 11-8 Overview of PCI-PMI projects in the BEMIP region





Trinomics B.V.
Mauritsweg 44
3012 JV Rotterdam
The Netherlands

T +31 (0) 10 3414 592

www.trinomics.eu

KvK n°: 56028016
VAT n°: NL/1519.48.662.B01

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